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McCaffree / Citizens For Renewables / Citizens Against LNG
April 25, 2019
Coos Bay File No. 187-18-000153-PLNG-01

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April 25, 2019

City of Coos Bay Planning Commission

RE: City of Coos Bay Application File No. 187-18-000153-PLNG-01 - Concurrent Land Use Applications by Jordan Cove Energy Project L.P. Coos Bay Estuary Channel Navigation Alterations

Dear Coos Bay Planning Commission:

Please accept the following comments into the record concerning the proposed Jordan Cove Channel Navigation Alterations within the City of Coos Bay Zoning Districts.

Jordan Cove's Application proposes:

> (1) Map amendment to the Coos Bay Estuary Management Plan to change the designation of approximately 3.3 acres from 52-NA to DDNC-DA;
> (2) Text amendment to the City of Coos Bay Comprehensive Plan to take a reasons exception to statewide planning goal 16 to authorize the proposed map amendment;
> (3) Estuarine and Coastal Shoreline Uses and Activities Permit for "New and Maintenance Dredging" in the DDNC-DA
> (4) Estuarine and Costal Shoreline Uses and Activities Permit to allow an accessory temporary dredge transport pipeline in the 52-NA, 53-CA, 54-DA and 55-CA Estuarine Zones.

1. Issues with Land Ownership.

Coos Bay City Development Code **17.360.020 Initiation of amendment**.

> *Amendments of the comprehensive plan text or map, zoning map, or this title may be initiated by the following:*
>> *(1) A Type III application, CBDC 17.130.100, Type III procedure, **by one or more owners of the property proposed to be changed** or reclassified consistent with the adopted comprehensive plan; or*
>> *(2) A Type IV legislative process, CBDC 17.130.110, Type IV procedure, by motion of the planning commission and adoption by the city council. [Ord. 503 § 1 (Exh. B), 2018; Ord. 473 § 3 (Exh. A), 2016. Formerly 17.215.020].*

Jordan Cove is taking out land use permits for the Estuary when they are not the legal owner of the Coos Estuary nor do they have **the private right of property acquisition pursuant to ORS Chapter 35.**

The person who signed the application was **Natalie Eades.** She has signed other documents as senior council for Jordan Cove/Pacific Connector, Pembina Pipeline Corporation. (***See Exhibit 1***) Ms Eades essentially works for Pembina, a Canadian Energy Company, via JCEP**.** She is signing statements with respect to the Coos Estuary that say**: "*The undersigned property owner(s) hereby authorizes the filing of this application, and authorizes on site review by staff*."…**

Natalie Eades is NOT a legal owner of the Coos Estuary and she does NOT have legal rights to obtain a zoning compliance letter or change the zoning in the Coos Estuary. The Authorization provided by the Applicant (***See Applicant exhibit 8 page 1***) signed by Oregon Dept of State Lands Director, Vicki Walker, allows for an "application" to be taken out by Jordan Cove but does not specifically allow ownership changes nor does it state that it allows for any map or text amendments in the 52-NA zoning district. In addition, the signed form does not override the authority requirements specified by the City of Coos Bay under Coos Bay Development Code (CBDC) **Chapter 17.360**. The Oregon Dept of State lands is currently reviewing Jordan Cove's application and has yet to sign off on any approvals for the project. (***See Exhibit 2***)

On July 6, 1967, the Oregon Beach Bill[1] was passed by the legislature and signed by Oregon Governor Tom McCall. The Beach Bill declares that all "wet sand" within sixteen vertical feet of the low tide line **belongs to the State of Oregon**. The Beach Bill recognizes public easements of all beach and tidal areas up to the line of vegetation, regardless of underlying property rights. The public has free and uninterrupted use of these areas and property owners are required to seek **state permits** for building and other uses. While some parts of the beach and tidal areas remain privately owned, state and federal courts have upheld Oregon's right to **regulate development** of those lands and preserve public access.[2]

2017 ORS 537.110[3]

> *All water within the state from all sources of water supply **belongs to the public**.*
> (Emphasis added)

Citizens who actually live in Coos County have been trying for some 12 years now to get the natural hazard maps added to the Estuary and Coastal Shoreland zoning districts in Coos County and THAT STILL HAS NOT OCCURRED. And yet, when Jordan Cove wants to make changes to the Estuary zoning districts these applications are processed right away? **There needs to be some kind of investigation into these matters**. The natural hazard maps need to be added to the Coos Estuary and Shoreland zoning districts and Statewide Planning Goal #7, which prohibits the siting of hazardous facilities in identified natural hazard areas, **needs to be enforced by Coos County and the State of Oregon**.

In the matter of Jordan Cove, condemnation authority comes from the Federal Energy Regulatory Commission's (FERC) approval of the "Certificate of Public Convenience and Necessity" under the Natural Gas Act and FERC has not issued Pembina's Jordan Cove Project a Certificate of Public Convenience and Necessity. The "private' Jordan Cove/Pacific Connector Project DOES NOT HAVE THE RIGHT OF EMINENT DOMAIN.

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[1] House Bill 1601, 1967
[2] https://en.wikipedia.org/wiki/Oregon_Beach_Bill
[3] https://www.oregonlaws.org/ors/537.110

We agree with the Lane Council of Governments Condition of Approval #3 with the exception that Jordan Cove must first become the owner of the property and/or have full sign off approval from the Oregon Department of State Lands (DSL). The DSL must issue their final unchallenged approval along with the DEQ under their 208 and 401 water quality permit approvals. A Final Record of Decision must be issued by the Federal Energy Regulatory Commission before any commencement of dredging can occur along with approvals from the Army Corps of Engineers, the Oregon State Water Policy Review Board, the Department of Agriculture, and other State and Federal agencies as deemed necessary including those given notice under Coos Bay City Code 17.352.060 (2), and those specified in Statewide Planning Goal 16 and Coos Bay Estuary Management Plan (CBEMP) **Policy 11.**

2. NEPA Process / Environmental Impact Statement (EIS) must be completed first

Full impacts to all potentially affected waterbodies and coastal shorelands and impacted species connected to those waterbodies and shorelands <u>should be analyzed by a third party independent analyst</u> in a properly completed NEPA process and Environmental Impact Statement long before any additional decisions are made with respect to the proposed project or before any potential approval is given to the project. **Alternatives to the Project <u>do exist</u> and those alternatives are not being considered in this application process.** Several alternatives were submitted to the FERC during scoping. (***See Exhibit 63***)

The construction and operation of the Jordan Cove LNG export terminal and the Pacific Connector Gas Pipeline are entirely dependent on the issuance of an Order for authorization and *Certificate of Public Convenience and Necessity* under sections 3 and 7 of the Natural Gas Act (NGA) and Parts 153 and 380 of the Federal Energy Regulatory Commission's (FERC) regulation. Under existing law, FERC is required to document its decision-making process leading to the issuance **<u>or non-issuance</u>** of the FERC Certificate via an Environmental Impact Statement (EIS) prepared in conformance with National Environmental Policy Act (NEPA) regulations.

The EIS is to "*provide full and fair discussion of significant environmental impacts and shall <u>inform decisionmakers and the public</u> of the reasonable alternatives which would avoid or minimize adverse impacts or enhance the quality of the human environment*" (40 CFR 1502.1) "***<u>Agencies shall not commit resources prejudicing selection of alternatives before making a final decision</u>***" (40 CFR 1502.2(f)) (Emphasis added)

The EIS should "*serve practically as **<u>an important contribution</u>** to the decision-making process and **<u>will not be used</u>** to rationalize or justify decisions already made*." (40 CFR 1502.5) (Emphasis added) An EIS, in and of itself, is not a decision document. Rather, after public review and comment, it is followed up by a formal record of decision (ROD) which documents how and why one of the alternatives analyzed in the EIS was selected for implementation.

By processing Jordan Cove's Land Use Applications prior to the completion of the EIS, the City of Coos Bay is committing agency resources for the Jordan Cove Energy Project and their preferred LNG terminal siting location and pipeline route alternative prior to the final alternative selection by the FERC. The City of Coos Bay would inadvertently be approving a terminal and pipeline design that may **<u>or may not</u>** be the best alternative. The failure to limit the actions of the applicant prior to the completion of the EIS process as called for in existing regulations, clearly demonstrates that the City of Coos Bay's view of the EIS is not as a critical part of the decision process, but rather as a disclosure and justification document relating to a decision that has already been made. This posture is a direct violation of both the letter and intent of the NEPA.

How can the FERC "*have the exclusive authority to approve or deny an application for the siting, construction, expansion, or operation of an LNG terminal*" [15 U.S. Code § 717b(e)(1)] if the Jordan Cove and Pacific Connector project are allowed to process permits for one of the preferred alternatives?

The fact that these applications for Jordan Cove permits and approvals are being processed at this time in advance of Jordan Cove/Pacific Connector FERC publication of a Final EIS tends to lend credence to the following assumptions:

- The Jordan Cove/Pacific Connector applicant, by spending the time, effort, and funding to pursue these Federal, State and County permits in advance of the Final EIS, apparently fully believes the FERC EIS process, when fully undertaken, will result in the issuance of the federal permit. Thus, Jordan Cove fully expects that the EIS will be simply the justification of a pre-conceived action rather than an objective and un-biased analysis of all reasonable alternatives as explicitly called for in existing Federal regulations.

- The City of Coos Bay, FERC, Army Corps, DEQ, DSL, Coos and Douglas Counties, by allowing the processing of these various Federal/State/County permit applications at this time, is demonstrating that it essentially concurs with this <u>violation</u> of the NEPA process.

How can Oregonians be expected to fully participate in the NEPA process by objectively evaluating the range of alternatives that would be provided in a valid EIS if, in fact, Oregon state, County and City agencies have already issued permits and certifications for one of the alternatives beforehand?

3. Evidence provided does not support a Rezone or Text Amendment.

The Coos Bay Development Code states the following: (Emphasis has been added)

CBDC **17.110.040 Purpose.**

> *The purposes of this title are to: implement the Coos Bay comprehensive plan (CBCP);* ***<u>encourage appropriate use of land</u>****;* ***<u>conserve and stabilize the value of property; aid in rendering of fire and police protection; provide adequate open space for all types of recreation</u>****; lessen the congestion on streets; create orderly growth within the city and UGA; distribute population wisely; improve the city's appearance; facilitate adequate provision of urban level utilities and facilities such as water, sewage, electrical distribution, transportation, schools, parks, and other public requirements; and* ***<u>promote public health, safety and general welfare</u>****. [Ord. 503 § 1 (Exh. B), 2018; Ord. 473 § 3 (Exh. A), 2016].* (Emphases added)

CBDC **7.360.010 Comprehensive plan amendment.**

> (*1) The boundaries of the comprehensive plan map designations and the comprehensive plan text may be amended as provided in CBDC 17.360.020.*
>
> *(2) The city may amend its comprehensive plan and/or plan map.* ***<u>The approval body shall consider the cumulative effects of the proposed comprehensive plan and/or map amendments on other zoning districts and uses within the general area</u>****.* ***<u>Cumulative effects include</u>***

sufficiency of capital facilities services, transportation, zone and location compatibility, and other issues related to public health and safety and welfare the decision-making body determines to be relevant to the proposed amendment*. [Ord. 503 § 1 (Exh. B), 2018; Ord. 473 § 3 (Exh. A), 2016. Formerly 17.215.010].* (Emphases added)

CBDC **17.360.015 Zoning text and map amendment**.

The boundaries of the zoning districts established on maps by this title, the classification of uses therein, or other provisions of the title may be amended as provided in CBDC 17.360.020. [Ord. 503 § 1 (Exh. B), 2018; Ord. 473 § 3 (Exh. A), 2016. Formerly 17.215.015].

CBDC **17.360.020 Initiation of amendment**.

Amendments of the comprehensive plan text or map, zoning map, or this title may be initiated by the following:

(1) A Type III application, CBDC 17.130.100, Type III procedure, by ***one or more owners of the property*** *proposed to be changed or reclassified consistent with the adopted comprehensive plan; or*

(2) A Type IV legislative process, CBDC 17.130.110, Type IV procedure, by motion of the planning commission and adoption by the city council. [Ord. 503 § 1 (Exh. B), 2018; Ord. 473 § 3 (Exh. A), 2016. Formerly 17.215.020].
(Emphases added)

CBDC **17.360.060 Approval criteria.**

(1) For a Type III or Type IV review, the city council shall approve the proposal upon finding that:

(a) The proposed amendment is consistent with the applicable policies of the comprehensive plan or that a significant change in circumstances requires an amendment to the plan or map;

(b) ***The proposed amendment is in the public interest****; and*

(c) Approval of the amendment will not result in a decrease in the level of service for capital facilities and services identified in the Coos Bay capital improvement plan(s). [Ord. 503 § 1 (Exh. B), 2018; Ord. 473 § 3 (Exh. A), 2016. Formerly 17.215.060].
(Emphases added)

CBDC **17.360.080 Concomitant rezone**.

(1) Rezone Agreements.

(a) The purpose of this subsection is to allow for the implementation of the comprehensive plan policies relating to future commercial centers and industrial developments, as appropriate and consistent with the Coos Bay comprehensive plan and Coos Bay capital improvement plan. If, from the facts presented, and the findings, report and recommendations of the planning commission as required by this section thereof, ***the city council determines that the public health, safety and general welfare will be best served by a proposed change of zone****, the city council may indicate its general approval, in principle, of the proposed rezoning by the*

adoption of a "resolution of intent to rezone" the area involved. This resolution shall include any conditions, stipulations or limitations which the city council may feel necessary to require in the public interest as a prerequisite to final action. The fulfillment of all conditions, stipulations and limitations contained in said resolution, on the part of the applicant, shall make such a resolution a binding commitment on the city council. Such a resolution shall not be used to justify spot zoning, to create unauthorized zoning categories by excluding uses otherwise permitted in the proposed zoning, or by imposing setback, area or lot coverage restrictions not specified in the code for the zoning classification, or as a substitute for a variance.

Upon completion of compliance action by the applicant, the city council shall, by ordinance, effect such rezoning. The failure of the applicant to meet any or all conditions, stipulations or limitations contained in the resolution, including the time limit placed in the resolution, shall render the resolution of intent to rezone null and void, unless an extension is granted by the city council upon recommendation of the planning commission. Generally, the time limitation shall be one year. The city council may grant one one-year extension, after which the resolution shall be null and void if all conditions, stipulations and limitations have not been met by the applicant.

(b) Concomitant Rezone Agreements.

(i) Purpose. The purpose of this subsection is to explicitly provide for the use of agreements concomitant to rezone approvals. ***<u>The agreement may call for performance by the applicant which is directly related to public needs which may be expected to result from the proposed usage of the property</u>****.* ***<u>The performance called for will mitigate the public burden in meeting those resulting needs by placing it more directly on the party whose property use will give rise to such needs</u>****. The agreement shall generally be in the form of a covenant running with the land. The provisions of the agreement shall be in addition to all other pertinent CBDC requirements.*

(ii) Applicability. This agreement process will not generally be used for rezones to residential zoning districts. It may, however, be used in any situation where extraordinary potential adverse impacts from a proposed rezone may be neutralized by the agreement. The agreement process may be employed for rezones in sensitive geographic areas or areas such as critical transportation corridors. The agreement process will generally be used for rezones to commercial, industrial, and non-single-family residential not specifically identified by the comprehensive plan map. The intent is that concomitant rezone agreements shall only be used when normal review and approval procedures are not adequate to resolve the specific issues involved in the rezone proposal.

(iii) ***<u>Mitigating Measures. The agreement may include mitigating measures</u>****, ...*
*   *   *   *
(Emphases added)

ORS 196.805

(1) The protection, conservation and best use of the water resources of this state are matters of the utmost public concern. Streams, lakes, bays, estuaries and other bodies of water in this state, including not only water and materials for domestic, agricultural and industrial use but also habitats and spawning areas for fish, avenues for transportation and sites for commerce

and public recreation, are vital to the economy and well-being of this state and its people. ***Unregulated removal of material from the beds and banks of the waters of this state may create hazards to the health, safety and welfare of the people of this state. Unregulated filling in the waters of this state for any purpose, may result in interfering with or injuring public navigation, fishery and recreational uses of the waters****. In order to provide for the best possible use of the water resources of this state, it is desirable to centralize authority in the Director of the Department of State Lands, and implement control of the removal of material from the beds and banks or filling of the waters of this state.*

(2) The director shall take into consideration all beneficial uses of water including streambank protection when administering fill and removal statutes.

(3) ***There shall be no condemnation, inverse condemnation, other taking, or confiscating of property under ORS 196.600*** *(Definitions for ORS 196.600 to 196.655) to 196.905 (Applicability)* ***without due process of law****. [Formerly 541.610 and then 196.675; 2003 c.738 §16; 2012 c.108 §7]*
(Emphases added)

Oregon's Statewide Planning GOAL 16 (OAR 660-015-0010(1))[4] requires Oregon:

To recognize and protect the unique environmental, economic, and social values of each estuary and associated wetlands; and

To protect, maintain, where appropriate develop, and where appropriate restore the long -term environmental, economic, and social values, diversity and benefits of Oregon's estuaries…

… Estuary plans and activities ***shall protect the estuarine ecosystem****, including its natural biological productivity, habitat, diversity, unique features and water quality.*

The general priorities (from highest to lowest) for management and use of estuarine resources as implemented through the management unit designation and permissible use requirements listed below shall be:

1. Uses which maintain the integrity of the estuarine ecosystem;
2. Water-dependent uses requiring estuarine location, as consistent with the overall Oregon Estuary Classification;
3. Water-related uses which do not degrade or reduce the natural estuarine resources and values;
4. Nondependent, nonrelated uses which do not alter, reduce or degrade estuarine resources and values

* * * *

IMPLEMENTATION REQUIREMENTS
…2. Dredging and/or filling ***shall be allowed only****: a. If required for navigation or other water-dependent uses that require an estuarine location or if specifically allowed by the applicable management unit requirements of this goal; and, b.* ***If a need (i.e., a substantial public benefit) is demonstrated and the use or alteration does not unreasonably interfere with public trust***

[4] http://www.oregon.gov/LCD/docs/goals/goal16.pdf

rights; and c. If no feasible alternative upland locations exist; and, d. If ***adverse impacts are minimized***. Other uses and activities which could alter the estuary shall only be allowed if the requirements in (b), (c), and (d) are met. All or portions of these requirements may be applied at the time of plan development for actions identified in the plan. Otherwise, they shall be applied at the time of permit review.*

3. State and federal agencies shall review, revise, and implement their plans, actions, and management authorities to maintain water quality and minimize man-induced sedimentation in estuaries. ***Local government shall recognize these authorities in managing lands rather than developing new or duplicatory management techniques or controls****. Existing programs which shall be utilized include:*

a. The Oregon Forest Practices Act and Administrative Rules, for forest lands as defined in ORS
527.610-527.730 and 527.990 and the Forest Lands Goal;
b. The programs of the Soil and Water Conservation Commission and local districts and the Soil Conservation Service, for Agricultural Lands Goal;
c. The nonpoint source discharge water quality program administered by the Department of
Environmental Quality under Section 208 of the Federal Water Quality Act as amended in 1972 (PL92-500); and
d. ***The Fill and Removal Permit Program administered by the Division of State Lands under ORS 541.605 -541.665****.*

4. The State Water Policy Review Board, assisted by the staff of the Oregon Department of Water Resources, and the Oregon Department of Fish and Wildlife, the Oregon Department of Environmental Quality, the Division of State Lands, and the U.S. Geological Survey, shall consider establishing minimum fresh-water flow rates and standards so that resources and uses of the estuary, ***including navigation, fish and wildlife characteristics, and recreation, will be maintained****.*
(Emphases added)
[Oregon GOAL 16: Estuarine Resources pages 1 and 2.]

Statewide Planning Goal 2 states:

PART II -- EXCEPTIONS
A local government may adopt an exception to a goal when:
(a) The land subject to the exception is physically developed to the extent that it is no longer available for uses allowed by the applicable goal;
(b) The land subject to the exception is irrevocably committed to uses not allowed by the applicable goal because existing adjacent uses and other relevant factors make uses allowed by the applicable goal impracticable; or
(c) The following standards are met:
(1) ***Reasons justify why the state policy embodied in the applicable goals should not apply****;*
(2) ***Areas which do not require a new exception cannot reasonably accommodate the use;***
(3) ***The long-term environmental, economic, social and energy consequences*** *resulting from the use of the proposed site* ***with measures designed to reduce adverse impacts*** *are not significantly more adverse than would typically result from the same proposal being located in areas requiring a goal exception other than the proposed site; and*

*(4) **The proposed uses are compatible with other adjacent uses or will be so rendered through measures designed to reduce adverse impacts.***

*   *   *   *

Upon review of a decision approving or denying an exception:

(a) The commission shall be bound by any finding of fact for which there is substantial evidence in the record of the local government proceedings resulting in approval or denial of the exception;
(b) The commission shall determine whether the local government's findings and reasons demonstrate that the standards for an exception have or have not been met; and
(c) The commission shall adopt a clear statement of reasons which sets forth the basis for the determination that the standards for an exception have or have not been met.

*   *   *   *

(Emphases added)

Provisions of OAR 660-004-0022 Reasons Necessary to Justify an Exception Under Goal 2, Part II(c), must be followed:

An exception under Goal 2, Part II(c) may be taken for any use not allowed by the applicable goal(s) or for a use authorized by a statewide planning goal that cannot comply with the approval standards for that type of use. The types of reasons that may or may not be used to justify certain types of uses not allowed on resource lands are set forth in the following sections of this rule. Reasons that may allow an exception to Goal 11 to provide sewer service to rural lands are described in OAR 660-011-0060. Reasons that may allow transportation facilities and improvements that do not meet the requirements of OAR 660-012-0065 are provided in OAR 660-012-0070. Reasons that rural lands are irrevocably committed to urban levels of development are provided in OAR 660-014-0030. Reasons that may justify the establishment of new urban development on undeveloped rural land are provided in OAR 660-014-0040.

*   *   *   *

*(7) Goal 16 — Water-Dependent Development: To allow water-dependent industrial, commercial, or recreational uses that require an exception in development and conservation estuaries, **an economic analysis must show that there is a reasonable probability that the proposed use will locate in the planning area during the planning period, considering the following**:*

> *(a) Goal 9 or, for recreational uses, the Goal 8 Recreation Planning provisions;*
> *(b) The generally predicted level of market demand for the proposed use;*
> *(c) The siting and operational requirements of the proposed use including land needs, and as applicable, moorage, water frontage, draft, or similar requirements;*
> *(d) Whether the site and surrounding area are able to provide for the siting and operational requirements of the proposed use; and*
> *(e) The economic analysis must be based on the Goal 9 element of the County Comprehensive Plan and must consider and respond to all economic needs information available or supplied to the jurisdiction. The scope of this analysis will depend on the type of use proposed, the regional extent of the market and **the ability of other areas to provide for the proposed use.***

> *(8) Goal 16 – Other Alterations or Uses: An exception to the requirement limiting dredge and fill or other reductions or degradations of natural values to water-dependent uses or to the natural and conservation management unit requirements limiting alterations and uses is justified, where consistent with ORS chapter 196, in any of the circumstances specified in subsections (a) through (e) of this section:*
>
> > *(a) Dredging to obtain fill for maintenance of an existing functioning dike where an analysis of alternatives demonstrates that other sources of fill material, including adjacent upland soils or stockpiling of material from approved dredging projects, cannot reasonably be utilized for the proposed project or that land access by necessary construction machinery is not feasible;*
> > *(b) Dredging* ***to maintain adequate depth*** *to permit continuation* ***of the present level of navigation*** *in the area to be dredged;*
> > *(c) Fill or other alteration for a new navigational structure where both the structure and the alteration are shown to be necessary for the continued functioning of an existing federally authorized navigation project such as a jetty or a channel;*
> > *(d) An exception to allow minor fill, dredging, or other minor alteration of a natural management unit for a boat ramp or to allow piling and shoreline stabilization for a public fishing pier;*
> > *(e) Dredge or fill or other alteration for expansion of an existing public non-water-dependent use or a nonsubstantial fill for a private non-water-dependent use (as provided for in ORS 196.825) where:*
> >
> > *(A) A Countywide Economic Analysis based on Goal 9 demonstrates that additional land is required to accommodate the proposed use;*
> > *(B) An analysis of the operational characteristics of the existing use and proposed expansion demonstrates that the entire operation or the proposed expansion cannot be reasonably relocated; and*
> > *(C) The size and design of the proposed use and the extent of the proposed activity are the minimum amount necessary to provide for the use.*
> >
> > *(f)* ***In each of the situations set forth in subsections (7)(a) to (e) of this rule, the exception must demonstrate that the proposed use and alteration (including, where applicable, disposal of dredged materials) will be carried out in a manner that minimizes adverse impacts upon the affected aquatic and shoreland areas and habitats****.*
> > (Emphases added)

Environmental and Economic analysis have yet to be provided by the Applicant and the Findings provided in the staff report are totally inadequate to satisfy the requirements of the code for a Conditional Use and/or an Exception to a Use. Jordan Cove has not met the criteria noted above in order to be given an Exception to the Goals and does not meet the protection requirements in the various zoning districts as clearly shown in more detail further below. They have provided no mitigation plans or evidence as to how they would protect the resources in the various zoning districts they would be impacting.

4. Application must be in compliance with Coastal Zone Management Act / Estuary Protection Act

Changes to the Coos Bay Estuary must be in line with the Coastal Zone Management Act. This is not just a local decision but also a State and Federal decision. Statewide Planning Goals 16, 17 and 18 are based on the protection requirements that are spelled out in the Coastal Zone Management Act and the Estuary Protection Act. **Once the Coos Bay Estuary Management Plan has been approved by the National Oceanic and Atmospheric Administration (NOAA) it cannot be changed without the Oregon Dept of Land Conservation and Development (DLCD) and NOAA's approval**. Jordan Cove cannot just come in here and do what they want to the Estuary or the Coastal Shoreland areas. Changes in those areas require extra State and Federal approvals in order to protect the integrity of the estuary.

The Coos Bay Estuary is the sixth largest estuary on the Pacific coast of the contiguous United States and the largest estuary completely within Oregon state lines. The Coos estuary is one of only 28 National Estuarine Research Reserves in the United States.[5] The process for federal designation of a National Estuarine Research Reserve has many steps and involves many individuals and organizations. Established by the Coastal Zone Management Act of 1972, as amended, the reserve system is a partnership program between the National Oceanic and Atmospheric Administration (NOAA) and the coastal states. The Coastal Zone Management Act of 1972, as Amended, is clear:

§ 1452. Congressional declaration of policy (Section 303) states:

The Congress finds and declares that it is the national policy--

1) **to preserve, protect**, develop, **and where possible, to restore or enhance, the resources of the Nation's coastal zone for this and succeeding generations**; (Emphasis added)

2) to encourage and **assist the states** to exercise effectively their responsibilities in the coastal zone through the development and implementation of management programs to achieve wise use of the land and water resources of the coastal zone, **giving full consideration to ecological, cultural, historic, and esthetic values** as well as the needs for compatible economic development, which programs should at least provide for-- (Emphasis added)

   2(A) **the protection of natural resources, including wetlands, floodplains, estuaries, beaches, dunes, barrier islands, coral reefs, and fish and wildlife and their habitat, within the coastal zone**, (Emphasis added)

   2(B) the management of coastal development **to minimize the loss of life and property caused by improper development** in flood-prone, storm surge, geological hazard, and erosion-prone areas and in areas likely to be affected by or vulnerable to sea level rise, land subsidence, and saltwater intrusion, and by the destruction of natural protective features such as beaches, dunes, wetlands, and barrier islands,

   2(C) the management of coastal development to improve, safeguard, and restore the quality of coastal waters, and to protect natural resources and existing uses of those waters.

[5] National Estuarine Research Reserve System (NERRS): http://estuaries.noaa.gov/About/Default.aspx?ID=116

These laws as well as many others also listed in this act need to be fully considered and evaluated in with this Permit Application. The law demands protection and public access to the coastal areas for recreation purposes and assistance in the redevelopment of deteriorating urban waterfronts and ports, and sensitive preservation and restoration of historic, cultural, and esthetic coastal features.

Coos Bay consists of about 14,000 acres of varied intertidal and subtidal substrate habitat conditions including algae beds, eelgrass sites, marshlands, and mostly unconsolidated substrate. The upper Coos Bay estuarine habitat contains important rearing habitat supplied by estuarine wetlands, algae, and eelgrass beds, which are important conditions for estuarine fish and migratory salmon, as well as commercial oyster beds and other marine habitat including a variety of birds. One-third of Oregon wetlands are estimated to have been lost since the late 1700s. **Wetlands are now protected under federal law**

Estuaries are the most important and dynamic habitat type known on earth; where fresh and saline waters mix, creating natural resource biomass far exceeding all others. Recent signs show improvement or biological recuperation of the Coos Bay estuary but despite this the estuary is still listed as a 303D limited waterbody **so the protection codes must apply**. The proposed channel alterations being proposed by the **Jordan Cove / Pacific Connector LNG development would cause irreplaceable and irretrievable ecosystem change.**

If waterbodies and wetlands are destroyed or degraded even by temporary workspace, depending on mitigation, they may never recover to their former character or it may take 5 years or more to do so. The loss of primary productivity and nutrient distribution is permanent and not temporary. **Proper Environmental studies have not been done by the applicant and are necessary in order to proceed. If a potential risk to the survival or recovery of a threatened or endangered species exists, the applicant must redesign or relocate the facility to avoid that risk or propose appropriate mitigation measures**.[6] (***See Exhibits 3, 4, 9, 10 and 12 to 16***)

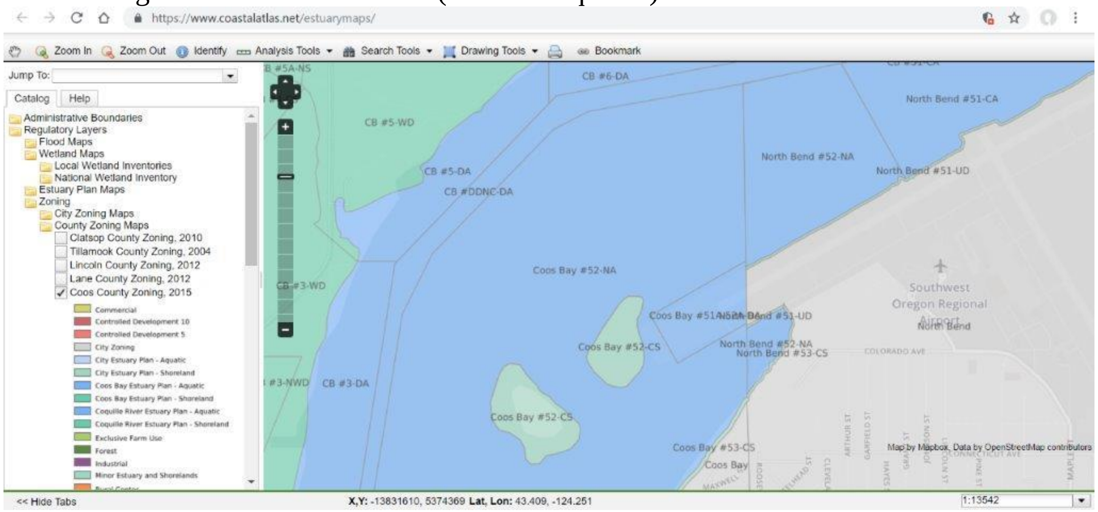
5. Proposed Dredging/Fill is not in compliance with Land Use

In addition to the proposed channel alteration to excavate 3.3 acres from 52-NA to DDNC-DA in submerged areas lying adjacent to the federally-authorized Channel, the applicant has also proposed other channel alterations with Coos County (10.53 Acres of 2-NA, 2.18 Acres of 3-DA, and 10.51 Acres of 59-CA to DDNC-DA). The Jordan Cove Energy Project (JCEP) also has plans to remove 5.7 million cubic yards of material for their proposed marine terminal and access channel along with plans to excavate another submerged area for eel grass mitigation within the City of Coos Bay zoning boundary. According to Jordan Cove, proposed channel alterations will allow for transit of LNG vessels of similar overall dimensions to those listed in the July 1, 2008 USCG Waterway Suitability Report, but under a broader weather window.

In the current application, Jordan Cove wants to excavate and dredge in a Coos Estuary "Natural Aquatic" zoned area which only allows new dredging in order to dredge a small channel on the north side of the proposed airport fill as necessary to maintain tidal currents. In addition, this activity is only allowed subject to a finding that adverse impacts have been minimized.

[6] Endangered Species Act; Army Corps Standard Local Operating Procedures for Endangered Species (SLOPES).

JCEP Dredge area #4 zoned **52-NA** (Natural Aquatic)



City of Coos Bay Estuary Management Plan Zoning District:
52-NA

MANAGEMENT OBJECTIVE:
This aquatic unit contains extensive eelgrass beds with associated fish and waterfowl habitat, and shall accordingly be managed to maintain these resources in their natural condition in order to protect their productivity. (Emphasis added)

Dredging of a small channel on the north side of the proposed airport fill shall be necessary as a form of mitigation to maintain tidal currents.

Maintenance only of the existing sewage treatment plant outfall shall be permitted.

2. Dredging
   a. New… *
   b. Maintenance Dredging of Existing Facilities… N [Not Allowed]
   c. To Repair Dikes and Tidegates… N/A

* * * *

10. Temporary Alterations *

   Activity
   2a New dredging shall be allowed only to dredge a small channel on the north side of the proposed airport fill as necessary to maintain tidal currents. In addition, this activity is only allowed subject to a finding that adverse impacts have been minimized (see Policy #5).
   * * * *
   10, 11 This use is only allowed subject to the making of resource capability consistency findings and impact assessments (see Policy #4a).

City of Coos Bay Estuary Management Plan Zoning District:
53-CA

MANAGEMENT OBJECTIVE:
This unit shall be managed to (1) conserve its aquatic resources, and (2) to permit subtidal log storage in support of the mill to the south of the unit.

2. Dredging
    a. New N [Not Allowed]

* * * *

11. Temporary Alterations *

    Activity

    11,12 The use is allowed when it is established that the use is consistent with the resource capabilities of the area and the purposes of the management unit. (See Policy 4a.)

City of Coos Bay Estuary Management Plan Zoning District:
54-DA

MANAGEMENT OBJECTIVE:
This aquatic segment shall be managed to maintain water access for water-dependent/related industrial and recreational uses located in the upland

2. Dredging
    a. New *

* * * *

5. Navigational Structures * [listed due to <u>no listing</u> for Temporary Alterations]

    Activity

    1b, 2a, These activities are only allowed subject to finding that adverse impacts have
    b, 4,5 been minimized (see Policy #5); and to Policy #8 requiring mitigation.

City of Coos Bay Estuary Management Plan Zoning District:
55-CA

MANAGEMENT OBJECTIVE:
This aquatic segment shall be managed to allow recreational uses consistent with aquatic resource characteristics.

2. Dredging
    a. New N [Not Allowed]

* * * *

5. Navigational Structures N [Not Allowed]

ZONING DESIGNATION: DDNC-DA
GENERAL LOCATION: LOWER BAY/UPPER BAY
ZONING DISTRICT: Deep-Draft Navigation Channel (37' authorized draft)

CBEMP SECTION 3.2.201. MANAGEMENT OBJECTIVE:

This district shall be regularly maintained to authorized depths as the deep-draft navigation channel. Conflicting uses and activities are not permitted.

* * * *

2. Dredging
   a. New ACU-S, G [Allowed subject to Administrative Conditional Use – Special Conditions and General Conditions]
   b. Maintenance dredging of existing facilities ACU-S, G
   c. To repair dikes and tidegates N/A

3. Dredge Material Disposal ACU-S,G

* * * *

12. Temporary alterations P-G

* * * *

GENERAL CONDITIONS [G] (**the following conditions apply to ALL uses and activities**):

1. Inventoried resources requiring mandatory protection in this unit shall be protected, and is subject to Policies #17 and #18.

Activities: (ACU-S)

2a., 2b. **These activities are only allowed subject to finding that adverse impacts have been minimized (see Policy #5).** (Emphasis added)

1. Flow-lane disposal may be permitted, pursuant to Policies #46 and #46a.

* * * *

Any changes to the Coos Bay Estuary Management Plan (CBEMP) zoning districts or any impacts to the zoning districts must be in compliance with the other resource preservation and protection policies established elsewhere in the CBEMP. You cannot just pick and chose the sections you want to follow while ignoring everything else. That is not how the Plan is to be followed. The Resource productivity of the Coos Bay Estuary must be maintained as established by Statewide Planning Goals 16, 17 and 18. Jordan Cove's proposed map amendment cannot throw out the resource protection requirements and other process requirements spelled out in the Goals.

CBEMP 3.2 POLICY DEFINITIONS:

DREDGED MATERIAL DISPOSAL:

The deposition of dredged material in aquatic or upland areas. Methods of disposal include in-water disposal, beach and land disposal, and ocean disposal. In-Water Disposal is the deposition or dredged materials in a body of water. Ocean Disposal is the deposition or dredged materials in the ocean. Beach Disposal is the deposition of dredged materials in *beachfront areas west of the foredunes. Land Disposal is the deposition of dredged materials landward of the line of non-aquatic vegetation, in "upland" areas.*

DREDGING:

The removal of sediment or other material from a stream, river, estuary or other aquatic area. Maintenance Dredging refers to dredging necessary to maintain functional depths in maintained channels, or adjacent to existing docks and related facilities; New Dredging refers to deepening either an existing authorized navigation channel or deepening a natural channel, or to create a marina or other dock facilities; Dredging to Maintain Dikes and Tide gates refers to dredging necessary to provide material for existing dikes and tide gates; Minor Dredging refers to small amounts of removal as necessary, for instance, for a boat ramp. Minor dredging may exceed 50 cubic yards, and therefore, require a permit.

TEMPORARY ALTERATION:

Dredging, filling, or another estuarine alteration occurring over a specified short period of time which is needed to facilitate a use allowed by an acknowledged plan. Temporary alterations may not be for more than three years and the affected area must be restored to its previous condition. Temporary alterations include: (1) alterations necessary for federally authorized navigation projects (e.g., access to dredged material disposal sites by barge or pipeline and staging areas or dredging for jetty maintenance), (2) alterations to establish mitigation sites, alterations for bridge construction or repair and for drilling or other exploratory operations, and (3) minor structures (such as blinds) necessary for research and educational observation.

CB - CBEMP Policy 4a. Deferral of (A) Resource Capability Consistency Findings and (B) Resource Impact Assessments

Local government shall defer, until the time of permit application, findings regarding consistency of the uses/activities listed in Policy #4 with the resource capabilities of the particular management segment.

Additionally, the impact assessment requirement for those uses/activities as specified in Policy #4 shall be performed concurrently with resource capability findings above at the time of permit application.

This strategy shall be implemented through an administrative conditional use process that includes local cooperation with the appropriate state agencies *such that:*

A. Where aquaculture is proposed as a use, local government shall notify the Oregon Department of Fish and Wildlife (ODFW) in writing of the request, together with a map of the proposed site;

B. Where log storage dredging is proposed as an activity, local government shall notify the Oregon Department of Environment Quality)DEQ) in writing of the request, together with a map of the proposed site.

* * * *

For all other uses/activities specified above, local government shall determine appropriate findings whether the proposed use/activity is consistent with the resource capabilities of the management segment and shall perform the assessment of impacts required by Policy #4.

This strategy recognizes:

A. that resource capability consistency findings and impact assessments as required by LCDC Goal #16 can only be made for the uses specified above at the time of permit application, and

B. that the specified state agencies have expertise appropriate to assist local government in making the required finding and assessments.

This strategy is based upon the recognition that the need for and cumulative effects of estuarine developments were fully addressed during development of this Plan and that no additional findings are required to meet Implementation Requirement #1 of Goal #16.
(Emphasis added)

CB - CBEMP Policy 5 Estuarine Fill and Removal (Emphasis added)

Dredging and/or filling shall be allowed only:

A. If required for navigation or other water-dependent uses that require an estuarine location or if specifically allowed by the applicable management unit requirements of this goal; and
B. If no feasible alternative upland location exists; and
*C. **If a pubic need (i.e., a substantial public benefit) is demonstrated and the use or alteration does not unreasonably interfere with public trust rights**; and*
*D. **If adverse impacts are minimized**; and*
*E. **The activity is consistent with the objectives of the Estuarine Resources Goal and with other requirements of state and federal law**, specifically the conditions in ORS541.615 and Section 404 of the Federal Water Pollution Control Act (P.L. 92-500).*

***Other uses and activities which could alter the estuary shall only be allowed if the requirements in B, C, and D are met**. All portions of these requirements may be applied at the time of plan development for actions identified in the Plan. Otherwise, they shall be applied at the time of permit review.*

*This strategy shall be implemented by the preparation of findings by local government documenting that such proposed actions are consistent with the Comprehensive Plan, and with criteria "a" through "e" above. However, **where goal exceptions are included within this plan, the findings in the exception shall be sufficient to satisfy criteria "a" through "c" above**. Identification and minimization of adverse impacts as required in "d" above **shall follow the procedure set forth in Policy #4a**. The findings shall be developed in response to a "request for comment" by the Division of State Lands, which shall seek local government's determination regarding the appropriateness of a permit to allow the proposed action.*

*"Significant," as used in "other significant reduction or degradation of natural estuarine values," **shall be determined by**:*

A. The U.S. Army Corps of Engineers through its Section 10 and 404 permit processes; or
B. The Department of Environmental Quality for approvals of new aquatic log storage areas only; or
C. The Department of Fish & Wildlife for new aquaculture proposals only.

This strategy recognizes that Goal #16 limits dredge, fill and other estuarine degradation in order to protect the integrity of the estuary.

A need (ie., a substantial public benefit) has not been demonstrated by the applicant. The project would unreasonably interfere with navigation, fishing and public recreation, as explained in more detail further below, and would therefore not be in compliance with CBEMP Policy 5(C). Jordan Cove's proposed use/activity is not consistent with the resource capabilities of the management segment and no assessment of impacts required by CBEMP Policy #4 has been done. CBEMP Policy 5 is an important CBEMP Policy that applies to **all Estuarine Fill and Removal**. Policy 5 requires that "*a need (ie., a substantial public benefit) is demonstrated and the use or alteration does not unreasonably interfere with public trust rights*." Policy 5 also requires that a determination be made that proves: D. *Adverse impacts are minimized*. **These requirements must be demonstrated before an exception is allowed**. (**OAR 660-004-0022)**

The applicant seems to think that all they need for an exception is the testimony of a Coos Bay Bar Pilot saying the channel modifications would improve shipping. At a recent public meeting that occurred on March 21, 2019, in Coos Bay, Captain George Wales from the Coos Bay Pilots Association made the statement that there are roughly 5 vessel calls per month on the Port of Coos Bay. The Port of Coos Bay's Annual Report for 2017 indicates there were around 8 calls in 2017.[7] The real reason for the current request is spelled out in Captain Wales' letter filed by the applicant in with their application (***See Applicant's Exhibit 3 page 3***) in which he states, "*The Pilots believe the proposed NRI's are essential for achieving the **required number of LNG vessel transits needed** to lift the JCEP design annual LNG production volume. JCEP has informed the Pilots that excessive delays in LNG Carrier transits to and from the LNG terminal could result in a **shore storage tank topping situation**, requiring the project to curtail production of LNG…*" (July 25, 2018 letter from Coos Bay Pilots Association - Emphasis added) So this is **ALL about what is best for Jordan Cove and not necessarily what is best for other users or uses of the Coos Bay Estuary.**

Jordan Cove has agreements with the Roseburg Forest Products Company to use some of their property on the North Spit for an undisclosed amount of $$. It must be considerable considering the extreme hazards the LNG project presents to this chip facility and their 17 or so employees.[8] On the other hand, a 2008 study by the Oregon State Marine Board (OSMB) found that recreational boaters in Coos Bay took a total of 31,560 boat trips the previous year. Nearly 90 percent of the boat use days involved fishing. In a March 2016 KCBY news article, Richard Dybevik, with Roseburg Forest Products Company, stated that the **lower bay is always crowded with boats during the summer** and that he has counted as many as 100 boats in that area at one time.[9] (***See Exhibit 42***) **The negative impacts to fishing, crabbing and shellfish habitat would be a significant impact on all those boat users and the fishing industry as a whole.**

CB - CBEMP Policy 5a. Temporary Alterations

> *Local government shall support as consistent with this Plan (**without taking exception to the Statewide Planning Goals**) temporary alterations to areas and resources that the Goal otherwise requires to be preserved or conserved. **This exemption is limited to alterations in support of uses permitted by Goal 16; it is not intended to allow uses which are not otherwise permitted by the Goal**. Such actions shall be limited to the following:*

[7] Oregon International Port of Coos Bay Annual Report 2018 – Maritime https://www.oipcbannualreport18.com/maritime
[8] https://theworldlink.com/news/local/who-pays-the-most/article_37797b7c-4711-5608-869b-19dc0ee4e389.html
[9] *After a year of planning, Coos Bay has new marine patrol boat dock;* by KCBY; Wednesday, March 16th 2016 https://kcby.com/news/local/after-a-year-of-planning-coos-bay-has-new-marine-patrol-boat-dock

A. Alterations necessary for federally authorized Corps of Engineers projects, such as access to dredged material disposal sites by barge or pipeline, or staging areas or dredging required for jetty maintenance;
B. Alterations necessary for access to dredged material disposal site, for mitigation actions, for bridge construction or repair, and for drilling or other exploration operations;
C. Alterations necessary to install pipelines for utilities and communication facilities.

Further, application of the resource capabilities test to temporary alterations should ensure:

*A. **That the short-term damage to resources is consistent with resource capabilities of the area**; and*
*B. **That the area and affected resources can be restored to their original condition**.*

Mitigation shall not be required by this Plan for such temporary alterations.

This policy shall be implemented through the administrative conditional use process and through local review and comment on state and federal permit applications.

This policy is based on the recognition that temporary estuarine fill and habitat alterations are frequently legitimate actions when in conjunction with jetty repair and other important economic activities. It is not uncommon for projects to need staging areas and access that require temporary alteration to habitat that is otherwise protected by the Plan.
(Emphasis added)

CB - CBEMP Policy 8 Estuarine Mitigation Requirements

Local government recognizes that mitigation shall be required when estuarine dredge or fill activities are permitted in inter-tidal or tidal marsh areas. The effects of the dredge or fill activities shall be mitigated by creation, restoration or enhancement of another area to ensure that the integrity of the estuarine ecosystem is maintained. Comprehensive plans shall designate and protect specific sites for mitigation which generally correspond to the types and quantity of intertidal area proposed for dredging or filling, or make findings demonstrating that it is not possible to do so.

However, mitigation shall not be required for projects which the Division of State Lands has determined meet the criteria in ORS196.830(3).

This strategy shall be implemented through procedures established by the Division of State Lands, and as consistent with ORS196.830 and other mitigation/restoration policies set forth in this Plan.

This strategy recognizes the authority of the Director of the Division of State Lands in administering the statutes regarding mitigation.

CB - CBEMP Policy 11 Authority of Other Agencies

Local government shall recognize the authority of the following agencies and their programs for managing land and water resources:

- The Oregon Forest Practices Act and Administrative Rules, for forest lands as defined in ORS 527.5610-527.730 and 572.990 and the Forest Lands Goal;

- The nonpoint source discharge water quality program administered by the Department of Environmental Quality under Section 208 of the Federal Water Quality Act as amended in 1972 (PL 92-500);
- The Fill and Removal Permit program administered by the Division of State Lands under ORS 541.605-541.665; and
- The Programs of the State Soil and Water Conservation Commission and local districts and the Soil Conservation Service for the Agricultural Lands Goal.

*This strategy recognizes that there are several agencies with authority over coastal waters, and that **<u>their management programs should be used rather than developing new or duplicatory management techniques or controls</u>**, especially as related to existing programs functioning to maintain water quality and minimize man-induced sedimentation.*
(Emphasis added)

CB - CBEMP Policy #17 Protection of "Major Marshes" and "Significant Wildlife Habitat" in Coastal Shorelands

***<u>Local government shall protect major marshes, significant wildlife habitat, coastal headlands, and exceptional aesthetic resources</u>** located within the Coos Bay Coastal Shorelands Boundary and included in the Plan inventory, except where exceptions allow otherwise. Local government shall consider:*

A. "major marshes" to include areas identified in the Goal #17 "Linkage Matrix" and the Shoreland Values inventory map;
B. "significant wildlife habitats," coastal headlands and exceptional aesthetic resources to include those areas identified, on the map "Shoreland Values."

This strategy shall be implemented through:

A. plan designations and use and activity matrices set forth elsewhere in this Plan that limit uses in these special areas to those that are consistent with protection of natural values, and
B. through use of the "Shoreland Values" map that identifies such special areas and restricts uses and activities therein to uses that are consistent with the protection of natural values. Such uses may include propagation and selective harvesting of forest products, consistent with the Oregon Forest Practices Act, grazing, harvesting wild crops, and low-intensity water-dependent recreation.

*This strategy recognizes that **<u>special protective consideration must be given to key resources in coastal shorelands over and above the protection afforded such resources elsewhere in this Plan</u>**.*
(Emphasis added)

Various other CBEMP polices must also be followed including CBEMP Policies 4, 4a, 18, 20a, 22b, 23, 25, 27, 33, 46, 46a, 47, 48, among several others. It is unclear to my why the CBEMP Policies found in Coos Bay's CBEMP Documents differ so greatly in text or in even being listed with what is found on file with Coos County Planning for the **<u>same</u>** CBEMP Policies. (***See Exhibit 76***)

There is no American public benefit to the loss of fish, marine and wildlife habitat due to the destructive nature of all the proposed dredging for the Jordan Cove / Pacific Connector Project. The Pacific Connector Pipeline's construction is projected to impact 485 wetlands and waterbodies in Southern Oregon, many of which are salmon bearing.

The Coos Bay Estuary is already 303D limited and this project will only make that situation worse. We can look to what has happened at other LNG projects with respect to channel dredging and see that **even though the LNG industry promises there would be no negative impacts, promises and what actually happens does not always end up being the same**. (***See Exhibit 3***) Our fishing industry has ALREADY been negatively impacted and is in need of renewal, not more degradation. (***See Exhibit 4)*** Jordan Cove's sedimentation expert expects us to believe that there would be no negative impacts with sedimentation or turbidity from all their proposed dredging. Our sedimentation expert actually proved their expert to be wrong on this issue during the land use process under Coos County File No. REM 10-01 for HBCU-10-01. (***See Exhibit 29****)*

In order to protect the integrity of the Estuary, Policy 5 must be adhered to and marine habitat in the estuary protected. This is even a requirement in **DDNC-DA** zoning district for which the **applicant is not seeking a goal exception for**. The strong tidal currents have the ability to transfer sediments a great distance**. No contaminated soils or fill should be suspended in the estuary.** The applicant should be made to mitigate for any damage done. In addition, evacuation measures in the event of an earthquake and/or tsunami event off our coastline should also be taken into account as a part of permit requirements in order to fulfill the Comprehensive Plan's purpose of protecting the health, safety and welfare of area residents.

In 2010 Clausen Oyster Company was hit with a $25,000 fine from the Oregon Department of Environmental Quality for wastewater violations. Clausen maintained that no oyster meat was entering the wash water - just mud that it was washing off the oyster that had just been taken out of the bay. "The mud comes out of the bay; it goes back in the bay," said Lilli Clausen. (***See Exhibit 28***) Despite the fact that the mud had just come out of the bay it was still considered a Clean Water Act violation.

The same scrutiny and oversight should be imposed with respect to the Jordan Cove Project and their proposed dredging and placement of fill and/or sedimentation in Waters of the State due to the negative impacts those sediments could have on fishing and recreation.

This should be of particular concern due to the fact that Jordan Cove has ALREADY been sited by the DEQ for violations with respect to their Project for work they were doing on May 8, 2014, at the Jordan Cove Ingram Yard site (***See Exhibit*** 49)

6. Mitigation Insufficient / Temporary Dredge Pipeline would impact Eelgrass and other habitat areas.

Jordan Cove's proposed dredging and temporary pipeline would impact eelgrass areas in the lower Coos Bay and in zoning district 52-NA as shown in the following diagram. Jordan Cove has yet to prove a need for their dredging project that outweighs the negative impacts to fishing, recreation and navigation. They have provided no plans to mitigate habitat areas and marine life that would be destroyed in the lower bay by their proposed dredging plans. Jordan Cove's proposed eelgrass mitigation site also lacks sufficient proof that it would be successful and not harm other already productive eelgrass areas.

A March 2019 letter by the Shon Schooler, Ph.D., Research Coordinator with the South Slough National Estuarine Research Reserve states: (***See Exhibit 10***)

> *We are particularly concerned with the potential impacts to eelgrass (Zostera marina) populations as eelgrass is an important habitat for many estuarine species and improves estuarine water quality. The following comments fit under CBEMP Policy 4: Resource Capability Consistency and Impact Assessment. Eelgrass habitat in the Coos Estuary has experienced a net loss since 2005 (from mapping/GIS methods) and abundance has declined more recently since 2016 (from intertidal field surveys).*

Below find maps of eelgrass areas found in the lower bay in 2005:

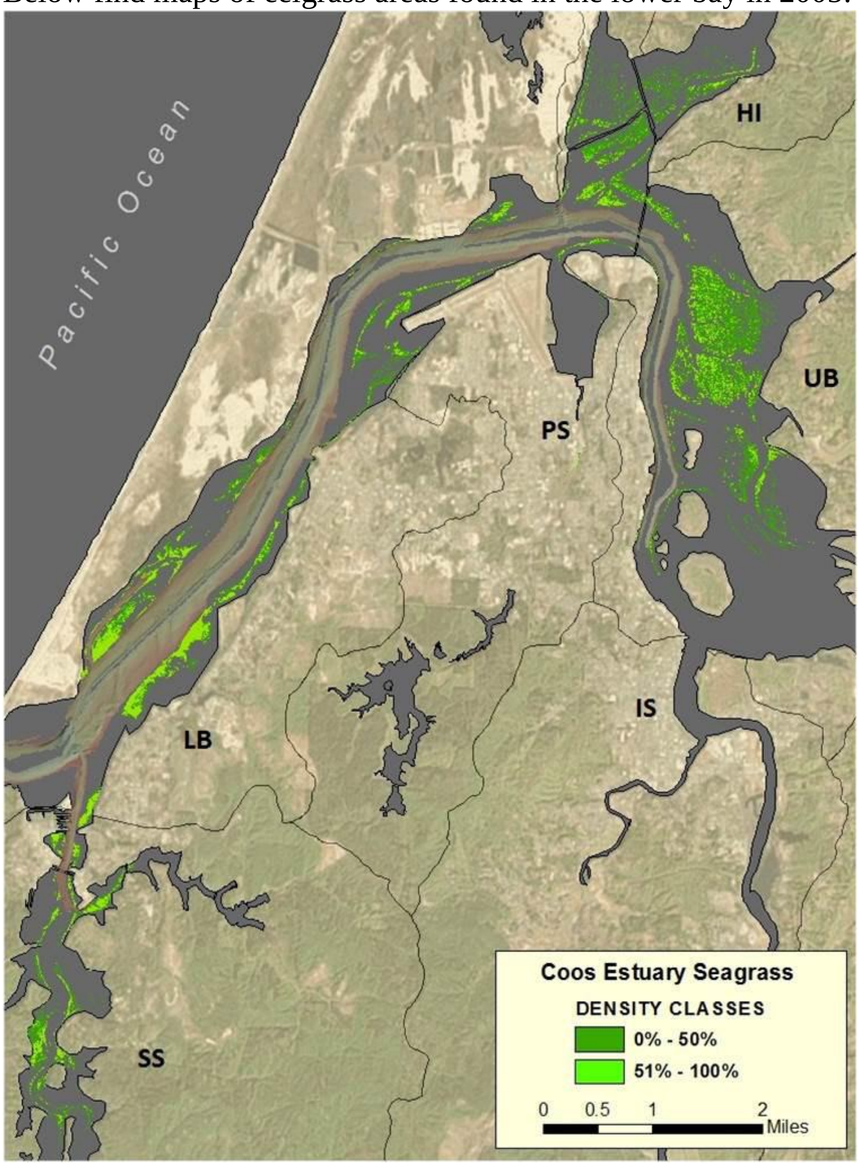
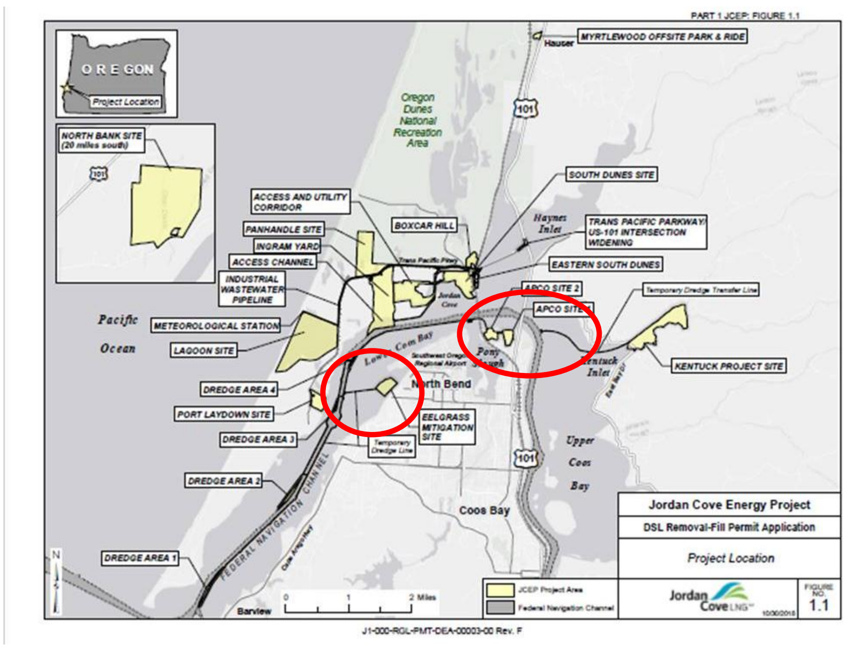


Figure 1 above: Distribution of seagrass beds (green) and location of deep water in the shipping channel (tan). Dense beds (> 50% ground cover from seagrasses) are shown in light green. Seagrass data generated from aerial photos taken in 2005. Data: Clinton et al. 2007, NGDC 2014

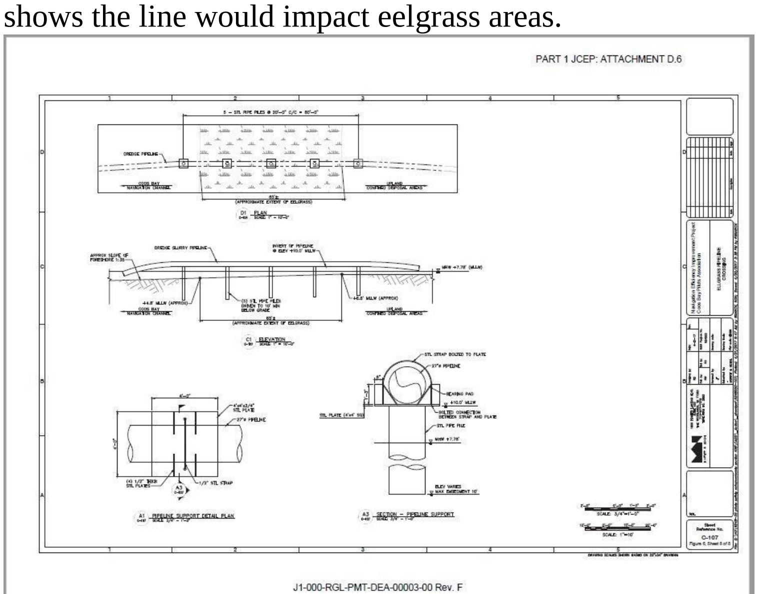
Jordan Cove's proposed temporary dredge pipeline would transit through most of the lower bay. It is unknown how much restriction this would cause to other bay users or how secure this line would be against the vast tidal action of the lower bay. **This temporary pipeline activity is only permitted**

subject to Policy #5a noted above. The temporary pipeline must be consistent with the resource capabilities of the area (see CBEMP Policy #4) and must also satisfy the impact minimization criterion of Policy #5. The affected areas are to be restored to their previous condition. Jordan Cove is not asking for an exemption for the impact their temporary pipeline alteration would have on the estuary and **they have yet to provide the necessary evidence that they have met the CBEMP requirements**. Jordan Cove's proposed dredging, eelgrass mitigation site, and temporary pipeline would directly impact known eelgrass areas in the Coos Bay as documented by the letter from Shon Schooler, Ph, D and as shown in the following diagrams. No evidence has been provided as to how these impacted areas would be successfully restored after being impacted. In addition, Jordan Cove's 2007 Coos Bay Estuary Mitigation permit has long since expired. (CBDC **17.130.140**) It is unclear how they plan to successfully mitigate eelgrass areas that would be destroyed by their dredging plans.

Estuary Mitigation permit has long since expired. It is unclear how they plan to successfully mitigate eelgrass areas that would be destroyed by their cumulative dredging plans.



Dredge Transfer Line diagram below is from page Page 460 of Jordan Cove's DSL Application and shows the line would impact eelgrass areas.



Jordan Cove's proposed temporary dredge transfer line support structures are slated to sit on current known eelgrass bed areas. There is no indication how stable this transfer line would be with the swiftness of the tides in our area nor is there any mitigation being proposed for the negative impacts this temporary line would have on eelgrass and other habitat areas that **are to be protected** in zoning district 52-NA.

7. Tidal Soil Contaminant Testing is Absent and/or Not Adequate

Jordan Cove's DSL application on electronic page 1015 states, "*The chemical analytical data from the Corps FNC indicate that chemicals of concern present near the project area generally include metals, phenols, various phthalates and PAHs*." The Roseburg Chip facility berth was tested in 2009 and TBT was detected above the SL1 in the west part of the berth; discrete re-sampling did not detect TBT but dredging was restricted to the eastern portion of the berth anyway. Past shipping contaminants including Tributyltin (TBT), arsenic, copper, lead, mercury, nickel, zinc, polycyclic aromatic hydrocarbons (PAHs), and polychlorinated biphenyls (PCBs) **could be re-suspended into the Coos Bay** harming marine life and businesses that depend on that marine life. (***See Exhibits 11 and 12***) Tidal muds need to be tested prior to any approval and Jordan Cove's sedimentation plan MUST CONTAIN TESTING FOR ALL POTENTIAL CONTAMINANTS AND CURRENTLY DOESN'T. (See electronic page 524 of DSL application, Table 9-2)

The cumulative damage to the Coos Bay Estuary from the proposed JCEP project would be significant due to the extensive dredging, ballast water, invasive species and water quality impacts.[10] **This would violate the Coastal Zone Management Act [11] and the Estuary Restoration Act of 2000** [12]

8. Oysters, Clams, Crabs, Fish and other Habitat would be Negatively Impacted by the Jordan Cove/Pacific Connector Project

The Coos Bay is the largest commercial producer of shellfish in the state of Oregon. Jordan Cove's cumulative dredging plans would excavate approximately .7 mcy of material from submerged areas lying adjacent to the federally-authorized Channel along with 5.7 million cubic yards (mcy) of material to create the slip basin and access channel in an area currently known as Ingram Yard. It is well known that Ingram Yard contains toxic materials from past industrial activities that were buried out there long ago. **Appropriate environmental reviews need to be done in all dredging areas**. The Ingram Yard property has been filled over many years with material dredged from a bay surrounded by heavy industries, and the property was used by Menasha and then Weyerhaeuser for many years before strict contamination controls were required. In July of 1999, Nucor Corporation withdrew from purchasing 575 acres of land on the North Spit from Weyerhaeuser. Nucor purportedly backed out because Weyerhaeuser insisted on transferring all potential liability for past contamination of the property to the buyer.

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[10] The proposed Jordan Cove LNG Export Project would dredge 5.7 million cubic yards of dredge material in order to build their LNG marine slip dock and another .6 mcy of dredging in the Coos Bay for a total of 6.3 million cubic yards of material. The Port of Coos Bay has plans for an extensive deepening and widening of the shipping channel in the lower Coos Bay and removal of 18 mcy. This amounts to 24.3 million cubic yards of material in total. Ballast water, invasive species and water quality impacts from the project would be significant.

[11] The Coastal Zone Management Act. http://coast.noaa.gov/czm/act/?redirect=301ocm

[12] The Estuary Restoration Act: http://www.era.noaa.gov/information/act.html

Despite multiple requests, Jordan Cove continues to ignore these concerns and has yet to properly test the soils in Ingram Yard where toxic compounds are likely to be found. (***See Exhibits 5 and 6***) **Contaminates in the tidal muds of the project area have also not been fully evaluated for past industrial contaminates which are highly likely to be re-mobilized during dredging activities.** This would make the already poor water quality conditions of the Coos Estuary even worse. Tidal soils also need to be evaluated for soil stability.

Both Clausen Oysters[13] and Coos Bay Oyster Company[14] (***See Exhibit 7***) have expressed concerns in the past about the potential for turbidity and loss of their commercial oysters from Jordan Cove's dredging activities. Commercial oysters would be at risk as well as populations of Olympia oysters which are protected and not harvested. Page 13 of Jordan Cove's Oct 2017, 404 Application states under item #4 that *"…dredging associated with the navigation reliability improvements and eelgrass mitigation site, will be performed during the ODFW in water work window (October 1 to February 15).*" Electronic page 123 of Jordan Cove's DSL application ALSO states the same thing (See Page 28 of David Evans and Associates Technical Memorandum filed with DSL). **October is the height of the Olympia oyster reproductive cycle[15] and would mean that Olympia oyster spat would be at risk of massive die-off** should dredging occur during this time.

Eelgrass can also be adversely affected by turbidity because the depth and distribution of eelgrass is strongly associated with water clarity and depth of light penetration (Dennison and Orth 1993; Thom et al. 1998) as well as nutrient availability (Short et al. 1995), salinity, and water temperatures (Thom et al. 2003). (***See Exhibit 57***) The proposed marine slip and access channel would result in the permanent loss of 14.5-acres of shallow subtidal and intertidal habitat, 0.06-acre of estuarine saltmarsh habitat and approximately 1.9-acres of submerged aquatic vegetation habitat (eelgrass). **This would affect baby salmon and other marine organisms that depend on these ecosystems remaining intact.**

The Oregon DEQ's Integrated Report identifies the Coos Bay Estuary status as Category 5, water quality limited, 303(d) (in CWA), and a Total Maximum Daily Load (TMDL) plan is needed due to elevated fecal coliform measurements. (ODEQ 2012d).[16] This is also the case for several of the tributaries and rivers that are upstream of the Coos Estuary.

The Clam Diggers Association of Oregon have already found high levels of contaminants in clams coming from the Coos Bay [17] (***See Exhibit 8***) and Commercial oysters are currently not always able to be harvested due to elevated fecal coliform measurements within the Coos Bay.

Dredging on the scale that is being proposed by Jordan Cove and the Port of Coos Bay has the potential to significantly affect both marine habitat and the amount and velocity of water flowing in

[13] FERC Motion to Intervene Out-of-Time of Clausen Oysters and Lilli Clausen, as in individual and owner, under CP13-483, et. al.: http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20141015-5087
[14] FERC Motion to Intervene and update Contact Information of Coos Bay Oyster Company / Jack Hampel under CP13-483, et. al.: http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20150302-5065
[15] "*Settlement Preference and the Timing of Settlement of the Olympia Oyster, Ostrea Lurida, In Coos Bay, Oregon"*, by Kristina M. Sawyer, A Thesis, Presented to the Department of Biology and the Graduate School of the University of Oregon in partial fulfillment of the requirements for the degree of Master of Science, September 2011.
[16] https://www.deq.state.or.us/wq/assessment/rpt2012/results303d12.asp
[17] Motion to Intervene Out-of-Time Clam Diggers Association of Oregon under CP13-483., et. al.: http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20140221-5118

and out of Coos Bay during the tidal cycle. All these increased impacts need to be evaluated due to their potential to significantly degrade these waters.

Sylvia Yamada, a marine ecologist who has studied native crabs and the European green crab in Oregon and Washington for over 20 years, submitted comments into the DSL record where she stated the following: (***See Exhibit 9***)

> *I have been studying crabs in Oregon estuaries, including Coos Bay, for over 20 years*
> * * * *
> *…Not only will the turbidity during the construction phase be of concern to the ecological community, the on-going dredging to maintain the berth and shipping channels will continue be a disturbance to the ecosystem.* ***It will result in habitat loss for native species, including the valuable Dungeness crab****. In one study between 45 to 85 % of the Dungeness crabs died during a simulated dredging operation (Chang and Levings, 1978). Marine habitat modification by construction of the Jordan Cove Energy Project could impact the important Oregon Dungeness fishery.*[18] (Emphasis added)

Dr. Mark Chernaik succinctly summarizes the issues in the following statement found on page 9 of this November 14, 2011 Coos County Surrebuttal report under File No. HBCU-10-01/REM-10-01:

> "*Proponents of multi-billion dollar industrial projects have vast resources to pay for scientific reports with elaborate illustrations that have the allure of scientific validity. Because citizens who are concerned about the impacts of such projects must make do with far fewer resources, these project proponents are not accustomed to close inspection of their technical data, assumptions, reasoning and conclusions. This imbalance describes the situation between PCGP and CALNG and the question of whether the proposed project would fail to protect the resource productivity of Haynes Inlet.*
>
> *"Despite the David-versus-Goliath situation they find themselves in, CALNG has revealed numerous, serious flaws in the technical arguments put forward by PCGP, including the early claim by Dr. Bob Ellis that Olympia oysters "are not known to inhabit the Project Action Area (ODLCD, 1998)." LUBA Record at page 1331. Following this, CALNG has revealed additional errors, including but not limited to the following errors that are the subject of this round of testimony: that PCGP relied on untrained surveyors to identify and find native oysters in Haynes Inlet; that PCGP misunderstands the nature of native oyster restoration experiments performed by Dr. Danielle Zacherl; and that PCGP relied on un-validated estimates of background turbidity and inaccurate assumptions of sediment particle size when predicting the impact of trenching activities.*[6] *Combined with previous errors, such as proposing to commence trenching activities at the beginning of October, just before the height of the spawning season for Olympia oysters in Coos Bay, these numerous mistakes place the applicant far short of meeting their burden of demonstrating that their proposed project would not have more than a de minimis or insignificant impact on native oysters in Haynes Inlet.*"[19]

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[18] Comments of Sylvia B Yamada, Ph.D. in FERC Docket for Jordan Cove – PF-17-4 ;http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20170622-0008
[19] November 14, 2011: Mark Chernaik, Ph.D., Surrebuttal Report; Page 9 under Coos County File No. HBCU-10-01/*REM-10-01*

ESTUARY ISSUES OF CONCERN THAT NEED TO BE FULLY ADDRESSED

- Loss of habitat for fish, crabs, clams oysters and other marine and wildlife.
- Loss of vital eelgrass beds (this is supposedly to be mitigated, but State Agencies in the past have expressed series doubts about the adequacy of the planned mitigation)
- Possible erosion issues caused from the massive dredging and ship and tug wakes.
- The use of riprap and the altering of the bay's water velocity and flow.
- Sediment transport issues that can occur when channels are deepened. Tidal amplification and hyper concentrated sediment conditions can occur in the upstream tidal rivers. Channel deepening may increase up-estuary suspended sediment transport due to enhanced salinity-induced estuarine circulation and have a large impact on increasing suspended sediment concentration (SSC)[20]
- Risk of destabilizing Henderson Marsh wetlands and the North Spit due to the excessive dredging.
- Potential negative impacts to wetland areas including habitat and vegetation.
- Potential negative impacts to the nearby floodplains.
- Potential negative impacts to adjacent wildlife and people. What effect will dredging have on adjacent shorelands? Snowy Plover habitat? Clam beds? Other marine and wildlife? People? Shoreland structures? Rising water levels due to climate change?
- An increase in the Tsunami hazard zone areas due to an increase in amount of water and water velocity that will be in the bay due to the increased dredging.
- Interference with Traditional Activities on the Lower Bay (Fishing, Crabbing, Boating, Recreation, etc) including economic impacts to businesses associated with these activities.
- The potential for increased flooding upstream of the Kentuck Inlet.

ENDANGERED SPECIES IMPACTS

The Project is not in compliance with Regulations for protecting threatened and endangered species including Army Corps Standard Local Operating Procedures for Endangered Species (SLOPES).

According to the former FERC September 2015 Jordan Cove FEIS page 5-15 to 5-16:

> The Project is ***likely to adversely affect***:

[20] *The impact of channel deepening and dredging on estuarine sediment concentration* D.S.van Maren, T.van Kessel, K.Cronin, L.Sittoni ; Continental Shelf Research Volume 95, 1 March 2015, Pages 1-14

the proposed threatened fisher (west coast DPS);
the threatened MAMU;
the threatened NSO;
the threatened green sturgeon (Southern DPS);
the threatened Pacific eulachon (Southern DPS);
the threatened coho salmon (SONCC);
the threatened coho salmon (Oregon Coast ESU);
the endangered Lost River sucker;
the endangered shortnose sucker;
the threatened vernal pool fairy shrimp;
the endangered Applegate's milk-vetch;
the endangered Gentner's fritillary;
the endangered large-flowered meadowfoam; and
the threatened Kincaid's lupine.

This list is not complete and needs to be updated. For example, the Project would impact Point Reyes Birds Beak which is a Federal plants species of concern and an Oregon endangered plant species. (***See Exhibit 13)***

ORS 196.805 [21] Policy

> *(1)* ***The protection, conservation and best use of the water resources of this state are matters of the utmost public concern****. Streams, lakes, bays, estuaries and other bodies of water in this state, including not only water and materials for domestic, agricultural and industrial use but also* ***habitats and spawning areas for fish, avenues for transportation and sites for commerce and public recreation, are vital to the economy and well-being of this state and its people****. Unregulated removal of material from the beds and banks of the waters of this state may create hazards to the health, safety and welfare of the people of this state. Unregulated filling in the waters of this state for any purpose, may result in interfering with or injuring public navigation, fishery and recreational uses of the waters. In order to provide for the best possible use of the water resources of this state, it is desirable to centralize authority in the Director of the Department of State Lands, and implement control of the removal of material from the beds and banks or filling of the waters of this state.*
> *(2)* ***The director shall take into consideration all beneficial uses of water including streambank protection when administering fill and removal statutes.***
> *(3) There shall be no condemnation, inverse condemnation, other taking, or confiscating of property under ORS 196.600 to 196.905 without due process of law. [Formerly 541.610 and then 196.675; 2003 c.738 §16; 2012 c.108 §7]*
> (Emphasis added)

OAR 141-122-0020 Policies

> *(13)* ***The Department will not grant an easement if the proposed use or development is inconsistent with any endangered species management plan adopted by the Department under the Oregon Endangered Species Act*** *(ORS 496.171 to 496.192).*

[21] http://www.oregonlaws.org/ors/196.805

Abalone

Southern Oregon is on the northern edge of red abalone range and the state's fishery is managed conservatively to protect the health of Oregon's relatively small population. Abalone are highly prized and the fishery creates a high demand, primarily among divers. While seven species exist on the West Coast, **five of these have some listing status under the Endangered Species Act**.[22] Red abalone are the only species still fished in the contiguous United States, and southern Oregon and northern California are the only areas where recreational harvest has occurred in recent years. Commercial harvest is not allowed in either state. Currently Oregon has postponed the 2018 recreational season that was set to open on Jan. 1 until further review and Commission consideration.

9. Turbidity Modeling Flawed

Jordan Cove did not actually do testing of the static tidal action with respect to sedimentation transport; they used computer modeling that is obviously severely flawed. The modeling methodology used by Moffatt & Nichols (the contractor hired to do the modeling) is fundamentally flawed for a number of reasons. The most important reason is they treat Coos Bay as a 2D problem when it is in fact 3D due to vertical variability in temperature, salinity, and sediment concentrations in the water column. This will affect how and where suspended sediment is transported by the currents in the bay, it will also affect the concentration of the suspended sediment.

Their flawed modeling makes it look like the sediments will only go a short distance out from the dredging activity when that would NOT be the case. In addition, widening of the tidal channels actually increases estuarine circulation and suspended sediment concentration (SSC). (***See Exhibit 55***) At what point is a critical amount of dredging performed which raises deposition levels beyond an acceptable criterion? The negative impacts from dredging can sometimes last for many months and even in some cases years (***See Exhibits 55 to 59***)

It has long been known that a thin layer of sedimentation impairs the attachment of oyster larvae to hard substrate. A covering of less than 50 microns (1/500th of an inch) is enough to impair the attachment of O. lurida larvae to hard substrate. According to the U.S. Army Corps of Engineers:

> U.S. Army Corps of Engineers (December 1998) "Technical Note DOER-E2: Environmental Windows Associated with Dredging Operations."
>
> *"Although a thin layer (several mm) of sediments may not be fatal to adult oysters, it may affect reproduction. Because larval oysters require hard substrata for settlement, the presence of even a few millimeters of sediment covering an oyster reef may inhibit larval recruitment (Galtsoff 1964; McKinney et al.1976)."*

Tidal Action in the Coos Estuary is extremely swift. In October of 2014 a construction worker died when he apparently accidentally drove his pickup truck off a work platform at the North Bend McCullough Bridge. His body was found a few hours later some 4 miles from where his truck had entered the water. If a human male body can move that far just from Coos Bay's tidal action, it makes sense to assume that much lighter weight sediments would also move with the swift tidal action in the Coos Bay and essentially could impact the entire estuary. This is another example why independent

[22] https://www.dfw.state.or.us/news/2017/12_dec/122817.asp

review by other experts should be brought in by the City of Coos Bay, North Bend, Coos County, the Department of State Lands, and the FERC, to confirm these findings being presented by Jordan Cove.

In 1999 Clausen Oysters lost 70 to 75 percent of their oysters when a freighter known as the New Carissa grounded on Horsfall beach about a mile north of the North Spit. The tides brought oil that escaped from the New Carissa into the Coos Bay and in addition to oysters more than 200 birds were killed along with immeasurable damage to local sea organisms. (***See Exhibit 59***)

The Department of Agriculture continually stops oyster harvesting in the bay when certain bacteria levels reach a certain level. It can take anywhere from several days to several weeks for the bay to clear. Unless appropriate modeling is used it is impossible to make projections of how dredging is going to impact water circulation which affects bacteria levels and how long it takes for it to clear out, among other critical issues.

Proper testing of tidal muds and dredging soils has also not occurred. Past shipping contaminants including Tributyltin (TBT), arsenic, copper, lead, mercury, nickel, zinc, polycyclic aromatic hydrocarbons (PAHs), and polychlorinated biphenyls (PCBs) could be re-suspended into the Coos Bay harming marine life and business that depend on that marine life. (***See Exhibit 58***) As far as I can tell there are no plans to test for all these contaminants (See Table 9-2 found on electronic page 524 of Jordan Cove's DSL application). The Roseburg Chip facility berth was tested in 2009 and TBT was detected above the SL1 in the west part of the berth; discrete re-sampling did not detect TBT but dredging was restricted to the eastern portion of the berth anyway. (See electronic page 1015 of Jordan Cove's DSL application.) So these contaminates ARE there in areas right next to the planned project area and proper testing by an independent analysis has yet to be done.

The DSL should consider the analysis that was done by sedimentation expert Thomas Ravens on Jordan Cove's Vladimir Shepsis's Coast Harbor and Engineering report (***See Exhibit 29***) A properly completed Environmental Impact Statement (EIS) analysis should be done that is not just rubber stamp the industry's data.

Dr. Thomas Ravens who has been modeling hydrodynamics and sediment transport in estuarine environments for 18 years found serious deficiencies in Dr. Vladimir Shepsis's modeling work. Dr. Thomas Ravens states the following on page 2 of his November 13, 2011 report:

> "*Chapters 10 and 11 of Exhibit 4 (entitled Jordan Cove Energy Project and Pacific Connector Gas Pipeline - Volume 2) present sediment transport calculations which purport to show that sediment transport impacts of the proposed dredging project in Haynes Inlet would have minimal impacts. However, close scrutiny of Exhibit 4 shows that there are **serious deficiencies in the methodology employed in the sediment transport modeling**. Consequently, the finding that there would only be limited impacts is lacking a solid foundation*…." (Emphasis added)

Dr. Thomas Ravens goes on to outline in his report the most serious flaws under the following subheadings:

> 1. Use of un-validated sediment transport model to establish background conditions.
> 2. Assumption of spatially uniform sediment size despite data indicating significant heterogeneity.5

10. Increased LNG Vessel Transits = Increased Turbidity

Physical movement of LNG vessels 950 feet in length and 150 feet wide and drafting 40 feet of water will greatly disturb the channel and its physical structure. The two to three 80 ton tugboats pulling or pushing the vessel will cause even more turbidity and erosive wave action.

The LNG Terminal could generate a maximum of 120 LNG carrier calls per year, although the average is expected to be between 110 and 120 LNG carriers per year. [Jordan Cove Resource Report #1 page 25 & 26] **This amounts to 220 to 240 harbor disruptions per year during high slack tides which are also prime tides used currently by other bay users.**

The 240 trips up and down the seven and one-half mile channel that are predicted by the applicant would cause the estuary to become more turbid. According to a study done by the Jordan Cove Energy Project,[23] propeller wash velocities from the LNG vessels and tugs would be of similar magnitude to tidal currents in the navigation channel but the potential propeller wash velocities would be somewhat higher than the typical maximum tidal currents in the channel. Compounding negative effects, such as erosion of intertidal lands and shorelines would continually degrade water quality as vessels moved in and out of the bay. Increases in turbidity would negatively impact aquatic plant life, shellfish, and benthic organisms. **These disturbances would not be able to be abated to the overall detriment of the Coos Bay estuary.**

11. Alternatives Analysis Lacking

Jordan Cove did not provide any alternative analysis to satisfy the requirements specified in Statewide Planning Goal #2 for showing ***the long-term environmental, economic, social and energy consequences*** *resulting from the use of the proposed site* ***with measures designed to reduce adverse impacts*** *are not significantly more adverse than would typically result from the same proposal being located in areas requiring a goal exception other than the proposed site.* There are other better alternative LNG siting locations that would not require any estuary alterations. (***See Exhibit 63***) The proposed Jordan Cove project would in fact INCREASE hazards to shipping in the Coos Bay due to the project's LNG tanker ships, thermal plumes, increases in fog, and safety issues. The proposed channel alterations do not alleviate all the problems presented with the transport of LNG in the Coos Estuary. The Jordan Cove project is highly likely to not be able to make a Final Investment decision thus eliminating the need currently being presented. With the Port of Coos Bay only serving 5 or so ships a month, that is not enough to justify the harm and negative impacts that would occur as a direct result of habitat losses from Jordan Cove's proposed dredging on fishery and recreational uses of the water.

Coos Bay Comprehensive Plan Volume 1 / Part 1 Appendix C (pages 2 and 3) state the following:

> **Land Use Alternatives:**
> *** * * ***
> *The 1974 plan was intended to provide a "realistic approach to comprehensive planning and City development" (City of Coos Bay, 1974), yet it is extremely visionary and optimistic.*

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[23] 8.0 Summary ; "*Jordan Cove Energy Project* - "*Jordan Cove LNG Terminal Shoreline Erosion Study - Recommendation #15"* M&N Project No. 6753; Document No. 6753RP0002 Rev: 0; (Page 48) Docket No. CP07-444-000 http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20081205-5122

Although the plan's strategies have recently been criticized as being unrealistic in certain instances, the 1974 plan was designed to guide Coos Bay's growth to 1990 or 1995.

Assumptions
The 1974 plan was built upon 13 basic assumptions. These were:

1. That favorable economics, employment opportunities, increasing medical, cultural, educational and recreational opportunities will continue to attract [sic] steady migration into the Coos Bay Area.
2. That the City of Coos Bay will continue to grow in regional significance and will remain the largest city on the Oregon Coast.
3. That all Federal and State policies supporting and encouraging all facets of urban development will continue and the City of Coos Bay will participate.
* * * *
7. That the many physical and social problems normally associated with the city life are primarily caused by uncontrolled and undirected population growth.

*8**. That urban development will be guided and regulated in accordance with sound environmental protection principles and practices.***
* * * *
11. That City planning and programming will continue to play an increasingly important role in all aspects of physical community development.
* * * *
13. That certain environmental resources are limited, and therefore, future urban development must be accommodated with the proper level of constraints and public services designed to insure the highest possible quality of life for the entire City. That Urban Growth is a variable to be influenced in the pursuit of a desirable quality of community life*. (City of Coos Bay, 1974:6-7)*

12. Issues with Earthquakes Fault Lines, Tsunamis and Flooding

The Application did not address how the proposed channel navigation alteration would affect a Cascadia subduction, tsunami inundation and flooding events that could occur at any time off our coastline here. (***See Exhibit 19***) The application also did not address how dredging and the blasting/cutting of rock would affect the current knowledge of a fault line that is found within Jordan Cove's proposed Coos County dredging areas #1 and #2.

The widening of the Bay would increase the velocity and flow of the bay and also increase tsunami inundation and flooding risk. Jordan Cove has provided no consultation with the Oregon Department of Geology and Mineral Industries (DOGAMI) as required, by Statewide Planning Goal 7. DOGAMI has expressed serious concerns with Jordan Cove's overall project. (***See Exhibit 60***)

A 13 year study completed by researchers in 2012 at Oregon State University, and published by the U.S. Geological Survey, concluded that **there is a 40 percent chance of a major earthquake in the Coos Bay, Ore., region during the next 50 years**. And that earthquake could approach the intensity of the Tohoku quake that devastated Japan in March of 2011.[24] (***See Exhibit 19***)

[24] 13-Year Cascadia Study Complete – And Earthquake Risk Looms Large; http://oregonstate.edu/ua/ncs/archives/2012/jul/13-year-cascadia-study-complete-%E2%80%93-and-earthquake-risk-looms-large

The Oregon Resilience Plan that was prepared for the 77th Legislative Assembly on February 2013 reported on earthquake and tsunami impacts from a Cascadia event and **showed subsidence levels of 5 to 9 feet in the Coos Bay area**. (***See Exhibit 20***) This adds to the extreme hazard and need for there to be a far better evacuation plans in order for lives to be saved. Workers and citizens should not be placed at extreme risk due to by improper planning. An LNG export terminal poses far too much risk and hazard to be built here.

There are no plans on how Jordan Cove would handle a transiting LNG tankership in the event of an earthquake and tsunami, or how their Fire and Safety Center would protect the Cities across the Bay that would be negatively impacted due to their increase in population and Jordan Cove's proposed LNG hazards. There are no plans for Jordan Cove to hire extra emergency response personnel within the City of Coos Bay and in fact the Cities of North Bend and Coos Bay have both signed documents that have indemnified Jordan Cove from any hazard liability.

The Guano Rock formation found at the Coos Bay Harbor entrance would make it difficult for LNG tanker traffic and/or any efforts to widen and deepen the channel. Attempts to blast the rock would have dire consequences on water quality and marine life in the area and could very well bring on an earthquake or at least impact the earthquake fault that runs diagonally through the Bay in this same area. This was not considered in Jordan Cove's application.

Page 130 of Jordan Cove's 1-12-2016 submittal into the Coos County file No. HBCU-15-05 land use proceeding was from their GRI report and shows the following Earthquake Faults that were included in their study with respect to the LNG terminal:

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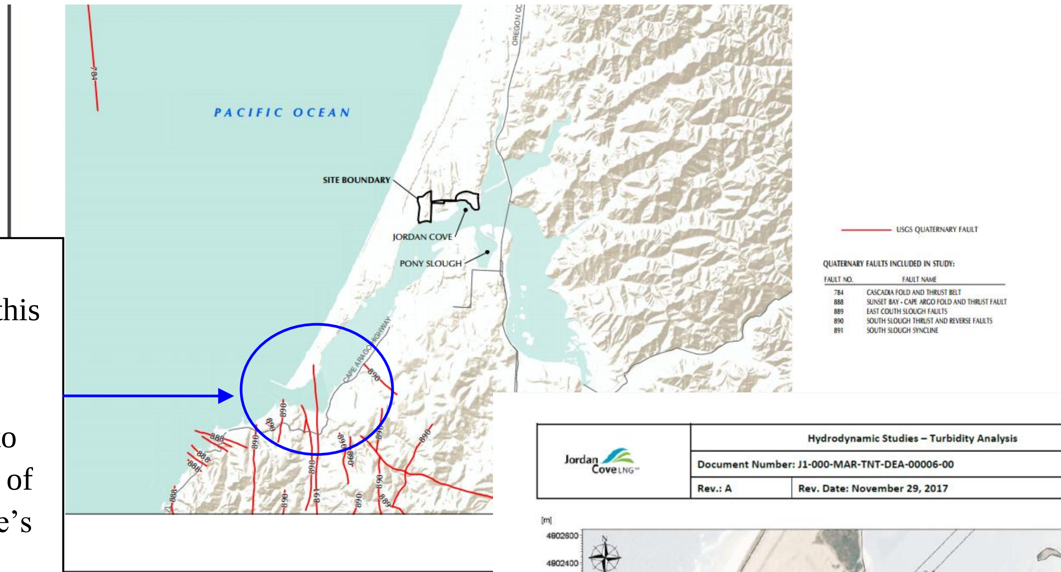
Study Link: *Turbidite Event History—Methods and Implications for Holocene Paleoseismicity of the Cascadia Subduction Zone* - By Chris Goldfinger, C. Hans Nelson, Ann E. Morey, Joel E. Johnson, Jason R. Patton, Eugene Karabanov, Julia Gutiérrez-Pastor, Andrew T. Eriksson, Eulàlia Gràcia, Gita Dunhill, Randolph J. Enkin, Audrey Dallimore, and Tracy Vallier - http://pubs.usgs.gov/pp/pp1661f/

Note the location of this earthquake fault and compare it to the location of Jordan Cove's proposed channel dredging project area #1, which is extremely close to this fault.



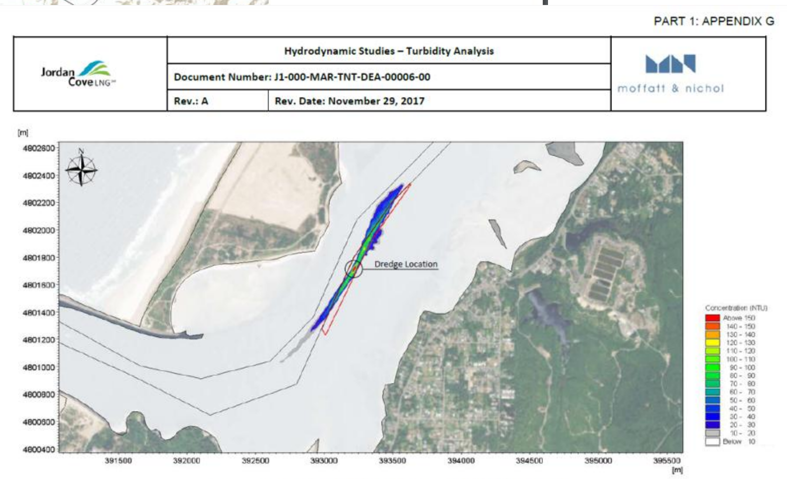
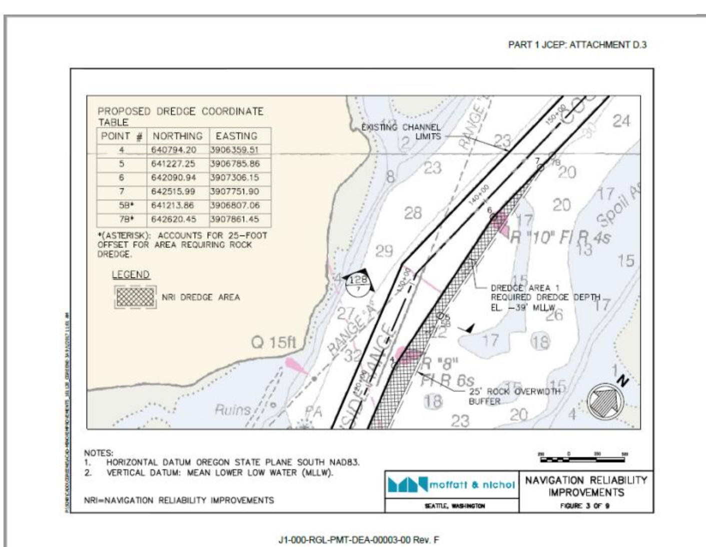
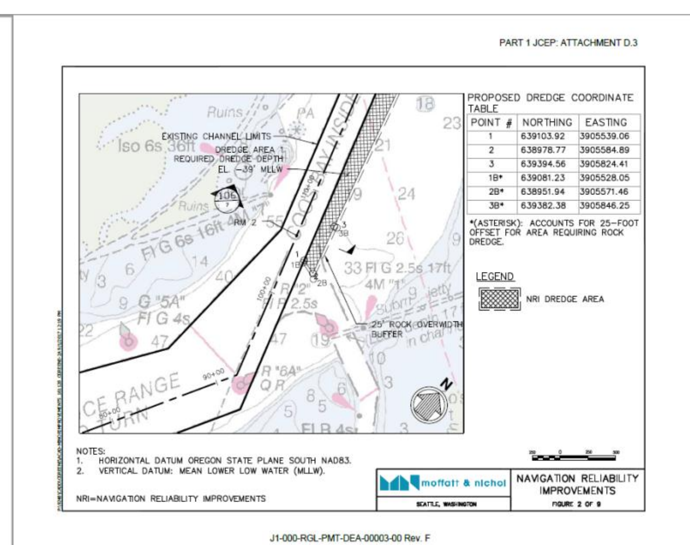
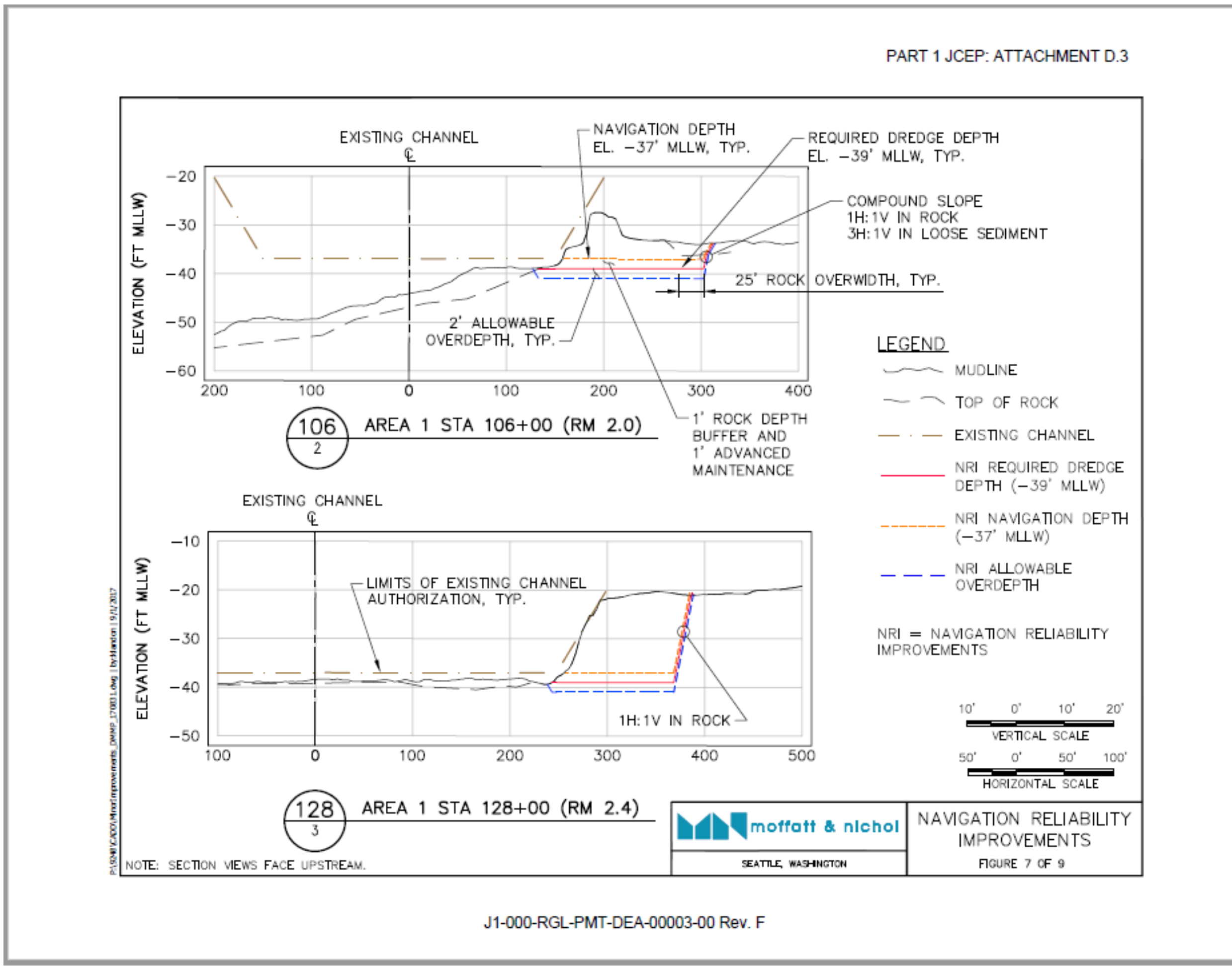


Figure 5-1: Capital dredging with cutter suction dredge, NRI 1

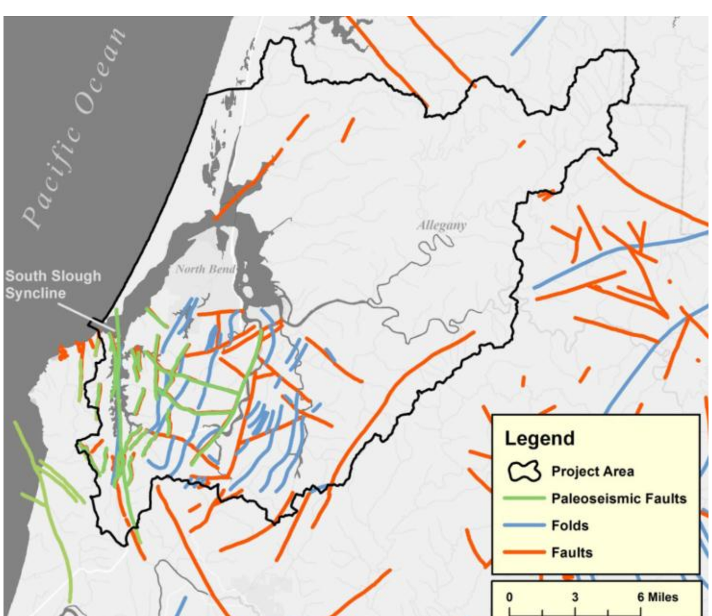
Jordan Cove's proposed dredge area #1 will involve the blasting/cutting of rock near this earthquake fault line. **What impact would this have on the fault? How easy would it be to move this rock through their temporary dredge transport pipeline**? See diagrams below from Jordan Cove's DSL application electronic pages 433,434 and 438.



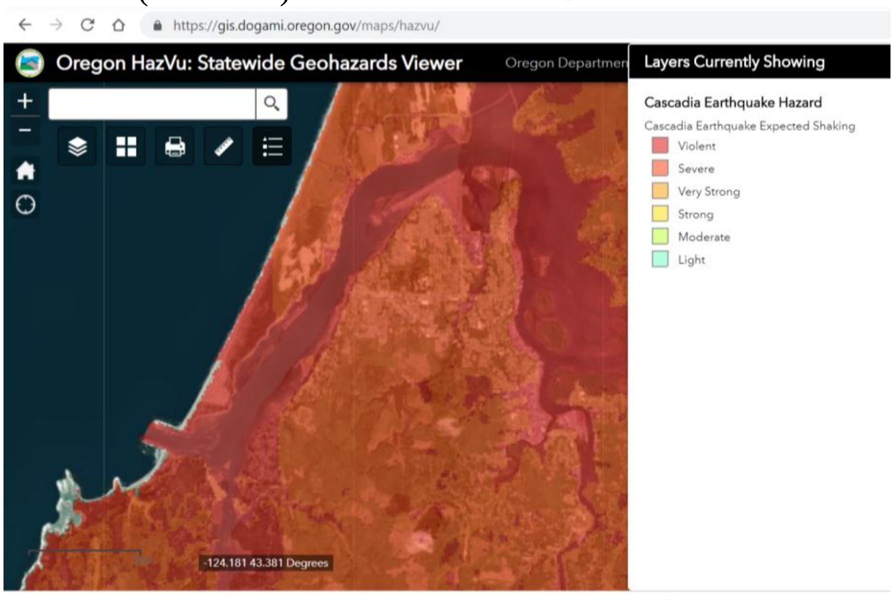




Jordan Cove's Earthquake liqufaction and seismic hazards should be considered fully. The Figure below shows faults and folds occurring within project boundaries. Paleoseismic faults are highlighted, designating faults that were the source of significant earthquake (6.0 or greater) in the past 1.6 million years. Data: USGS 2005; DOGAMI 2009. (***See Exhibit 18***)



Earthquake Hazard Diagrams below were taken from the Department of Geology and Mineral Industries (DOGAMI) on-line Geohazards Viewer



http://www.oregongeology.org/hazvu/

Cumulative impacts of Jordan Cove's entire project along with other proposed Port projects should be considered in with the current application. Jordan Cove provided no analysis of these increased hazards in with their permit application. Jordan Cove's Earthquake liqufaction and seismic hazards should be considered fully.

The New Yorker magazine reported on July 20, 2015 the following concerning the projected Cascadia subduction event that is scheduled to occur at any time off our coast here in an article by Kathryn Schultz entitled, "***The Really Big One - An earthquake will destroy a sizable portion of the coastal Northwest. The question is when***." [25]

> *…**By the time the shaking has ceased and the tsunami has receded, the region will be unrecognizable**. Kenneth Murphy, who directs FEMA's Region X, the division responsible for Oregon, Washington, Idaho, and Alaska, says, "**Our operating assumption is that everything west of Interstate 5 will be toast**."…*
>
> *…**FEMA projects that nearly thirteen thousand people will die in the Cascadia earthquake and tsunami**. Another twenty-seven thousand will be injured, and the agency expects that it will need to provide shelter for a million displaced people, and food and water for another two and a half million. "This is one time that I'm hoping all the science is wrong, and it won't happen for another thousand years," Murphy says.*
>
> *In fact, the science is robust, and one of the chief scientists behind it is Chris Goldfinger. Thanks to work done by him and his colleagues, we now know that the odds of the big Cascadia*

[25] *The Really Big One - An earthquake will destroy a sizable portion of the coastal Northwest. The question is when.* By Kathryn Schulz; The New Yorker; July 20, 2015
http://www.newyorker.com/magazine/2015/07/20/the-really-big-one

earthquake happening in the next fifty years are roughly one in three. The odds of the very big one are roughly one in ten. ***Even those numbers do not fully reflect the danger—or, more to the point, how unprepared the Pacific Northwest is to face it****….*

…Those who cannot get out of the inundation zone under their own power will quickly be overtaken by a greater one. ***A grown man is knocked over by ankle-deep water moving at 6.7 miles an hour. The tsunami will be moving more than twice that fast when it arrives. <u>Its height will vary with the contours of the coast, from twenty feet to more</u> <u>than a hundred feet</u>****. It will not look like a Hokusai-style wave, rising up from the surface of the sea and breaking from above. It will look like the whole ocean, elevated, overtaking land. Nor will it be made only of water—not once it reaches the shore. It will be a five-story deluge of pickup trucks and doorframes and cinder blocks and fishing boats and utility poles and everything else that once constituted the coastal towns of the Pacific Northwest….*

…OSSPAC estimates that in the I-5 corridor it will take between one and three months after the earthquake to restore electricity, a month to a year to restore drinking water and sewer service, six months to a year to restore major highways, and eighteen months to restore health-care facilities. ***On the coast, those numbers go up. Whoever chooses or has no choice but to stay there will spend three to six months without electricity, one to three years without drinking water and sewage systems, and three or more years without hospitals. Those estimates do not apply to the tsunami-inundation zone, which will remain all but uninhabitable for years****….*

An Oregonian article that was published on June 26, 2014, entitled, "**Jordan Cove LNG terminal at Coos Bay designed for Cascadia quake, tsunami though hazards remain**," stated among many other things the following:

…"It should be an assumption that this will happen during the lifetime of the facility," said Chris Goldfinger, a seismologist at Oregon State University and leading authority on subduction zone earthquakes. "You can engineer anything to survive anything if you put enough money into it, but I've seen a lot of very well-engineered stuff destroyed as if it were Legos."

*"****From my perspective, and the probabilities, I would certainly have reservations about building one of these terminals down there****," he said…*

*…"****I would say every one of us would be reluctant to suggest a liquefied natural gas terminal on the coast here****," said Anne Trehu, an OSU geologist who studies the Cascadia Subduction Zone….*

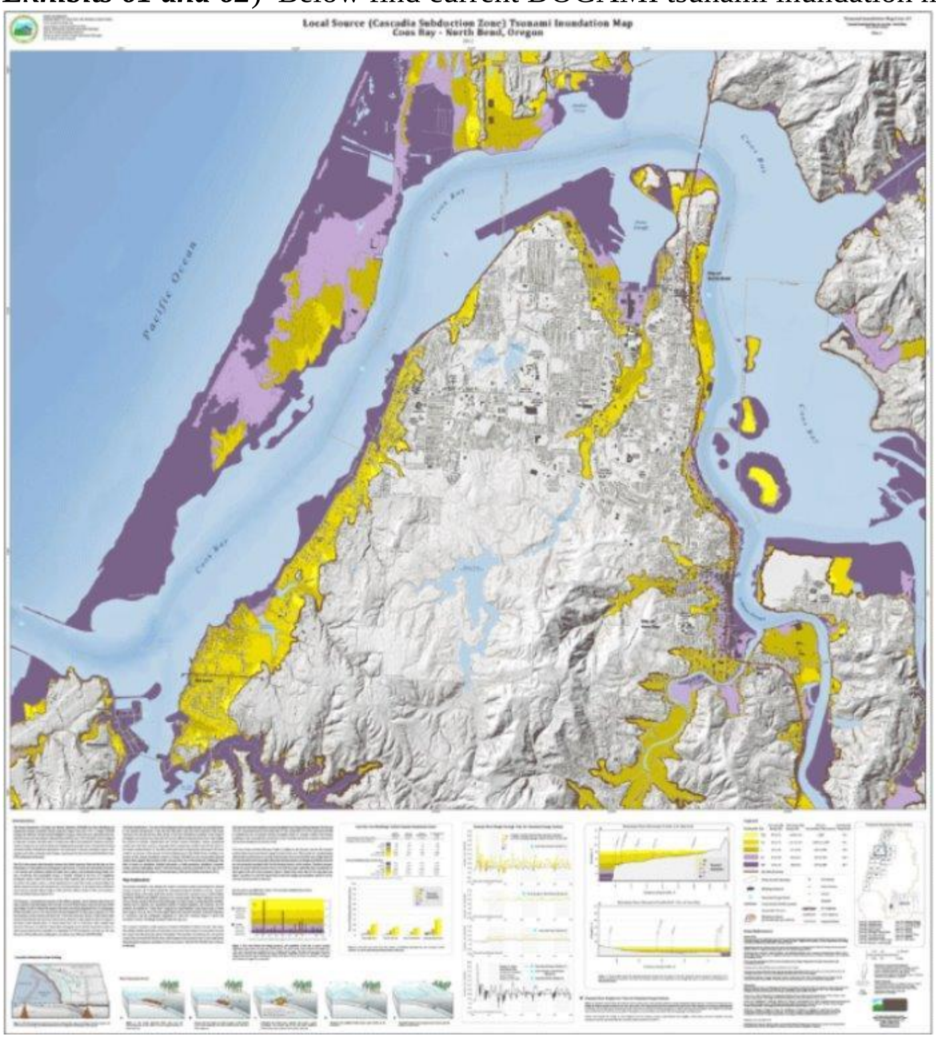
…Run-up and subsidence estimates were considerably less for the smaller, more likely, earthquake scenarios that Zhang modeled. In either case, the study concluded that the height of the proposed design "exceeds the design level tsunami event."

*Yet Zhang also says "****all the results need to be taken with a grain of salt****." Before the Japanese quake in 2011, he said****, geophysicists had concluded that 15-meter-high waves <u>were not possible at Fukushima</u>****.*

__Yet that's exactly what happened, resulting in cascading series of failures that ultimately resulted in the meltdown of three nuclear reactors__.[26] (Emphasis added)

Statewide Planning Goal 7 does not allow the building of hazardous facilities in natural hazard zones. It also requires that applicants consult with the Oregon Department of Geology and Mineral Industries (DOGAMI). The DOGAMI determined in a letter dated November 6, 2017 that Jordan Cove's Resource Reports were incomplete and deficient in scientific and engineering analyses related to geologic hazards and were not adequate to insure public safety. (***See Exhibit 60)***

Project would increase water volume in the Coos Bay which would increase tsunami hazards. (***See Exhibits 61 and 62***) Below find current DOGAMI tsunami inundation map:



The tsunami that inundated Japan in 2011 proved that tsunami wave heights can and likely will go up much higher than what Jordan Cove is preparing for. USA today reported that:

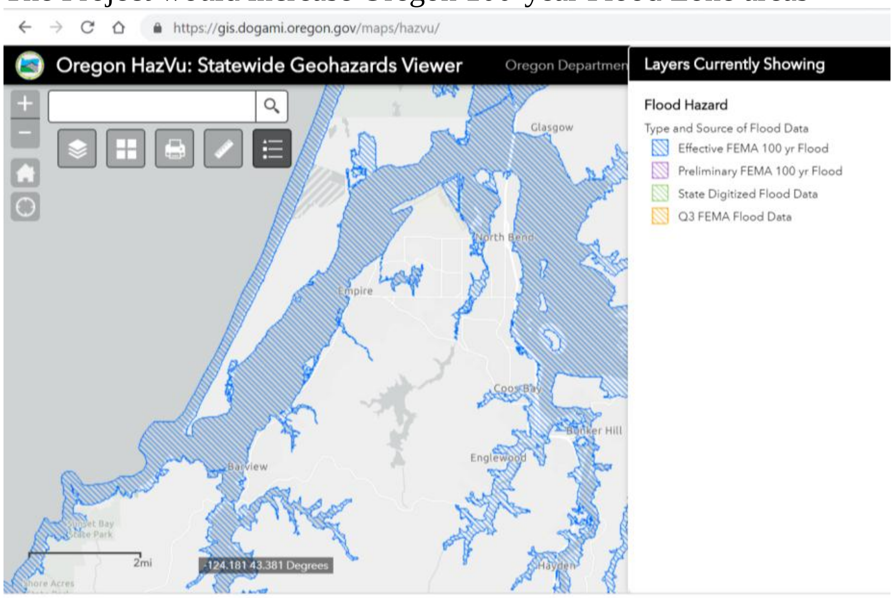
> ***Tsunami waves topped 60 feet or more*** *as they broke onshore following Japan's earthquake, according to some of the first surveys measuring the impact along the afflicted nation's entire*

---

[26] *Jordan Cove LNG terminal at Coos Bay designed for Cascadia quake, tsunami though hazards remain*
By Ted Sickinger - The Oregonian - June 26, 2014
http://www.oregonlive.com/business/index.ssf/2014/06/coos_bay_lng_terminal_designed.html#incart_river

*coast. **<u>Some waves grew to more than 100 feet high, breaking historic records</u>**, as they squeezed between fingers of land surrounding port towns.*[27] (Emphasis added)

The Project would increase Oregon 100-year Flood Zone areas



The applicant has not met the requirements for *restricting or prohibiting uses which are dangerous to health, safety, and property due to water or erosion hazards, or which result in damaging increases in erosion or in flood heights or velocities*. (**CBDC 17.318.050 Methods of reducing flood losses.**)

In addition, the Oregon Department of State Lands also must sign off on any removal of dredged material from the Coos Estuary as explained below.

ORS § 196.805 Policy

*(1)**<u>The protection, conservation and best use of the water resources of this state are matters of the utmost public concern</u>**. Streams, lakes, bays, estuaries and other bodies of water in this state, including not only water and materials for domestic, agricultural and industrial use but also habitats and spawning areas for fish, avenues for transportation and sites for commerce and public recreation, are vital to the economy and well-being of this state and its people. **<u>Unregulated removal of material from the beds and banks of the waters of this state may create hazards to the health, safety and welfare of the people of this state. Unregulated filling in the waters of this state for any purpose, may result in interfering with or injuring public navigation, fishery and recreational uses of the waters</u>**. In order to provide for the best possible use of the water resources of this state, it is desirable to centralize authority in the Director of the Department of State Lands, and implement control of the removal of material from the beds and banks or filling of the waters of this state.* (Emphasis added)

The Jordan Cove proposal is not consistent with land use laws and the comprehensive plan for protecting the public health, safety and welfare of citizens. The permit should be DENIED. **ORS 196.825 (3)(f)**

[27] *Japan's tsunami waves top historic heights*; By Dan Vergano, USA TODAY; 4/25/2011 http://usatoday30.usatoday.com/news/world/2011-04-24-Japan-record-tsunami-waves.htm

13. Project would have Negative Impacts on Navigation

On May 10, 2018 the U.S. Coast Guard issued a Letter of Recommendation (LOR) that stated the Coos Bay was now suitable for LNG traffic.[28] **If that is the case why is Jordan Cove currently proposing modifications to the Coos Bay channel?** The U.S. Coast Guard's LOR did not consider FAA Presumed Airport Hazard determinations for LNG tanker ships in the Coos Bay Estuary and many other channel hazard concerns including those listed in their 2008 Water Suitability Assessment (WSA) for Jordan Cove.[29]

The Coast Guard's July 1, 2008, Water Suitability Assessment (WSA) Report for the Jordan Cove project states on page 1 "*that Coos Bay is **<u>not currently suitable</u>**, but could be made suitable for the type and frequency of LNG marine traffic associated with this proposed project*." [30] (Emphasis added) Coast Guard mitigation measures include **limiting the LNG carrier to the physical dimensions of a 148,000 m3 class vessel**. The ship dimension used in the study reflected an overall length of 950 feet and a beam of 150 feet with a loaded **<u>draft of 40 feet</u>**. [31] (***See Exhibit 30***)

Jordan Cove's updated Resource Report #1 filed with the FERC on November 16, 2018 [32] states on page 41 (electronic page 82):

> *The waterway for LNG vessel marine traffic would traverse 7.5 miles of the existing Federal Navigation Channel within Coos Bay. The Federal Navigation Channel is zoned "Deep-Draft Navigation Channel" in the CBEMP. **<u>The Federal Navigation Channel, which is generally 300 feet wide and 37 feet deep</u>**, is maintained by the USACE on behalf of the Port. It is used by deep-draft commercial ships and barges, a commercial fishing fleet, and recreational boats*. (Emphasis added)

Jordan Cove Energy Project (JCEP) Nov 16, 2018 Update Resource Report #1 pages 25 to 26:

> *The Project's plans for the LNG carriers calling on the LNG Terminal and their transit route in Coos Bay, as described below, are primarily within the jurisdiction of the USCG. Because the USCG has authorized carriers of approximately 950 feet length, 150 feet beam, and loaded draft of 40 feet (nominal 148,000 m^3)[2] as the size of LNG carrier, the LNG Terminal could generate a maximum of 120 LNG carrier calls per year, although the average is expected to be between 110 and 120 LNG carriers per year. The actual number of LNG carriers per year will be dependent on the capacity of the LNG carriers calling on the LNG Terminal and the actual output production of the LNG Terminal. The LNG loading berth is designed so that it could accommodate LNG carriers up to 217,000 m^3 if larger-sized carriers were to be authorized by the USCG in the future, resulting in a reduced number of LNG carrier calls each year*

JCEP Nov 16, 2018 Update Resource Report #1 page 36:

> *The LNG Terminal would be located on the bay side of the North Spit, about 7.5 miles up the existing Federal Navigation Channel, **<u>approximately 1,000 feet north of the city limit of North Bend</u>**, in Coos County, Oregon*

[28] https://content.govdelivery.com/accounts/USDHSCG/bulletins/1ef91ba
[29] https://content.govdelivery.com/accounts/USDHSCG/bulletins/1ef91ba
[30] Coast Guard WSA for Jordan Cove LNG project, July 2008: https://homeport.uscg.mil/Lists/Content/Attachments/1008/WSRscan.pdf
[31] https://homeport.uscg.mil/Lists/Content/DispForm.aspx?ID=1008
[32] https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20181116-5198

Page 2 of the Coast Guard WSA states that "*the channel* ***must demonstrate sufficient adequacy to receive LNG carriers for any single dimension listed***." (Emphasis added) As noted above the Coos Bay is only dredged to 37 feet currently and the **current proposed dredging plans would not alter that fact**. LNG ships would transit the bay during high slack tides, the same tides used by the fishing fleet.

The May 10, 2018 U.S. Coast Guard LOR included in with the document the July 2008 WSA which clearly states that the Coos Bay waterway is "not" suitable, so the entire document kind of contradicts itself. In any event, the current proposed channel navigational alterations DO NOT demonstrate sufficiency for Jordan Cove's proposed LNG vessels as there are no plans to deepen the navigational channel or widen the Coos Bay channel entrance where weather, waves and undertows play a key role in increasing channel transit hazards

LNG VESSEL TRANSITS AND CHANNEL DEPTHS NOT COMPATABLE

Jordan Cove's Ship Simulation Study modeled its LNG carrier dimensions at 950 feet long, 150 feet at the beam, with a loaded draft of 40 feet deep, and a capacity of 148,000 m3**.**[33] **LNG ships with a 40 foot draft would transit the Coos Bay Navigation Channel that is dredged only 300 feet in width and 37 feet in depth. Current proposed Channel Alternations would not change the overall depth of the estuary.** (JCEP Rev RR#1) LNG vessels would be arriving and leaving at high tide (WSA page 3). **Jordan Cove's proposed Channel Navigation Alterations DO NOT FIX all the problems.**

On February 13, 2015, Jordan Cove uploaded into the FERC library their 2008 Report "*148,000 m3 Class LNG Carrier Transit and Maneuvering Simulations March 17-20, 2008*" by Moffatt & Nichol. This report clearly shows that the Coos Bay Navigation Channel is NOT SUFFICIENT FOR TRANSITING LNG VESSELS.

Modeling items noted upon review of the 2008 LNG Carrier study are as follows:

Electronic page 174
Run 17030801
LNG ship hits Slip Channel Entrance Cement Barrier

Electronic page 193-195
Run 17030802
Maneuvering Tugboat on the wrong side of the Slip Channel Entrance Cement Barrier
LNG ship and Maneuvering tugs very close to hitting buoy

Electronic page 212
Run 17030804
LNG Ship runs over buoy

[33] 2-13-2015 filing with FERC by JCEP Re- USACE Permit Application of Jordan Cove Energy Project, L.P. under CP13-483. includes 2008 Report "*148,000 m3 Class LNG Carrier Transit and Maneuvering Simulations March 17-20, 2008*" by Moffatt & Nichol http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20150213-5115

Electronic page 242-243
Run 18030802
Maneuvering Tugboat runs over buoy

How does the Coast Guard and the Jordan Cove Energy Project plan to account for these issues in regard to JCEP's transiting LNG Carriers, which are designed to have a 40-foot draft? Even transiting at high slack tide this does not appear to be a sufficient clearance.

At the Port Harbor Safety meeting held on January 15, 2019, Jordan Cove's consultant told everyone that the LNG ships would only have to transit during high slack tide when they were outgoing. Incoming LNG ships would be able to transit the channel <u>at any time</u>.

Despite Jordan Cove's recently refiled Resource Report #1 stating that the LNG ships would have an approximate loaded draft of 40 feet, Jordan Cove's consultant assured us that the ships had only a 37 foot draft at the Jan 15th Harbor Safety meeting. It wasn't clear how a 37 foot drafted ship could transit a 37 foot dredged channel, but even if Jordan Cove is allowed to dredge the channel down to 39 feet, by stating that this is a "required dredge depth" for a 37 foot navigational channel, **that still does not give enough clearance allowance**.

Criteria for the Depths of Dredged Navigational Channels Dec 12, 1983
https://apps.dtic.mil/dtic/tr/fulltext/u2/a135628.pdf

> Rules of Thumb The criteria used by the U.S. Army Corps of Engineers are empirical--rules of thumb. For design depth, or underkeel clearance, the rule is to select the design ship, add its draft + squat* (3 ft) + rolling and pitching allowance (estimate) + clearance (2 ft for soft channel bottoms; 3 ft for rocky or hard bottoms). The Corps' criteria recommend model tests and site evaluations.

The Feb 2018 Coos Bay Harbor Safety Plan[34] on electronic page 62 it states the following:

> *Guidelines for Under Keel Clearance in Coos Bays is on average 10% and is established by each vessel in consultation with the pilots.*

Ten percent of a 37 foot drafted ship would be 3.7 feet and of a 40 foot drafted ship would be 4 feet. **There is NOT enough clearance in the Coos Bay for safe passage of LNG tankerships even with Jordan Cove's proposed navigation improvements.**

The Feb 2018 Coos Bay Harbor Safety Plan states on electronic page 17: (***See Exhibit 31***)

> **3.5 Anchorage**
> * * * *
> *Due to the rapid and severe onset of weather from the North Pacific Ocean, **<u>anchorage in the ocean outside of Coos Bay is reported not safe and is dangerous during the winter months</u>**. Like all unprotected areas along the Oregon coast, large swells and heavy winds characterize the area during the winter. These conditions can suddenly and unexpectedly besiege the*

[34] https://static1.squarespace.com/static/569e6f1176d99c4f392858c4/t/5abc1b252b6a28c8f42cfd14/1522277173846/Coos+Bay+HSP+2018FEB20+update+2018MAR27.pdf

unwary with catastrophic results. The prevailing direction of both swell and wind will drive disabled or improperly handled vessels onto the shore.

While desired, ***there are currently no designated anchorage areas off the coast or within the channel, primarily due to the grounding of the M/V New Carissa in 1999 off the coast of Coos Bay.*** (Emphasis added)

The Feb 2018 Coos Bay Harbor Safety Plan states on electronic page 26:

4.1.3 Prevailing winds
Prevailing winds in the offshore sector are southerly winds, ***15-30 knots, in the summer and most of the year*** *but shifting to northerly winds in the winter. Prevailing NW winds and winter southerly storms.*

- *25 knots winds and above affect big ship movements*

*   *   *   *

Deep draft ships are warned of anchoring offshore during winter while awaiting calmer winds to transit. ***The rapid and severe onset of weather may expose the vessel to the risk of dragging ashore****.* (Emphasis added)

U.S. Coast Guard July 2008 Water Suitability Report states on page 3:

Tug Escort and Docking Assist*: ...Based on the ship simulation study conducted by Moffatt and Nichol on March 17-20, 2008,* ***vessels are limited to transiting during periods of high tide and 25 knot winds or less****. While unloading, all three tugs will remain on standby to assist with emergency departure procedures.* (Emphasis added)

If LNG vessels are to remain off-shore in bad weather HOW DOES THIS MAKE US SAFE? **No Plan exists that I know of with respect to SAFE offshore anchoring or maneuvering of LNG tanker ships off of Coos Bay for periods when winds exceed 25 knots.** HOW DO THEY PLAN TO PREVENT ANOTHER NEW CARISSA GROUNDING or WORSE?

Coos Bay Navigational Channel Entrance is most treacherous part of Shipping Transit

Jordan Cove's proposed Channel Navigation Alterations DO NOT SOLVE major shipping transit problems that occur at the Coos Bay channel entrance. Not only would the proposed alternations put more water volume in the channel and alter the Coos Bay channel's velocity and flow, the changes do not solve the problems with high surf and sneaker waves that commonly occur at the Coos Bay channel jetty entrance. It is not uncommon for the Coast Guard to close all the maritime entrances in Oregon and Washington due to flood debris, high seas.

"My job as a Captain of the Port is to ensure safety throughout the maritime infrastructure and part of that is to sometimes close the lanes of traffic that mariners use," said Capt. Dan Travers, commander Sector Columbia River and Captain of the Port for all ports in Oregon and Southwest Washington. "The storms that we all experienced over the last several days have made it dangerous for mariners to transit in and out of our many rivers due to severe sea conditions and debris."

"It's not rare at all to close the ports," said Coast Guard spokesman, Petty Officer 1st Class Levi Read. "The closures usually come with heavy sea conditions and the ships can't get out. The reason for this closure in addition to the heavy seas is because of the amount of the debris." [35]

Photo below is of the Rose Lynn as it crosses the Coos Bay Bar late in the afternoon as a wave breaks behind it in 2014. Photo by Kristal Talbot

14. Guidelines for Safety are Not Being Followed

Many of the guidelines for safety that are suggested in the gas industries own "*Society of International Gas Tanker & Terminal Operators"* (SIGTTO**)**[36] Information Paper No. 14 have been completely ignored in this terminal siting.

Examples of SIGTTO guidelines not addressed adequately include:

1) **Approach Channels. Harbor channels should be of uniform cross-sectional depth and have a minimum width, equal to five time the beam of the largest ship**
2) **Turning Circles. Turning circles should have a minimum diameter of twice the overall length of the largest ship, where current effect is minimal. Where turning circles are located in areas of current, diameters should be increased by the anticipated drift.**
3) **Tug Power. Available tug power, expressed in terms of effective bollard pull, should be sufficient to overcome the maximum wind force generated on the largest ship using the terminal, under the maximum wind speed permitted for harbor maneuvers and with the LNG carrier's engines out of action.**
4) **Site selection process should remove as many risk as possible by placing LNG terminals in sheltered locations remote from other port users. Suggest port**

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[35] *Coast Guard closes all maritime entrances in Oregon, Washington due to flood debris, high seas (video)*; Dec 11, 2015 https://www.oregonlive.com/pacific-northwest-news/2015/12/coast_guard_closes_all_maritim.html
* Coast Guard transiting Coos Bay Channel Entrance: https://www.youtube.com/watch?v=qvordhPI8Ds
* Sneaker wave south of Coos Bay Caught on camera: https://www.youtube.com/watch?v=RPypT9dOvSY
[36] *Site Selection & Design for LNG Ports & Jetties – Information Paper No. 14* **-** Published by Society of International Gas Tanker and Terminal Operators Ltd / 1997

designers construct jetties handling hazardous cargoes in remote areas <u>where ships do not pose a (collision) risk</u> and <u>where any gas escaped cannot affect local populations.</u> Site selection should limit the risk of ship strikings, limiting interactive effects from passing ships and reducing the risk of dynamic wave forces within mooring lines.

5) **Building the LNG terminal on the outside of a river bend is considered unsuitable due to fact that a passing ship may strike the berthed carrier if the maneuver is not properly executed.**
6) **SIGTTO Examples given for reducing risk factors beyond normal operations of ship/shore interface include LNG terminal patrols of the perimeter of the offshore safety zones with guard boats and <u>to declare the air-space over an LNG terminal as being a restricted zone where no aircraft is allowed to fly</u> without written permission.**
7) **Restriction of the speed of large ships passing close to berthed LNG carriers.**

Also ignored were some of the safety guideline preventative measures found in the Sandia National Laboratories Report – "*Guidance on Risk Analysis and Safety Implications of Large Liquefied Natural Gas (LNG) Spill Over Water*" – Dec 04:

Guidelines (Pg 64) include: [37]

1) Appropriate off-shore LNG ship interdiction and inspections for explosives, hazardous materials, and proper operation of safety systems;
2) Appropriate monitoring and control of LNG ships when entering U.S. waters and **protection of harbor pilots and crews**;
3) **Enhanced safety zones around LNG vessels (safety halo) <u>that can be enforced</u>;**
4) **<u>Appropriate control of airspace over LNG ships</u>**; and
5) **Appropriate inspection and protection of terminal areas, tug operations prior to delivery and unloading operations.**

In addition, scientist have found that safety measures incorporated in the proposed Jordan Cove LNG terminal actually increase the chance of a catastrophic failure and present a far more serious public safety hazard than regulators have analyzed and deemed acceptable.[38] Jerry Havens , Distinguished Professor of Chemical Engineering at University of Arkansas, and James Venart, Professor Emeritus of Mechanical Engineering at University of New Brunswick, have asked specific questions to the FERC concerning these hazard issues. [39] Those questions need to be addressed properly. The proposed Jordan Cove Project would impact potential future industry and the Ports proposed Oregon Gateway cargo terminal to the East of the proposed LNG facility, which would not be allowed to operate in these hazard areas.

"*Once ignited, as is very likely when the spill is initiated by a chemical explosion, the floating LNG pool will burn vigorously…Like the attack on the World Trade Center in New York City,*

[37] Without an emergency response plan to review it is hard to know if some of these recommendations have been met.
[38] January 14, 2015 Report filed by Jerry Havens Ph.D and James Venart Ph.D. to FERC concerning *discrepancies and problems with Jordan Cove Energy Project hazard analysis* under CP13-483 et. al.
http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20150114-5038
[39] Feb 6, 2014 Follow-up Report/ *Questions concerning discrepancies and problems with Jordan Cove's hazard analysis* under CP13-483 et al.
http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20150206-5040

*there exists no relevant industrial experience with fires of this scale from which to project measures for securing public safety***.**" – Statement by Professor James Fay, Massachusetts Institute of Technology . (Emphasis added.)

Sandia Laboratory's Dec 2004 Report; "*Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water"*, states on page 83; "*... The distance from the fire to an object at which the radiant flux is 5 kW/m2 is 1.9 km"* (1.181 miles). **To clearly understand this one must understand that 5 kW/m2 is the heat flux level that can cause 2nd degree burns on exposed human skin in 30 seconds.**

An estimated 16,922 people would live in the hazardous zones of concern according to the former Jordan Cove Export Final EIS (page 4-1031) under CP13-483-000/CP13-492-000, and yet there is little concern given for their safety. Trees and burnable scrub brush cover our area. Secondary fires will be paramount and **most of our emergency responders are located in the LNG hazardous zones of concern**. The Coos Bay area has one hospital, it does not have a "Burn Unit." We have yet to see an emergency response plan on how the medical response to even a minor LNG hazardous event could be handled in light of our area's obvious insufficiency of appropriate medical facilities and personnel. This was just one of many concerns that were raised in scoping comments to FERC that have yet to be addressed.

On Friday, March 29, 2019 the Federal Energy Regulatory Commission (FERC) released the Draft Environmental Impact Statement (DEIS) on Pembina's proposed Jordan Cove LNG Export Project under Docket Nos. CP17-494-000 and CP17-495-000. The DEIS for the Jordan Cove/Pacific Connector project shows the following diagram on page 4-709

Jordan Cove Energy Project *Draft EIS*

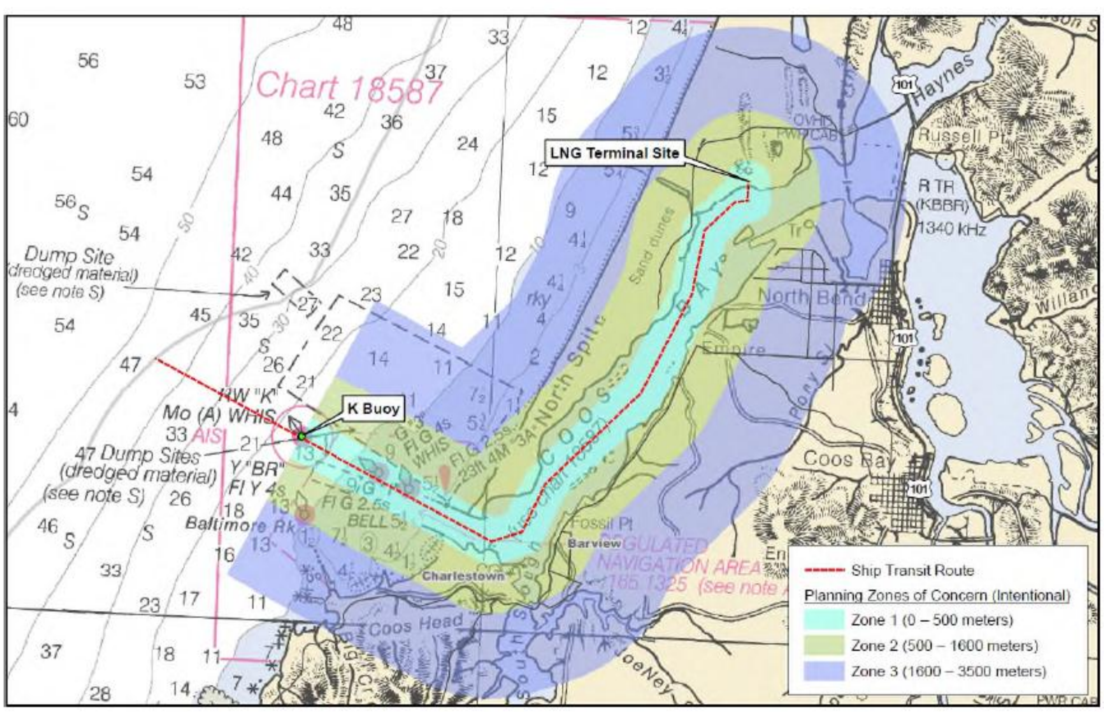
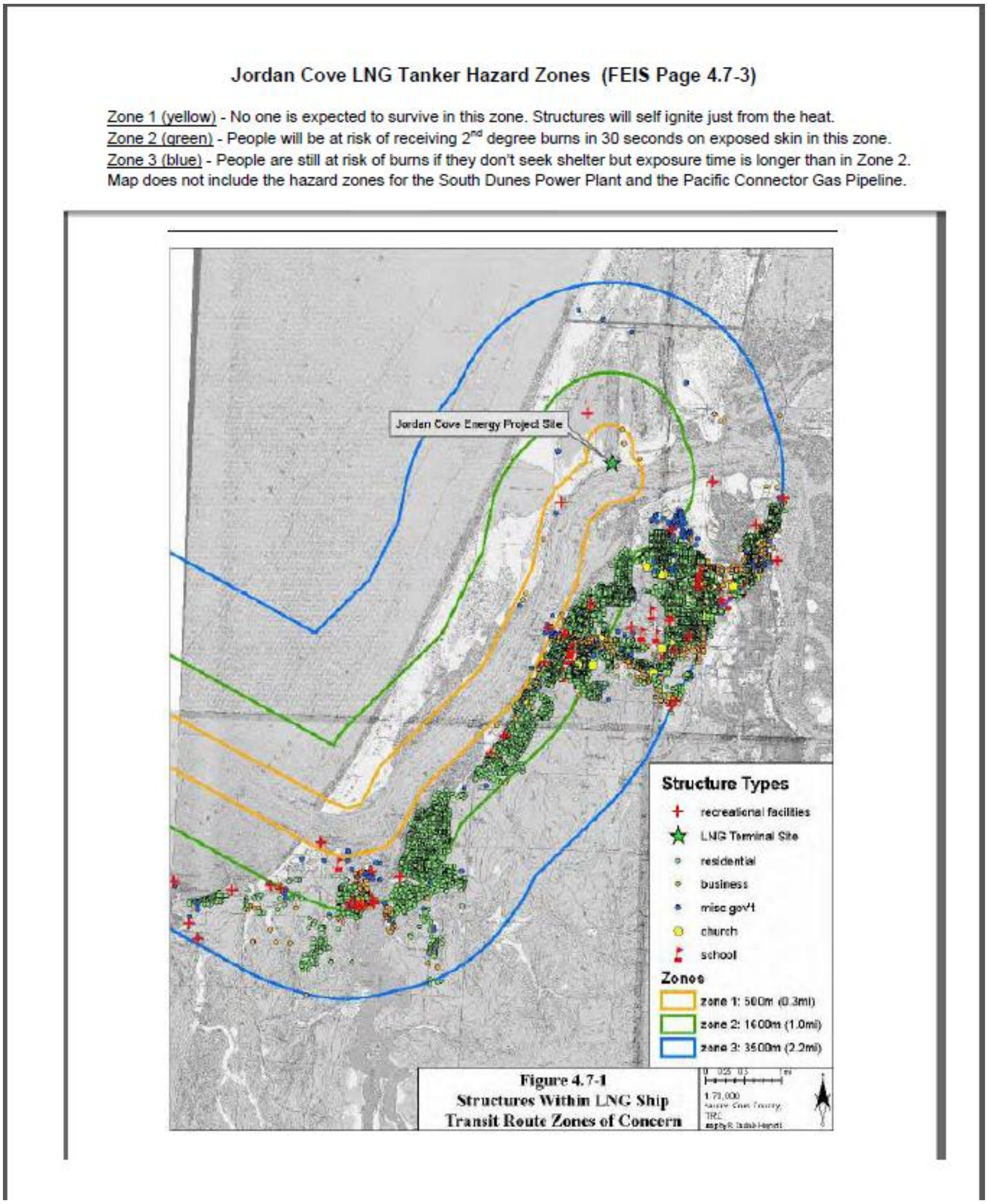


Figure 4.13-2. Intentional Hazard Zones along LNG Marine Vessel Route

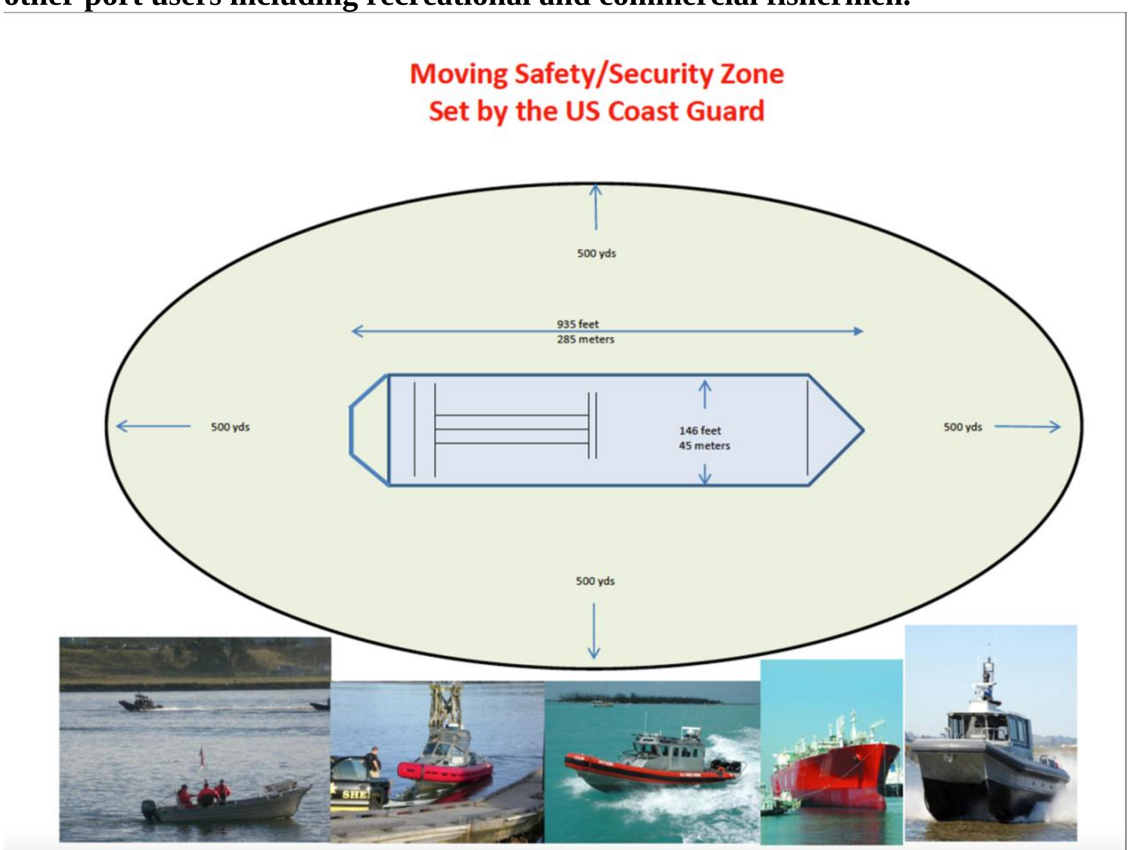
The Diagram below is from the Jordan Cove Import Final EIS page 4.7-3 under CP07-444-000/CP07-441-00 and shows a little more detail with respect to Jordan Cove's LNG Hazard impacted areas:



The City of Coos Bay needs to consider these issues and make sure that all SIGTTO guidelines for LNG carriers are followed in our narrow channel and bay. LNG tankers would transit only 6/10ths of a mile from children attending Sunset and Madison schools. The LNG tankers would transit within 1,350 feet of the community of Empire, 2,150 feet of the community of Barview, 1,900 to 2,300 feet of the Charleston breakwater, and 2,100 to 3,100 feet of the North Bend Airport. This is well within the LNG hazard zone distances that have been established by the many government and scientific reports. If the LNG facility is sited and built, thousands of people would be living and working in an LNG hazardous burn zone in the North Bend, Coos Bay, Empire, Barview, Charleston, and Glasgow comminutes. Thousands of people that visit the National Dunes Recreation Area year round would also be placed at risk. Even a minor incident may be devastating to our Coos Bay area of 30,000 to 40,000 people.

The Coast Guard WSA has established Safety/Security Zones for LNG vessels **both** while the vessels are moored and when they are not moored. When an LNG vessel is at the docking facility there is to be a 150 yard security zone around it, to include the entire terminal slip, and when there is no LNG vessel moored, the security zone will cover the entire terminal slip and extend 25-yards into the waterway. (See CG-WSA page 2) In addition, the Coast Guard has set a moving safety/security zone for the LNG tanker ship that extends 500-yards around the vessel but ends at the shoreline. **No vessel may enter the safety/security zone without first obtaining permission from the Coast Guard Captain of the Port who resides in the Portland, OR office**.[40] (See CG-WSA page 2)

This safety and security zone will encompass the entire bay in some areas and be a hindrance to other port users including recreational and commercial fishermen.



The Coast Guard WSA states on page 3 under Tug and Docking Assist:

> *…Based on the Ship simulation Study conducted by Moffatt & Nichol on March 17 -20, 2008, **vessels are limited to transiting during periods of high tide and 25 knot winds or less**. While unloading, all three tugs will remain on standby to assist with emergency departure procedures.*

This is also optimal tides that the fishing fleet uses.

[40] Coast Guard - LOR / WSR / WSA for Port of Coos Bay / Jordan Cove Energy Project: https://homeport.uscg.mil/Lists/Content/DispForm.aspx?ID=1008

How close is too close for proposed transiting LNG Tanker Ships in Coos Bay? (***See Exhibit 32***)

Photos above are of cargo ships transiting our Coos Bay Harbor. These ships are considerably smaller than LNG ships. (See photo comparison below) The photo above on the left is the view from the deck of a local homeowner. The photo on the right is from the Boat House Auditorium in Charleston at a Coos County Board of Commissioners meeting held on July 10, 2012. A wood transport ship passes by in the Coos Bay Channel next to the Boat House Auditorium

Below a typical local cargo ship as compared to a smaller LNG ship

The LNG Terminal could generate a maximum of 120 LNG carrier calls per year, although the average is expected to be between 110 and 120 LNG carriers per year. [Jordan Cove RR #1 page 25 & 26]

This amounts to 220 to 240 harbor disruptions per year during high slack tides which are also prime tides used currently by other bay users.

If the Coast Guard choses to not follow their own Water Suitability Assessment requirements designed to protect the safety and security zone around both a transiting and docked LNG tanker ship, they would be placing some 20,000 to 40,000 people in Coos Bay Area at extreme risk, including Coast Guard personnel.

JCEP Computer Modeling Flawed with Respect to Public Safety Hazards

On Monday, April 1, 2019, Jerry Havens, Distinguished Professor of Chemical Engineering at University of Arkansas, submitted detailed comments with respect to public safety hazards being underestimated at the proposed Jordan Cove LNG terminal under FERC Docket Nos. CP17-494-000 and CP17-495-000. (***See Exhibit 67***)

According to Havens, computer modeling used to predict the Jordan Cove Energy Project (JCEP) LNG export terminal vapor cloud explosion hazards have not been approved for predicting explosion overpressures by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA). Havens expressed concerns to both the FERC and to the PHMSA that the Government is failing to adequately provide for the risks of potentially devastating Unconfined Vapor Cloud Explosions (UVCEs) of heavier-than-methane hydrocarbons at the proposed Jordan Cove Export Terminal (JCET) site. **Those hazards appear to be seriously underestimated**.

> *The new Draft Environmental Impact Statement (DEIS) for the Jordan Cove Export Terminal, just issued, continues to seriously underestimate vapor cloud explosion overpressures (damage) that could occur following credible releases of heavy hydrocarbons at the JCET site. The latest predictions that I am aware of appear to be an order of magnitude lower than are indicated by physical evidence of numerous documented UVCEs that have occurred worldwide with the potential to cause injuries and deaths to persons and result in destruction of the facility.*
> Jerry Havens, PhD, April 1, 2019

This is not the first time these concerns have been raised by the Distinguished Professor. On January 14, 2015 [41], and February 6, 2015 [42], both Professor Havens and Professor James Venart (Professor Emeritus of Mechanical Engineering at University of New Brunswick) published several papers with respect to the former Jordan Cove LNG Export Terminal Draft Environmental Impact Statement under FERC Docket No. CP13-483 et al. **Professor Havens and Professor Venart found significant discrepancies and problems with Jordan Cove's hazard analysis and determined the hazards had been significantly underestimated.** Safety measures incorporated in the proposed Jordan Cove LNG export terminal actually increased the chance of a catastrophic failure and presented a far more serious public safety hazard than regulators had analyzed or deemed acceptable. On January 16, 2015, Oregonian reporter Ted Sickinger wrote an article summarizing the January 2015 FERC filing; "*Scientists say public safety hazards at Jordan Cove LNG terminal in Coos Bay are underestimated*" (***See Exhibit 68***)

PHMSA Finds Hazard Concerns Justified

On April 11, 2016, the PHMSA contracted with the British Health and Safety Laboratories (HSL) for an Expert Evaluation of the Risk of Unconfined Vapor Cloud Explosions. On May 18 and 19, 2016, the PHMSA conducted a two day Public Workshop on Liquefied Natural Gas (LNG) Regulations in Washington, DC. The PHMSA stated at that time that:

> "*This two-day LNG Workshop is to solicit input and obtain background information for the formulation of a future regulatory change to CFR 49 Part 193, Liquefied Natural Gas*

[41] https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20150114-5038
[42] https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20150206-5040

> *Facilities. This workshop will bring federal and State regulators, emergency responders, NFPA 59A technical committee members, industry, and interested members of the public together to participate in shaping a future liquefied natural gas (LNG) rule.*"

On June 7, 2016, E&E reporter, Jenny Mandel, published an article, "*Explosive LNG issues grab PHMSA's attention,*" concerning the two day PHMSA LNG Workshop event. (***See Exhibit 69***)

After input from the LNG Workshop, the HSL finalized their Report: "*Review of Vapor Cloud Explosion Incidents*" in June of 2016.

Despite the findings found in the HSL Report and multiple comments submitted to the PHMSA with respect to this issue by Professor Havens on July 28, 2016, September 22, 2018, October 2, 2018, December 3, 2018, and now once again on April 1, 2019, nothing has ever been done by the PHMSA to formulate a regulatory change or address these critical hazard issues.

Sightline / CSB Confirm Regulatory Gaps

On June 3, 2016, Sightline reporter, Tarika Powell, did a follow-up report on the explosion that had occurred on March 31, 2014 at a much smaller liquefied natural gas (LNG) peak shaving plant in eastern Washington. That explosion forced hundreds to evacuate their homes within a two mile radius of the facility, injured five workers, and caused $69 million in damages.

Powell's 2016 Sightline article[43] states that the Washington Department of Labor and Industries (Washington L&I), which had conducted an investigation into the safety of employees at the Plymouth plant found that Williams endangered its employees, lacked an adequate emergency response plan, and had deficient safety training. The company's track record—not just in the Northwest, but throughout the US—revealed a pattern of failing to heed safety regulations. This illustrates why we should not underestimate the fire and explosion hazards of natural gas processing plants such as LNG facilities. (***See Exhibit 75***)

On October 21, 2015, the U.S. Chemical Safety Board (CSB) finalized an investigation report into the 2009 massive explosion at the Caribbean Petroleum, or CAPECO, terminal facility near San Juan, Puerto Rico.[44] The report included recommendations for addressing regulatory gaps in safety oversight of petroleum storage facilities by the Occupational Safety and Health Administration (OSHA) and Environmental Protection Agency (EPA). It is not clear to me whether the CSB recommendations were ever addressed by regulators. While the CAPECO incident involved the storage of gasoline, the same overfilling of a storage tank could also occur with LNG, but with even more disastrous results.

Jordan Cove Continues to Ignore Hazard Concerns

Despite all the concerns about safety that have been raised with respect to the proposed Jordan Cove LNG Project over the last 15 years, the Project sponsors have continued to ignore or disregard most of these concerns.

[43] https://www.sightline.org/2016/06/03/williams-companies-failed-to-protect-employees-in-plymouth-lng-explosion/
[44] https://www.csb.gov/caribbean-petroleum-refining-tank-explosion-and-fire/

Jordan Cove is proposing to build an LNG export terminal on dredging spoils located on a sand spit (an unstable sand dune area), directly across the bay from an airport runway, in the flight path of the runway, in an extreme tsunami inundation zone, in an earthquake subduction zone, in an area known for high winds and ship disasters, less than a mile from a highly populated city. Thousands of people in the Coos Bay/North Bend area would be put at risk due to living in Jordan Cove's LNG Hazardous Burn Zones. The Project is one of the worst sited LNG export proposals out there.

FERC's current Draft EIS and suggested unprecedented 137 Conditions of Approval do not alleviate the concerns.

At some point here regulators need to stop catering to the gas and oil industry and stop delaying all the regulatory oversight and updates that are necessary in order to protect the public health, safety and welfare of the American people.

Please include the following supporting documents into the record concerning this issue:

Exhibit 70: "*Site Selection & Design for LNG Ports & Jetties – Information Paper No. 14*" - Published by *Society of International Gas Tanker and Terminal Operators Ltd* / 1997

Exhibit 71: United States Government Accountability Office, Report to Congressional Requesters, Maritime Security; "*Public Safety Consequences of a Terrorist Attack on a Tanker Carrying Liquefied Natural Gas Need Clarification*", February 2007; GAO-07-316: http://www.gao.gov/new.items/d07316.pdf

Exhibit 72 : U.S. Department of Energy "*Liquefied Natural Gas Safety Research*" Report to Congress May 2012.

Exhibit 73: "*An Assessment of the Potential Hazards to the Public Associated with Siting an LNG Import Terminal in the Port of Long Beach"* - Dr. Jerry Havens, September 14, 2005

Exhibit 74: *"LNG and Public Safety Issues – Summarizing Current Knowledge about Potential Worst Case Consequences of LNG spills onto water"*. Jerry Havens, Coast Guard Journal Proceedings, Fall 2005

The Pembina pipeline company, which is now 100% owner of the Jordan Cove LNG Project, is relatively new to this project. They are out of Canada where it appears regulation is rather lax when it comes to oversight . We don't therefore know how good of a company these guys actually are.

Spills and Leaks
https://albertaviews.ca/spills-and-leaks/
Just how safe are Alberta's oil and gas pipelines?
By Tadzio Richards
October 1, 2013

The Star.com – Canada
https://www.thestar.com/news/canada/2012/06/20/alberta_oil_spills_highlight_aging_pipelines_lax_regulations_say_environmental_groups.html
Alberta oil spills highlight aging pipelines, lax regulations, say environmental groups

Environmental groups are pointing to three major oil spills in Alberta in the last six weeks as proof that the government needs stricter regulations and oversights over the provinces aging pipeline infrastructure
By Petti Fong - Western Canada
Wed., June 20, 2012

> *…"We have over 300 spills a year and it's due to the aging pipeline infrastructure. That's why the government should appoint an independent body.* ***There are obviously huge problems with oversight and we're leaving too much to companies to regulate and enforce themselves****," he said Wednesday….* (Emphasis added)

Alberta Energy Regulator Investigation Reports
https://www.aer.ca/data-and-publications/publications/ongoing-investigations

Pembina Pipeline failure June 15, 2008
https://www.aer.ca/documents/reports/IR_20090219_PembinaPipelineFailure.pdf

Pembina Pipeline failures July 20 and Aug 15, 2011
https://www.aer.ca/documents/reports/IR_20130226-Pembina.pdf

On April 27, 2016 the Calgary press reported that Pembina Pipeline Corp. (TSX:PPL) had reported that a contractor working at a facility in Alberta had died in an accident. The company says it happened at about 1:40 p.m. MT at the Williams' Redwater Olefinic Fractionator in Redwater, northeast of Edmonton. The man was working in a tower at the Pembina pipeline plant, using a breathing mask with supplied oxygen when he became distressed, an Occupational Health and Safety spokeswoman said. A safety watch employee attempted CPR but was unable to revive the worker, who died on scene.

https://www.winnipegfreepress.com/business/contractor-killed-in-accident-at-pembina-facility-in-alberta-377372721.html
and
http://www.cbc.ca/news/canada/edmonton/man-dead-after-workplace-incident-near-redwater-alta-1.3557269

Pembina doesn't have such a great track record either it appears from the following news story below.

The Globe and Mail
http://www.globoble.com/news/ngp-sues-pembina-pipeline-for-501million-over-mosaic-energy-collapse#.WZMhs1GGM2w
Texas firm sues Pembina for $501-million over Mosaic Energy collapse
By Jeff Lewis
August 14, 2017

> *A Texas private equity firm is suing Pembina Pipeline Corp. for a half-billion dollars, arguing one of its investments was driven into receivership by the pipeline company.*
>
> *Irving, Tex.-based NGP Energy Capital Management LLC is seeking at least $501-million in damages tied to its investment in defunct Mosaic Energy Ltd., according to a statement of claim filed in the Court of Queen's Bench of Alberta in Calgary….*

Citizens have a right to have their lives and property protected and not subjected to harm or even death due to improper planning. When the projected Cascadia subduction earthquake occurs off the Oregon Coast this would compound the problem and mean more harm.

15. Project would have Negative Impacts on the Airport. FAA Determinations Declare Project Creates Airport Hazards.

The Feb 2018 Coos Bay Harbor Safety Plan states on electronic page 18:

> ***Southwest Oregon Regional Airport****: For safety reasons, the FAA limits the height of vessel transiting in front of the runway. Inbound and outbound vessel traffic near the Airport may affect procedures for aircraft landing and departing at the airport. Vessels with an air draft of 144 feet or greater present a potential obstruction to airspace that requires advisories be issued to aircraft by air traffic controllers, and in some cases, runway use may need to be restricted. See Special Navigational Conditions for more for more details.*

On May 7, 2018 the FAA released 13 determinations of PRESUMED AIRPORT HAZARD with respect to the proposed Jordan Cove Project.[45] Jordan Cove has not resolved these issues and they are not able to be mitigated. **Nine of these FAA Presumed Airport Hazards involve transiting LNG tanker ships at various points within the Coos Bay Estuary**. (***See Exhibit 33***) This would be devastating to the Southwest Oregon Regional Airport operations, navigation and fishing. It clearly violates OAR 141-122-0020(5)(a) and ORS 196.825(1)(a)(b);(3)(a)(e). No FAA or Dept of Aviation approval has been given

Presumed Airport Hazards are included in Exhibit 33 as follows:

- LNG Carrier Vessel - Stack, Transit Point 6 - 2018-ANM-720-OE
- LNG Carrier Vessel - Stack, Transit East Point - 2018-ANM-719-OE
- LNG Carrier Vessel - Stack, Transit West Point - 2018-ANM-718-OE
- LNG Carrier Vessel - Stack, Transit Point 5 - 2018-ANM-8-OE
- LNG Carrier Vessel - Stack, Transit Point 4 - 2018-ANM-7-OE
- LNG Carrier Vessel - Stack, Transit Point 3 - 2018-ANM-6-OE
- LNG Carrier Vessel - Stack, Transit Point 2 - 2018-ANM-5-OE
- LNG Carrier Vessel - Stack, Transit Point 1 - 2018-ANM-4-OE
- LNG Carrier Vessel - Stack - 2017-ANM-5418-OE
- Amine Regenerator - 2017-ANM-5389-OE
- Oxidizer - 2017-ANM-5388-OE
- LNG Tank North - 2017-ANM-5387-OE
- LNG Tank South - 2017-ANM-5386-OE

ORS 196.825

> *"The Director of the Department of State Lands shall issue a permit applied for under ORS 196.815 (Application for permit) if the director determines that the project described in the application:*

[45] See Part 8 of Jordan Cove response filing with the FERC that includes the 13 FAA documents: http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20180510-5165

(a) Is consistent with the protection, conservation and ***best use of the water resources of this state*** *as specified in ORS 196.600 (Definitions for ORS 196.600 to 196.655) to 196.905 (Applicability); and*

(b) ***Would not unreasonably interfere with the paramount policy of this state to preserve the use of its waters for navigation, fishing and public recreation****.*

*   *   *   *

3) In determining whether to issue a permit, the director ***shall consider all of the following****:*

(a) ***The public need*** *for the proposed fill or removal….*

*   *   *   *

(e) Whether the proposed fill or removal conforms to sound policies of conservation and ***would not interfere with public health and safety****.*

*   *   *   *

(Emphasis added)

OAR 141-122-0020 Policies

5) The Department ***will not grant an easement*** *if:*

(a) As a result of its circulation for public comment of the application for easement as described in OAR 141-122-0050(3) it determines that ***the proposed use or development would unreasonably impact uses or developments proposed or already in place within the requested area****; …*

(Emphasis added)

The Southwest Oregon Regional Airport in North Bend is a key part of the Coos Bay area's transportation system that is **already in use**. United Airlines flies to San Francisco daily. United also offers a seasonal flight to Denver on Wednesdays and Sundays from June 10th to October 3rd.[46] The airport also continues efforts to also secure Portland air service.[47]

The Coos Bay Navigation Channel is located here between the North Spit and the end of the East/West runway of the Southwest Oregon Regional Airport. OTH

[46] https://cooscountyairportdistrict.com/faq/

[47] https://cooscountyairportdistrict.com/airport-continues-efforts-to-secure-portland-air-service/

Photo below – Private jets facing north are lined up at Coos Aviation in Sept of 2015. The Bandon Dunes World Renowned Golf Course brings in a lot of private planes like this to our area.

The proposed Jordan Cove project would unreasonably negatively impact the Southwest Oregon Regional Airport and likely cause loss of federal dollars that the airport depends on in order to maintain operations.

Electronic page 107 of Jordan Cove DSL application states:

> ***6.2.3 Access and Utility Corridor***
> *An approximately 1-mile-long permanent access and utility corridor* ***will be constructed between Ingram Yard and the South Dunes site*** *to provide a conduit for the underground feed gas supply to the LNG Terminal and a number of underground utilities, as well as a location for permanent aboveground facilities, including fire water storage tanks for the LNG Terminal and the Fire Department facility.* (Emphasis added)

A utility corridor on top of proposed fill may not necessarily be an increased airport hazard but a high-pressure/high-volume hazardous natural gas pipeline with its significant hazard zone would be an increased hazard since it would cross the approach surface overlay of the South West Oregon Regional Airport. The proposed Pacific Connector Gas Pipeline hazardous zone would extend out 800 to over 1,000 feet from the center of the proposed pipeline. **It would NOT be acceptable to locate a hazardous pipeline such as this in the approach surface of the airport runway.** This hazard must be dealt with by someone outside of the County local planning jurisdiction since the Coos County Planning Department has not been addressing this hazard.

Jordan Cove is proposing that large volumes of LNG be stored in two (2) full-containment LNG storage tanks, each designed to store 160,000 cubic meters of LNG, along with LNG ships that would be transiting our narrow harbor capable of storing up to 148,000 cubic meters. LNG tankerships would pass within feet of the end of the airport runway and the two storage tanks are located within a mile of the runway. **This would NOT be in the public interest and violates safety recommendations for the safe siting of LNG ports and jetties.**

Planes also do not always fly down the centerline of the runway approach surfaces, as one can see in the photo below (looking across the Coos Bay towards the North Spit and Jordan Cove's property on Sept 20, 2014). Perhaps this planes direction was due to a missed approach or maybe it was just due to people doing some sightseeing along our Oregon Adventure Coastline.[48] A lot of people do that here.

COOS BAY AREA FOG

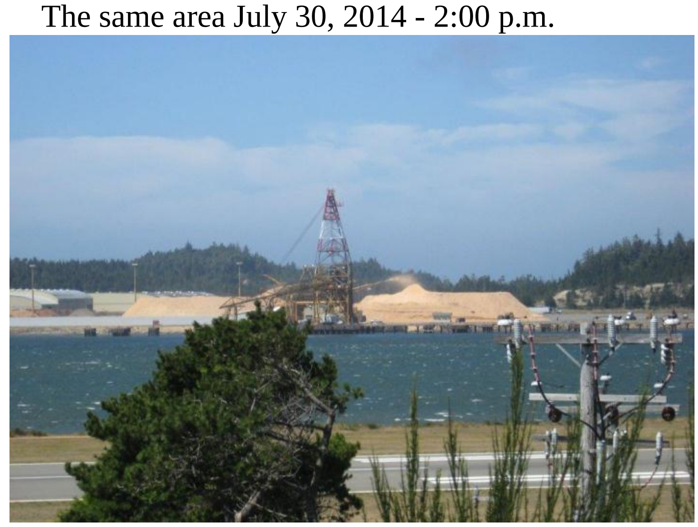
The Feb 2018 Coos Bay Harbor Safety Plan states on electronic page 18:

> ***4.1 Weather***
> *4.1.1 Fog*
> *The area is subject to fog conditions very similar to many west coast ports. Fog can be found anywhere within Coos Bay and its tributaries. Fog occurs mostly during summer and fall though is known to occur during other seasons too.*

Photos below are looking from the City of North Bend to the North at the Roseburg Chip Facility on the North Spit across the Bay from the Southwest Oregon Regional Airport.

July 30, 2014 - 10:00 a.m.

The same area July 30, 2014 - 2:00 p.m.



[48] http://www.oregonsadventurecoast.com/

Photos below are looking from the City of North Bend to the North across the Southwest Oregon Regional Airport Runway at the proposed area for the Jordan Cove LNG Export facility that includes the proposed LNG marine terminal, liquefaction trains and two 242 foot high LNG storage tanks.

July 30, 2014 - 10:00 a.m.

The same area July 30, 2014 - 2:00 p.m.

Coos Bay area fog comes on rapidly and sometimes unexpectedly. Thermal heat plumes that would be coming from the proposed Jordan Cove facility and LNG vessels **would only increase this problem by causing even more fog clouds to form on cold days**. **This increased hazard is not acceptable.**

JORDAN COVE'S THERMAL PLUMES

According to Jordan Cove's application they plan on liquefying a maximum of 7.8 mtpa (1,077 MMscf/d) of LNG production net, after deduction for Boil-Off Gas ("BOG") generation.[49] This requires an entirely different process from importing LNG that is considerably more hazardous. Liquefaction Trains that are currently proposed as a part of the Jordan Cove LNG Export facility would emit enormous amounts of heat into the atmosphere. This would contribute to thermal plumes and additional fog in the area. **This would create additional hazards to both navigation in the Bay and to the operation of the South West Oregon Regional Airport**.

On January 21, 2015, the FAA put out a Memorandum concerning a "*Technical Guidance and Assessment Tool for Evaluation of Thermal Exhaust Plume Impact on Airport Operations.*"[50] (***See Exhibit*** 34)

Pilots in Troutdale, Oregon, have pointed out the hazards of such "heat" plumes in front of airport approach surfaces. An article that came out on April 22, 2015 in the Willamette Week entitled, "*Hot Air*" stated the following: [51] (***See Exhibit 35***)

> *...Initially, pilots worried that a power plant at Troutdale would hamper visibility. Gas-fired generating plants work by boiling water to produce steam that drives turbines. When the water*

[49] Jordan Cove Revised Draft Resource Report #1 page 20. http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20181116-5198
[50] https://www.faa.gov/airports/environmental/land_use/media/Technical-Guidance-Assessment-Tool-Thermal-Exhaust-Plume-Impact.pdf
[51] http://www.wweek.com/portland/article-24594-hot_air.html

is cooled, the steam roiling out of the plant's cooling towers could fog pilots' flight paths and create a hazard.

But the bigger concern now is heat.

Earlier this year, the Federal Aviation Administration directed Troutdale users to an independent consulting firm to analyze the potential impact of the invisible plume of hot air that the combustion of gas by the plant would produce.

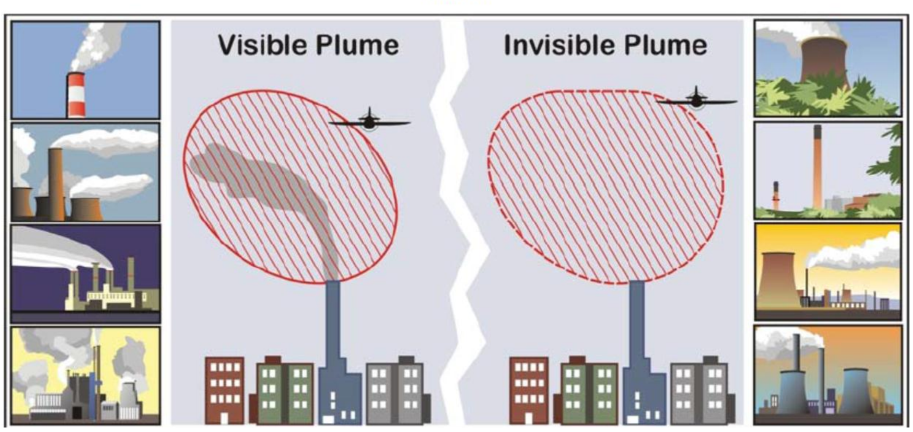
"You're putting a known but invisible hazard right into the path that pilots using Troutdale must fly," says Mary Rosenblum, a Canby resident and president of the Oregon Pilots Association.

Rosenblum says modeling shows the plume could suddenly lift one wing and flip a plane upside down.

"This would happen when the plane is 1,000 feet or less off the ground," Rosenblum says. "At that altitude, you cannot recover."

The FAA consultant's initial analysis in March found that the invisible plumes could cause as many as a dozen planes to lose control and crash annually—with fatal consequences. A second run of the same model earlier this month found it could happen even more often.
Risk modeling done for the Troutdale Energy Center in 2013 found no such danger….
(Emphasis added)

FIG 7-5-2
Plumes



(***See Exhibits 36 and 37***)

The top of the 160,000 cubic meter LNG tank is very vulnerable as this is where the supply pipeline penetrates the tank for both the transfer of LNG and capture of boil off gases. Dr. James Venart raised issue with the fact that a worst case scenario tank top fire hazard had not been sufficiently analyzed in the hazard analysis of the Jordan Cove LNG Export project. The potential hazards would be far worse than what has been estimated by Jordan Cove. There is no comparison between a plane hitting a tree as has been previously suggested by Jordan Cove's consultants and a plane hitting a 160,000 cubic meter storage tank full of liquefied natural gas or an LNG tanker transiting in the waterway. A tree does not have the ability to cause cascading failures that could lead to some 17, 000+ people, who live, work and recreate in Jordan Cove's acknowledged hazardous burn zones, from being severely burned and/or killed.

Shanghai Wuhaogou LNG Expansion Project two new 50,000 m3 LNG storage tanks.

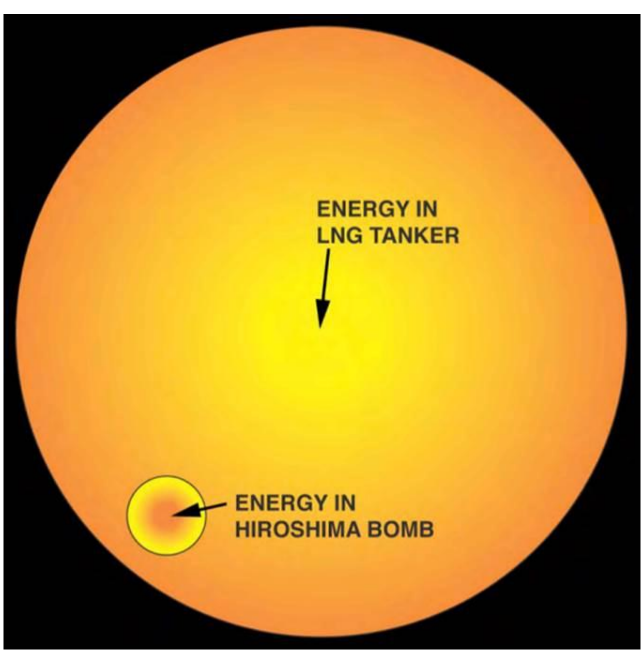
In an interview with Steve Curwood on NPR radio that aired in April of 2005, Robert (Bud) MacFarlane, former national security advisor to President Reagan and James Woolsey, former director of the CIA under the Clinton administration stated the following:

> *CURWOOD: Just to be clear, how vulnerable is vulnerable when you say that there are parts in the Persian Gulf that could be easily disrupted by a terrorist? How easy?*
> *WOOLSEY: Well, let me use only an illustration from Bob Baer, a former CIA officer that's written a book called, "Sleeping with the Devil," in which the opening scenario is a terrorist crashing a 747 into the sulfur cleaning towers up near Ras Tanura in northeastern Saudi Arabia. Since you have to get sulfur out of the Saudi oil that would take several million barrels, probably around five or six million barrels a day, off line for a year or more. And Bud here is an old artilleryman. He and I were talking the other day; I think he'll tell you you probably don't need a big 747 to do that. A pretty skilled guy with some orders could probably do it.*
> *CURWOOD: So, Bud MacFarlane, now the national security aspect of this?*
> *MACFARLANE:* ***Well, as Jim said, I was an artilleryman for 20 years and I can tell you with high confidence that I would have no problem at all in shutting down Ras Tanura on any given afternoon. Four-point-two inch mortar can go 4,000 yards very accurately and the ability of an Al-Qaeda terrorist to come within that distance is easy. There are other threats through shipping, through pipelines that are terribly vulnerable, easy targets and virtually impossible to defend. So, in short, back in the '70s we didn't have a declared enemy with that kind of capability, but today we do****....*[52]
> (Emphasis added)

[52] http://loe.org/shows/segments.html?programID=05-P13-00013&segmentID=4

Tom Bender, myself and several other citizens expressed concerns specific to this issue under FERC submittals 20150113-4002; 20141211-5046; 20141212-5017; 20141218-5046; 20150217-5145; among many others. **Accidental or intentional airplane crashes or dropping a fuel-air bomb would be virtually impossible to prevent or mitigate.**

According to a study called *Brittle Power, Energy Strategy for National Security*, originally prepared for the Pentagon, should the unthinkable happen, the energy content of ONE standard 125,000 cubic meter liquefied natural gas tanker, is equivalent to .7 megatons of TNT (that's 1.4 billion pounds of dynamite), or about fifty-five (55) Hiroshima bombs.



The gas industry March 2006 Cabrillo Port Liquefied Natural Gas Deepwater Port Revised Draft EIR determined that: (on page 4.2-38)[53]

> *For the worst credible intentional or accidental event release of 53 million gallons (200,000 m^3) from two tanks of LNG, it was determined that a wind speed of 2 m/s (4.5 mph) resulted in **the worst case in which the flammable vapor cloud extended about 6.3 NM (7.3 miles or 11.7 km)** downwind from the FSRU….*
> (Emphasis added)

This hazard in the Coos Bay area would NOT BE IN THE PUBLIC INTEREST

16. Project would have Negative Impacts on Tourism - Recreation – Fishing

Tourism spending accounted for 3,300 jobs in Coos County in 2017[54]. Those jobs would be negatively impacted as would also jobs in fishing, clamming, crabbing and oyster growing. (***See Exhibit 11***)

Coos County CBEMP Policy 5 clearly requires that the applicant prove their project is *needed for a public use and would satisfy a public need that outweighs harm to navigation, fishing and recreation*

CB - CBEMP Policy #33 Water-Based Recreation:

> *Local governments support increased use of the Coos Bay estuary for water-based recreation.*

The Jordan Cove FERC Final EIS under Docket CP13-483-000 et al states on page 4-737:

> *According to a 2008 study by the Oregon State Marine Board (OSMB), recreational boaters in Coos Bay took a total of 31,560 boat trips the previous year. Nearly 90 percent of the boat use days involved fishing (including angling, crabbing, and clamming), 9 percent was for pleasure cruising, and the remainder was for sailing and water skiing. Sixty-eight percent of the boating activities in Coos Bay originated from the Charleston Marina and the Empire ramp, 19 percent at the California Avenue boat ramps, and 4 percent at the North Spit ramps.*

[53] http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13982605
[54] http://www.deanrunyan.com/doc_library/ORImp.pdf

In the photo above, boats line the harbor during fall fishing runs on a sunny September afternoon in the lower Coos Bay in front of the area of the proposed LNG terminal. Recreational fishing is a big industry here with lots of events centered on the sport that go on throughout the year. ***See Exhibit 38*** for an example of one such event.

According to Roy Elicker, director of the Oregon Department of Fish and Wildlife "In the coastal counties up to 20 percent of the total net earnings in those counties come from fisheries ... commercial fisheries, in particular." [55]

Project Would Negatively Impact Current Coos Bay Estuary Dependent Industries.

Kayaking in Coos Bay has increased in recent years.

The proposed site of the Jordan Cove LNG terminal, seen here in the background, would border a National Recreation Area.

Terrestrial wildlife may not lose significant amounts of habitat in acres with the project. However, it is wrong to conclude their displacement to other areas is non-impacting. We take exception to the statement that the South Slough would not be impacted. Waterfowl and shorebirds and their natural cohorts displaced by construction or disturbed by vessel operations in the estuary will move away, likely to the South Slough. Displaced human uses such as clamming, crabbing, wildlife observation, fishing, and hunting would likely move these activities and conflict with the existing human uses in that area. Displacement of tourist activities could actually thwart future visitation numbers, negatively

[55] *Wildlife officials confirm economic position of coast's fishing industry* By Steve Lindsley, The Umpqua Post Aug 25, 2014; https://theworldlink.com/news/local/wildlife-officials-confirm-economic-position-of-coast-s-fishing-industry/article_aa056b02-2c7b-11e4-adb5-0019bb2963f4.html

affecting the local economies.

Many local industries depend on a healthy bay and estuary. The Coos Bay Estuary currently supports many different types of industries such as fishing, crabbing, oyster growing, clamming, wildlife observation, shipping of wood and other products, recreation, tourism, etc. These all work in conjunction with one another. The proposed Jordan Cove LNG export terminal would have impacts that are a vast deterrent from that trend.

A report prepared for the Oregon Department of Fish and Wildlife listed the following estimates of expenditures for Fishing, Hunting, Wildlife Viewing, and Shellfishing in Coos County and Oregon in 2009[56]:

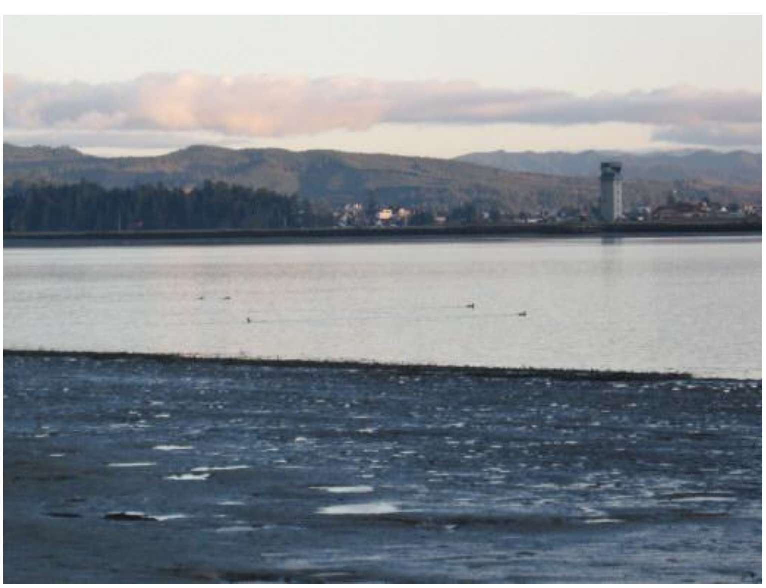
Coos County Local Recreation Expenditures, 2008

Category	Value	% of State Total*	% of All Travel**
Hunting	$904,977	2.90%	N/A
Fishing	$2,551,433	3.30%	N/A
Wildlife Viewing	$1,637,158	4.90%	N/A
Shellfishing	$1,080,963	20.60%	N/A
Total	$6,174,531	4.20%	N/A

Coos County Travel-Generated Expenditures, 2008

Category	Value	% of State Total*	% of All Travel**
Hunting	$2,534,940	2.40%	1.40%
Fishing	$12,253,254	4.60%	6.70%
Wildlife Viewing	$14,110,950	3.10%	7.70%
Shellfishing	$4,552,379	14.70%	2.50%
Total	$33,451,523	3.90%	18.30%

Below birds swim just off of tidal sand areas at low tide and



[56] "Fishing, Hunting, Wildlife Viewing, and Shellfishing in Oregon - *2008 State and County Expenditure Estimates*"; Prepared for the Oregon Department of Fish and Wildlife - Travel Oregon; DeanRunyan Associates; May 2009 http://www.dfw.state.or.us/agency/docs/Report_5_6_09--Final%20%282%29.pdf

several species leave footprints in the wet tidal sands where the LNG slip dock is proposed to be built.

According to the World Newspaper; Monday, November 02, 2009:

> *"Coos Bay got a bit of a tourism boost over the last several days,* ***as 200 or so birders came to the bay to see a rare brown booby that is hanging out near Charleston.*** *People came to scope out the tropical bird from places including Eugene, Portland, Bend, McMinnville, Coos Bay and Washington. The rare tropical bird showed up last week and is the fourth verified sighting of this species of bird in Oregon. The last local sighting was in October 2008, when a dead female washed ashore at Lighthouse Beach."*[57]

The Weyerhaeuser site is arguably one of the best birding destinations in Coos County and attracts a multitude of breeding, migrant and vagrant species year-round. There are species like Wilsons Phalarope and Ring necked Duck. This is a crucial stop-over location for shorebirds during migration where they can rest and refuel, building fat reserves to last them on the next leg of their migration flight. Oregon has lost much of its shorebird habitat through urban development and filling in wetlands and this site is one of the last significant "refueling stations" left on the Oregon Coast. Shorebirds by the thousands feed in late summer and fall here.

KCBY reported on March 27, 2019 that Spring Breakers were flocking to the Oregon Coast for Whale Watching Season: [58]

> *OREGON COAST - Whale Watching week returns once again.*
> * * * *.
> *Laura Burright is whale watching volunteer at the Cape Perpetua Visitor Center. She says it's been a good whale watching day at the cape with a total of about 15 sightings on Wednesday.*
>
> *Burright says about 20,000 grey whales are passing through Oregon. The males migrating first.*

---

[57] "*Flocking to see a rare bird*"; The World Newspaper; Monday, November 02, 2009
http://www.theworldlink.com/articles/2009/11/02/news/doc4aef7304e1c5b861714126.txt

[58] *Spring breakers flock to the Oregon Coast for Whale Watching season;* by Kelsey Christensen and KVAL.com Staff Wednesday, March 27th 2019;
https://kcby.com/news/local/spring-breakers-flock-to-the-oregon-coast-for-whale-watching-season

"The moms and babies stay in Baja, fattening the baby up so they come a little bit later than the males," she says.

Burright says this week, the males are typically swimming far from shore.

But, anywhere from now to June, the momma's and babies will be easier to spot because they swim closer to land away from any predators

Jordan Cove would have both a negative impact on tourism dollars and also would increase the risk of vessel strikes on passing migrating whales.

There are many efforts currently underway in Oregon to restore flow restoration priorities for recovery of anadromous salmonids in Coast Basins.[59] (***See Exhibit 39***) The Jordan Cove / Pacific Connector project would be counterproductive and in fact detrimental to these efforts. This is an important issue to both commercial and recreational fishermen on the South Coast of Oregon. Recreational boaters average about 31,560 trips per year in Coos Bay, the majority of which are for fishing. (FEIS under CP13-483 page ES-11) **Total direct visitor travel spending in Coos County has gone from $95.8 million in 2009 to $271.1 million in 2017**.[60] (***See Exhibit 11***)

FEIS under CP13-483 page 4-734 states:

The ODNRA [Oregon Dunes National Recreation Area] *contains the largest expanse of coastal sand dunes in North America, as well as a coastal forest and over 30 lakes and ponds. Recreational opportunities at the ODNRA include OHV use, hiking, camping, horseback riding, angling, canoeing, sailing, waterskiing, and swimming.*

Photo to Left:
People clamming at low tide in the Lower Coos Bay along Cape Arago Hwy.

Photo to Right:
Evidence of Clams in the tidal areas where the LNG slip dock is proposed to be built.

[59] South Coast Basin – Rivers and Streams – Flow Restoration Priorities for Recovery of Anadromous Salmonids in Coastal Basins -; http://nrimp.dfw.state.or.us/nrimp/information/streamflow/17southcoast/17stream.pdf
[60] http://www.deanrunyan.com/ORTravelImpacts/ORTravelImpacts.html# and http://www.deanrunyan.com/doc_library/ORImp.pdf

FEIS under FERC Docket CP13-483 page 4-827 states

> *DIA study by the COE in 2002 found that recreational marine activities along the Oregon coast and river ports generated $42 million in personal income and supported 1,700 jobs. This included spending on marina rental slips, boat ramp users, and other visitors to ports in Oregon. It was estimated that 735,000 party days a year resulted in $79 million in trip spending in the state (Chang and Jackson 2003). In the South Coast (Coos and Curry Counties), 106,000 saltwater fishing trips were counted in 2008, with $8.4 million in expenditures in Coos County. The OSMB counted 32,774 recreational boat fishing trips in Coos Bay in 2007. Ocean recreational fishing for salmon out of Coos Bay generated $693,000 in 2012 (The Research Group 2013a).*

Please consider these vital industries which will be negatively affected when making your decisions.

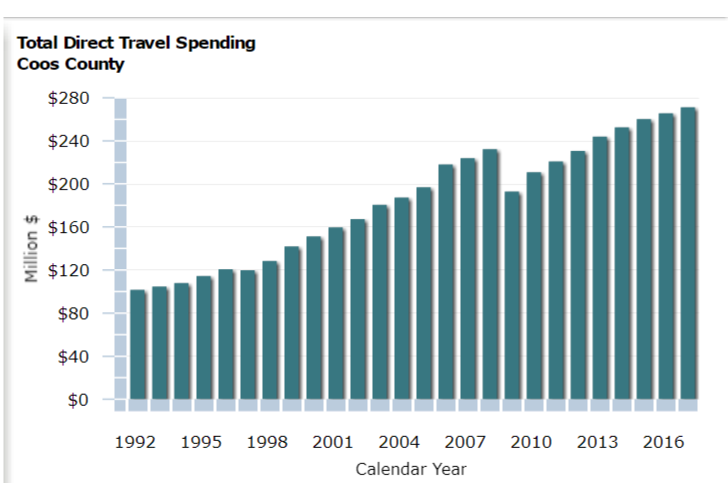
The FERC 2015 Jordan Cove Final EIS stated that there would be ballast water impacts in the estuary from Jordan Cove's LNG ships which would have their **engines running the entire time they are in Port** (***See Exhibit 40***). This would negatively impact not only the estuary but surrounding habitat and shorelands, along with recreation.

Jordan Cove states in the Sept 2017 RR#2 page 26

> *…The discharge velocities for the ballast water are low enough that it is not anticipated that any larger organisms (fish, marine mammals, and reptiles or amphibians) will be adversely affected by the ballast discharge. Some smaller organisms may be temporarily displaced by the discharge flow, but the displacement should be negligible in the confines of the slip.*

This is not a reasonable assumption. Ignoring the potential invasive species problem and the warming of the water in the lower bay due to the release of ballast water from LNG ships will not make these problems go away.

Dean Runyan has reported the following for Total Direct Travel Spending since 1991 and as you can see it has gone up almost every year. [61] (***See Exhibit 11***)



[61] http://www.deanrunyan.com/index.php?fuseaction=Main.TravelstatsDetail&page=Oregon

In Oct of 2007 Sunset Magazine listed the North Spit as one of the top 10 Beach Strolls. In September 2008 the National Geographic listed Coos Bay as one of the top 50 places to live. (***See Exhibit 41***). Jordan Cove would damage those remarkable attributes about our special area which would greatly harm recreation and tourism dollars coming into the area.

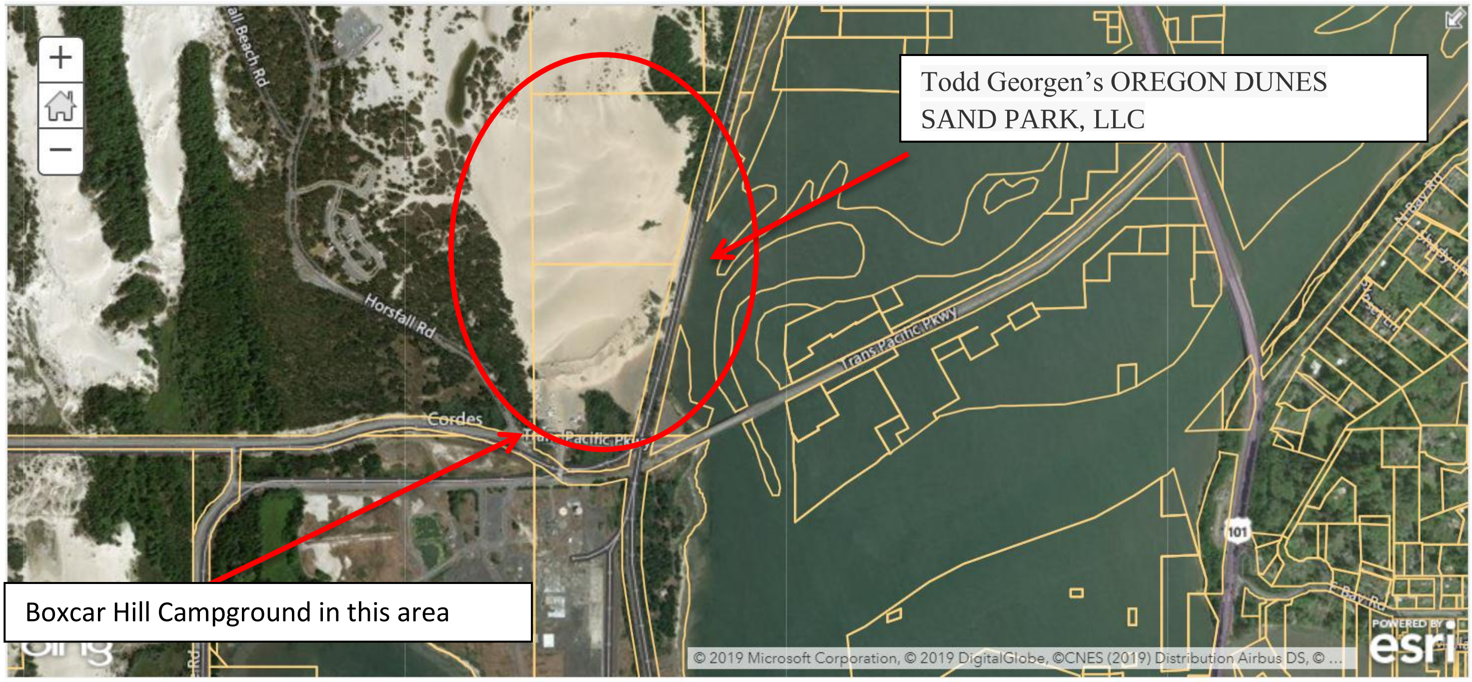
DSL Application Electronic page 676 states:

- *Approximately 10 acres at the Box Car Hill site will be used for temporary offices, parking, and a temporary concrete batch plant.*

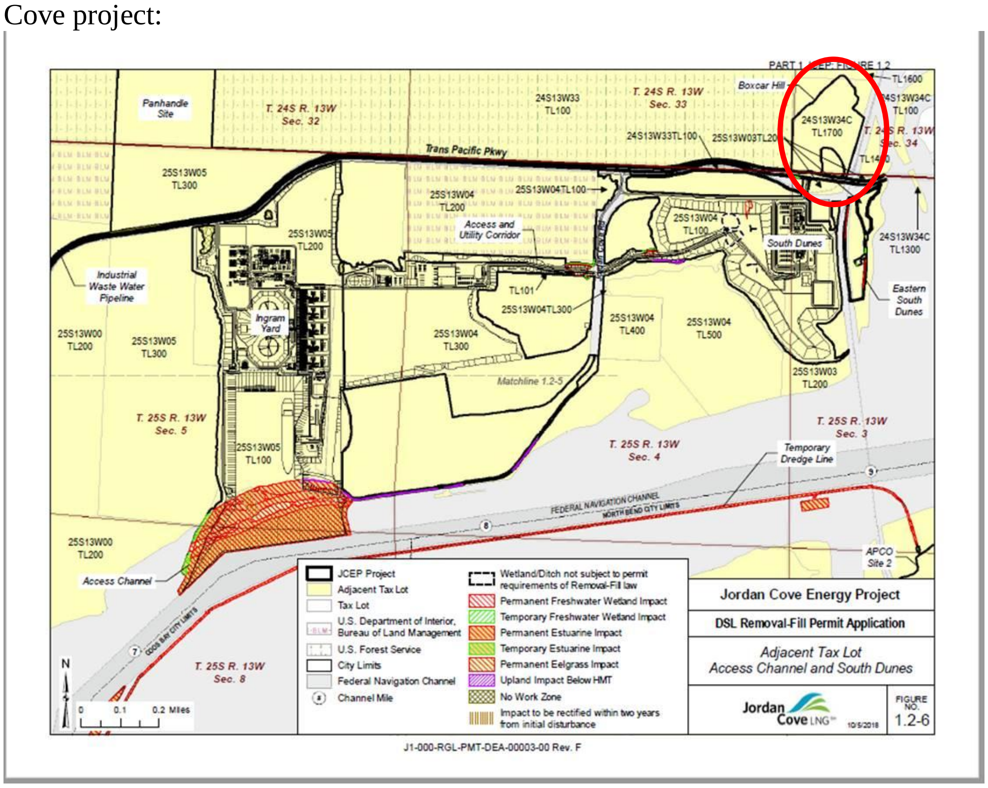
Page 123 of Jordan Cove's 1-12-2016 submittal under Coos County file No. HBCU-15-05 had the following diagram:

There are 65 spaces at the Boxcar Hill camping area that is directly next to the proposed Jordan Cove South Dunes Property. Jordan Cove was leasing the entire Boxcar Hill Campground on the North Spit with plans to sign a 99 year lease due to this area being a noise sensitive property if their proposed LNG facility should proceed. (***See Exhibit 43***) The Boxcar Hill camping area is currently used all year long by people visiting the Dunes. Taking it out of service would detour future visitors from coming to camp, ride and play in our Dunes National Recreational Area. This would cost jobs and negatively cause harm to our tourism and recreation industries.

The heavily used Boxcar Hill camping area below would be negatively affected by the Jordan Cove project should it proceed:



Below from page 59 of Jordan Cove's DSL application includes Boxcar Hill campground as a part of the Jordan Cove project:



Page 749 from Jordan Cove's DSL application shows the campground to be a laydown area for Jordan Cove:

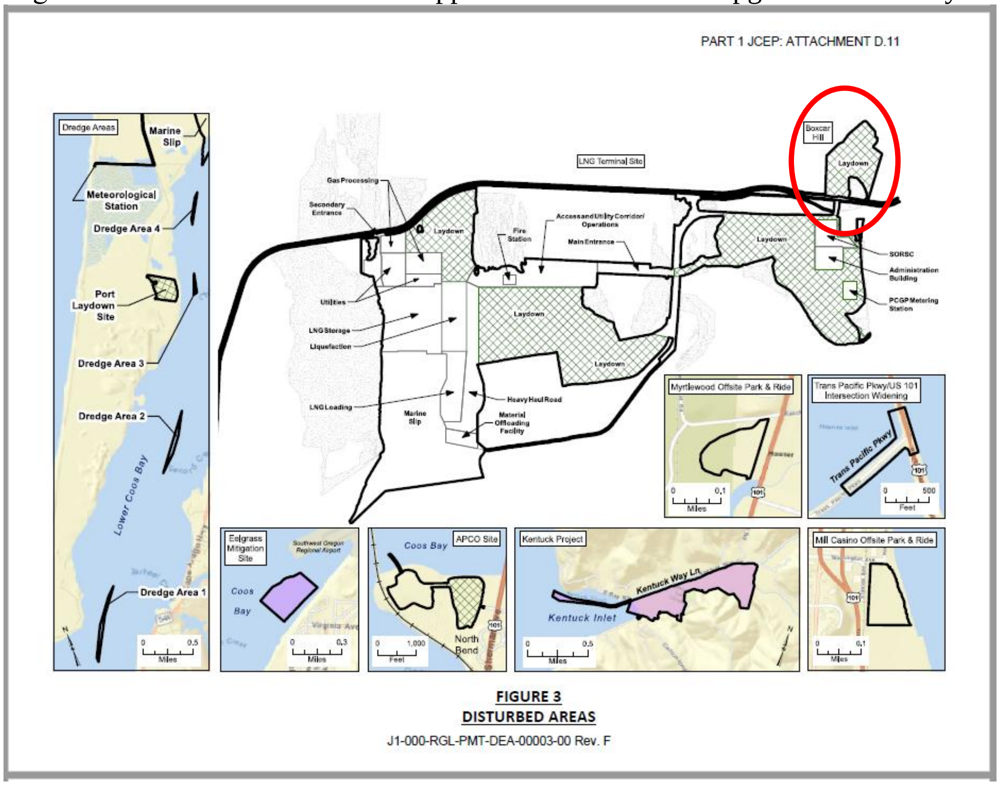


FIGURE 3
DISTURBED AREAS
J1-000-RGL-PMT-DEA-00003-00 Rev. F

Boxcar Hill Campground Expansion Project -vs- JCEP Personal Cement Plant

In 2017 Todd Georgen applied for and obtained a permit to extend the Oregon Sand Park Campground and add another 250 Camping spaces.[62]

What Jordan Cove is proposing with their Cement batch plant and offices **will take out some 250 planned Camping sites that had been approved and 65 current camping sites** at Boxcar hill campground directly south of the Dunes National Recreation Area. **This would be a loss of Recreational opportunities for many people**.

There are lots of negative impacts to nearby towns that allow LNG terminals and work camps for the temporary workers. In 2007 when Royal Dutch Shell built an LNG export terminal on Russia's Sakhalin Island an article in Fortune magazine entitled "*Shell Shakedown*" about the Gazprom takeover of the project stated the following with respect to what happened to the locals in that area:

> *...Residents say the company led them to believe that housing for 6,000 construction workers would be located in the town, where it could later be reused by the community, which sorely needs it.* ***Many people in Korsakov earn less than $300 a month - a sharp contrast to the***

[62] Oregon Sand Park Application:
http://www.co.coos.or.us/Portals/0/Planning/ACU-17-009/application.pdf?ver=2017-05-02-144014-527
Coos County Decision of approval:
http://www.co.coos.or.us/Portals/0/Planning/ACU-17-009/ACU-17-009%20Notice%20of%20Decision%20and%20Staff%20Report.pdf?ver=2017-05-02-144013-753
Amended notice of approval to reflect the correct map of the property:
http://www.co.coos.or.us/Portals/0/Planning/ACU-17-009/amended%20notice%20of%20decision.pdf?ver=2017-05-02-144014-237

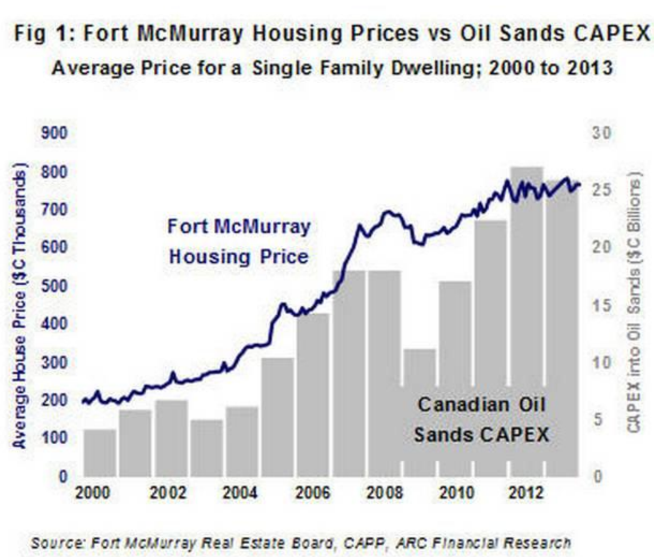
***wealth of Sakhalin Energy employees, many of whom, especially those who come from other countries, make more than $1,000 a day**.*

*But when construction began, Sakhalin Energy built its housing for workers next to the plant itself, inside a one-kilometer safety zone, where it will be illegal for people to live once operations begin. "People here could use this place for their well-being, and it will be demolished," says Elena Lopukhina, director of a Korsakov advocacy group and an assistant to a regional government official, who says that is just one of the emotional issues in the community that have swayed people against Sakhalin Energy. "**<u>The company did everything that was good for them and not good for us</u>**."*

*…Still, there are the small things - the $4 pencils and $500 space heaters a customs officer says she saw listed on a Sakhalin import form, the flaunting of money by expatriate staff in downtown nightclubs, the waxed and polished Land Cruiser fleet lined up in an island parking lot **- that give Sakhaliners a feeling of watching a party in their living room to which they haven't been invite.***

*If Sakhaliners think spending is out of control, that could explain why prices in Yuzhno also seem divorced from reality... **…houses can cost nearly $1 million, while a one-bedroom apartment can rent for $3,000 a month, comparable to New York City prices**. A five-minute taxi ride costs $12, and lunch at a casual Indian restaurant starts at about $40 per person.*[63] (Emphasis added)

Housing and rent prices in the Coos Bay Area would most definitely go up as they have done in other areas. **This would not be in the public interest.** The following graph published in the Globe and Mail on Feb 24, 2014 [64] also confirms this to be the case:



[63] *Shell shakedown - Fortune's Abrahm Lustgarten reports how the world's second-largest oil company lost control of its $22 billion project on Russia's Sakhalin Island*. By Abrahm Lustgarten; Fortune; February 1, 2007 http://archive.fortune.com/magazines/fortune/fortune_archive/2007/02/05/8399125/index.htm

[64] *Fort McMurray's house prices vs. capital spending in the oil sands*
Special to The Globe and Mail; Published Monday, Feb. 24 2014
http://www.theglobeandmail.com/report-on-business/fort-mcmurrays-house-prices-vs-capital-spending-in-the-oil-sands/article17066573/?from=17066648

17. Project would Increase Pollution / GHG / Ocean Acidification / Domoic Acid Impacts

Increased LNG Shipping Impacts would not be in the Public Interest.

Increased volumes of LNG being exported would mean increased volumes of actual shipments. DEQ representatives stated at a February 18, 2015 public meeting held in Coos Bay, Oregon, that the **LNG ships were not a part of their permit analysis**.[65] Despite this statement, Jordan Cove's LNG ships and all their necessary support vessels would contribute to a significant additional air pollution impact on local residents in the North Bend/Coos Bay area and would also contribute to an increase in the risk of LNG hazards to our area. Jordan Cove has totally downplayed these impacts and the information found in the Oil Change International report (***See Exhibit 51***), despite the fact that particulate pollutants from the life cycle impact of the Jordan Cove LNG export project **would increase respiratory and immune health problems in the local community**. Children and elders are especially at risk.[66] Many people have moved here to get away from such impacts. A local (now retired) medical doctor who specialized in allergies has submitted several letters over the years expressing his concerns with Jordan Cove's air particulates and the affect it would have on the local population here. Those particulates would increase with increased export volumes.

Increased Impacts on Shellfish / Food Production / Greenhouse Gasses / Domoic Acid would not be in the Public Interest

Increasing LNG export volumes would increase lifecycle greenhouse gas (GHG) emission volumes as a direct result of the LNG project. This would contribute to increased planet warming impacts, increased droughts, wildfires and ocean acidification. Droughts have already negatively affected our U.S. west coast states and our food production.[67] **Ocean Acidification has already cost the Oregon and Washington shellfish industries $110 million, and endangered some 3,200 jobs**.[68] (***See Exhibits 44, 45 and 46***)

George Waldbusser, an Oregon State University marine ecologist and biogeochemist, said the spreading impact of ocean acidification is due primarily to increases in greenhouse gases. Waldbusser recently led a study that documented how larval oysters are sensitive to a change in the "saturation state" of ocean water - which ultimately is triggered by an increase in carbon dioxide. The inability of

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[65] *Oregon DEQ: Jordan Cove pollution estimates not accepted on blind faith - LNG opponents urge DEQ to consider impact of Jordan Cove's projected greenhouse gas emissions;* Chelsea Davis ; The World ; Feb 18, 2015

[66] ● Dr. Joseph T Morgan Oct 9, 2012, testimony concerning pollutants and the JCEP project:
http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20121018-5150
● "*An Exploratory Study of Air Quality near Natural Gas Operations*" - Peer-reviewed and accepted for publication by Human and Ecological Risk Assessment (November 9, 2012).
Theo Colborn, Kim Schultz, Lucille Herrick, and Carol Kwiatkowski
http://www.endocrinedisruption.com/files/HERA12-137NGAirQualityManuscriptforwebwithfigures.pdf

[67] ● "*Drought prompts cuts to farm irrigation in California, Oregon*" Portland, Ore. | By Courtney Sherwood
http://www.reuters.com/article/2015/05/15/us-usa-drought-farming-idUSKBN0O02BL20150515
● *Oregon Governor Expands Drought Declaration* - Reuters 04/06/2015 By Courtney Sherwood
http://www.huffingtonpost.com/2015/04/06/oregon-drought_n_7014406.html
● *Kitzhaber declares drought emergency for four southern Oregon counties, opens up assistance*
By Bruce Hammond; Feb 14, 2014;
http://www.oregonlive.com/environment/index.ssf/2014/02/kitzhaber_declares_drought_eme.html

[68] *Study outlines threat of ocean acidification to coastal communities in the U.S.*; Feb 23, 2015
http://today.oregonstate.edu/archives/2015/feb/study-outlines-threat-ocean-acidification-coastal-communities-us

ecosystems to provide enough alkalinity to buffer the increase in CO_2 is what kills young oysters in the environment.

> "*This clearly illustrates the vulnerability of communities dependent on shellfish to ocean acidification," said Waldbusser, a researcher in OSU's College of Earth, Ocean, and Atmospheric Sciences and co-author on the paper. "We are still finding ways to increase the adaptive capacity of these communities and industries to cope, and refining our understanding of various species' specific responses to acidification*."
>
> "Ultimately, however, **without curbing carbon emissions, we will eventually run out of tools to address the short-term and we will be stuck with a much larger long-term problem**," Waldbusser added. [31] (Emphasis added)

Researchers and fishermen worry ocean acidification *could* be impacting Dungeness crab life cycles already. Dungeness crab represents the most valuable fishery on the West Coast, generating $167 million[69] in ex-vessel value in California in 2011. Like oysters, Dungeness crabs are a key driver of the fishing industry, so lucrative that many fishermen rely on them to guarantee an annual income. Fishermen have seen increased closures due to elevated levels of domoic acid, directly linked to lower ocean Ph levels as temperatures rise.[70] (***See Exhibit 46***) These closures have been devastating to the fishing industry. **As reported on Feb 19, 2018,[71] the industry was already in a volatile state due to the latest start to a crab season most Oregon fishermen have ever remembered**. These problems are likely to get worse in the coming decades.

Commercial crabbers in Oregon and California are suing 30 fossil fuel companies, claiming they are to blame for climate change, which has hurt their industry. The Pacific Coast Federation of Fishermen's Associations filed a lawsuit in November of 2018 with the California State Superior Court in San Francisco against gas and oil companies including Chevron and Exxon Mobil. [72] In October, **the Pacific Coast Federation of Fishermen's Associations successfully sued the U.S. Environmental Protection Association to protect salmon and steelhead trout populations in the Columbia River basin from warm water temperatures caused by dams and climate change**. (***See Exhibit 47***)

Researchers have found that **elevated concentrations of CO2 in seawater can disrupt numerous sensory systems in marine fish**. This is of particular concern for Pacific salmon because they rely on olfaction during all aspects of their life including during their homing migrations from the ocean back to their natal streams.[73] (***See Exhibit 48***)

Increasing exports of Canadian hydro-fracked gas would not be in the public interest.

Jordan Cove's February 6, 2018 U.S. Department of Energy Amendment Application page 4 and 5 states:

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69 https://www.psmfc.org/crab/2014-2015 files/DUNGENESS_CRAB_REPORT_2012.pdf
70 https://newfoodeconomy.org/ocean-acidification-oysters-dungeness-crabs/
71 http://theworldlink.com/news/local/new-legislation-to-localize-domoic-acid-closures/article_6933a960-59bd-5949-a9cc-c6191ae31de8.html
72 *Oregon and California crabbers sue fossil fuel companies* Updated Nov 27, 2018 https://www.oregonlive.com/pacific-northwest-news/index.ssf/2018/11/oregon_and_california_crabbers.html
73 Williams CR, Dittman AH, McElhany P, et al. *Elevated CO2 impairs olfactory‐ mediated neural and behavioral responses and gene expression in ocean‐ phase coho salmon (Oncorhynchus kisutch)*. Glob Change Biol. 2018;00:1–15. https://doi.org/10.1111/gcb.14532 November 2018

> *JCEP also hereby informs DOE/FE of a change in corporate ownership from what was described in the Applications. On October 2, 2017, Pembina Pipeline Corporation ("Pembina"), a Canadian corporation, acquired 100 percent of the outstanding shares of Veresen Inc., **JCEP's parent entity. JCEP is now a wholly owned subsidiary of Pembina**.* (Emphasis added)

For some time now Pembina has been trying to develop a West Coast export facility in order to export Canadian oil and gas products. Pembina's CEO Michael (Mick) Dilger has publicly stated that the purpose of their company is to get **Canadian hydrocarbons to the rest of the world**. [74] Dilger feels the shorter travel time to Asian markets versus the U.S. Gulf Coast would mean lower transportation costs for its LNG. (***See Exhibit 50***) He has become frustrated by Canada's infrastructure gridlock and sees the U.S. as a way to get Canadian gas and oil projects to Asia. His company would be in direct competition with U.S. Gulf Coast LNG terminals that are already in operation.

In December 2017 a joint venture of Pembina Pipeline Corp., Calgary, and Petrochemical Industries Co. KSC (PIC) of Kuwait was announced which involves a proposed 1.2 billion-lb/year grassroots, integrated propane dehydrogenation and polypropylene (PP) complex in Sturgeon County, Alberta, Canada.[75] In November 2017 Pembina announced construction of a $260M propane export facility on B.C.'s Watson Island.[76] The facility, which still requires regulatory and environmental approvals, **would use rail cars, not pipelines**, to transport propane to the facility from Alberta and B.C.. It is expected to be in service by mid-2020. Pembina dropped a proposal in February of 2016 to build a $500 million propane oil terminal in Portland, Oregon, after the City of Portland determined Pembina had not made a strong enough case as it relates to meeting Portland's environmental standards.[77]

The same could be said for the proposed Jordan Cove project. In January 2018, a new report released by Oil Change International, which looked at a full accounting of greenhouse gas emissions, found that the Jordan Cove Project would result in over 36.8 million metric tons of carbon dioxide equivalent (CO_2e) per year.[78] (***See Exhibit 51***) This is some 15.4 times the emissions from Oregon's last remaining coal-fired power plant, the Boardman Coal plant, which is set to be retired by 2020 due to climate and air pollution concerns. When only considering the in-state emissions alone, **the Jordan Cove project would end up being the largest source of greenhouse gas emissions in the state by 2020**. The project would make it impossible for Oregon to achieve Governor Kate Brown's goal to have Oregon's climate reductions line-up with the targets of the Paris Accords, as well as the emission reduction goals enshrined by the Oregon legislature in 2007. The Oil Change Briefing paper found no evidence to support an assumption that gas supplied by the LNG project would replace coal in global markets

[74] *Pembina Pipeline's new purpose: Get Canada's oil and gas to the rest of the world* ;By Claudia Cattaneo; February 16, 2018; http://business.financialpost.com/commodities/energy/pembina-pipelines-new-purpose-get-canadas-oil-and-gas-to-the-rest-of-the-world

[75] *Canada Kuwait Petrochemical advances Alberta PP complex*; By Robert Brelsford – Houston; Dec. 5, 2017; https://www.ogj.com/articles/2017/12/canada-kuwait-petrochemical-advances-alberta-pp-complex.html

[76] *Pembina Pipeline approves construction of $260M propane export facility on B.C. island*; The Canadian Press; November 30, 2017 ; http://calgaryherald.com/business/energy/pembina-pipeline-approves-construction-of-260m-propane-export-facility-on-b-c-island

[77] *Pembina officially pulls away from $500M Portland propane terminal* By Andy Giegerich - Portland Business Journal; Feb 29, 2016 https://www.bizjournals.com/portland/blog/sbo/2016/02/pembina-officially-pulls-away-from-500m-portland.html

[78] *Jordan Cove LNG and Pacific Connector Pipeline Greenhouse Gas Emissions Briefing*; Oil Change International; January 2018 http://priceofoil.org/content/uploads/2018/01/JCEP_GHG_Final-Screen.pdf

The fact is renewable energy is challenging both coal and gas-fired power generation on a cost-of-energy-produced basis. A peer-reviewed study published in the international journal Energy[79] found that LNG exports from the U.S. could raise emissions in destination markets by triggering additional energy demand rather than displacing coal, and by diverting capital from renewable energy development. According to the U.S. Department of Energy, **exporting natural gas from the U.S. to Asia could end up being worse from a greenhouse gas perspective than if China simply built a new power plant and burned its own coal supplies**.[80] In addition, Oil Change International found that due to wind and solar now being cheaper than coal and gas in many regions, <u>new gas capacity often displaces new wind and solar rather than old coal</u>.[81]

This would not be in the public interest!

18. LNG Market does Not show Need for Jordan Cove LNG Project

The International Gas Union (IGU) reported in their 2018 World LNG Report (***See select pages in Exhibit 52***)[82] that a record 293.1 million tonnes (MT) of LNG was traded in 2017. This marks an increase of 35.2 MT (+12%) from 2016; while global liquefaction capacity reached 369 million tonnes per annum (MTPA) as of March 2018. Despite a 75.9 MTPA of excess LNG being produced over what was traded, an additional 92.0 MTPA of liquefaction capacity was under construction as of March 2018.

According to the IGU World Gas LNG Report – 2018 Edition page 5:

> *…In engineering progress, the first floating liquefaction (FLNG) project came online in Malaysia, with additional FLNG projects set to come online during 2018 and beyond. Although no new liquefaction capacity had been added in Russia since Sakhalin 2 LNG T2 in 2010, the first train of Yamal LNG achieved commercial operations in March 2018 and* ***<u>is expected to ultimately add 17.4 MTPA of liquefaction capacity</u>***. (Emphasis added)

Even with an increase of 8.5% a year in export trading capacity (a 5% increase occurred from 2015 to 2016 (13.1 MT) and a 12% increase occurred from 2016 to 2017 (35.2 MT)), it would take 6.7 years for an average 8.5% increase per year (5% + 12% / 2 years = 8.5% average) (75.9MTPA + 92.0 MTPA = 167.9MTPA excess LNG divided by 25.MTPA (293.1 MTPA in 2017 x 8.5% = 25.MTPA yearly increase) = 6.7yr) until the <u>current excess</u> of LNG volumes would likely be absorbed into the international LNG export markets. The current excess of LNG available for export would take until 2024 to be absorbed using these calculations (2018 + 6yr = 2024), and that is 'without' the addition of other projects that are currently in the works <u>ahead</u> of Jordan Cove.

For example, in May of 2018 Petronas bought a 25% share of LNG Canada Project a year after it cancelled its own proposed Pacific NorthWest LNG project at Port Edward, British Columbia due to market conditions. Now that the deal is completed, LNG Canada's ownership interests are Shell at

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[79] *US liquefied natural gas (LNG) exports: Boom or bust for the global climate*?; Energy Volume 141, 15 December 2017, Pages 1671-1680; https://www.sciencedirect.com/science/article/pii/S0360544217319564?via%3Dihub
[80] https://www.washingtonpost.com/news/wonk/wp/2014/06/09/exporting-u-s-natural-gas-isnt-as-clean-as-you-think/?utm_term=.6abe89578728
[81] *BURNING THE GAS 'BRIDGE FUEL' MYTH;* Oil Change International; November 2017; This analysis provides five clear reasons why fossil gas is not a "bridge fuel." It shows that even with zero methane leakage, gas is not a climate change solution.;
[82] https://www.igu.org/sites/default/files/node-news_item-field_file/104747-IGU-Book-Final_062818.pdf

40%, Petronas at 25%, PetroChina at 15%, Diamond LNG Canada (an affiliate of Mitsubishi Corporation) at 15%, and Kogas Canada LNG at 5%.[83] LNG Canada announced in October 2018 that it would go ahead with its $40-billion export facility on the West Coast.[84] **Given the players involved, the LNG Canada west coast LNG project has a far greater chance of development over the Jordan Cove Project**. Jordan Cove does not have the financial means necessary to build a greenfield LNG project, nor the experience. Pembina, Jordan Cove's parent company, has already announced that it intends to seek partners for both the pipeline and liquefaction facility thereby reducing its 100 percent ownership interest to a net ownership interest of between 40 and 60 percent.[85]

RBN Energy reported on March 26, 2019 that a second wave of North American LNG export projects was officially underway. As noted above, LNG Canada took final investment decision (FID) last October and would be the first large-scale LNG export facility in Canada. Golden Pass and Calcasieu Pass followed in February, marking the beginning of the next round of LNG export build on the U.S. Gulf Coast. Sabine Pass Train 6 is expected to get the green light any day. It still remains to be seen if these projects will all actually make it to completion given the glutted LNG market.

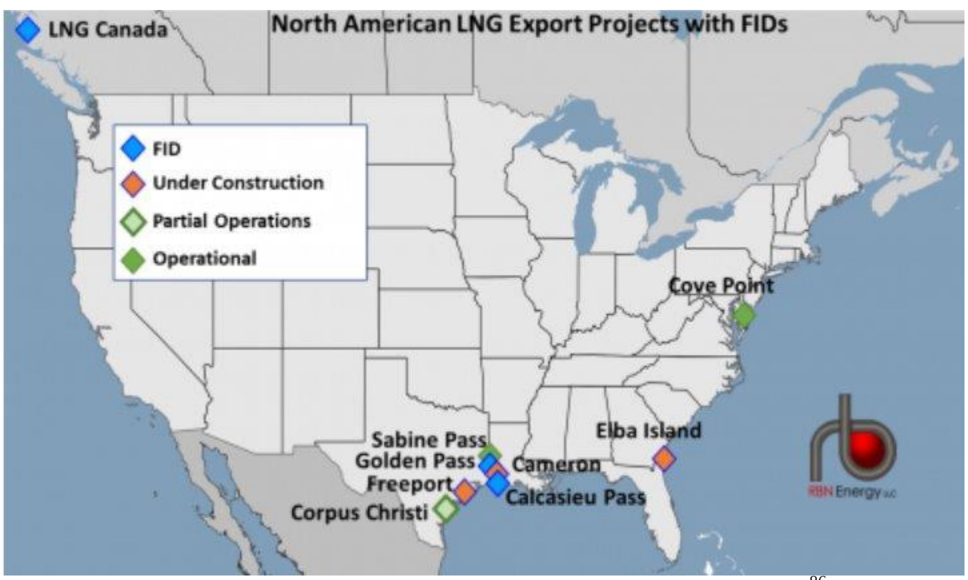


Figure 1. North American LNG Export Projects. Source: RBN Energy LLC[86]

According to the IGU World Gas LNG Report – 2018 Edition, page 65:

> ***Will LNG Contracting and Liquefaction FIDs Take Shape This Year? Investment decisions on new LNG supply have come to a near standstill over the last two years. In 2017, only one large-scale LNG project reached FID – the 3.4 MTPA Coral South FLNG in Mozambique –***

[83] *Petronas Buys 25% Share of LNG Canada Project* Posted on May 31, 2018 https://www.lnglawblog.com/2018/05/petronas-buys-25-share-of-lng-canada-project/?utm_source=vuture&utm_medium=email&utm_campaign=vuture-emails

[84] *$40B LNG facility is the light at the end of a long tunnel for Canada's natural gas sector*
Struggling gas industry faces several more years of low prices until new Asia export project is built
Kyle Bakx · CBC News · Posted: Oct 03, 2018 https://www.cbc.ca/news/business/lng-canada-gmp-firstenergy-arc-1.4847377

[85] *Pembina Pipeline Corporation Announces 2019 Capital Program and Guidance;* By Pembina Pipeline Corporation Dec 10, 2018; https://www.prnewswire.com/news-releases/pembina-pipeline-corporation-announces-2019-capital-program-and-guidance-300762358.html

[86] https://rbnenergy.com/catch-a-wave-what-it-takes-for-an-lng-export-project-to-reach-fid

> ***marking the lowest volume of sanctioned LNG in nearly twenty years***. *This follows the trend established in 2016, when only two projects reached FID for a combined sanctioned capacity of 6.3 MTPA. This contrasts with the high level of FIDs in 2011–15, when annual sanctioned capacity exceeded 20 MTPA. The slowdown in investments is partly a reflection of the wider trend of cutting back capital expenditure across the oil and gas industry during the commodity downturn, but can also be attributed to the lack of contracting activity from buyers hesitant to sign long-term deals in the face of growing near-term LNG supply.* ***Without long-term contracts, new liquefaction projects will find it challenging to proceed***
>
> ***The total volume and number of LNG contracts signed has declined consistently for the past three years***. *In 2017, only one firm long-term contract was signed that was tied specifically to a proposed project working toward FID (Edison's SPA at Calcasieu Pass LNG), as the majority of deals completed were portfolio contracts (67% of all firm deals signed). The lower total volume of contracts is not only a result of fewer contracts being signed, but is also tied to the trend of smaller volume contracts – the average size of contracts signed has dropped, which means that marketing timelines extend as they seek to fill the entire capacity…*

The IGU World Gas LNG Report – 2018 Edition, page 19 states:

> *Projects planning to reach an FID in the near term are competing for customers willing to sign foundational contracts ahead of the large near-term buildup in supply, leading to a general slowdown in contracting activity over the last several years. Demand uncertainty, capital budget constraints, and a desire for shorter-term contracts are challenges facing project sponsors, many of which are emphasising their cost structures and location-specific advantages in an attempt to move forward.*

The IGU World Gas LNG Report – 2018 Edition, page 26 states:

> *Expectations of a well-supplied market in the near term, greater demand uncertainty, and lower oil and gas prices have reduced the number of FIDs and long-term foundational contracts that have been signed over the past two years. A number of projects were delayed or cancelled in 2016 and 2017 owing to project economics and partner alignment challenges in the current market environment.* ***Given the large number of projects aiming to reach an FID in 2018, further culling of projects is expected***. (Emphasis added)

Page 29 states:

> ***Only one US project – Calcasieu Pass LNG – signed a binding long-term contract in 2017, with Italy's Edison. Shell, the project's first customer, signed an SPA for 1 MTPA in 2016 and agreed in February 2018 to purchase an additional 1 MTPA***. *Two binding contracts between Cheniere and China's CNPC were also signed in early 2018. In conjunction with a contract signed with Trafigura in early 2018, the deals are expected to support an FID at Corpus Christi LNG T3. The CNPC agreements stem from a memorandum of understanding (MOU) signed last November and* ***are the first long-term deals signed between a US LNG developer and Chinese companies***

The IGU World Gas LNG Report – 2017 Edition[87] stated that there was 879 MTPA of proposed liquefaction capacity, as of January 2017: (page 5)

> *New Liquefaction Proposals: Given abundant gas discoveries globally and the shale revolution in the US, proposed liquefaction capacity reached 890 million tonnes per annum (MTPA) by January 2016. This figure fell slightly to 879 MTPA at end-January 2017 in an attempt at rationalization with market demand.* ***More of these projects will not go forward as demand remains far below this ambitious target****; particularly as ample pipeline supply - by Russia and Norway to Europe, and the US to Mexico - reduce the need for LNG in those markets. Additionally, Egypt will experience a drastic reduction in LNG demand as the Zohr field comes on-line and preferentially supplies the domestic market. In fact, there is potential for Egypt to again be a significant LNG exporter. The areas with the largest proposed volumes include the US GOM, Canada, East Africa, and Asia-Pacific brownfield expansions.*

The IGU World Gas LNG Report – 2017 Edition, page 27 states:

> *Apart from high liquefaction costs, greenfield projects proposed in Western Canada and Alaska require lengthy (300 miles or more) pipeline infrastructure. Integrated Western Canadian projects have announced* ***cost estimates of up to $40 billion****, while in Alaska the estimate was revised downward in 2016 to approximately $45 billion from $45-65 billion previously*

The IGU World Gas LNG Report – 2017 Edition, page 31 states:

> *Eleven[18] projects have now moved through the FERC environmental review process, including four in 2016: Cameron LNG T4-5, Elba Island, Golden Pass, and Magnolia LNG. While there is greater clarity regarding expected timelines and costs, FERC also denied approval of an LNG export project for the first time in 2016.* ***FERC did not approve the 6 MTPA Jordan Cove LNG project and its associated pipeline, citing concerns that the pipeline had not demonstrated sufficient commercial need to outweigh landowner concerns****. After an unsuccessful appeal, the sponsor plans to submit a new application.* ***Most other projects in the continental US do not require significant new pipeline infrastructure and so may be less likely to face the same obstacles****.* (Emphasis added)

The IGU World Gas LNG Report – 2017 Edition, page 60 states:

> **How will existing LNG contracts come under pressure in 2017?**
> *** * * ***
> *Gas demand has slowed quicker than anticipated in some importing markets – particularly in Asia Pacific. As a result, buyers in those countries have to be creative to manage over-commitments.* ***China has been over-contracted since 2015*** *and this may continue in 2017 given the large additions of Australian capacity and associated contracts with the Chinese NOCs. Beyond the NOC's, smaller LNG players in China – e.g., ENN Energy, Beijing Gas, Jovo Group – are becoming more active players.* ***In the same way, other Asian LNG buyers in Japan and South Korea are potentially overcommitted in the near term and many have formed trading businesses to manage their portfolios****.*

[87] https://www.igu.org/sites/default/files/103419-World_IGU_Report_no%20crops.pdf

Reports Show Jordan Cove LNG Project Not Viable or in Public Interest.

The Jordan Cove LNG Project does not have signed contracts yet and despite them saying they have agreements, nothing they have is binding at the moment. They have yet to supply any contractual documents to the U.S. Department of Energy. Several Reports clearly show that the project is not likely to succeed. **We would be significantly alternating the Coos Estuary and taking critical fish, clam and crab habitat out of production for a project that is not likely to be successful.**

Back in October 9, 2015, the Natural Gas Intelligence reported the following in an article by Richard Nemec titled, *"West Coast LNG Export Projects Doubtful in Current Environment, Analysts Say"*[88]:

> *In the current oversupplied global energy market, a liquefied natural gas (LNG) export terminal on the U.S. West Coast is unlikely to become a reality anytime soon, according to several industry analysts speaking at a natural gas forum in Los Angeles.*
>
> *The consensus at the LDC Gas Forum Rockies & the West conference is that the **five terminals now under construction or about to start on the Gulf and East Coasts are the only ones likely to be operating by 2020.** Combined, they represent incremental demand growth of 10.5 Bcf/d in the world market, which is somewhat saturated already.*
>
> *That scenario leaves out the two proposed export projects in Oregon -- Jordan Cove and Oregon LNG -- which are in the midst of the permitting process at the Federal Energy Regulatory Commission.*
>
> *"There is debate about how much U.S. LNG can make it into the global market," said David Braziel, director of finance and fundamental analysis at RBN Energy LLC. "If all the U.S. LNG export facilities that have been proposed were built (45 Bcf/d), the capacity would dwarf the global market." **There are other significant LNG exporters worldwide, including Canada, Australia, Indonesia, East Africa and Russia**, he said.*
>
> *RBN thinks 33% of the global market for U.S. LNG is a reasonable assumption, Braziel said, but that leaves no room for the West Coast facilities. "Thirty percent would be about 12 Bcf, and there is already 13.2 Bcf/d of capacity being built, so that's how we get to our [one-third] estimate and **there is nothing beyond the five terminals [Sabine Pass, Freeport, Cameron, Corpus Christi and Cove Point, MD]."** ...*
> (Emphasis added)

On September 3, 2015, the Financial Post reported the following in an article by Yadullah Hussain titled, "*Window of opportunity' for new LNG projects is gone because of supply glut, consultancy says*"[89]:

> ***The window to build liquefied natural gas projects in Canada and elsewhere has closed amid a global supply glut**, says global energy consultancy Wood Mackenzie.*

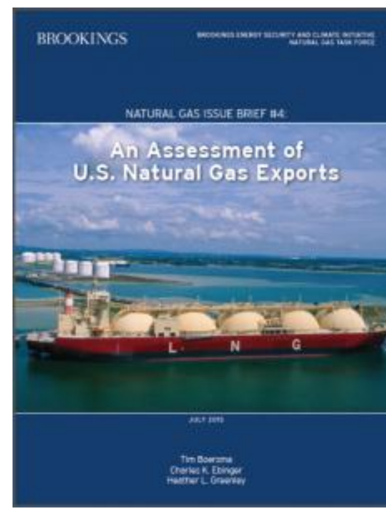
[88] http://www.naturalgasintel.com/articles/103968-west-coast-lng-export-projects-doubtful-in-current-environment-analysts-say
[89] http://business.financialpost.com/news/energy/window-of-opportunity-for-new-lng-projects-is-gone-because-of-supply-glut-consultancy-says?

*"**There is a clear reluctance by companies to stand down, __but the reality is that the window of opportunity closed over six months ago for everyone__, not just for Canada**" Noel Tomnay, vice-president global gas and LNG research for Wood Mackenzie said in an interview.*

Qatar and Australia led the first two waves of LNG development with the U.S. spearheading the third wave, even as Canadian and East Africa proposals were stalled.

*"**Canada's biggest competitor is not the U.S. – it is probably Mozambique**." Tomnay said, noting that these two regions would probably play the role of niche, "strategic resources" for investors in the next wave of development that will cater to demand after 2022. …* (Emphasis added)

On July 14, 2015, Fuel Fix stated in another article by By Rhiannon Meyers titled, "*Most U.S. LNG projects won't cross the finish line, new study says*"[90]:



Most of the proposed U.S. liquefied natural gas export projects won't get built amid stiffening competition from foreign competitors who will flood the market with the supercooled gas as demand begins to slow, a new study finds.

***__Five U.S. LNG projects already under construction__, including Cheniere's two terminals in Louisiana and Corpus Christi, will cross the finish line, __but beyond that, construction appears "increasingly unlikely" for the remaining proposals__**, according to the latest study unveiled Tuesday by a task force of natural gas experts assembled by the Brookings Institution, a Washington D.C.-based thinktank.*

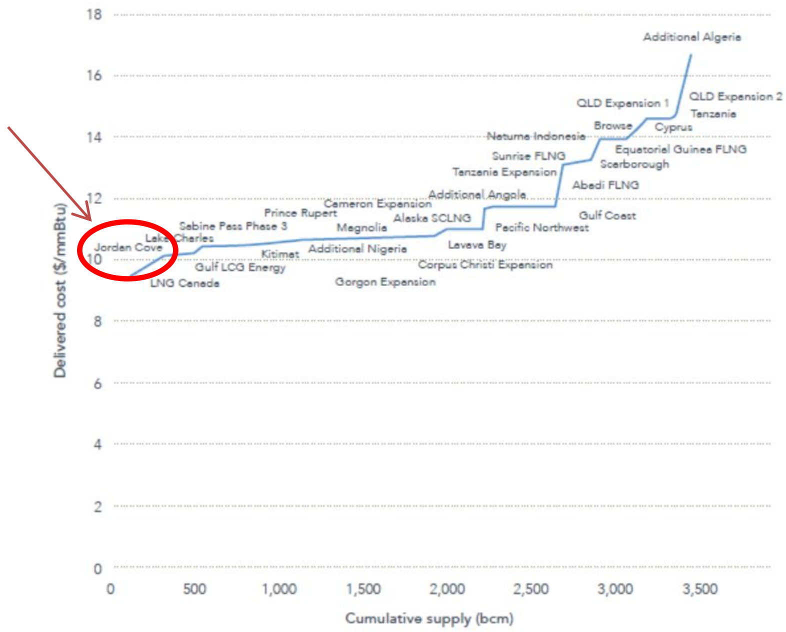
It's the latest report to raise doubts about the flurry of multi-billion dollar proposals announced in recent years that would soak up vast supplies of cheap U.S. natural gas destined for markets in Asia…. (Emphasis added)

The task force of natural gas experts assembled by the Brookings Institution stated that it will be increasingly unlikely that new liquefaction projects will be financed, beyond the ones that have been contracted and reached a final investment decision. The July 2015 Brookings Report, *"An Assessment of U.S. Natural Gas Exports,"* is attached as ***Exhibit 64***.

A July 7, 2015, Sutherland LNG Blog Posting titled, "*New Report Projects $283 Billion of Planned LNG Projects Potentially Unneeded by 2025,"*[91] reported on a Carbon Tracker report: "*Carbon Supply Cost Curves: Evaluating financial risk to gas capital expenditures.*"[92] Figure 11 on page 23 of the Carbon Tracker report list Jordan Cove as one of the many "not needed" LNG Export projects. The Carbon Tracker Report is attached as ***Exhibit 65***.

[90] http://fuelfix.com/blog/2015/07/14/most-u-s-lng-projects-wont-cross-the-finish-line-new-study-says/#27079101=0
[91] http://www.lnglawblog.com/2015/07/new-report-projects-283-billion-of-planned-lng-projects-potentially-unneeded-by-2025/
[92] http://www.carbontracker.org/wp-content/uploads/2015/06/CTI-gas-report-Final-WEB.pdf

Figure 11: LNG projects not needed in low demand scenario to 2035



Moody's Investors Service published a Moody's Announcement on April 7, 2015, "*Liquefied natural gas projects nixed amid lower oil prices,*"[93] which stated the following:

(***See Exhibit 66)***

> *New York, April 07, 2015 — Liquefied natural gas (LNG) suppliers are curtailing their capital budgets, amid low oil prices and a coming glut of new LNG supply from Australia and the US, Moody's Investors Service says in a new report, "Lower Oil Prices Cause Suppliers of Liquefied Natural Gas to Nix Projects."…*
>
> *…**<u>Moody's says low LNG prices will result in the cancellation of the vast majority of the nearly 30 liquefaction projects currently proposed in the US, 18 in western Canada, and four in eastern Canada</u>**.*
>
> *"**<u>The drop in international oil prices relative to US natural gas prices has wiped out the price advantage US LNG projects</u>**,* … (Emphasis added)
>
> *…Greenfield projects on undeveloped property are much more expensive, involve more construction risk, and take longer to build than brownfield projects, which re-purpose existing LNG regasification sites.* ***Greenfield projects are also frequently challenged by local opposition and occasionally by untested laws and regulations****. Based on the public estimates of companies building new LNG liquefaction capacity, the median cost to build a US brownfield project is roughly $800 per ton of capacity, compared with the more advanced Australian greenfield projects, now estimated at around $3,400 per ton…* (Emphasis added)

93 https://www.moodys.com/research/Moodys-Liquefied-natural-gas-projects-nixed-amid-lower-oil-prices--PR_322439

On Sept 10, 2018 article by Gaurav Sharma titled, "*Next Wave Of U.S. LNG Projects Lurks But Market Fistfight is Inevitable*"[94] reported the following:

> *…Ultimately, whichever way you look at it – the fistfight for offtake agreements, both within and beyond North America, would determine which U.S. LNG project makes it or not. **Its highly likely many will not**.*

The GJ Sentinel reported on November 26, 2018 in an article titled, "*Jordan Cove about to be overwhelmed by Canadian LNG terminals at Kitimat"*[95]

> *…LNG Canada is now breaking ground while Jordan Cove is still awaiting both FID from its sponsor and a US government OK from the Federal Energy Regulatory Commission. **Betting here is that it will never get either one**.*
>
> *Location, location, location is why this happened. Jordan Cove is proposed for a very scenic undeveloped place on the **Oregon coast beloved by locals and tourists alike, and they are hollering their disapproval**. But LNG Canada creates no complainers since Kitimat is a brownfield site with a smelter, deep water port and rail….* (Emphasis added)

On November 7, 2018 Reuters reported that Japan's Toshiba Corp will exit its U.S. liquefied natural gas (LNG) business by paying China's ENN Ecological Holdings Co more than $800 million to take over the unit as part of a plan to shed money-losing assets. "***The project posed a huge risk, because no one knows how the situation will be over the next 20 years***," Toshiba's Chief Executive Officer Nobuaki Kurumatani told reporters at a press conference.[96]

Apparently JERA Co, the same company that Pembina states is willing to sign a long term contract with them for JCEP LNG was not able to help Toshiba find buyers for its LNG[97] coming from the Freeport LNG project in the U.S. Gulf Coast. So what does this mean? How can JERA sign a long-term contract with Pembina if they cannot even sell U.S. gas that is already under contract? …?

On Oct 11, 2018, the LNG Law Blog in an article titled, "*Tokyo Gas Signs HOA for LNG Canada Purchases*"[98] the following:

> *Platts reports that Tokyo Gas Tuesday has signed a heads of agreement (HOA) with Diamond Gas International, the trading arm of Mitsubishi Corporation, **to purchase LNG from the proposed LNG Canada project in British Columbia.** According to the report, the HOA provides that Tokyo Gas will purchase up to 0.6 million metric tonnes/year from LNG Canada*

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[94] https://www.forbes.com/sites/gauravsharma/2018/09/10/next-wave-of-u-s-lng-projects-lurks-but-market-fistfight-is-inevitable/#3c008b552fa8

[95] https://www.gjsentinel.com/opinion/jordan-cove-about-to-be-overwhelmed-by-canadian-lng-terminals/article_c6608c2c-f194-11e8-b5a0-cf3bb7245574.html
and; https://fromthestyx.wordpress.com/2018/11/26/jordan-cove-about-to-be-overwhelmed-by-canadian-lng-terminals-at-kitimat/

[96] *Toshiba to pay ENN more than $800 million to exit U.S. LNG business;* Osamu Tsukimori, Jessica Jaganathan; November 7, 2018; https://www.reuters.com/article/us-toshiba-lng-sale/toshiba-to-pay-enn-more-than-800-million-to-exit-u-s-lng-business-idUSKCN1ND0DT

[97] https://newsbase.com/topstories/toshiba-sees-lng-business-big-risk

[98] https://www.lnglawblog.com/2018/10/tokyo-gas-signs-hoa-for-lng-canada-purchases/?utm_source=vuture&utm_medium=email&utm_campaign=vuture-emails

for a period of 13 years, from April 2026 to March 2039, delivered on an ex-ship basis with destination flexibility.

Tokyo Gas is Japan's second-biggest LNG importer, taking in 14 million tonnes per year, after JERA Co, the LNG buying joint venture of Tokyo Electric Power Co (Tepco) and Chubu Electric.[99]

The CBC News reported in Oct 2018:

$40B LNG facility is the light at the end of a long tunnel for Canada's natural gas sector - Struggling gas industry faces several more years of low prices until new Asia export project is built[100] by Kyle Bakx · CBC News · Posted: Oct 03, 2018

On Tuesday morning, hours after LNG Canada announced it would go ahead with its $40-billion export facility on the West Coast, analyst Martin King gave a presentation about the state of the oil and gas industry at the Calgary Petroleum Club in the city's downtown.

The LNG announcement is massive for the natural gas sector, but King had some cold truth for hundreds of people who came to hear him despite the heavy snow outside. ***Until the LNG export facility is up and running, he said, there is little reason for optimism****...* (Emphasis added)

In July of 2017 ConocoPhillips Senior Communications Specialist Amy Burnett made the following statement:

"Over the last few years, more facilities have come online to export LNG," Burnett said "So there are ***more sources available*** *for the product which* ***makes competition more difficult****."* (Emphases added)

Larry Persily, Chief of Staff for the Kenai Peninsula Borough also stated in the same 2017 article:

"It's also a hard reminder to Alaskans that no matter how much we want to sell our oil and gas, if the market doesn't want it, doesn't need it or isn't willing to pay a price to make it profitable — we can't sell our oil and gas," Persily said.

Prices have tumbled from $15-$18 per million btu, to just over $5.

*"****You can't buy gas out of Cook Inlet, pay to liquify it, burn up some of it while you're liquefying it, put it in a tanker and deliver it for $5.50 per million btu and make money****," Persily said. "****It is a[n] inhospitable market and will be for the near future****."*[101]

[99] https://www.reuters.com/article/japan-tokyo-gas/tokyo-gas-will-not-accept-destination-clauses-in-new-lng-contracts-president-idUSL4N1MG0O1
[100] https://www.cbc.ca/news/business/lng-canada-gmp-firstenergy-arc-1.4847377

[101] *Facing global gas glut, ConocoPhillips to mothball Kenai LNG plant*
By Rashah McChesney, Alaska's Energy Desk - Juneau - July 13, 2017
http://www.alaskapublic.org/2017/07/13/facing-global-gas-glut-conocophillips-to-mothball-kenai-lng-plant/

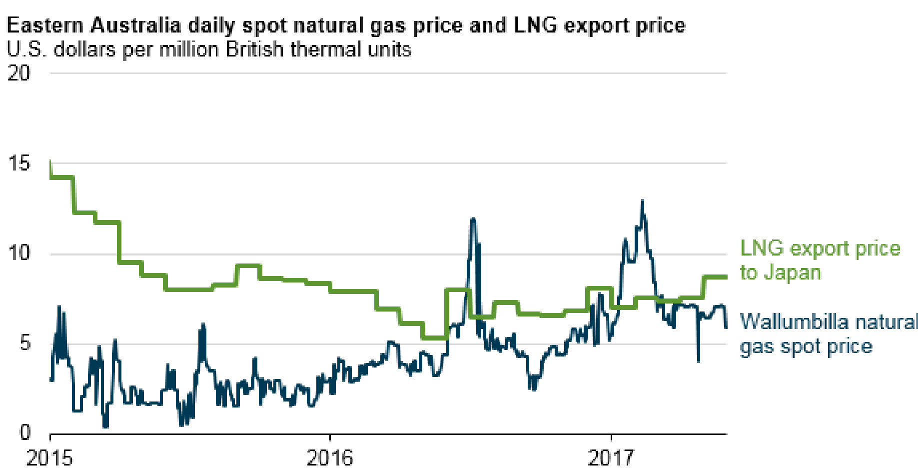
International Market / U.S. Manufacturers Do Not Support Higher Levels of U.S. LNG Exports

There are too many competitors in the international market currently and there is a glut of LNG that will last for many years. Due to this fact a higher level of scrutiny and independent review **is required in order to prevent an overbuild of pipelines and LNG facilities**, particularly when considering the negative impact these facilities can have on U.S. Manufacturing, jobs in other industries, American landowners, and rural / low-income communities. The FERC, U.S. Department of Energy, DSL and City of Coos Bay should fully consider the American public interest and need and not just what is best for corporations who may or may not have the best interest of Americans.

It should be very clear that liquefied natural gas export plans face years of oversupply.[102] In addition, the press reported in August of 2016 that Japan's JERA had plans to cut long-term LNG contracts by 42 percent by 2030.[103]

The U.S. Energy Information Administration (EIA) reported on October 20, 2017 in an article titled, "*Australian domestic natural gas prices increase as LNG exports rise*" that:

> *Australia became the world's second-largest exporter of liquefied natural gas (LNG) in 2015 and is likely to overtake Qatar as the world's largest LNG exporter by 2019.* ***As Australia's LNG exports have increased, primarily from LNG projects in eastern Australia, the country has had natural gas supply shortages in eastern and southeastern Australia and an increase in domestic natural gas prices****...*[104] (Emphasis added)



The EIA October 20, 2017 Report also states:

> *The U.S. experience with growing LNG exports is unlikely to be similar to Australia's.* ***More than half of Australia's total natural gas production was exported in 2016****. Australia's Energy Market Operator expects Australia's LNG exports will account for 80% of domestic*

[102] Liquefied Natural Gas Export Plans Face Years of Oversupply (July 18, 2017) https://www.bna.com/liquefied-natural-gas-n73014461925/

[103] Japan's Jera plans 42 percent cut in long-term LNG contracts by 2030 (August 10, 2016) https://wwwreuters.com/article/us-lng-jera/japans-jera-plans-42-percent-cut-in-long-term-lng-contracts-by-2030-idUSKCN10L117

[104] EIA Australian domestic natural gas prices increase as LNG exports rise Oct 20, 2017 https://www.eia.gov/todayinenergy/detail.php?id=33412#

production by 2020. Despite the rapid LNG export capacity growth, EIA's latest Annual Energy Outlook 2017 (AEO2017) Reference case—which reflects current policies and regulations—projects U.S. LNG exports to amount to only about 9% of total domestic natural gas production by 2020. (Emphasis added)

This EIA statement above concerning U.S. impacts is misleading due to the fact that as of April 9, 2018 the U.S. Dept of Energy (DOE) had accepted applications for **LNG export volumes totaling 57.14 Bcf/d to Free Trade Agreement Nations <u>and</u> 54.46 Bcf/d to Non-Free Trade Agreement Nations**.[105] <u>Most of these volumes have already been approved either directly or conditionally</u>.

The U.S. EIA reported in an August 9, 2017 article titled, *United States expected to become a net exporter of natural gas this year* [106] that:

*Natural gas production in the **<u>United States increased from 55 billion cubic feet per day (Bcf/d) in 2008 to 72.5 Bcf/d in 2016</u>**. Most of this natural gas—about 96% in 2016—**<u>is consumed domestically</u>**.* (Emphasis added)

The U.S. EIA was wrong to not consider in their analysis that the U.S. DOE has ALREADY APPROVED LNG Exports in excess of the EIA projected U.S. production and is HEADING THE U.S. FOR WORSE THAN WHAT IS HAPPENING IN AUSTRALIA where unfettered LNG Exports have tripled natural gas prices, harmed domestic consumers and caused manufacturing plants that rely on natural gas to close, throwing people out of work.[107]

This is NOT IN THE PUBLIC INTEREST.

On July 11, 2017, The Industrial Energy Consumers of America (IECA) President, Paul N. Cicio, issued the following statement following a July 11, 2017 Wall Street Journal story titled "*How Energy-Rich Australia Exported Its Way Into an Energy Crisis*."[108]

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[105] https://www.energy.gov/sites/prod/files/2018/06/f53/Summary%20of%20LNG%20Export%20Applications_0.pdf
[106] EIA *United States expected to become a net exporter of natural gas this year* - August 9, 2017
https://www.eia.gov/todayinenergy/detail.php?id=32412
[107] • *Everyone's a Loser in Australia's LNG Boom* By David Fickling March 26, 2017
https://www.bloomberg.com/gadfly/articles/2017-03-26/everyone-s-a-loser-in-australia-s-lng-boom
• *IECA to Congress: Australians' Gas Bills Soar Amid LNG Export Boom*
(view letter to U.S. House / Senate) October 3, 2014
http://www.ieca-us.com/wp-content/uploads/10.03.14_Australia-LNG-Article_Senate1.pdf
http://www.ieca-us.com/wp-content/uploads/10.03.14_Australia-LNG-Article_House2.pdf
• *Australian Nitrogen Fertilizer CEO Confirms Unfettered LNG Exports Have Tripled Natural Gas Prices*
April 15, 2014
http://www.ieca-us.com/wp-content/uploads/04.15.14_Australia-Congressional-Communication_Incitec-Pivot.pdf
[108] The Wall Street Journal "*How Energy-Rich Australia Exported Its Way Into an Energy Crisis*"
The world's No. 2 seller abroad of liquefied natural gas holds so little in reserve that it can't keep the lights on in Adelaide—a cautionary tale for the U.S. By Rachel Pannett; July 10, 2017
On a sweltering night this February, the world's No. 2 exporter of liquefied natural gas didn't have enough energy left to keep its own citizens cool.
A nationwide heat wave in Australia drove temperatures above 105 degrees Fahrenheit around the city of Adelaide on the southern coast. As air –conditioning demand soared, regulators called on Pelican Point, a local gas –fueled power station running at half capacity to crank up….
https://www.wsj.com/articles/how-energy-rich-australia-exported-its-way-into-an-energy-crisis-1499700859

"We applaud the Wall Street Journal on their story on how the Australian government failed the public and their manufacturing sector by failing to put consumer safeguards in place. Foreign consumers benefited from LNG exports, while Australian consumers saw natural gas prices skyrocket. Shortages forced power plant outages and manufacturers were forced to cut back production or shutdown. Manufacturers continue to leave the country, resulting in the loss of good paying jobs.

"The U.S. is following the same failed policy. There are no consumer protections in place on U.S. LNG exports. Currently, a breathtaking volume equal to 71 percent of 2016 U.S. natural gas supply has been approved for exports.

"The Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2017 forecasts that cumulative demand in 2050, only 33 years away, indicates that 56 percent of all U.S. natural gas resources in the lower 48 states will be consumed. Natural gas is unique and a valuable resource for manufacturing jobs and investment, for which there is no substitute.

*"**The U.S. still has time to put common-sense consumer safeguards in place now**."* [109] (Emphasis added)

On August 16, 2017, the Industrial Energy Consumers of America (IECA) sent a letter to Secretary Perry which outlines how the previous Administration failed to properly conduct public interest determinations on LNG application volumes for export to non-free trade agreement (NFTA) countries, as required under the Natural Gas Act (NGA).[110] On August 22, 2017, the Industrial Energy Consumers requested that the DOE conduct a legal review of this matter.[111] **We continue to stand in solidarity with the Industrial Energy Consumers of America (IECA) and fully support their urgent request for a legal review**.

On March 1, 2018 Reuters reported in an article titled "*U.S. trade group urges halt to further LNG export applications*"[112]

*A U.S. manufacturing trade group on Thursday urged the U.S. Department of Energy not to approve further liquefied natural gas (LNG) export applications, citing concerns that **the country was consuming and exporting the fuel at a faster clip than it was finding new resources**.*

***The agency's approval of LNG export volumes equal almost 70 percent of 2016 U.S. demand for periods of 20 to 30 years, which cannot possibly be in the "public interest**," the Industrial Energy Consumers Of America (IECA) said….* (Emphasis added)

[109] IECA Press Release "*WSJ Story Illustrates How Australian LNG Exports Resulted in a Domestic Shortage for Consumers*" July 11, 2017 http://www.ieca-us.com/wp-content/uploads/07.11.17_WSJ_Australian-LNG-Story-Press-Release.pdf

[110] Manufacturers Justify LNG Export Approval Moratorium: 58 to 71 Percent of all Natural Gas Could be Consumed by 2050 (view press release) Aug 16, 2017 http://www.ieca-us.com/wp-content/uploads/08.16.17_Perry-Two-Exports-Scenarios-Letter_FINAL.pdf

[111] Manufacturers Request DOE to Conduct Legal Review of LNG Export Applications to NFTA Countries (view press release) Aug 22, 2017 http://www.ieca-us.com/wp-content/uploads/08.22.17_Letter-to-DOE-Legal.pdf

[112] https://www.reuters.com/article/us-lng-tradegroup/u-s-trade-group-urges-halt-to-further-lng-export-applications-idUSKCN1GD6FY

On January 30, 2019 the Industrial Energy Consumers of America published a report entitled; "*Excessive Liquefied Natural Gas (LNG) Exports To NFTA Countries Are Not In The Public Interest And Increase Natural Gas And Electricity Prices To Consumers*." (***See Exhibit 27***)

Why on earth would we harm our American manufacturing base like this, not to mention American consumers, property owners and rural and low income communities?

19. Application should require ESEE Analysis of Conflicts and Provide Opportunities for Citizen Involvement as required under OAR Chapter 660, Division 16 (old Goal 5 Rule).

Coos Bay Comprehensive Plan 2000 Volume 1 / Part 1 Chapter 8 Page 3 states:

8.2 AGENCY COORDINATION
* * * *
State statute not only applies to city and county governments, it also states that state and local agencies have planning responsibilities, duties, and powers. It is extremely important that the planning for each agency, city, and county does not conflict

Coos County ZLDO SECTION 4.11.120 GOAL #5 CONFLICT RESOLUTION PROCESS:
When in the course of implementing the Coos County Comprehensive Plan it becomes evident that a conflict exists concerning the use of land identified as a Oregon Statewide Planning Goal conflicting#5 resource that is otherwise protected pursuant to OAR 660-16-005(1), then any proposed use may only be allowed after the an Administrative Conditional Use application has been completed based on findings that address the requirements of OAR 660-16-0005(2) and OAR 660-165-0010.

REQUIREMENTS AND APPLICATION PROCEDURES FOR COMPLYING WITH STATEWIDE GOAL 5
OAR 660-016-0005

Identify Conflicting Uses
*(1) It is the responsibility of local government to identify conflicts with inventoried Goal 5 resource sites. This is done primarily by examining the uses allowed in broad zoning districts established by the jurisdiction (e.g., forest and agricultural zones). **A conflicting use is one which, if allowed, could negatively impact a Goal 5 resource site**. Where conflicting uses have been identified, Goal 5 resource sites may impact those uses. These impacts must be considered in analyzing the economic, social, environmental and energy (ESEE) consequences:*
*(2) **Preserve the Resource Site: If there are no conflicting uses for an identified resource site, the jurisdiction must adopt policies and ordinance provisions, as appropriate, which ensure preservation of the resource site**.*
*(3) Determine the Economic, Social, Environmental, and Energy Consequences: **If conflicting uses are identified, the economic, social, environmental and energy consequences of the conflicting uses must be determined**. Both the impacts on the resource site and on the conflicting use must be considered in analyzing the ESEE consequences. The applicability and requirements of other Statewide Planning Goals must also be considered, where appropriate, at this stage of the process. A determination of the ESEE consequences of identified conflicting*

uses is adequate if it enables a jurisdiction to provide reasons to explain why decisions are made for specific sites.

CB - CBEMP #18 - Protection of Historical and Archaeological Sites within Coastal Shorelands

Local government shall provide special protection to historic and archaeological sites located within the Coos Bay Coastal Shorelands Boundary, except where Exceptions allow otherwise. These sites are identified in the section entitled: "Coastal Shoreland Values Requiring Mandatory Protection" and on the "Special Considerations Map". Further, local government shall continue to refrain from widespread dissemination of site-specific information about identified archaeological sites.

This strategy shall be implemented by requiring review of all development proposals involving an archaeological or historical site to determine whether the project as proposed would protect the archaeological and historical values of the site.

The development proposal, when submitted, shall include a site development plan showing, at a minimum, all areas proposed for excavation, clearing and construction. Within three (3) working days of receipt of the development proposal, the local government shall notify the Coos, Siuslaw, Lower Umpqua Tribal Council in writing, together with a copy of the site development plan. The Tribal Council shall have the right to submit a written statement to the local government within ten (10) days of receipt of such notification, stating whether the project as proposed would protect the historical and archaeological values of the site, or if not, whether the project could be modified by appropriate measures to protect those values.

"Appropriate measures" may include, but shall not be limited to the following:

A. Retaining the historic structure in situ or moving it intact to another site; or
B. Paving over the site without disturbance of any human remains or cultural objects upon the written consent of the Tribal Council; or
C. Clustering development so as to avoid disturbing the site; or
D. Setting the site aside for non-impacting activities, such as storage; or
E. If permitted pursuant to the substantive and procedural requirements of ORS 97.750, contracting with a qualified archaeologist to excavate the site and remove any cultural objects and human remains, reinterring the human remains at the developer's expense; or
F. Using civil means to ensure adequate protection of the resources, such as acquisition of easements, public dedications, or transfer of title.

If a previously unknown or unrecorded archaeological site is encountered in the development process, the above measures shall still apply. Land development activities which violate the intent of this strategy shall be subject to penalties prescribed in ORS 97.990 (8) and (9). Upon receipt of the statement by the Tribal Council, or upon expiration of the Tribal Council's ten-day response period, the local government shall conduct an administrative review of the development proposal and shall:

A. approve the development proposal if no adverse impacts have been identified, as long as consistent with other portions of this plan, or
B. approve the development proposal subject to appropriate measures agreed upon by the landowner and the Tribal Council, as well as any additional measures deemed necessary by the local government to protect the historical and archaeological values of the site. If the property owner and the Tribal Council cannot agree on the appropriate

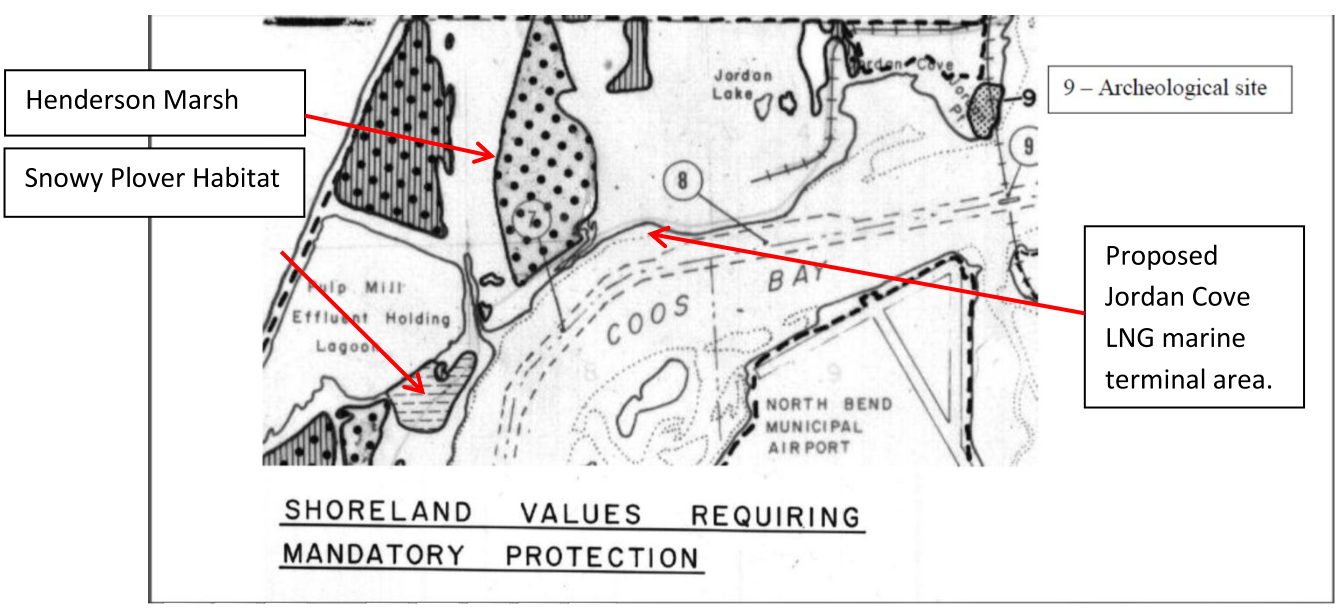
measures, then the governing body shall hold a quasi-judicial hearing to resolve the dispute. The hearing shall be a public hearing at which the governing body shall determine by preponderance of evidence whether the development project may be allowed to proceed, subject to any modifications deemed necessary by the governing body to protect the historical and archaeological values of the site.

<u>This strategy recognizes that protection of historical and archaeological sites is not only a community's social responsibility, but is also legally required by Goal #17 and OBS 97.745. It also recognizes that historical and archaeological sites are non-renewable cultural resources</u>.

For example, the Coos County Shoreland Values Requiring Mandatory Protection Map (***See a section of this map below***) clearly shows that the property impacted by the Jordan Cove Export Project is an area of known archeological significance. Due to the fact that this is already known and established it is the State, County and City's duty to protect the resource whether the Tribe chooses to protect it or not. Any dynamic compaction or vibro compaction to the site could essentially destroy any and all archeological and cultural resources that may be buried on the site. It is the duty of the City of Coos Bay to protect these **<u>and other critical resources</u>**. The State, County, and City of Coos Bay should follow the ESEE analysis of conflicts process as lined out by OAR Chapter 660, Division 16. This is also relevant to other conflicts such as important natural habitat areas and marine life.

SHORELAND VALUES REQUIRING MANDATORY PROTECTION

The following shows the Coos County Shoreland Values Map Requiring Mandatory Protection under the Coos Bay Estuary Management Plan:

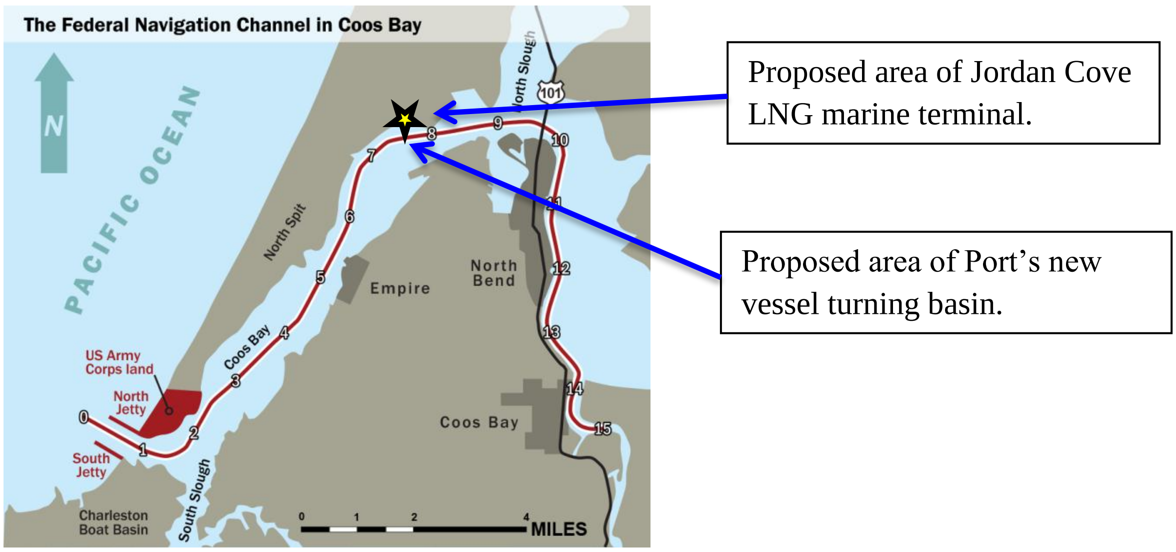


20. Cumulative Impacts with other Proposed Projects must be considered.

- Port of Coos Bay dredging proposal for Channel Deepening and Widening involving the removal of 18 mcy of dredge material under Corps review

- City of North Bend California Street Boat Ramp Replacement including dock and piling replacement under Corps 47964 / DSL APP0061371[113]
- Southport Forest Products LLC / R/F for 5 mooring dolphins adjacent to Barge Berth (Piling, RemFill) / DSL APP0061629[114]
- City of Coos Bay R/F for replacing 498 feet of existing sewer line parallel to Coal Bank Slough. (ErosionCon,Pipeline,RemFill,Util) / DSL APP0061778[115]
- Various other recent DSL projects at www.statelandsonline.com

The Port of Coos Bay channel modification project would include a new vessel turning basin with a designed length of 1,400 feet, width of 1,100 feet, and depth of -37 feet; constructed approximately between River Miles 7.3 to 7.8.



Obviously the proposed Jordan Cove LNG Export Project would benefit greatly from the Port of Coos Bay's proposed Channel Modification project including the proposed new vessel turning basin. I do not understand, however, why the Port would propose deepening and widening the Coos Bay shipping channel to -45 feet and then develop a turning basin that is only -37 feet. The -37 foot turning basin negates the need for the shipping channel to be any deeper than the -37 feet that it currently is.

21. Immense Dredging would have Negative Impacts on the Coos Bay and Bay Users.

The proposed Port of Coos Bay channel modification would require the dredging and disposal of approximately 18 million cubic yards of material (sand and rock) to deepen and widen the navigation channel.

To give a comparison as to how much material this actually is; a football field is 120 yards by 53 yards so it can hold 6,360 cubic yards (120yards X 53yards =6,360 square yards. 6,360 square yards one yard in height would be 6,360 cubic yards). The estimate of 18 million cubic yards of material would be approximately 2,830 yards in height in a football field sized area (18,000,000 cubic yards divide by 6,360 cubic yards = 2,830 cubic yards) or 8,490 feet in height (2,830 yards X 3 since there are 3 feet in

[113] http://statelandsonline.com/index.cfm?fuseaction=Comments.AppDetail&id=61371
[114] https://lands.dsl.state.or.us/index.cfm?fuseaction=Comments.AppDetailLF&id=61629
[115] https://lands.dsl.state.or.us/index.cfm?fuseaction=Comments.AppDetailLF&id=61778

a yard = 8,490 feet). **<u>In other words, roughly 85</u>** (8,490ft divide by 100ft) **<u>football fields filled one hundred feet high with dredge material would be needed for storage of 18 million cubic yards of material</u>**. In comparison, the Tioga Building in Coos Bay is roughly 118 feet high. It would take **72** (8,490ft divide by 118ft) football fields the same height as the Tioga Building in Coos Bay to store 18 million cubic yards.

Another way to look at this is that there are 5,280 feet in a mile. So you could also say that 18 million cubic yards of material would be **<u>a football field filled 1.6 miles high with dredged material</u>** (8,490ft divided by 5,280ft). **That is an enormous amount of dredged material.** <u>There is no way one could take that much material out of our bay without causing significant harm to the function and vitality of the Coos Estuary</u>. This would completely alter the Bays velocity and flow along with ecosystems that currently thrive there, particularly when you combine it with what Jordan Cove is also planning.

Jordan Cove's Sept 21, 2017 Application that was filed with the Federal Energy Regulatory Commission (FERC) states the following in Resource Report #1:

> ***<u>Approximately 5.7 million cubic yards of material will be removed to create the marine slip basin</u>***. *Approximately 1.23 million cubic yards will be land based excavation (dry upland material) and the remaining 4.07 million cubic yards will be wet material.*
>
> ***<u>The number of ship calls at the LNG vessel berth has increased to 110 to 120</u>***. *This number was previously 90 to 100. Increase in LNG production capacity from 6.8 mtpa to 7.8 mtpa.* [116] (Emphasis added)

The estimate of 5.7 million cubic yards would be a football field approximately 896 yards in height or 2,688 feet high. (5,700,000 cubic yards divide by 6,360 cubic yards = 896 cubic yards) or 2.688 feet in height (896 cubic yards X 3 since there are 3 feet in a yard = 2,688 feet). **<u>In other words, roughly 26.8</u>** (2,688 divide by 100ft) **<u>football fields filled one hundred feet high with dredge material would be needed for storage of 5.7 million cubic yards of material</u>**.

In addition to the removal of 5.7 mcy of material from the Slip and Access channel, Jordan Cove's DSL application has a Table C graph found on electronic page 126 that shows the Navigational dredging and Eel grass dredging would add another .6 mcy of dredging in the Coos Bay for a **<u>total of 6.3 million cubic yard of material</u>** (5.7 + .6) being dredged out of the Coos Bay by the Jordan Cove project ALONE.

6.3 mcy (for Jordan Cove) + 18 mcy (for Port of Coos Bay) = 24.3 million cubic yards of material. **<u>In other words, roughly 114.6 football fields filled one hundred feet high with dredge material for BOTH Jordan Cove's and the Port of Coos Bay's combined projects.</u>**

[116] JCEP Resource Report #1_Table 1.2-2_page 13_Sept 21, 2017_FERC Filing under CP17-495-000

Table C: Proposed Dredged Material Management for Construction Activities

Area	Construction Phase	Volume (mcy)	Placement Location
Freshwater Dredging Phase 1			
Slip	Land-Based Excavation	1.40	LNG Terminal
Slip	Dredging in Pocket Behind Berm	2.40	LNG Terminal Site and Roseburg Site
Saltwater Dredging Phase 2			
Access Channel	Dredging from Bay	1.40	LNG Terminal Site and Roseburg Site
Slip	Removal of Berm	0.20	LNG Terminal Site
Slip	Removal of Berm	0.30	Kentuck Project Site
	TOTAL	**5.70**	
Eelgrass Mitigation Dredging		0.04	APCO Site 1 and 2
Navigation Reliability Improvements		0.59	APCO Site 1 and 2

The proposed Jordan Cove marine slip and channel access dredging project would be in ADDITION to the Port's proposed Channel Modification project. The Port has been denying that there is a relationship between the LNG project and their proposed Channel Modification project and their proposed Oregon Gateway project - for which there would each be several separate applications. A portion of the LNG facility would be constructed adjacent to the Port's Gateway site and LNG tankers would use a Port's Gateway turning basin. When examining the issues raised by these multiple permit applications, the Army Corps, DEQ, DSL and City of Coos Bay should consider the larger cumulative impacts of **all** these projects, together, including additional land use issues that would be required before these facilities would be able to operate.

It is still not clear as to whether the Oregon International Port of Coos Bay and Jordan Cove have made enough dredge disposal site allowance needed for maintenance dredging as was indicated in a June 8th 2009 and an August 18, 2015 comment letter(s) that were sent to the FERC from the United States Environmental Protection Agency, REGION 10, Seattle, WA 98101-3140.[117] (***See Exhibit 54** for the August 2015 letter*.)

CB - CBEMP Policy 20a. Dredged Material Disposal Guidelines:

> ***Future dredged material disposal should be carried out in accordance with the guidelines outlined in Section 6.2 of the Plan, which related to: drainage diversion, sediment quality and turbidity, timing of disposal, land surface use, revegetation, toxic materials, outfalls and influent discharge points and water quality***. *Future land use shall be governed by the uses/activities permitted and the management Objective in that management segment. Additional guidelines contained in the "Special considerations" section of the individual site field-sheets (see Inventory and Factual Base, Section 7, Appendix 'A') provide site-specific information on the procedures that should be followed.*
>
> *These guidelines are intended to indicate the type of conditions that federal and state agencies are likely to impose on dredged material disposal permits, which shall be the primary means of implementation. Local governments shall implement this policy by review and comment on permit applications.*
>
> *   *   *   *
>
> (Emphasis added)

117 http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20090617-0016 and http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20150901-0057

Conclusion

Based on the above documentation and evidence, the Jordan Cove text amendment and rezone request along with their CUP application should be denied. The Jordan Cove application does not meet the requirements necessary in order to apply for a Goal exemption. They have not provided an environmental, geotechnical or economic assessment, or a sufficient and complete mitigation plan in order to justify a text amendment, rezone or Conditional Use Permit (CUP). In addition, as explained above, Jordan Cove is not the property owner of the property and has not proven that their project has met “need” and “resource protection” requirements necessary in order for an exemption or CUP to occur. For these and many other reasons stated above their permit application should be denied.

Sincerely,

/s/ Jody McCaffree

Jody McCaffree

McCaffree / Citizens For Renewables / Citizens Against LNG
Index for Exhibits
April 25, 2019
Re: Jordan Cove Channel Navigation Alteration
Coos Bay File No. File No. 187-18-000153-PLNG-01

Exhibit 1: Dec 4, 2018 letter to the FERC under Docket Nos. CP17-494-000 and CP17-495-000 adding to Service list Natalie Eades, Manager, Environment, Jordan Cove Energy Project L.P. Pacific Connector Gas Pipeline, L.P**.** **/** contact NEades@pembina.com

Exhibit 2:

- March 5, 2019 Oregon Dept of State Lands Update announcing *DSL* ***Removal-fill permit decision deadline extended to September 20, 2019****.*
- DSL April 10, 2019 letter to Jordan Cove **requesting additional information** in order to process their removal-fill permit.

Exhibit 3:

- Evidence of Shell's Sakhalin II LNG project in Russia and the Environmental Impacts to Avina Bay along with devastating upland impacts.
- Pipeline Impacts from Shell's Sakhalin II LNG project in Russia
- Fortune article "Shell shakedown" By Abrahm Lustgarten, Feb 1, 2007

Exhibit 4:

- Nation & World - ***Ocean salmon seasons in jeopardy off southern Oregon;*** Originally published March 5, 2018; The Associated Press https://www.seattletimes.com/nation-world/ocean-salmon-seasons-off-southern-oregon-coast-in-jeopardy/
- ***West Coast senators join call for salmon disaster declaration****;* Saphara Harrell - The Umpqua Post; Jun 13, 2017 http://theworldlink.com/news/local/west-coast-senators-join-call-for-salmon-disaster-declaration/article_3690f87f-44b8-5f19-a385-7557776543b0.html

Exhibit 5: December 16, 2014 Public Comment by **Barbara Gimlin** on Jordan Cove Energy Project, L.P., Draft Environmental Impact Statement expressing concerns with respect to **contaminated soils on the Jordan Cove property** under CP13-483-000 via CP07-444-000.

Exhibit 6: February 13, 2015 Public Comment by **Barbara Gimlin** on Jordan Cove Energy Project, L.P., DEQ Water Quality permit process under FERC CP13-483-000.

Exhibit 7:

- Oct 15, 2014 Motion to Intervene Out of Time by **Clausen Oyster Company and Lilli Clausen** expressing concerns with **pipeline and sediment impacts to their Oysters**
- Feb 28, 2015 Motion to Intervene Out of Time by **Coos Bay Oyster Company and Jack Hampel** expressing concerns with **pipeline and sediment impacts to their Oysters**.

Exhibit 8: Feb 21, 2014 **Motion to Intervene Out of Time by Clam Diggers Association of Oregon** expressing concerns with LNG project **sedimentation and estuary impacts on clams**

Exhibit 9: ***Potential Impact of Jordan Cove LNG Terminal construction on the Nursery Habitat of Dungeness crab*** by Sylvia Yamada Ph.D. January 2019 for DSL and oral comment outline provided on January 15, 2019 under APP0060697 at Salem Hearing.

Exhibit 10: Letter from Shon Schooler, Ph.D., Research Coordinator with the South Slough National Estuarine Research Reserve concerning Eelgrass (March 2019)

Exhibit 11: Select pages from ***Oregon Travel Impacts Statewide Estimates 1992 - 2017p Report*;** June 2018 ; Dean Runyan Associates **(Coos County Impacts)**
http://www.deanrunyan.com/doc_library/ORImp.pdf

Exhibit 12: May 21, 2010 and **Sept 17, 2007 testimony from Ron Sadler** placed into Jordan Cove and Pacific Connector Conditional Land Use Permit processes in Coos County concerning **sedimentation impacts in the Coos Estuary**.

Exhibit 13:

- ODFW – **Threatened / Endangered Species List**
  http://www.dfw.state.or.us/wildlife/diversity/species/threatened_endangered_candidate_list.asp
- **NOAA – Oregon Coast Coho protected species:**
  http://www.westcoast.fisheries.noaa.gov/protected_species/salmon_steelhead/salmon_and_steelhead_listings/coho/oregon_coast_coho.html
- **NOAA - Green Sturgeon protected species:**
  http://www.westcoast.fisheries.noaa.gov/protected_species/green_sturgeon/green_sturgeon_pg.html
- **NOAA – Pacific Eulachon protected species**
  http://www.westcoast.fisheries.noaa.gov/protected_species/eulachon/pacific_eulachon.html
- **ESA listed Marine Mammals**
  http://www.westcoast.fisheries.noaa.gov/protected_species/marine_mammals/esa.html
- **ESA listed Sea Turtles**
  http://www.westcoast.fisheries.noaa.gov/protected_species/sea_turtles/marine_turtles.html
- **Point Reyes bird's-beak** – Oregon Dept of Agriculture - Endangered
  http://www.oregon.gov/oda/shared/Documents/Publications/PlantConservation/CordylanthusMaritimusPalustrisProfile.pdf

Exhibit 14: Natural Resources of Coos Bay Estuary - Inventory Report Vol 2, No 6 prepared by Oregon Dept of Fish and Wildlife; 1979.

Exhibit 15: **Critical Species & Habitats of Oregon's Coastal Beaches & Dunes** - Oregon Coastal Zone Management Association, Inc 1979**:**

Exhibit 16: **Oregon Shorebird Festival Bird List** Compiled from all field trips August 26-28, 2011

Exhibit 17: ***7,500 songbirds killed at Canaport gas plant in Saint John*** - Migrating birds, some possible endangered species, flew into gas flare CBC News Posted: Sep 17, 2013 http://www.cbc.ca/news/canada/new-brunswick/7-500-songbirds-killed-at-canaport-gas-plant-in-saint-john-1.1857615

Exhibit 18: ***Geology of the Coos Estuary and Lower Coos Watershed*** from Partnership for Coastal Watersheds Report https://www.partnershipforcoastalwatersheds.org/geology-of-the-coos-estuary-and-lower-coos-watershed/

Exhibit 19: ***13-Year Cascadia Study Complete – And Earthquake Risk Looms Large*** http://oregonstate.edu/ua/ncs/archives/2012/jul/13-year-cascadia-study-complete-%E2%80%93-and-earthquake-risk-looms-large

Exhibit 20: Select pages from ***The Oregon Resilience Plan Reducing Risk and Improving Recovery for the Next Cascadia Earthquake and Tsunami***; Report to the 77th Legislative Assembly from Oregon Seismic Safety Policy Advisory Commission (OSSPAC); Feb 2013

Exhibit 21: Oct 5, 2011 Letter from Alan Trimble Ph.D. regarding Olympia oysters submitted into REM-10-01 proceeding on the Pacific Connector Gas Pipeline.

Exhibit 22: ***Confirmed Presence of Olympia oysters within Haynes Inlet***, *Coos Bay (29-30 June 2011)* Dr. Steve Rumrill, Dr. Laura Peterio-Garcia, Joanne Choi.

Exhibit 23: ***History of Olympia oysters (Ostrea Lurida Carpenter 1864) in Oregon Estuaries and a description of recovering populations in Coos Bay*** By Scott Groth and Steve Rumrill; Journal of Shellfish Research, Vol. 28, No. 1, 51-58, 2009.

Exhibit 24: October 8, 2011 letter from Professor Danielle Zacheri, PhD, Associate Professor, Dept of Biological Science, California State University, Fullerton, with respect to Olympia oysters.

Exhibit 25: November 27, 2017 Oregon **Land Use Board of Appeals Final Opinion and Order for LUBA No. 2016-095** Remanding back to Coos County the Jordan Cove Energy Project LNG Terminal Conditional Land Use Permit under Coos County HBCU-15-05. *Oregon Shores et.at. –v- Coos County et.at.*

Exhibit 26: December 26, 2018 **Appeal of City of North Bend Planning Director's Decision** and Issuance of LUCS on the Jordan Cove/Pacific Connector Project. LUCS17-18 and LUCS18-18.

Exhibit 27: Industrial Energy Consumers of America "***Excessive Liquefied Natural Gas (LNG) Exports To NFTA Countries Are Not In The Public Interest And Increase Natural Gas And Electricity Prices To Consumers***" - January 30, 2019

Exhibit 28: ***DEQ hits Clausen Oysters with $25,000 fine*** By Gail Elber, Staff Writer Aug 25, 2010https://theworldlink.com/news/local/deq-hits-clausen-oysters-with-fine/article_9fb57e0c-b070-11df-8cc0-001cc4c03286.html

Exhibit 29: ***Limitations of the Haynes Inlet sediment transport study*** by Tom Ravens, Ph.D., Professor, Dept. of Civil Engineering University of Alaska, Anchorage

Exhibit 30: U.S. Coast Guard ***July 1, 2008, Water Suitability Assessment (WSA) Report*** for the Jordan Cove project.

Exhibit 31: ***Coos Bay Harbor Safety Plan*** by Coos Bay Harbor Safety Committee, February 2018

Exhibit 32: ***Coos Bay Channel Entrance - Distances and Buoy Markings***. Proximity of Channel Buoys to the Shoreline.

Exhibit 33: Thirteen NOTICE OF PRESUMED HAZARD (s) issued by the FAA on the Jordan Cove Energy Project components, **Nine involving LNG tank ships in the Bay.** - May 7, 2018

Exhibit 34: FAA Memorandum Re: "***Technical Guidance and Assessment Tool for Evaluation of Thermal Exhaust Plume Impact on Airport Operations";*** January 21, 2015

Exhibit 35: "*Hot Air"* Pilots say the Port of Portland's plans to sell land for a power plant next to the Troutdale Airport include a fatal flaw; April 22, 2015; Willamette Week
http://www.wweek.com/portland/article-24594-hot_air.html

Exhibit 36: *"**Position Paper - Safety Concerns of Exhaust Plumes**"* -Prepared by: Federal Aviation Administration - Airport Obstructions Standards Committee Working Group; July 8, 2014

Exhibit 37: Potential Flight Hazards 8-22-13 AIM: "*7-5-15.* ***Avoid Flight in the Vicinity of Thermal Plumes (Smoke Stacks and Cooling Towers)"***

Exhibit 38: September 6, 2014 Newspaper **Ad announcing the 15th annual Coos Basin Salmon Derby** in Coos Bay, Oregon Sept 13 & 14th 2014

Exhibit 39: South Coast Basin - **Flow Restoration Priorities** for Recovery of Anadromous Salmonids in Coastal Basins

Exhibit 40: September 15, 2015 Jordan Cove Final EIS under CP13-483-000 et al pages 4-370 to 4-739 having to do with **Ballast Water**

Exhibit 41:

- North Spit listing in"**Top 10 Beach Strolls**" Sunset Magazine, Vol. 219, Issue 4, October 2007
- Coos Bay, Oregon listing in **50 Best Places to Live National Geographic Adventure Magazine** - September 2008

Exhibit 42: ***After a year of planning, Coos Bay has new marine patrol boat dock*** by KCBY; Wednesday, March 16th 2016; https://kcby.com/news/local/after-a-year-of-planning-coos-bay-has-new-marine-patrol-boat-dock

Exhibit 43: June 24, 2015 Letter from attorney's Motschenbacher and Blattner LLP concerning **Jordan Cove leasing the Boxcar Hill Campground**.

Exhibit 44: Study outlines threat of ***ocean acidification to coastal communities in the U.S***.; Oregon State University; Feb 23, 2015 http://today.oregonstate.edu/archives/2015/feb/study-outlines-threat-ocean-acidification-coastal-communities-us

Exhibit 45: ***Vulnerability and adaptation of US shellfisheries to ocean acidification****;* By Julia A. Ekstrom; Lisa Suatoni; Sarah R. Cooley; Linwood H. Pendleton; George G. Waldbusser; Josh E. Cinner; Jessica Ritter; Chris Langdon; Ruben van Hooidonk; Dwight Gledhill; Katharine Wellman; Michael W. Beck; Luke M. Brander; Dan Rittschof; Carolyn Doherty; Peter Edwards; and Rosimeiry Portela; Perspective in Nature Climate Change; Published on-line – Feb 2015

Exhibit 46: ***Oysters on acid: How the oceans's declining pH will change the way we eat*** ; By H. Claire Brown; November 28th, 2017; https://newfoodeconomy.org/ocean-acidification-oysters-dungeness-crabs/

Exhibit 47:

- **Oregon and California crabbers sue fossil fuel companies** Updated Nov 27, 2018; Posted Nov 26, 2018 https://www.oregonlive.com/pacific-northwest-news/index.ssf/2018/11/oregon_and_california_crabbers.html
- Superior Court of the State of California ***Pacific Coast Federation of Fishermen's Association, Inc –vs- Cheron Corp; Chevron U.S.A. Inc, Exxon Mobil Corp et.al.*** Petitioners Complaint under Case CGC-18-571285.
- United States District Court Western District of Washington at Seattle ***Columbia Riverkeeper et. al.-v- Scott Pruitt, et. al*** Order Re: Motions for Summary Judgment under Case No C17-289RSM

Exhibit 48: Williams CR, Dittman AH, McElhany P, et al. ***Elevated CO2 impairs olfactory-mediated neural and behavioral responses and gene expression in ocean-phase coho salmon (Oncorhynchus kisutch)***. Glob Change Biol. 2018;00:1–15. https://doi.org/10.1111/gcb.14532 November 2018

Exhibit 49: June 25, 2014 DEQ Warning letter issued to Jordan Cove for violations that occurred at the Ingram Yard property on May 8, 2014, along with the follow-up that also occurred.
Times New Roman

Exhibit 50: ***Pembina Pipeline's new purpose: Get Canada's oil and gas to the rest of the world*** ;By Claudia Cattaneo; February 16, 2018;
http://business.financialpost.com/commodities/energy/pembina-pipelines-new-purpose-get-canadas-oil-and-gas-to-the-rest-of-the-world

Exhibit 51: ***Jordan Cove LNG and Pacific Connector Pipeline Greenhouse Gas Emissions Briefing***; Oil Change International; Jan 2018;
http://priceofoil.org/2018/01/11/jordan-cove-lng-and-pacific-connector-pipeline-greenhouse-gas-emissions/

Exhibit 52: Pages 4 and 5 from ***IGU 2018 World LNG Report*** - 27th World Gas Conference Edition

Exhibit 53: ***Current Removal-Fill Permit Applications*** in Coos County

Exhibit 54: August 18, 2015 **letter from United States Environmental Protection Agency Region 10** - concerning maintenance dredging disposal availability.

Exhibit 55 ***The impact of channel deepening and dredging on estuarine sediment concentration*** D.S. vanMaren n, T.vanKessel, K.Cronin, L.Sittoni - Coastal and Marine Systems 95(2015)1–14 Deltares, Delft, the Netherlands

Exhibit 56: ***The effects of marine gravel extraction on the macrobenthos: Results 2 years post-dredging*** A.J. Kenny, H.L. Rees ; Marine Pollution Bulletin ; Volume 32, Issues 8–9, August–September 1996, Pages 615-622
https://www.sciencedirect.com/science/article/pii/0025326X96000240?via%3Dihub

Exhibit 57: ***Seagrasses, Dredging and Light in Laguna Madre, Texas, U.S.A.***
Christopher P. Onuf - National Biological Survey, National Wetlands Research Center, Campus Estuarine, Coastal and Shelf Science; Volume 39, Issue 1, July 1994, Pages 75-91
https://www.sciencedirect.com/science/article/pii/S027277148471050X?via%3Dihub

Exhibit 58: ***Dredging related metal bioaccumulation in oysters***
L.H. Hedge , N.A. Knott, E.L. Johnston; Marine Pollution Bulletin; Volume 58, Issue 6, June 2009, Pages 832-840
https://www.sciencedirect.com/science/article/pii/S0025326X09000472?via%3Dihub

Exhibit 59: ***Shell shock*** , June 14, 2010, By Nate Traylor, Staff Writer - The World
http://theworldlink.com/news/local/shell-shock/article_389a9be8-77dc-11df-9127-001cc4c03286.html

Exhibit 60:
November 6, 2017 **DOGAMI comments related to Geologic Hazards** and the Proposed Jordan Cove LNG terminal and Pacific Connector Gas Pipeline.

Exhibit 61:
January 11, 2015 Public Comment by Barbara Gimlin, ***Intertidal Flats Mitigation Proposed for Kentuck Slough*** - Jordan Cove Energy Project Joint Permit Applications
U.S. Army Corps of Engineers/Oregon Department of State Lands

Exhibit 62:
Supplement to Technical Memorandum - ***Jordan Cove LNG Facility Tsunami Hydrodynamic Modeling*** – January 24, 2014

Exhibit 63: Examples of **Alternative LNG Terminal/Pipeline locations** that should be considered.

Exhibit 64: July 2015 Brookings Report *"**An Assessment of U.S. Natural Gas Exports**"*

Exhibit 65: Carbon Tracker report: "***Carbon Supply Cost Curves: Evaluating financial risk to gas capital expenditures***." http://www.carbontracker.org/wp-content/uploads/2015/06/CTI-gas-report-Final-WEB.pdf

Exhibit 66: Moody's Investors Service -April 7, 2015 Announcement: "***Moody's: Liquefied natural gas projects nixed amid lower oil prices.***"

Exhibit 67: April 1, 2019, Comment by Jerry Havens, Distinguished Professor of Chemical Engineering at University of Arkansas, on the FERC DEIS under CP-17-494 and CP-17-495. Concerns public safety hazards being underestimated at the proposed Jordan Cove LNG terminal

Exhibit 68: "***Scientists say public safety hazards at Jordan Cove LNG terminal in Coos Bay are underestimated***" by Ted Sickinger; The Oregonian; January 16, 2015

Exhibit 69: June 7, 2016, article, "***Explosive LNG issues grab PHMSA's attention***" *by* E&E reporter, Jenny Mandel.

Exhibit 70: "***Site Selection & Design for LNG Ports & Jetties – Information Paper No. 14*" - Published by *Society of International Gas Tanker and Terminal Operators Ltd*** / 1997

Exhibit 71: United States Government Accountability Office, Report to Congressional Requesters, Maritime Security; "***Public Safety Consequences of a Terrorist Attack on a Tanker Carrying Liquefied Natural Gas Need Clarification***", February 2007; GAO-07-316: http://www.gao.gov/new.items/d07316.pdf

Exhibit 72: U.S. Department of Energy "***Liquefied Natural Gas Safety Research***" Report to Congress May 2012;
http://energy.gov/sites/prod/files/2013/03/f0/DOE_LNG_Safety_Research_Report_To_Congre.pdf

<u>Exhibit 73</u>: "***An Assessment of the Potential Hazards to the Public Associated with Siting an LNG Import Terminal in the Port of Long Beach***" - Dr. Jerry Havens, September 14, 2005

<u>Exhibit 74</u>: *"**LNG and Public Safety Issues – Summarizing Current Knowledge about Potential Worst Case Consequences of LNG spills onto water**"*. Jerry Havens, Coast Guard Journal Proceedings,

<u>Exhibit 75:</u> WILLIAMS COMPANIES FAILED TO PROTECT EMPLOYEES IN PLYMOUTH LNG EXPLOSION The natural gas company eyeing other Northwest projects has a history of unsafe work conditions. June 3, 2016
https://www.sightline.org/2016/06/03/williams-companies-failed-to-protect-employees-in-plymouth-lng-explosion/

<u>Exhibit 76</u>: Coos County CHAPTER III ESTUARY ZONES - Coos Bay Estuary Management Plan Policies.

Exhibit 1

Jordan Cove Energy Project, L.P.

Pacific Connector GAS PIPELINE

December 4, 2018

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: *Pacific Connector Gas Pipeline, LP* and *Jordan Cove Energy Project L.P.*
Docket Nos. CP17-494-000 and CP17-495-000
Request to Update Service Lists

Dear Ms. Bose:

Pursuant to Rule 2010 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission, 18 C.F.R. § 385.2010 (2018), Jordan Cove Energy Project L.P. ("JCEP") and Pacific Connector Gas Pipeline, LP ("PCGP") respectfully request that the Commission update the official service lists in the captioned dockets as shown below.

Please **add** the following individuals to the service lists:

Natalie Eades
Manager, Environment
Jordan Cove Energy Project L.P.
Pacific Connector Gas Pipeline, LP
5615 Kirby Drive, Suite 500
Houston, Texas 77005
Phone: 832-255-3841
Email: NEades@pembina.com

Michael Koski
Senior Manager, External Affairs
Jordan Cove Energy Project L.P.
Pacific Connector Gas Pipeline, LP
5615 Kirby Drive, Suite 500
Houston, Texas 77005
Phone: 971-940-7800
Email: MKoski@pembina.com

Please **remove** the following individuals from the service lists:

Elizabeth Spomer
Jordan Cove Energy Project L.P.
Pacific Connector Gas Pipeline, LP
5615 Kirby Drive, Suite 500
Houston, Texas 77005
Phone: (866) 227-9249
Email: espomer@vereseninc.com

Rose Haddon
Jordan Cove Energy Project L.P.
Pacific Connector Gas Pipeline, LP
5615 Kirby Drive, Suite 500
Houston, Texas 77005
Phone: (866) 227-9249
Email: rose.haddon@jordancovelng.com

JCEP and PCGP respectfully request that the Commission waive Rule 203(b)(3), 18 C.F.R. § 385.203(b)(3), in order to allow all designated representatives to be included on the Commission's official service lists. In addition to changing the service list, please direct future correspondence to me at the address written above. Should you have any questions, please contact me at neades@pembina.com or 832-255-3841.

Sincerely,

/s/ Natalie Eades
Natalie Eades
Jordan Cove Energy Project L.P.
Pacific Connector Gas Pipeline, LP

CERTIFICATE OF SERVICE

I hereby certify that I have this 4th day of December, 2018, served the foregoing document upon each person designated on the official service list compiled by the Secretary in these proceedings.

*/s/ Victoria R. Galvez*________________
Victoria R. Galvez
Attorney for
Jordan Cove Energy Project L.P.
Pacific Connector Pipeline, LP

Exhibit 2

Jordan Cove Update: March 5, 2019

Removal-fill permit decision deadline extended to September 20, 2019

The permit decision deadline for the Jordan Cove Energy Project removal-fill application has been extended to September 20, 2019. A decision may be made sooner if the Oregon Department of State Lands (DSL) is in possession of all necessary information to make a permit decision.

Why is an extension needed?
There are several remaining steps in the removal-fill permitting process. Due to robust participation in the review and comment period for the Jordan Cove removal-fill permit application, additional time is needed for these remaining steps:

Current Step: Final Technical Review. This step includes:

- **DSL Review of Comments.** Approximately 49,000 to 57,000 comments were received (*please see FAQ for more info about the approximate number*). DSL staff is currently in the process of reading all comments received. Extension of the permit decision deadline allows DSL staff to complete review of comments in order to identify substantive issues relevant to the removal-fill law. DSL will ask the applicant to address those issues along with any other unresolved technical issues identified by the Department.
- **Applicant Response.** The final technical review step also includes time for the applicant to address relevant comments and unresolved technical issues. These may addressed by the applicant in written response,

applicant is asked to respond.

Final Step: Permit Decision. DSL evaluates the entire application record against the criteria for permit issuance and makes a decision to either approve or deny the permit application. The extension also allows DSL the time necessary to thoroughly evaluate the record and make a decision.

FAQs

Who makes the permit decision?

Oregon laws and rules assign DSL responsibility for overseeing the removal-fill permitting process, and for making permit decisions. An overview of the state's removal-fill jurisdiction and the Department's role is here: https://www.oregon.gov/dsl/WW/Documents/JordanCoveEnergyProjectApplicationMemoJune-11-2018-DSL.pdf

Why is the number of comments received approximate?

The number of comments received is approximate because as many as 8,000 comments received may have been an exact copy of the same comment from the same person. This occurred, for example, when someone emailed copies of their comment to multiple DSL staff.

If the same person submitted two different comments, that is included in the estimate as two comments. If different people submitted the same comment, via a web form or form letter, each person's comment is included in the estimate.

Is the number of comments received, or whether comments supported or opposed the project, factored into the permit decision?

The number of comments received indicates that many people had information they wanted the Department to consider. The number itself does not factor into the Department's decision-making.

In reviewing comments, the Department does not tally the number of comments that support or oppose a project. Regardless of whether a commenter supports or opposes a project, if the comment raises an issue that relates specifically to the state's removal-fill law DSL will ask the applicant to address that issue.

Will comments be posted online?

Yes, all comments received will be posted on the DSL website here: https://www.oregon.gov/dsl/WW/Pages/jordancove.aspx.

now. Comments received in writing will be posted as soon as possible.

Will the notice to the applicant regarding remaining issues, and the applicant's response, be posted online?
Yes, as soon as they are available.

ADDITONAL FAQs AND INFORMATION
Additional FAQs, as well as answers to questions submitted during public hearings, are available on the DSL website:
https://www.oregon.gov/dsl/WW/Pages/jordancove.aspx

Additional answers and information about the application will be added to this website on an ongoing basis. Please check back frequently for information. Be sure to sign up for email updates as well:
https://www.oregon.gov/DSL/News/Pages/Subscribe.aspx, check the Jordan Cove Energy Project box.

Exhibit 2 (Part 2)

Oregon
Kate Brown, Governor

Department of State Lands
775 Summer Street NE, Suite 100
Salem, OR 97301-1279
(503) 986-5200
FAX (503) 378-4844
www.oregon.gov/dsl

April 10, 2019

RL600/60697
JORDAN COVE ENERGY PROJECT, L.P.
ATTN DERIK VOWELS
111 SW 5TH AVE, STE. 1100
PORTLAND OR 97204

Re: DSL Removal-Fill Permit Application No. 60697-RF
Jordan Cove Energy Project, Multiple Counties

Dear Mr. Vowels:

The Oregon Department of State Lands' (Department) 60-day public review period has closed for the above-referenced permit application. Public comments submitted and other investigative work by the Department have raised various issues for which the Department needs additional information.

Overview of Decision Process and Need for Additional Information

Specific applicable portions of the Department's Oregon Administrative Rules (OAR) in the narrative below in order to help Jordan Cove Energy Project, L.P. (Jordan Cove) understand the Department's permit decision process and why the additional information is needed.

OAR 141-085-0550 addresses the level of documentation used by the Department to make decisions:

- Section (4) provides that "The applicant is responsible for providing sufficient detail in the application to enable the Department to render the necessary determinations and decisions. The level of documentation may vary depending upon the degree of adverse impacts, level of public interest and other factors that increase the complexity of the project."
- Section (7) provides that "The Department may request additional information necessary to make an informed decision on whether or not to issue the authorization."

The Department analyzes a proposed project using the factors and determination criteria set forth in Oregon Revised Statute (ORS) 196.825 and OAR 141-085-0565. The applicant bears the burden of providing the Department with all information necessary for the Department to consider the factors and make the determinations.

- Section (1) of the OAR provides that "The Department will evaluate the information provided in the application, conduct its own investigation, and consider the comments submitted during the public review process to determine whether or not to issue an individual removal-fill permit."

- Section (2) of the OAR provides that "The Department may consider only standards and criteria in effect on the date the Department receives the complete application or renewal request." This application was deemed complete for public review and comment on

December 6, 2018. OAR 141 Division 85 contains the standards and criteria that will be considered throughout the review of this application.

- Section (3) of the OAR provides that "The Department will issue a permit if it determines the project described in the application:
  - (a) Has independent utility;
  - (b) Is consistent with the protection, conservation and best use of the water resources of this state as specified in ORS 196.600 to 196.990, and
  - (c) Would not unreasonably interfere with the paramount policy of this state to preserve the use of its waters for navigation, fishing and public recreation."

- Section (4) of the OAR provides that "In determining whether to issue a permit, the Department will consider all of the following:
  - (a) The public need for the proposed fill or removal and the social, economic or other public benefits likely to result from the proposed fill or removal. When the applicant for a permit is a public body, the Department may accept and rely upon the public body's findings as to local public need and local public benefit;
  - (b) The economic cost to the public if the proposed fill or removal is not accomplished;
  - (c) The availability of alternatives to the project for which the fill or removal is proposed;
  - (d) The availability of alternative sites for the proposed fill or removal;
  - (e) Whether the proposed fill or removal conforms to sound policies of conservation and would not interfere with public health and safety;
  - (f) Whether the proposed fill or removal is in conformance with existing public uses of the waters and with uses designated for adjacent land in an acknowledged comprehensive plan and land use regulations;
  - (g) Whether the proposed fill or removal is compatible with the acknowledged comprehensive plan and land use regulations for the area where the proposed fill or removal is to take place or can be conditioned on a future local approval to meet this criterion;
  - (h) Whether the proposed fill or removal is for stream bank protection; and
  - (i) Whether the applicant has provided all practicable mitigation to reduce the adverse effects of the proposed fill or removal in the manner set forth in ORS 196.600."

- Section (5) of the OAR provides that "The Department will issue a permit only upon the Department's determination that a fill or removal project is consistent with the protection, conservation and best use of the water resources of this state and would not unreasonably interfere with the preservation of the use of the waters of this state for navigation, fishing and public recreation. The Department will analyze a proposed project using the criteria set forth in the determinations and considerations in sections (3) and (4) above (OAR 141-085-0565). The applicant bears the burden of providing the Department with all information necessary to make this determination."

Summary of Substantive Public Comments

DSL has reviewed all the comments received concerning Jordan Cove application for a removal-fill permit. The Department's summary of the substantive comments (below) is not exhaustive. Jordan Cove should review and address the substantive comments that relate directly to the proposed removal and fill or that relate to the potential impacts of the proposed removal and fill. All substantive comments received are provided here.

Jordan Cove failed to demonstrate the project is in the public interest, Jordan Cove failed to demonstrate a public need. (ORS 196.825(3)(a)): Comments received on this topic stressed that the Department must affirmatively determine that the project would address a public need consistent with *Citizens for Resp. Devel. In the Dalles v. Walmart* 295 Or App 310 (2018). With a privately-sponsored project of this scale and complexity, the Department must consider public need in a transparent and comprehensive analysis that weighs all the relevant impacts and alleged benefits of the project.

Jordan Cove failed to demonstrate the project is consistent with the protection, conservation, and best use of Oregon's waters. (ORS 196.825(1)(a)): Commenters are concerned that the project would likely do unnecessary harm and damage to water quality in Oregon and suggest the applicants have failed to demonstrate that the project is consistent with the protection, conservation and best use of the water resources of this state. The proposed project will likely impair designated beneficial uses, threatening drinking water supplies and fish habitat. It will also likely further degrade stream segments in which water quality is already impaired for temperature, dissolved oxygen, pH, turbidity, mercury, and sedimentation.

The project does not conform to sound policies of conservation and will likely interfere with public health and safety (ORS 196.825(3)(e)): The Department received comments with concerns that the applicant has failed to demonstrate that the project will not interfere with public health and safety. Potential risks to public health and safety include natural hazards, such as floods, tsunamis, wildfires, landslides, and earthquakes, identified under Statewide Planning Goal 7. The potential for high-flow events that expose the pipeline or inadvertent drilling fluid releases (frac-outs) during construction at proposed stream crossings may result in increased risks to public health and safety. Failure at any of the major waterbody crossings claiming avoidance by using either Hydraulic Directional Drill (HDD) method, conventional bore or direct pipe method would have detrimental impacts to waters of the state and potentially contaminate state waters. Several risks to public health and safety were raised during public review that need to be addressed by the applicant, such as the list provided below. Please address these adverse impacts of this project:

- An accidental explosion of a fully loaded Liquefied Natural Gas (LNG) ship or at the terminal, including the worst-case scenario for the immediate area;
- How are the Federal Aviation Administration (FAA) presumed hazard determinations being addressed by Jordan Cove;
- Tsunami risks increasing from the project dredging activities;
- Improper facility siting, Society for International Gas Tanker and Terminal Operators (SIGTTO) standards not followed (i.e., on the outside bend of the navigation channel, near other terminal users, near population centers);
- Impacts on municipal drinking water sources, private wells, irrigation sources and agricultural uses;
- Increased wildfire risks as construction season coincides with the in-water work period which also coincides with fire season; and
- Impacts of massive scale clearing and grubbing with pipeline installation on water quality, land stability, erosion and turbidity of doing these activities during the rainy winter seasons, all water flows downhill.

The project would interfere with navigation, fishing, and public recreation: Comments received on this topic addressed that the Department must conduct a weighing of the public benefits of the project against interference with factors including navigation, fishing, and public recreation (See *Citizens for Resp. Devel. In the Dalles v. Walmart,* 295 Or App 310 (2018)). As part of this weighing of public benefits, the Oregon Legislature has clearly demonstrated that it is the State's "paramount policy" to preserve Oregon waters for navigation, fishing, and public recreation. ORS 196.825(1).

The comments indicate that the applicant has failed to demonstrate that the project will not unreasonably interfere with navigation, fishing, and public recreation in this application. Potential conflicts include but are not limited to:

- Crabbing, fishing and all types of recreational uses in and around Coos Bay;
- Safe bar passage issues/LNG tanker bar crossings only at high tides conflict with recreational fishers and the commercial fleets that also cross the bar at high slack tides for safety reasons should be evaluated;
- Exclusion zones required around LNG tankers while the LNG tanker is in transit will impact the recreating public crabbing via the ring method. This is reportedly the most common recreational crabbing method in Coos Bay. High slack tides are optimum for crabbing and if an LNG tanker must transit only at high tides, given the security and exclusion zones, there is interference with existing recreational uses within Coos Bay; and
- Impacts on the commercial fisheries uses of Coos Bay and adjacent ocean resources.

Jordan Cove failed to demonstrate independent utility (OAR 141-085-0565(3)(a)): Commenters assert that the project is connected to the Coos Bay Channel Modification (CBCM) Project. The applicant would be the primary benefactor from the proposed widening and deepening of the federal navigation channel as part of the CBCM project or similar efforts to expand the navigation channel. Further, there are serious questions about the feasibility of LNG vessels transiting the federal navigation channel under the dredging currently proposed as part of this application. Oregon Department of Fish and Wildlife (ODFW) contends that the Jordan Cove Energy Project and Port of Coos Bay Channel Modification project are connected actions and should be evaluated that way. The applicant has failed to demonstrate that the project has independent utility as required under OAR 141-085-0565(3)(a).

Jordan Cove failed to demonstrate a comprehensive analysis of alternatives to the project (OAR 141-085-0550(5), ORS 196.825(3)(c) and (d)): Commenters outline that the applicant has failed to demonstrate a comprehensive analysis of alternatives to the project, and therefore, the Department does not have the information to consider the availability of alternatives both for the project and for proposed fill and removal sites. Also, the Department was not able to determine that the project is the practicable alternative with the least adverse impacts on state water resources. Comments detail that through a flawed, overly-narrow purpose and need statement, the resulting biased alternative analysis prevents the Department from considering a reasonable range of alternatives to the project.

Navigation Reliability Improvements (NRI) Dredging: Comments indicate that there is no documented need for the 590,000 cubic yards to dredge the four corners outside the existing Federal Navigation Channel (FNC). Comments also state that Jordan Cove can export 99.5% of the anticipated annual output of the LNG facility (7.8 million tons) without the NRI dredging, which leaves the question, is there a 'need' to excavate 590,000 cubic yards of material for a nominal gain in transport capacity to allow Jordan Cove to travel at higher wind speeds than the current channel configuration could safely allow. Comments further suggest this minor economic benefit to only Jordan Cove does not equate to a 'need' to impact trust resources of the State of Oregon. The adverse impacts are understated or not explained in terms of the salinity impacts and hydrologic changes that will result from widening the existing navigational channel. The potential tsunami run-up impacts are not well explained either, nor are any hydrodynamic changes that would likely result or any analysis on potential increases to bank erosion adjacent to the proposed NRI channel improvements. The need should be substantiated, and a robust alternatives analysis prepared to address these issues and justify the dimensions and depths needed with supporting documentation in the form of simulation modelling showing that the current channel is insufficient for Jordan Cove.

Pile Dike-Rock Apron: Comments raised concerns that no alternatives were presented regarding the proposed 6,500 cubic yards (cy) of rock riprap proposed to protect the existing pile dike against erosion from the slip and access channel location, depth and dimensions. With no alternatives presented on the dimensions or design alignment of the slip and access channel, no reasonable range of alternatives can be considered. There is no discussion on impact avoidance, minimization, and/or mitigation to offset any adverse impacts to waters of the state. Please address:

- Why 6,500 cy?
- Why not more?
- Why not less?
- Why any at all?

Dredged Material Disposal (DMD) transfer of materials to APCO 1 & 2 from the NRI dredging: Comments received raised the following questions, please answer:

- How will the rock be excavated and transferred to the DMD site? Vague alternatives analysis presented, leaves more questions than answers.
- What types of equipment will be used to excavate the NRI's?
- Which works best in what type of materials (bedrock, rock, sand or silts), which has least environmental impacts depending on the material encountered?
- How will the rock be dredged? Different equipment?
- Can rock be transferred to a DMD site via slurry line as the application states? Inadequate discussion on alternatives, leaving the details to the contractor is insufficient.

Slip and Access Channel: Comments raised the concern of a lack of discernable alternative analysis for the precise dimensions and location of the slip and access channel. The slip and access channel are designed for a ship class of 217,000 cubic meters, yet the Coast Guard Waterway Suitability Analysis recommends allowing ships no larger than 148,000 cubic meters. Please answer the following questions and concerns:

- Why design a slip to accommodate a ship class that is not currently allowed nor physically capable of navigating into Coos Bay given the constraints of the Coos Bay bar and currently authorized limitations of the federal navigation channel?
- The application claims the stated depth needed for the slip and access channel is to maintain 'underkeel clearance' while an LNG ship is at dock. This is misleading as an LNG ship can only safely navigate the current channel at a high tide advantage, above 6ft tides to get through the channel to the slip before the tide recedes which would strand the vessel if it is not safely docked in the slip. Any LNG ship, 148,000 cubic meter class ship, would not be able to transit Coos Bay except periods of high tide, there would be no way for a ship to exit the slip at any lower tidal elevation as the ships draft would exceed navigational depth of the channel which could pose huge safety concern in the event of a tsunami.
- Water quality concerns from the 'sump effect' of having the proposed 45ft Mean Low Low Water (MLLW) deep slip and access adjacent to and on the outside bend of the 37ft MLLW navigation channel need to be addressed.
- What are the sedimentation impacts, salinity impacts, temperature and dissolved oxygen impacts that would likely result from a deep-water pocket created for the slip?

Questions were raised over whether the access channel dimensions can change, as no alternatives discussion exists, it is just one option, take it or leave it. Any reduction in the size of the slip or access channel would reduce water impacts and reduce the required mitigation. Any reduction in size or depth would also reduce adverse impacts associated with this project. The need should be substantiated, and a robust alternatives analysis prepared to address these issues.

DMD Alternatives: Commenters would also like to know why Jordan Cove will move 300,000 cubic yards of sand to the Kentuck site when other alternatives exist that would have less impact than transferring a line all the way across Coos Bay to Kentuck slough. The log spiral bay could accommodate more than 300,000 cubic yards, it is much closer to the dredge sites and would have significantly less impacts than the Kentuck proposal, yet it is dismissed. Please explain more thoroughly the alternatives that were considered and why those alternatives were dismissed within the greater DMD plan.

APCO DMD Site: Commenters have concerns over the capacity of the APCO site. Does this site have the capacity for the initial dredging and maintenance dredging over the lifespan of this project? Commenters also have site stabilization and liquefaction concerns over a mountain of sand piled up adjacent to Coos Bay in an earthquake and tsunami zone. There is safety, engineering, project feasibility, and water resources concerns that must all be addressed.

The project does not conform with existing land use laws (ORS 196.825(3)(g)):
Commenters indicate that the applicant has failed to demonstrate that the project conforms with existing land uses designated in the applicable comprehensive plan and land use regulations. They also mentioned that the applicant has failed to provide the Department with the information necessary to make the determinations required by ORS 196.825(3)(g) that the applicant's proposed fill or removal is compatible with the requirements of the comprehensive plan and land use regulations for the area in which it will take place. Current, up-to-date Land Use Consistency Statements are required for all parts of this project in all jurisdictions with an explanation of the current status, pending or resolved local issues, processes, or appeals status.

Further, commenters are concerned the applicant has failed to obtain land use permits for the project in Coos Bay. Because of the reasons adopted by the Land Use Board of Appeals (LUBA) in remanding the prior land use application are directly related to the inconsistency of the proposed dredge and fill in wetlands and in the Coos Bay Estuary with the Coos Bay Estuary Management Plan, the project cannot be conditioned on a future land use approval to meet this criterion.

In January 2019, the Douglas County Circuit Court Judge reversed the Douglas County extensions from December 2016 and 2017 that approved the Pacific Connector Gas Pipeline as a conditional use. Because the pipeline will require a new application for conditional use permit and utility facility necessary for public service, the applicant has not met its burden to demonstrate to the Department that the project conforms to Douglas County's acknowledged comprehensive plan and land use regulations.

The comments received indicate that the applicant has not met their burden to demonstrate to the Department that the project conforms to Jackson County's acknowledged comprehensive plan and land use regulations.

Insufficient Mitigation-Kentuck Compensatory Wetland Mitigation (CWM) Site: Concerns were raised about the lack of a discernable alternative analysis on many components of the Kentuck mitigation proposal to see what alternatives were considered and on what basis were rejected. The mitigation proposal itself is the largest wetland impact in this project proposal. Please answer the following questions:

- Why import 300,000 cubic yards of sand?
- Why not more or less materials?
- Why not use more suitable materials native to the area?
- Why sand vs. native cohesive clay soils for use as fill?
- What are the alternatives to move the sand to the site?
- Why were upland routes dismissed without reasonable justification?
    - Trucking the materials is a viable option with no impact to waters of the state.
- What other mitigation sites or options have you looked at addressing the following concern?
- The Kentuck site is already a freshwater wetland and has increased its functions in the past 10 years to the point that the current mitigation strategy might be inappropriate to offset functional losses. Please answer these questions as well:
    - Why is the dike so big, long, and wide?
    - Why is there no justification given to support dimensions of the proposed dike?
    - Why are there no alternatives are presented to evaluate the adverse effects of the dike and mitigation strategy?
    - Address the landowner concerns regarding the Kentuck Mitigation proposal and the Saltwater Intrusion impacts on adjacent lands.
    - Further address the concerns of flooding and impacting agricultural activities and existing farm uses.
    - Why is the pipeline proposed under a proposed mitigation site?
    - Where is the avoidance and/or impact minimization, especially given that each impact reduces the overall size of the mitigation project, therefore diminishing its potential function and values? Concerns were raised about the suitability of having a pipeline under the mitigation site that is supposed to be protected in perpetuity.

Insufficient Mitigation-Eelgrass CWM Site: Comments raised concerns about the lack of a discernable alternative analysis on many components of the eelgrass mitigation proposal. The CWM citing was found not to be in-kind or in proximity mitigation which would replace similar lost functions and values of the impact site. Disturbing existing mudflats and adjacent eelgrass beds is likely to have additional adverse impacts from construction. The proposal is inconsistent with ODFW Habitat Mitigation Policy. Alternatives should be considered, in consultation with ODFW, that favor impact avoidance to adjacent high value habitats (mudflats and adjacent eelgrass beds) and seek out appropriate in-kind, in proximity mitigation. The project impacts are to eelgrass beds adjacent to deep water habitats, while the proposed mitigation is near the airport runway and in shallow water habitats a considerable distance from deep water habitats. There are likely unforeseen FAA issues with the proximity of the mitigation site to the airport runway, this should be explored in detail with the FAA. The location of the eelgrass CWM site is situated in a portion of the Coos Bay Estuary classified as “52-Natural Aquatic” in the Coos Bay Estuary Management Plan where dredging is not allowed. This issue needs to be clarified by Coos County with respect to land use consistency.

Insufficient Mitigation-Stream Impacts: Comments assert that the project will impact many waterways’ beneficial uses, water quantity and quality will be further impaired from construction of this project. Potential impacts include but are not limited to increased water temperatures, dissolved water oxygen, turbidity, etc. from riparian shade removal in 303(d) listed waterways and other waters. Disruption of fluvial processes, increased erosion and downstream sedimentation and turbidity from construction activities, impacts on spawning and rearing habitats, impacts on fish migration and passage.

Many people have raised concerns that Federal Energy Regulatory Commission (FERC) procedures are vague and will not provide assurances that water quality/quantity standards will be protected. Stream risk analysis, alternative ways to avoid and minimize impacts for each water crossing are not possible on properties with denied access. How are any reasonable alternatives considered if access is denied and unattainable without a FERC Order granting condemnation authority? Alternatives are not fully explored or explained to avoid and minimize impacts at every opportunity.

ODFW Habitat Mitigation Policy Inconsistencies: Commenters expressed that the applicants should work with ODFW to appropriately categorize each wetland and waterway impact from start to end along the proposed pipeline route. Once the appropriate habitat category has been assigned in agreement with ODFW, appropriate mitigation can be discussed based on resources impacted. Currently, temporary impacts mitigation is insufficient and inconsistent with the ODFW Habitat Mitigation Policy for streams and wetlands crossed by the pipeline.

Fish Passage-Coastal Zone Management Act (CZMA) and Non-CZMA Streams: Comments expressed concern that fish passage has not been addressed by the applicant. According to ODFW, applications for fish passage have not been submitted and this is critical to the Department for impact analysis determinations yet to be made. Fish passage applications may need to include a contingency method for crossing each waterway. For instance, if any of the HDD's fail, what is next, certainly not open trench, wet cut methods that are not currently being evaluated as alternative crossing methods under consideration.

Wetland Delineations/Concurrence: Public comments point out that some of the wetland delineation reports have either expired or are about to expire, see C4, C5, C9 and C10 of the application.

Additional Information Requested by the Department

Delineation-status for JCEP/PCGP: To allow adequate review time of the wetland delineation report in order to meet the decision deadline, please submit the following data requests by the dates requested.

1) By April 17, 2019: GIS shape files of the new routes and re-routes so DSL can finish the initial review and provide any additional review comments in time to address this summer (involving additional field work, if needed);
2) End of April 2019: Responses to the initial delineation review questions and delineation maps (prototype subset of each map series for completeness review);
3) June 7, 2019: Responses to GIS review questions;
4) Last week of June 2019: Site visits (possible); and
5) August 9, 2019: Everything due: responses to all remaining requests for information based on site visits, GIS review responses and follow-up review requests, all final delineation maps, and all supporting materials for the concurrence.

Bonding Requirements: Prior to any permit issuance, a performance bond should be negotiated and put in place for the Eelgrass and Kentuck CWM projects. Bonds are required for non-public agencies that have permanent impacts greater than 0.2 acre. Proposed financial instruments need to demonstrate consistency with OAR 141-085-0700.

Administrative Protections Required for Eelgrass and Kentuck CWM projects: Administrative protection instruments need to demonstrate consistency with OAR 141-085-0695.

Oregon Department of State Lands, Land Management Issues: Any proposed uses or activities on, over, or under state owned lands requires Department proprietary authorizations.

Extensive Comments-Detailed response requested. The Department requests that the applicant respond to all substantive comments. Certain commenters provided extensive, detailed comments. The Department would like to call these comments to the applicant's attention to ensure that the applicant has time to sufficiently address them.

- Mike Graybill;
- Jan Hodder;
- Rich Nawa, KS Wild;
- Stacey Detwiler, Rogue Riverkeepers;
- Jared Margolis, Center for Biological Diversity;
- Jodi McCaffree, Citizens Against LNG;
- Walsh and Weathers, League of Womens Voters;
- Wim De Vriend;
- The Klamath Tribes, Dawn Winalski;
- Tonia Moro, Atty for McLaughlin, Deb Evans and Ron Schaaf;
- Regna Merritt, Oregon Physicians for Societal Responsibility;
- Oregon Women's Land Trust;
- Sarah Reif, ODFW;
- Margaret Corvi, CTLUSI;
- Deb Evans and Ron Schaaf;
- Maya Watts; and
- Steve Miller.

All comments received during the public review of this application were previously provided to Jordan Cove by the Department via Dropbox and should be responded to as well. Please submit any responses to the Department and copy the commenting party if contact information was provided.

The Department asks that any responses be submitted in writing within 25 days of the date of this letter to allow adequate time for review prior to making a permit decision. If Jordan Cove wishes to provide a response that will take more than 25 days to prepare, please inform me as soon as possible of the anticipated submittal date.

The Department will make a permit decision on your application by September 20, 2019, unless Jordan Cove requests to extend that deadline. Please call me at (503) 986-5282 if you have any questions.

Sincerely,

Robert Lobdell
Aquatic Resource Coordinator
Aquatic Resource Management

RL:jar:amf

Exhibit 3

Shell's Sakhalin II LNG project:
Impacts of LNG production

2002 project design included a LNG jetty of 1,400 m length, and around 160,000 m3 of dredging
2003 project design (finally implemented) involved a LNG jetty that was 800 m in length, requiring around 1,680,000 m3 of dredging. Final amount of dredging was about 2 million m3.
(2 million cubic meters is equal to 2.6 million cubic yards)

What Avina Bay looked like BEFORE dredging work and dumping of dredged materials…..

Cont:

What Avina Bay looked like BEFORE dredging work and dumping of dredged materials…..

Aniva Bay - the same area AFTER….

The 2 pictures below were done in Aniva Bay, a year after dumping on the area, which, according SEIC, should not have any negative impact (sedimentation) from the dumping zone.
Now this area is almost an underwater desert.

“Shell's Sakhalin II LNG project in Russia”

Photo to Left Above: *Shell's Sakhalin II LNG project in Russia. Upstream of wild salmon spawning river huge sedimentation contamination occurred. Salmon can swim up rivers with high content of suspended solids, but cannot spawn in water with suspended solids content 220 mg a liter and higher.*
Photo to Right Above: *Ozernaya river on Sakhalin Island several km downstream of pipeline crossings: Females died before laying eggs*
Photos below: *Landslides and erosion from Shell's Sakhalin II LNG pipeline project in Russia.*

Many of our local industries depend on environmentally sound, ecological and biological systems working properly in our Coastal Zone and those systems not being compromised. We know what the environmental impact results ended up being with regard to Russia’s Sakhalin Island. Fishing there is still suffering with low fish returns in areas where gas and oil developments have taken place. Can we expect these same kinds of impacts to occur in Oregon? Who will monitor the Pacific Connector Gas Pipeline so that what is being promised currently by them in regard to the construction of the Pacific Connector is actually completed as promised and without this same degradation? If proposed mitigation measures fail, what will be the recourse? We already have compromised streams and low fish runs in the South Coast Basin. Will Pacific Connector impacts push already compromised biological and ecological systems over the edge?

http://money.cnn.com/magazines/fortune/fortune_archive/2007/02/05/8399125/index.htm

FORTUNE

Shell shakedown

Fortune's Abrahm Lustgarten reports how the world's second-largest oil company lost control of its $22 billion project on Russia's Sakhalin Island.

By Abrahm Lustgarten, Fortune
February 1 2007: 12:10 PM EST

(Fortune Magazine) -- Word that control of the world's largest integrated oil and gas project had been wrested from Royal Dutch Shell trickled down to the company's staff on Russia's Sakhalin Island in December the same way it reached everyone else: via the newswires.

Outside Shell's six-story steel-and-glass compound in Yuzhno-Sakhalinsk, a town of 175,000, snow swirled in subzero wind past drab rows of communist-era cinderblock apartments. Inside, Jim Niven, the company's gregarious head of external affairs, was halfway through an upbeat presentation on the vast potential held in this claw-shaped island dangling from the Siberian Arctic - an estimated 45 billion barrels of oil and gas - when he was interrupted by a nervous colleague, paper in hand.

The news was stunning, even if rumors had been flying: Shell (Charts) was halving its ownership in the $22 billion project, cutting its stake from 55% to 27.5%, and Gazprom, the Russian gas giant, was stepping in, buying Shell's share plus half the stakes owned by Japanese partners Mitsui and Mitsubishi, for just $7.5 billion - the equivalent, says a Shell spokesman, of "paying to enter on the ground floor, as if they were a shareholder at the beginning." The foreign companies also agreed to absorb $3.6 billion of the project's mounting cost overruns.

Shell's top executives, who were in Moscow at the time, weren't negotiating from a position of strength. Not in Vladimir Putin's Russia, where strong-arm tactics have been used to reassert government control of the country's vast natural resources. Last summer the Russian Ministry of Natural Resources suddenly backed Sakhalin Island environmentalists, revoking permits and delaying work on twin 400-mile pipelines that connect to a monstrous LNG terminal and an oil-export facility. The threat of a $50 billion lawsuit meant Shell stood to lose everything.

"A guy says, 'Give me half of what is in your pocket, or I shoot you and kill you,'" says Oppenheimer oil analyst Fadel Gheit. "You give him half and say, 'Thank God I am alive to live another day.' They could have lost all of it."

That December night Yuzhno was abuzz with the news. In the Chameleon bar, where Russian bands hammer out Western rock riffs and twentysomethings pass the hose of a hookah pipe, phones started to vibrate and text messages were thumbed out. The talk was exultant, nationalistic. The feeling was that Shell had it coming.

"I'm not proud of how it was done," said one Russian oil worker. "Russia has lost a lot of reputation on this. But I am happy. Shell - they just don't understand how this place works."

Risks on the frontier

That Shell and its partners were victims of an unscrupulous campaign by the Russians to win leverage at the negotiating table is certainly true. The company's loss of its controlling interest in what chief executive Jeroen van der Veer called a "key part of Shell's upstream strategy," amounting to an estimated 5 percent of its global reserves, is largely a story about the high risks of frontier international energy projects. But it is also a tale of how Shell misplayed a strong hand and, after 12 years of work, lost untold billions of dollars in future earnings.

It starts with a production-sharing agreement that most observers agree was inherently unfair to Russia - a deal signed in 1996, when oil was $22 a barrel and Russia was on its knees, that gave the Shell-controlled Sakhalin Energy Investment Corp. the right to recoup all its costs plus a 17.5% rate of return before Russia would get a 10% share of the hydrocarbons coming out of the ground.

Then there was the cost of the second phase of the project, which ballooned from $10 billion in 1997 to $20 billion in 2005, fueling a perception that the company was profligate while Russians picked up the tab. The chapters in between include a calamitous safety record, a failure to meet local expectations for new roads and schools, a fuel spill in Sakhalin's third-largest city, and environmental concerns that caused anger and resentment toward Shell's leadership, earning it a reputation for stubbornness and for consistently misreading political realities.

Gallery: Scenes from Sakhalin

"Shell is always resisting," says Tom Madderom, a veteran Sakhalin contractor who has worked on the Shell project but is now employed at another site, run by Exxon Neftgas, on the northern tip of the island. "Instead of accommodating, they come out with lawyers and try to prove their case. You can run a project in Russia and have a win-win deal - even a project of this size. But it takes engaging with these people, and Sakhalin Energy hasn't been real good at it."

Take, for instance, the ire the company has drawn in Korsakov, a small weather-beaten port city on the island's southern coast, near Sakhalin Energy's Prigorodnoye LNG plant. Residents say the company led them to believe that housing for 6,000 construction workers would be located in the town, where it could later be reused by the community, which sorely needs it. Many people in Korsakov earn less than $300 a month - a sharp contrast to the wealth of Sakhalin Energy employees, many of whom, especially those who come from other countries, make more than $1,000 a day.

But when construction began, Sakhalin Energy built its housing for workers next to the plant itself, inside a one-kilometer safety zone, where it will be illegal for people to live once operations begin. "People here could use this place for their well-being, and it will be demolished," says Elena Lopukhina, director of a Korsakov advocacy group and an assistant to a regional government official, who says that is just one of the emotional issues in the community that have swayed people against Sakhalin Energy. "The company did everything that was good for them and not good for us."

Executives at Sakhalin Energy say the production-sharing agreement would have prohibited such a promise, and they maintain that these sorts of complaints are based on unrealistic hopes. "When big projects come along, expectations are always running higher than reality," says Niven. "But clearly there are also opportunities."

Local government revenue, he says, has increased fivefold, and unemployment is just over 1%. Sakhalin Energy has contributed more than $300 million so far to roads and infrastructure. And while it's too early to offer a verdict, he believes Sakhalin is on the cusp of a four-decade period of economic development. There are at least nine major oil and gas projects planned on the island, involving many of the world's largest oil companies. Shell's problem is that its project, known as Sakhalin II, is the largest of them all - and therefore the biggest target.

Much of the ammunition for Russia's political war against Sakhalin Energy comes from the cramped Yuzhno office of an independent environmental group called Sakhalin Environment Watch. At its helm is Dmitry Lisitsyn, a sharp-witted 39-year-old who has been hounding oil companies on the island for more than a decade. "We understand that our issues are being used as leverage," Lisitsyn says, "but at the same time, real problems exist."

If the government's inspections were politically fueled, though, Lisitsyn's motivations are not. He has the respect of his foes, and as Sakhalin Energy's Hilary Mercer, who heads the LNG project, puts it, "wants what is best for this place." Lisitsyn says Sakhalin II is a "lighthouse," a template for how future projects will deal with environmental and social standards. Chief among his concerns is the impact of the LNG plant, Russia's first, and the pipeline that leads to it.

The LNG plant and export terminal lie on a 1,210-acre patch of land about eight miles from Korsakov, abutting the steel-gray Aniva Bay. To the north a wide right-of-way cut in the forest marks the gas and oil pipelines' path up over the hills to the offshore platforms. To the south a jetty sticks out into the bay like a needle, ready to inject the 156 LNG tankers expected to dock there annually with liquefied gas, before sending them off to markets in the U.S., Japan, and Korea. The plant, mostly completed, won't come online until 2008, but already its output for the next 20 years is sold out.

Inside the perimeter fencing, where roughly 10,000 of Sakhalin Energy's 18,000 employees work, is - for now - the world's largest LNG facility. What happens inside the fence is by most accounts an orderly, world-class operation and a feat of engineering in Sakhalin's near-arctic conditions. It's what happens outside the fence that has drawn the scrutiny of Sakhalin Environment Watch and fomented ill will.

In order to bring LNG tankers into Aniva Bay, Sakhalin Energy had to dredge the bottom near shore, then dump the mud - two million cubic meters of it, Lisitsyn says - farther out in the bay. The island's second-largest industry after oil is fishing, and Aniva Bay is home to a diverse ecosystem that could be threatened by the dredging.

Lisitsyn wanted the company to use a longer pier, requiring less dredging, and dump the material farther out at sea. Instead Sakhalin Energy pursued the cheaper near-shore option. Now Lisitsyn is taking Sakhalin Energy to court, seeking a full accounting of environmental damages in the bay. Among other things, he alleges some of the dredging was conducted during the summer, in violation of laws protecting salmon spawning.

In that case and in disputes over the pipeline route, Lisitsyn has been highly critical of Sakhalin Energy's oil-spill preparedness and construction techniques. He says the company spends more time talking than taking action. "Sakhalin Energy loves the dialogue - it is one of their gods," he says. "But we don't want just talk, we want solutions."

Gallery: Scenes from Sakhalin

That approach has led to delays and cost increases. In 2005, Sakhalin Energy made routing adjustments to its pipeline design to minimize risk from a possible earthquake. The company says it followed proper channels, but Oleg Mitvol, deputy director for environmental inspections at the Natural Resources Ministry, told the press that the pipeline cut into a protected nature reserve, prompting him to describe Sakhalin Energy as "a pure banana republic - colonizers in cork helmets."

The following year a controversy erupted over large piles of earth left along the pipeline, which Sakhalin Environment Watch says were never permitted and which led to the temporary revocation of construction licenses last September.

"Look, this is a huge, complex, frontier type of project," says Sakhalin Energy's Niven, explaining the slew of confrontations. "We were the first company ever to put an offshore production platform in here. These are new to Russia, so the Russians themselves have had to learn how to manage and approve them."

To be sure, Shell isn't the only culprit. Russia's own oil and timber companies have been pillaging the island for resources for more than a century, and Lisitsyn says, "There is a common perception that Gazprom will be much worse." Furthermore, it was the Kremlin, not Shell, that recently cut the island's take of oil taxes from 60% to just 5%. And Sakhalin Energy deserves credit for keeping the project afloat and providing employment through a period of unprecedented economic and political change in Russia.

But to a large extent the mood on Sakhalin Island comes down to perception, not fact. Says Oleg Yugai, deputy for economic policy and budget for the regional government: "This is all about the psychology of the people."

When Shell signed the Sakhalin production-sharing agreement in 1996, the oil company had the upper hand. The oil and gas reserves on the island had been identified, and there weren't any exploration risks, but Moscow didn't have the capital to get to them. Shell and its partners did. Details about the document are sketchy, and the company won't comment. But in effect, the agreement meant that the higher the cost of the project, the longer the Kremlin would have to wait to see any royalties.

Production-sharing agreements are common in the oil industry, but the Sakhalin contract broke new ground. "This one is particularly disadvantageous to the Russian party," Ian Rutledge, an economist with Sheffield Energy & Resources Information Services, wrote in a 2004 report. "SEIC has transferred most of the risks... to the Russian government."

At the time the deal was struck, though, says Sakhalin Energy CEO Ian Craig, Russia was too volatile an investment without the framework and the fiscal regime the agreement provided. "You can debate whether [the terms] are fair or not now," he says, pointing out that the $13 billion invested to date is all shareholder-funded. "But it's a debate about dividing up a share that simply would not exist, had we not set them up then."

Russia's patience ran out in 2005, when Sakhalin Energy announced that project costs had doubled. Much of the jump can be attributed to a 20%-a-year leap in the price of labor, rising costs of materials like the steel used for pipelines, and higher oil prices. "It cost me twice as much to fly from Moscow to Yuzhno as it did two years ago," Craig says. "We're living in a $60-a-barrel world, and that applies to everything."

But even if many of the extra costs can be rationalized, frustrated residents tend to focus on the ones that can't. Sakhalin Energy is said by contractors to be spending up to $15,000 a month to house the families of some staff. When one contractor's barge ignored storm warnings to leave port and broke apart, spilling 55,000 gallons of fuel, Madderom says the tab was about $60 million, just for the boat.

Gallery: Scenes from Sakhalin

And when Sakhalin Energy rerouted the underwater portion of its pipeline in response to international criticism about the threat to endangered western gray whales - environmentalists say the original route was planned without thorough review - the shift cost nearly $300 million. The company says that was the pricetag for complying with environmental demands. It also denies spending extravagantly.

Still, there are the small things - the $4 pencils and $500 space heaters a customs officer says she saw listed on a Sakhalin import form, the flaunting of money by expatriate staff in downtown nightclubs, the waxed and polished Land Cruiser fleet lined up in an island parking lot - that give Sakhaliners a feeling of watching a party in their living room to which they haven't been invited.

If Sakhaliners think spending is out of control, that could explain why prices in Yuzhno also seem divorced from reality. The town stretches just a few square miles, with a neat grid of unremarkable streets bookended by a 25-foot statue of Lenin and an imposing Victory Square. The city center is for the most part architectural remnants of the communist era, while the suburbs contain acres of new middle-class housing developments - a reflection of the oil industry's impact on Sakhalin's economy. One of these houses can cost nearly $1 million, while a one-bedroom apartment can rent for $3,000 a month, comparable to New York City prices. A five-minute taxi ride costs $12, and lunch at a casual Indian restaurant starts at about $40 per person.

"I've spent time in Moscow, Tokyo, and Hong Kong," says an oil-well engineer for services company Schlumberger, who paid a $70 cover charge to walk into Yuzhno's newest nightclub, Schastie Project, only to fork over another $19 for a whiskey. "Yuzhno-Sakhalinsk is the most expensive town I've worked in."

Whether Gazprom or Shell owns Sakhalin Energy, the culture is probably not going to change. For one thing, as an analyst pointed out, Gazprom "might be omnipotent, but they still don't make LNG." That means Shell and many of its highly paid employees will stay on to manage the project, and staff may even increase as Gazprom brings in shadow workers to watch and learn.

One thing is certain, though: The deal stinks for Royal Dutch Shell, whose top executives declined to comment for this article. Its reserves will take a big hit, a tough swallow for a company already having trouble replacing its in-ground assets. Whether renegotiating a contract with a gun to its head was the smartest move for Shell is an open question. But now that the terms are settled in Russia's favor, oil majors around the world can expect their playing fields to tilt too. ■

Exhibit 4

https://www.seattletimes.com/nation-world/ocean-salmon-seasons-off-southern-oregon-coast-in-jeopardy/

Nation & World

Ocean salmon seasons in jeopardy off southern Oregon

Originally published March 5, 2018

The Associated Press

MEDFORD, Ore. (AP) — Ongoing problems with Sacramento River salmon survival means there likely will be very little, if any, sport and commercial salmon fishing this summer off the Southern Oregon coast.

Preliminary stock assessments estimate only 229,400 Sacramento River fall chinook will be in the ocean, according to federal Pacific Fishery Management Council reports. That's 1,300 fewer than last year's small run, whose protection shut down sport and commercial chinook fishing off Southern Oregon.

Salmon managers heading into the Pacific Fishery Management Council's March 8-14 meeting said they think the council will be able to propose at least possible sport and commercial seasons with as little impact to Sacramento salmon stocks as possible.

Richard Heap of Brookings-Harbor, who is vice chairman of the PFMC's salmon advisory subpanel, remains hopeful despite the numbers. "I'm going up there with the possibility that we'll fish this year, unlike last year.

"We'll have to wait and see how it plays out."

The Pacific Fishery Management Council is expected to float three sport and commercial season options for public comment. Heap said he "wouldn't be surprised" if one of those options calls for a repeat of last year when the season failed to happen, The Medford Mail Tribune reported .

The Pacific Fishery Management Council will set its final season recommendations when it meets April 5-11 in Portland. The federal Department of Commerce has the final say in setting ocean-fishing seasons.

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Information from: Mail Tribune, http://www.mailtribune.com/

http://theworldlink.com/news/local/west-coast-senators-join-call-for-salmon-disaster-declaration/article_3690f87f-44b8-5f19-a385-7557776543b0.html

West Coast senators join call for salmon disaster declaration

SAPHARA HARRELL The Umpqua Post
Jun 13, 2017

OREGON COAST — Some Oregon and California U.S. senators are asking for a federal salmon fishery disaster declaration to support economic recovery in coastal communities in the two states after extensive commercial fishing closures due to declining salmon populations.

In April, the Pacific Fishery Management Council, a federal body that regulates commercial and sport fishing, made its 2017 salmon season recommendations. As a result, nearly half of the Oregon coast and a 130-mile section of the California coast — from Florence to Horse Mountain- is closed to commercial fishing.

In a letter written to Commerce Secretary Wilbur Ross Friday, Oregon Sens. Ron Wyden and Jeff Merkley and California Sens. Kamala Harris and Dianne Feinstein wrote that salmon catches have consistently declined over the last decade and that the disaster designation will provide a safety net to keep fishermen in business.

The senators' request follows one made by Oregon Gov. Kate Brown and California Gov. Jerry Brown, who called for a disaster declaration in a May 24 letter to Ross.

That letter stated Oregon commercial salmon fisheries are projected to make 63-percent less this year compared to the 2012-2016 average earnings of $7.3 million.

Commercial operations aren’t the only ones that will be affected.

Recreational fishing will be closed from the Oregon and California border to just south of Eureka. Last year, the Oregon recreational Chinook salmon catch was expected to be 9,000, but fell short at 4,100.

Closures are also set to impact fish processors, fishing equipment retailers, marine repair businesses, charter boat operators, bait shops and motels.

Oregon has had four disaster declarations between 2006 and 2016. A disaster declaration in 2009 resulted in $100 million of disaster-relief aid given out by NOAA’s Fisheries Service.

Michael Milstein with NOAA fisheries said the administration has known that this was going to be a difficult year for a while.

“We’ve known that it was going to be a lean year for salmon, because we know the ocean conditions have been not as productive,” Milstein said.

He said the upwelling of deep colder water that provides the fish with nutrients has been minimal the last couple of years and that has a lot to do with salmon survival.

Milstein said the Klamath River area was closed because it’s an area where a lot of fish get caught when they’re returning from the ocean.

“It’s a management area where we know a lot of those fish sustain a lot of the fishing pressure,” he said.

To protect adult salmon returning to spawn, the California the Fish and Game Commission decided to close all in-river fishing on the Klamath-Trinity watershed from Aug. 15 through the end of the year.

California Department of Fish and Wildlife’s Wade Sinnen said in an email Monday that this is the lowest projected fall Chinook abundance on record. The projected number of fish is 54,200 compared to 142,200 last year. However, he said last year's estimate wasn't reflective of the actual outcome.

"The post-season estimate for last year was 68,438, which points out that the pre-season estimates are not always precise," Sinnen said in the email.

Knute Nemeth is a retired fisherman in Charleston.

He said some local fishermen have traveled as far as Newport to fish for salmon, but it's time-consuming and expensive. Couple that with the limit on the amount of fish that can be caught and Nemeth said it has cut back on the incentive to fish for salmon at all.

Now, most salmon fishing is out of Newport.

According to the letter written by the two governors, 74-percent of the Chinook salmon caught by the Oregon commercial fishery was in Newport.

Nemeth said fishermen in the area are focusing on other fish like cod and tuna instead. But there's not always a guarantee you'll catch anything, he adds.

"Fishing is a feast or famine type of a deal and there are people with pretty skinny stomachs right now," Nemeth said.

NOAA's Milstein echoed that sentiment.

"We've known that this is a tough year for everyone and certainly it's tough for the fleet to make it through a year like this," Milstein said.

Reach Saphara Harrell at (541) 269-1222 ext. 239 or by email at saphara.harrell@theworldlink.com

Exhibit 5

Barbara Gimlin, P.O. Box 1527, North Bend, OR 97459

(541) 404-0355 — bgimlin@charter.net

December 16, 2014

Jeff C. Wright, Director
Office of Energy Projects
Federal Energy Regulatory Commission
888 First Street N.E.
Washington, DC 20426

RE: Public Comment on Jordan Cove Energy Project, L.P., Draft Environmental Impact Statement; FERC/EIS-0223F; Docket No. CP07-444-000; LNG Terminal Facility

Dear Mr. Wright,

I am sincerely concerned about soil contamination issues at the proposed site for a liquefied natural gas (LNG) terminal facility for the Jordan Cove Energy Project (JCEP) in North Bend, Oregon. I am a biologist and environmental specialist with a 30-year professional background that includes working as an educator and contract biologist, in addition to working 15 years for the Federal Emergency Management Agency (FEMA) as an environmental specialist from 1998 to 2013. At FEMA I specialized in writing Environmental Assessments and ensuring compliance with the National Environmental Policy Act (NEPA) for FEMA-funded projects. My knowledge and awareness related to JCEP site contaminants comes from firsthand experience working for the JCEP while employed by SHN Consulting Engineers & Geologists, Inc. (SHN) in Coos Bay as a biologist and environmental compliance specialist from March 2013 to April 2014.

I was initially hired by SHN to revise JCEP Resource Report 3 for Vegetation, Wildlife and Fish. I have also assisted in writing Exhibits P (Fish and Wildlife Habitat) and Exhibit Q (Endangered Species) for the Oregon Energy Facility Siting Council (EFSC) application for the JCEP South Dunes Power Plant (SDPP) portion of the project. In between writing these reports, I have spent a considerable amount of time at the various JCEP sites associated with the terminal facility. I have participated in and written reports for numerous habitat-related surveys and studies for the project. In March 2014, I was named as the acting Environmental Inspector (EI) for the JCEP Kiewit $15 million exploratory test program conducted at the LNG terminal site on the North Spit of Coos Bay.

During my time at SHN I struggled at times with the resistance by others working on the JCEP, both inside and out of the company, to respond to what is required for environmental compliance. It was understandable on some levels (it's all in education), but not understandable when substantial environmental issues were discovered.

What I experienced while working as the acting EI for the JCEP Kiewit test program led me to submit a resignation letter to SHN on April 21, 2014, as a matter of professional integrity. When considerable contaminated soils and sediments were exposed during the test program, I was repeatedly told the issues were "being taken care of" and that I didn't need to be involved, even although I was the acting EI. What occurred during the test program did not follow the Unanticipated Hazardous Waste Discovery

Plan written for the JCEP in Resource Report 7. This plan is referred to in the JCEP Draft Environmental Impact State (DEIS) as the process that would be implemented for any construction activities. Instead of management allowing me to further assess the situation and develop an action plan for the contamination issues discovered, I became the problem. I was bluntly told more than once that my job as the acting EI was to not to delay the test program construction being conducted.

I was, and still am, very concerned about site contamination and had hoped the issues I brought to the forefront would be acknowledged and addressed in the DEIS. They have not been. In addition, the contaminant issues I drafted for EFSC Exhibit Q were left out of that exhibit and ignored.

To back up a bit, questioning practices at the JCEP terminal site first began when I found out months after the fact that Southern Oregon University Laboratory of Anthropology (SOULA) archaeologists had discovered contaminated black soils along the JCEP shoreline during cultural resources surveys conducted in September 2013. The soils were discovered at the approximate site of the proposed barge berth. SOULA archaeologists stopped their surveys in the area because of black soils that they deemed to be contaminated (allegedly arsenic) and unsafe to work in. At the time, they notified Steve Donovan, my former boss at SHN, who is an environmental engineer.

When I found out about the soils in February during a meeting with SOULA, I asked if the Oregon Department of Environmental Quality (DEQ) had been informed. I was met with a type of subdued hostility from Steve Donovan and was told it was being taken care of, that it was going to be filled anyway, and that it was not my concern. At the time I thought to myself, not before workers go in there and move the stuff around. And why not report it to DEQ immediately and address it? Since there was a window where it could eventually be addressed, I sufficed in my mind that I would just watch and make sure it was taken care of properly. It was clear from the response I received from my initial queries that further discussion was not welcome. Of note, the site is included as a borrow site to be used as fill for the SDPP. To the best of my knowledge, no further action has been taken to have the soils tested and addressed.

Fast forward to the Kiewit exploratory test program conducted in the spring of 2014 at the proposed LNG terminal site, which includes Ingram Yard and parts the dune forest. As the acting EI, I attended the pre-construction meeting and was introduced by Kiewit as the person who would oversee environmental considerations at the site. As unidentified contaminated soils and sediment surfaced during excavations conducted in Ingram Yard, during my research I came across DEQ Environmental Site Cleanup Information (ESCI Site #4704) online for the 80-acre Ingram Yard property. Previously, I had been repeatedly told it was all “clean fill” from dredging conducted by the U.S. Army Corps of Engineers (USACE) in the 1970s. That was not the complete case at all. It had been used as a log sorting yard and had been authorized as a mill waste dump site by the DEQ following the placement of fill by the USACE. There have also been allegations by locals that the site was used as a dump site outside of mill waste. Limited and inadequate testing has been done post-closure at the site to determine the full extent of the contaminants, and the testing has been limited primarily to the northern half of the site.

In my efforts to ensure the contaminated soils uncovered were addressed appropriately, I provided a copy of the Unanticipated Hazardous Waste Discovery Plan for the JCEP to Steve Donovan at SHN along with Kiewit personnel, West Coast Contractors personnel (a subcontractor hired by Kiewit), and to the archaeological monitor for the test program. As more contaminants were discovered during excavations, the protocol for site assessment, testing procedures, and compliance with regulations in place under the plan were not being followed. Although I pressed for compliance, I was precluded from any involvement in the matter as the EI. Instead, I was told it was being handled and that I didn't need to be involved. It became clear I was a figurehead EI. That worries me regarding how the future JCEP EI position will be managed.

Potential contaminates exposed by the Kiewit excavations conducted at the site included numerous black soils (north to south in Ingram Yard, including near the shoreline), bright yellow granulated/powder found in clumps of varying sizes, gray gummy material found in clumps (likely related to hydraulic drilling conducted by GRI), and the exposure of an underground concrete storage tank punched through by heavy equipment with unknown liquid inside. The underground tank was located within 15 feet of a temporary office trailer placed for workers at the site near the shoreline and was proclaimed to be an abandoned septic tank by Steve Donovan at SHN, without being tested or researched. There was no apparent smell and the liquid looked gray and foamy. The tank opening was covered by plywood and workers continued to park next to it and walk over it until I asked that it be cordoned off until tests were conducted.

To add to my growing alarm, the archaeologist hired to monitor Kiewit construction activities throughout the site reported his work boots were falling apart due to the seams disintegrating. Initially, he included reports of the potential contaminants he encountered during his monitoring for cultural resources. Under pressure he stopped including the information, as he's an employee who self proclaims he "rides for the brand." Additional information on the contaminants he encountered beyond his initial weekly reports can now only be found in his handwritten journals turned in for the project that are likely stuffed away in some box.

As the contaminant issues mounted, I stressed with my boss at SHN, Steve Donovan, that the Oregon DEQ needed to be contacted and that their policies and regulations needed to be followed. Instead, my hands were kept tied in terms of fulfilling my role as the acting EI and my attempts to initiate action were initially ignored (he was so busy) and then met with subdued hostility. Steve Donovan's standard line, similar to his response about the SOULA concerns with black soils, was to say that it was being taken care of and that I didn't need to be involved. When pressed, Steve Donovan would say he had contacted the DEQ but he wouldn't provide any details when asked for the sake of the administrative record. It was frustrating, to say the least.

While the potential contamination continued to be untested, I became the problem instead. When I repeatedly reported concerns about ongoing discoveries and the process that needed to be followed, my efforts were repeatedly ignored most of the time, or I was told I didn't need to be involved. I was restricted from taking any action that I felt would make the project not only compliant with environmental policies and regulations in place, but ultimately would assist the project as it continues to move forward. After submitting my resignation I contacted the primary DEQ contact for the environmental cleanup site at Ingram Yard, Bill Mason, and learned he had not been informed of any of the contaminant issues being exposed by the Kiewit test program.

The DEQ should have been contacted immediately when the black soils were discovered by SOULA archaeologists in September 2013, and again when the contaminated soils were uncovered during the Kiewit test program. Instead of taking action as the acting EI, I was restrained and told several times I needed to stop acting like a regulator. I have never been a regulator, but I do know the environmental laws and the ones I don't know I research when needed. There was a process that needed to be followed, but wasn't. And it was clear project managers did not want to hear about it from me.

I'm a supporter of the JCEP but am deeply concerned by the incidents that led me to sever my ties with SHN and the project. There is not a commitment to ensure regulatory compliance and, henceforth, accountability, transparency, and integrity for the project. I don't want to believe that the top project managers condone what has transpired. However, when I contacted Bob Braddock, JCEP Vice President and Project Manager, this past summer about my continued concerns, his short response was that he would take my concerns up with SHN. My response was, "therein lies the problem." I never heard back.

In the DEIS the Ingram Yard soils are repeated referred to as clean fill and as being free of contaminants. What little is mentioned as testing having been conducted does not address the limited areas tested and the concerns raised by the DEQ in 2006, including that there are bioaccumulating toxins that would be extremely harmful to marine life if released into the waters of Coos Bay (e.g., via stormwater during transportation, relocation, and use as filtration for stormwater management). The JCEP plans to excavate and transport approximately 2.3 million cubic yards of the upland soils from the terminal site for use as 20-30 feet of fill for the shoreline SDPP site.

The transparency of the JCEP has become a huge concern of mine since the implementation of the Kiewit test program. In addition to the large amounts of potential contaminants exposed during the test program that were not dealt with, I had repeatedly pointed out early in the design stage back in January that the access road along the shoreline was not paved during weekly conference calls with David Evans and Associates (DEA). It was not ever corrected in the NPDES permit submitted to the DEQ by DEA for the test program, or addressed by DEQ-required conditions for the permit, even though substantial improvements were conducted on this road. In addition, a staging area was constructed within 150 feet of the shoreline in Ingram Yard, ignoring standards established by the National Marine Fisheries Service. The approach of "let's wait and see if it comes out in the public comment period" proclaimed by Sean Sullivan, the DEA lead, for the NPDES permit didn't settle well with me. Vast improvements were made during the Kiewit test program to the shoreline dirt road, without any specifications or requirements by the DEQ for the work at that location because no one at the DEQ checked for site plan accuracy. Would other permits or authorizations have been required for work so close to the shoreline? That's what an environmental professional asks and I did. But only internally, as my comments were discounted by both SHN and DEA.

As the acting EI position for the Kiewit test program, I asked repeatedly that the correct process be followed, stressing transparency was paramount. I tried many times (oral, hand-delivered, phone messages, emails) to communicate this and either did not receive a response or was reprimanded. Despite my concerns raised, with not only SHN but with supervisors at the site, the process wasn't being followed. Prior to resigning from SHN, I learned of additional contaminants being exposed on Friday night of April 18, 2014. I went into work on Saturday morning and alerted all key personnel by email that the Unanticipated Hazardous Waste Discovery Plan for the JCEP needed to be implemented and the protocol followed. The message was tagged as urgent and I emphasized the plan needed to be implemented before workers returned to the site on Monday. I included a personal commitment to assist in addressing the potential issues as expeditiously as possible.

I did not receive one response or phone call in return. When I went into work Monday morning, I was greeted by Steve Donovan who told me I had gotten myself in trouble with Bob Braddock and that I had gone too far. He sternly told me I had gotten off on the wrong foot, that I needed to focus on the "birds and the bunnies," that I had been very disruptive for the Kiewit test program, and that my job with SHN was not to delay the construction occurring at the time. I learned that nothing would be done, construction at the site was commencing without interruption, and there was no plan to deal with the potential contaminants. At that point, after 2-1/2 weeks of trying to resolve the matter, I felt I had no choice and turned in my letter of resignation.

I have a good rapport with the various resource agencies in Oregon from my work for FEMA, and also from when I have worked on my own as an independent environmental consultant. My professional name and integrity was put at stake when I was told my job was to stand back, thereby restricting me from ensuring the proper environmental response was carried out. Within my discipline there is a strict code of ethics (or should be) and I chose not to turn my back on doing the right thing. Transparency, due diligence, and integrity are very important to me. I have not felt they have been important for the JCEP decision makers at hand during the critical moments when a response could have been initiated.

I support the JCEP. I do not support what has recently transpired and sincerely hope it is a reflection of bad judgment on those firms (SHN, DEA) tasked with ensuring this project is transparent and committed to ensuring laws will be followed, including commencing with environmental cleanup as necessary that is coordinated with the Oregon DEQ. The JCEP has inherited property that has issues. These issues can and should be addressed immediately as they arise, and as spelled out by the DEQ. It would be a huge endorsement for the project that they are committed to doing the right thing. Handled correctly, it does not need to be covered up and people like me do not need to be treated as obstacles.

I felt as if I made a strong point by resigning. I had hoped that SHN and DEA would present and address the issues exposed and that the appropriate analysis would be included in the FERC DEIS. Instead, once the DEIS was released I saw that my concerns were excluded and that the Ingram Yard contaminated fill is instead repeatedly referred to as clean and plans are proceeding to use it as fill for the proposed SDPP shoreline site. And no mention is made of the proposed barge berth site, also a borrow site for the SDPP, being contaminated (SOULA, 2013)

The DEIS refers to the DEQ as issuing a "No Further Action" for the environmental clean-up at the terminal site (DEQ, 2006), but if you look at DEQ's website it is listed as a "Partial No Further Action" and is based on the premise that contaminants at the site excavated during future site activities or development must be properly managed and disposed of in accordance with DEQ regulations and policies. Much more testing is needed at the site, due to the much larger extent of contaminated soil exposed during the Kiewit test program. The contamination occurs well outside of the range of where the previous testing was conducted in only the northern portion of the site. Black soils were found all the way to the shoreline at Ingram Yard, along with the additional forested shoreline site to the east encountered by the SOULA archaeologists. And I can't help but wonder if the underground storage tank was ever properly tested and analyzed. It certainly isn't mentioned in the DEIS. Very little regarding this whole issue is included in the DEIS, except for the misrepresentation of the fill being tested and as being free of contaminants.

In addition, the only stormwater management plan referred to in the DEIS is the one included in Resource Report 2, and it is far from adequate. A stormwater management plan needs to be individually developed for the site which clearly takes into account the contaminants at the site and ensures they are not transported to the shoreline SDPP site, where stormwater currently will be transported through a series of ditches and swales for release in the slip and access channel created for the project. Treatment is briefly mentioned as being included as needed, but there is no clear, site-specific plan included in the DEIS and there should be.

The narrative, plans and figures presented in the DEIS are substantially incomplete regarding the contaminant issues encountered by the project so far. It does not present or address these issues. Much more testing is needed and potentially hazardous materials need to be transferred off-site to a DEQ-approved facility for disposal, not transferred to the SDPP site for use as fill along the Coos Bay estuary. The matter is being swept under a rug and the project has set a very disconcerting precedence regarding how issues encountered at the terminal site will be managed. By not clearly and adequately analyzing the affected environment in the DEIS, the potential environmental consequences of the project are not being addressed. Therefore, cumulative effects and conclusions drawn from the misrepresentation of the site are inadequate.

The ongoing issues at the JCEP terminal site needs to be addressed, including corrective actions that will be taken to minimize potential adverse effects. This needs to be clearly spelled out in the Final EIS before a Record of Decision is issued; otherwise the NEPA process is not being followed.

I would be happy to answer any questions you may have and to steer you to the relevant reports that back up my allegations.

Sincerely,

Barbara Gimlin[1]

[1] electronic signature

cc: Ken Phippen, Branch Chief, Oregon Coast Habitat Branch, National Marine Fisheries Service (NMFS)
Brent Norberg, Office of Protected Resources, NMFS Northwest Region
Shawn Zinszer, Portland District Regulatory Branch Chief, USACE Portland District Regulatory Branch
Teena Monical, Eugene Section Chief, USACE Eugene Field Office
Tyler Krug, Project Manager, USACE North Bend Field Office
Patty Burke, District Manager, BLM Coos Bay District Office
Jennifer Sperling, Botanist, BLM Coos Bay District Office
Dennis McLerran, Administrator, U.S. Environmental Protection Agency (EPA), Region 10
Anne Dalrymple, Enforcement Coordinator, EPA Office of Compliance and Enforcement, Region 10
Laura Todd, Field Supervisor, Newport Field Office, U.S. Fish and Wildlife Service

Dick Pedersen, Director, Oregon Department of Environmental Quality (DEQ)
Sara Christensen, 401 Water Quality Certification Coordinator, Oregon DEQ
Bill Mason, Senior Groundwater Hydrologist, DEQ Western Region Office, Eugene
Steve Nichols, Permitting/Compliance Specialist, DEQ Coos Bay Office
Mary Abrams, Director, Oregon Department of State Lands (DSL)
Bob Lobdell, Resource Coordinator, Oregon DSL
Mike Gray, ODFW District Fish Biologist, Charleston Field Office
Stuart Love, ODFW District Wildlife Biologist, Charleston Field Office
Christopher Claire, ODFW Habitat Protection Biologist
Patti Evernden, Coos County Planning Department
Juna Hickner, Coastal State-Federal Relations Coordinator, Oregon Department of Land Conservation and Development
Crystal Shoji, Mayor, City of Coos Bay
Thomas Leahy, Councilor, Coos Bay City Council
Rick Wetherell, Mayor, City of North Bend
David Koch, Chief Executive Officer, International Port of Coos Bay
John Souder, Executive Director, Coos Watershed Association

Warren Brainard, Chief, Confederated Tribes of Coos Lower Umpqua and Siuslaw Indians (CTCLUSI)
Howard Crombie, Director, Department of Natural Resources, CTCLUSI
Bob Garcia, Chairman, CTCLUSI
Don Ivy, Chief, Coquille Indian Tribe
Brenda Meade, Chairperson, Coquille Indian Tribe

Exhibit 6

TOPIC	REQUESTED ACTIONS INCLUDING COMMENTS/QUESTIONS
Inconsistencies in Project Information That Have the Potential to Effect the Review of the DEQ WQC	The project information included in permit applications and authorization requests submitted to local, state and federal agencies by the Jordan Cove Energy Project (JCEP) varies, making it imperative that the Oregon Department of Environmental Quality (DEQ) coordinate with other respective agencies to ensure they are approving the same actions before approving the DEQ Water Quality Certification (WQC) for the project. Complete investigation and analysis is needed due to the substantial inconsistencies between what is presented to various agencies. There are significant lapses in portraying what the full scope of work for the project will entail and how potential adverse effects will be addressed. By not having a complete and consistent scope of work to evaluate, it makes it difficult for the DEQ to fully conduct the proper review and analysis needed for impacts to water quality.
Soil Contamination at the LNG Terminal Facility Site	The site of the LNG terminal (Ingram Yard) was the location of a livestock ranch until 1958. After it was acquired as part of the Menasha mill complex in 1961, the tract was occasionally used for log sorting activities. In 1972-1973, the U.S. Army Corps of Engineers spread materials dredged during maintenance of the Coos Bay navigation channel on the site. From the late 1970s through the early 1980s sand, boiler ash, and wood debris from milling operations were placed on the property. Weyerhaeuser, which acquired the mill in 1981, spread decant solids from its wastewater treatment facility at the site between 1985 and 1994. In addition to mill waste, it is common local knowledge that Ingram Yard was a dumping site used by other entities that found it a convenient place to dump waste of unknown origins. Following closure of the mill site in 2003, it was listed as an environment cleanup site by the DEQ (ECSI #1083) and included Ingram Yard (ECSI #4704). Both sites have undergone a series of limited environmental site assessments to determine the nature and extent of contaminants that occur. Contaminants detected during investigative work over the years have included: mineral spirits, hydraulic oil, diesel, heavy-oil-range petroleum hydrocarbons (total petroleum hydrocarbons, of "TPH"), heavy metals, butylated tin compounds, polynuclear aromatic hydrocarbons, polycholorinated biphenyls, and dioxins. The DEQ issued a <u>**partial**</u> **no further action** letter for both sites on September 15, 2006. Residual contamination remains at the former main mill complex and Ingram Yard sites and the DEQ approved leaving contamination based on the determination that the site will remain in commercial/industrial use. For Ingram Yard, the following requirements were noted: • **While surface soils at the Ingram Yard site meet human health and ecological screening criteria, they contain low levels of potentially bioaccumulating chemicals and must not be placed in waters of the**

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	state. Soils and/or sediments containing residual contamination must be managed or disposed of in accordance with DEQ rules. Additional testing, evaluation, and coordination with the DEQ is needed to ensure placement of fill removed from Ingram Yard or any other potentially contaminated sites within the project footprint consists of only clean fill that has been properly tested, due to the project's proximity to Coos Bay. **The potential release of contaminants into Coos Bay through improper placement of contaminated fill and subsequent release through stormwater or by washing into the bay due to a tsunami would expose fish and marine life to bioaccumulating toxins that would be devastating not only to the fish and marine life, but to humans who could potentially consume them.** During the implementation of a $15 million JCEP exploratory sheet pile and ground penetration test program at Ingram Yard and the dune forest to the east during the spring of 2014, contaminated soil was exposed virtually everywhere excavation occurred in Ingram Yard , all the way to the shoreline. This includes contaminated soils exposed during excavation of a 150'x150' staging area to approximately 4' depth in the northern portion of Ingram Yard and along the road improvements conducted in Ingram Yard from the Trans Pacific Parkway all the way to the shoreline. In addition, during archaeological surveys conducted in the southern portion of the dune forest along the Coos Bay shoreline (also mapped as a borrow area for project fill), archaeologists stopped surveys in the immediate vicinity due to dark black soils that they felt were too contaminated to safely proceed. The soils in this area have not been tested during previous site closure evaluations and the additional contamination issues exposed need to be taken seriously. It is now known that contamination at the JCEP terminal site occurs well outside of the range of where the previous testing was conducted. Much more testing is needed at the overall site to fully understand the extent. While the types of contaminants are somewhat understood, their extent is not. It is extremely important that all pertinent facts regarding potential contaminants be presented for consideration and evaluation prior to placement of fill anywhere within the project footprint. In the Draft Environmental Impact State (EIS) prepared for the project, the JCEP plans to excavate and transport approximately 2.3 million cubic yards of the upland soils from the terminal site (known as Ingram Yard) for use as fill for the shoreline South Dunes Power Plant (SDPP) site. This does not include additional sites along the forested shoreline where other contaminants have been exposed, and other potential sites within the project footprint on the North Spit of Coos Bay. Since the DEQ WQC application is not available for public review (at

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	least that I could find), my comments are based on what's presented regarding the use of the fill in the Draft EIS The Draft EIS states 20-30 feet of fill will be used at the South Dunes Power Plant (SDPP) site. However, in the JCEP's application to the Oregon Department of Energy (DOE) for the Energy Facility Siting Council, it states 40-46 feet of fill will be used and it will go right up to the shoreline along Jordan Cove. Regardless of the amount of fill, **due to the fact that it will be excavated from a site known to be a mill dumpsite with bioaccumulating toxins**, there should be a clear plan in place for how the extensive contamination will be managed, handled, and disposed of. It is not acceptable to use contaminated soils as fill anywhere within the project boundaries when the potential for stormwater runoff and/or being washed into the bay from a tsunami presents a very real concern to the marine and natural environment of Coos Bay. All contaminated soil needs to be hauled offsite, with Best Management Practices (BMPs) to ensure construction equipment and vehicles handling it do not result in the further spread of these contaminants into the bay. A testing and monitoring plan needs to be developed and approved by the DEQ prior to approval of the WQC to ensure any fill transferred within the project footprint for use as fill for elevation of the project is free of potential contaminants. By not clearly and adequately analyzing the contaminated soils throughout the JCEP North Spit site and at the Kentuck mitigation site, the effects to water quality have the potential to have significant adverse effects to fish and marine life in Coos Bay.
Unanticipated Hazardous Waste Discovery Plan and Need for Third Party Monitoring	The Unanticipated Hazardous Waste Discovery Plan developed by the JCEP sounds good, but I can tell you from firsthand experience as the acting Environmental Inspector for project's $15 million exploratory test program conducted at the LNG terminal site in the spring of 2014 that this plan was not followed in the least. Instead, I was ordered to not do my job, to not follow the plan, to not contact the DEQ, and to not delay the ongoing construction activities being conducted at the time**. It is essential that third-party environmental monitors are in place to ensure this doesn't happen again on a much larger scale.**
General Stormwater Management	Potential contaminants in stormwater need to be addressed in the development and implementation of a stormwater management plan that meets DEQ National Pollutant Discharge Elimination System (NPDES) permit requirements to reduce the potential impacts to fish and marine species, whether listed as threatened or endangered for not. The only stormwater management plan referred to in the Draft EIS is the one included in Resource Report 2, and it is far from adequate. A stormwater management plan needs to be individually developed for the site which

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	clearly takes into account the contaminants at the site and ensures they are not transported to the shoreline SDPP site or anywhere else inside the project footprint along the shoreline of Coos Bay. As stated in the Draft EIS, stormwater currently will be transported through a series of ditches and swales for release in the slip and access channel created for the project. Treatment is briefly mentioned as being included as needed, but there is no clear, site-specific plan included in the Draft EIS and there should be. For the Oregon Department of Energy site application with EFSC, a Conceptual Stormwater Management Plan for the JCEP (Document No. 142488-0000-DS0300) dated October 24, 2014, was included. It did not bring up or address the ongoing contamination issues at the site and the BMPs it proposes to not begin to properly address the real and relevant concerns. If anything, it is alarming as it states placement of what they refer to as "sand fill" throughout the plan (from Ingram Yard) will create approximately 2,512,300 square feet of exposed slopes along the SDPP shoreline. It also states monitoring and testing of the stormwater outfalls will be developed as the stormwater design is finalized. This is not good enough. If this issue is not fully evaluated and a stormwater management plan is approved by DEQ prior to issuing a WQC, there is no guarantee an adequate plan will be in place to address the ongoing issues. In addition, the proposed scope of work states the work will be conducted during the Oregon Department of Fish and Wildlife's work window for Coos Bay, which occurs during the months with the highest monthly averages of precipitation (November, December and January). This makes it imperative that extensive BMPs and policies are in place to ensure potential contaminants exposed during excavation at the site are not released into the bay via stormwater. In addition to ensuring ANY potential site contaminates are properly managed and disposed of, **a monitoring and testing program needs to be clearly spelled out in the WQC** in order for the DEQ to fully review and analyze the soil contamination issue and ensure the potential effects to the human and natural environment are minimized and mitigated.
Additional Contaminant Concerns Related to Stormwater	Stormwater management for the project plays on increasingly important role in determining the potential effects to coho salmon and other fish and marine species in Coos Bay. Potential concerns have been elevated in recent years regarding even trace amounts of contaminants (i.e., copper, zinc, PAHS, etc.) that may be discharged into waterways. Although limited studies have been conducted to date, it is theorized that depending on their reaction to water quality and activity within the mixing zone, coho salmon may have migration delays, may move into less-protected habitat, or may become more susceptible to predation.

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	Pollution reduction and treatment for stormwater runoff needs to clearly address how stormwater will be contained and/or transported from all contributing impervious areas within the project footprint to ensure contaminants harmful to fish and marine life are adequately controlled.
Intertidal Flats Mitigation Proposed for Kentuck Slough	Per the joint Public Notice by the DEQ and the U.S. Army Corps of Engineers (Corps), the JCEP proposes to mitigate for other estuarine aquatic resource impacts through the enhancement of 14.33 acres of freshwater wetland habitat, restoration of 1.88 estuarine wetland habitat and reestablishment of historic tidal flows to approximately 45.1 acres of wetland habitat (converting freshwater wetland to unvegetated tidal mudflat channels) at the former Kentuck Golf Course (Kentuck Slough Mitigation Site), east of North Bend. The estuarine intertidal flats mitigation proposed for Kentuck Slough by the JCEP has not undergone the serious environmental and hydrologic evaluation needed to ensure the mitigation will not result in contamination of the Coos Bay estuary due to the site's use as a golf course for over four decades, flooding of adjacent and upstream property owners, and a potential mosquito infestation that would affect area residents. Much more input is needed from hydrologists, engineers, natural resources scientists, and planners to fully understand and design a plan for the site that will address current and future site-specific conditions on the ground, including upstream of the site. There are substantial inconsistencies in the various compensatory mitigation plan versions floating around in the regulatory system for the Kentuck mitigation proposed by the JCEP. The lack of consistency is an indicator that the project warrants close and interactive scrutiny by the local, state and federal agencies that are authorized to review and approve the project. Each authorizing agency needs to ask tough questions, to coordinate with other respective agencies to ensure they are approving the same actions, and to expect complete investigation and analysis before approving any action. These inconsistencies, together with the lack of appropriate studies and associated documentation, is alarming. As it stands, there is a significant potential for substantial adverse effects from the mitigation proposed at Kentuck to water quality. My public comment to FERC submitted on February 12, 2015, provides substantially more information regarding this issue and I encourage the DEQ to review it (FERC Comment No. 20150212-5018).
State Endangered Plant Species (Point Reyes Bird's Beak) Occurrence Along the Jordan Cove Shoreline and North Point Workforce Housing Project Slough	The Point Reyes bird's-beak (*Chloropyron maritimum* ssp. *Palustre*, formerly *Cordylanthus maritimus* ssp. *palustris*) is an annual gray-green and purple-tinged herbaceous species with pinkish to purplish red flowers that grows 4 to 16 inches tall and has few branched stems. It is listed as endangered by the State of Oregon. In Oregon, the species is restricted to Netarts Bay, Yaquina Bay, and Coos Bay, with the majority of known occurrences located along the Coos Bay shoreline (ORBIC 2013). As required by the Oregon Department of Agriculture (ODA) under OAR 603-073-0090(5)(d)(A)-(E), the project needs to document that it has made a

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	reasonable effort to ensure that construction and operation of the project will not result in a population loss or decline of the Point Reyes bird's-beak at the locations where it is found on adjacent shorelines. Focused botanical surveys were conducted during July and August of 2013 during the appropriate blooming period to document occurrences of Point Reyes bird's-beak in or near the JCEP project footprint. Multiple occurrences of substantial populations were detected along the shoreline of Jordan Cove, near Wetland J at the SDPP site, on the shoreline east of the SDPP site boundary, and along the North Point Slough entrance at the proposed North Point Workforce Housing site. It is essential that appropriate Best Management Practices (BMPs) and mitigation measures are implemented to ensure the species is preserved and protected. Although the JCEP states appropriate mitigation measures will be developed and implemented through consultation with the ODA to ensure that suitable habitat for the Point Reyes bird's-beak will not be impacted by construction of the project, the lack of documentation of this actually happening is missing. While employed by SHN Consulting Engineers & Geologists, Inc. (SHN) for the JCEP, I initiated consultation with the ODA–but much more follow-up is needed. The project has dropped the ball on this one. The Point Reyes bird's-beak populations documented warrant further evaluation and site plans need to clearly document the potential impact to the species. At the North Point Slough location, current site plans call for a bridge to connect the two portions of the site on each side of the slough entrance and this action will involve the "take" of this species. Prior to approval of the WQC, the DEQ, as a state agency, needs to ensure mitigation measures developed in coordination with the ODA will be implemented to ensure that impacts to Point Reyes bird's-beak are avoided and minimized. A conservation and mitigation plan that includes monitoring needs be developed and approved by the ODA prior to issuance of the WQC by the DEQ to ensure the project is not likely to cause a significant reduction in the likelihood of survival or recovery of the species.
Tsunami Hazards	In a 13-year study completed by Oregon State University in 2012 (published online by the U.S. Geological Survey; Professional Paper 1661-F), **the study concluded that there is a 40 percent chance of a major earthquake in the Coos Bay region during the next 50 years due to its location along the Cascadia Subduction Zone**. The study determined such an earthquake could approach the intensity of the Tohoku quake that devastated Japan in March of 2011. This extensive study not discussed or considered in the risk evaluation by the JCEP. In addition, a multi-state mitigation project of the National Tsunami Hazard Mitigation Program (NTHMP) published Seven Principles for Planning and Designing for Tsunami Hazards in March 2001. Participants includes

TOPIC	REQUESTED ACTIONS INCLUDING COMMENTS/QUESTIONS
	the National Oceanic and Atmospheric Administration (NOAA), U.S. Geological Survey, Federal Emergency Management Agency, National Science Foundation and the states of Alaska, California, Hawaii, Oregon, and Washington. Funding for this project was provided by NOAA. This valuable study was not used either in determining the tsunami risks for the JCEP. The DEQ needs to review the findings of these two well researched reports in their decision-making process, as the potential for contaminants to be washed into the bay during a tsunami event becomes a very real concern to water quality.
Transparency and Integrity Issues	During my time working for the JCEP under SHN from March 2013 to April 2014, I encountered serious transparency and integrity issues with the management of both SHN and another primary consultant, David Evans and Associates. From inaccurate site plans submitted with permits to failing to address issues as they arose, the standard operating procedures of “let’s wait and see if it comes out in public comment” is not the proper response to issues. Hence my public comment.

Exhibit 7

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMSSION

IN THE MATTERS OF

Jordan Cove Energy Project, L.P.	)	**Docket No. CP13-483-000**
Pacific Connector Gas Pipeline, L.P.	)	**Docket No. CP13-492-000**

MOTION TO INTERVENE OUT OF TIME OF CLAUSEN OYSTERS AND LILLI CLAUSEN, AS AN INDIVIDUAL AND OWNER

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C. F. R., 385.214, I, Lilli Clausen, an individual and owner of Clausen Oysters, respectfully move to intervene out of time in the May 21, 2013, application of the Jordan Cove Energy Project, L.P. and the June 6, 2013, application of the Pacific Connector Gas Pipeline, L. P. in the above-captioned dockets.

I. Identity and Contact Information

I ask that all communication in regards to this motion be addressed to the following:

Lilli Clausen
Clausen Oysters
66234 North Bay Road
North Bend, Oregon 97459
[redacted]

II. Declaration of Interest

On May 21, 2013, Jordan Cove Energy Project, L.P. filed in FERC Docket No. CP13-483-000 an application under section 3 of the Natural Gas Act (NGA) and Parts 153 and 380 of the Commission's regulations, seeking authorization to site, construct and operate a natural gas liquefaction and liquefied natural gas (LNG) export facility on the bay side of the North Spit of Coos Bay in Coos County, Oregon, directly across from the Cities of North Bend, Coos Bay and the Southwest Oregon Regional Airport. The LNG Terminal would be capable of receiving natural gas via the Pacific Connector Gas Pipeline, liquefying it, storing it in its liquefied state in two cryogenic storage tanks, and loading the LNG onto ocean going vessels.

On June 6, 2013, Pacific Connector Gas Pipeline, L. P. filed an application under CP13-492-000 with FERC to construct and operate the Pacific Connector Gas Pipeline (PCGP) Project, a new 231.82-mile, 36-inch diameter interstate natural gas transmission system and related facilities. The proposed PCGP system will extend from the proposed Jordan Cove Liquefied Natural Gas (LNG) Terminal, being developed by Jordan Cove Energy Project, L.P. (JCEP), to interconnects with two interstate natural gas pipelines near Malin, Oregon. The PCGP is the proposed supply pipeline for the proposed Jordan Cove Terminal.

We continue to get conflicting information about the proposed route of the Pacific Connector Gas Pipeline and have been very concerned about the proposed route of the pipeline through Haynes Inlet and the West side of Coos Bay. As we understand it, the line is proposed to run between Silverpoint 1 and Silverpoint 3 oyster beds. The route going under the Highway 101 Bridge would be very detrimental to our oyster business for several reasons:

We need access to the three oyster beds: Silverpoint 1, 7 and 8, depending on the different tide levels, at various times of the day or night. The harvest crew goes out with the boats at low tide. The large barge is taken out at high tide to bring in the full nets. The channel between Silverpoint 1 and 3 is narrow. We couldn't fill orders if big equipment is being used to dig the trench for the pipeline, preventing us from going through.

Also, we need access to our three oyster beds, Silverpoint 1, 7 and 8, at all times. All the Silverpoint oyster beds: 1, 3, 5, 6, 7, 8 & 9, may be affected by mud or fines in the water which might prevent us from harvesting the oysters according to Dept. of Agriculture regulations. We are also storing our "re-beds" on S 1 for more grow out time. We bring them in as they are ready. Another problem would be the new seed placed around S 1 could potentially be affected by the fines suspended in the water.

When a pipeline is constructed in the water, mud and sand are suspended in the water, especially on windy days. It could drift over our one, two and three year old oysters in the bay. Oysters are filter feeders. They seine out the tiny plankton from the seawater to feed on. Mud, sand or fines could clog the gills of countless oysters. I would hate to have a repeat of the New Carissa oil spill effect. It took 4 years and 9 months before we were paid for the damage!

Another worry is the 250 foot construction right of way in the Bay! Any kind of hole or ditch dug in the mudflats takes years before the ground above it solidifies. One example is at the foot of the boat ramp next to us. A five foot diameter hole left by someone was like quicksand, and one couldn't walk across it for several years!

The line between Silverpoint 1 and 3 could cause problems when accessing the oyster beds, especially at night. Usually the boats are parked in shallow water close to the area to be harvested. I would hate for our guys to get stuck there. And the channel is very narrow! Since the original Silverpoint oyster beds were established in 1890 in Coos Bay and over the years have been worked by various oyster companies, we feel that this resource should be maintained and not jeopardized.

Due to the fact that the Pacific Connector Gas Pipeline's current proposed route could destroy our oyster business, I move to intervene out of time in this proceeding. No other party has been willing or is able to adequately represent our interest in this proceeding and it is for this reason I wish to be made a party to this proceeding, with all the rights attendant to such status. The decision by FERC to allow this Motion/Notice of Intervention Out of Time would be in the public interest.

Dated this 15th day of October 2014.

Lilli Clausen

Lilli Clausen, Clausen Oysters

CERTIFICATE OF FILING

I certify that on the 15th day of Oct 2014, I filed by electronic filing the original document, Motion to Intervene Out of Time electronically with:

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Dated this 15th day of Oct 2014

Lilli Clausen

Lilli Clausen, Clausen Oysters

CERTIFICATE OF SERVICE

I certify that on the 15th day of Oct 2014 I served electronically or by first class mail this Motion to Intervene Out of Time to each person designated on the official service list compiled by the Commission in the above-captioned proceedings.

Dated this 15th day of Oct 2014

Lilli Clausen

Lilli Clausen, Clausen Oysters

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMSSION

IN THE MATTERS OF

Jordan Cove Energy Project, L.P.	)	**Docket No. CP13-483-000**
Pacific Connector Gas Pipeline, L.P.	)	**Docket No. CP13-492-000**

MOTION TO INTERVENE OUT OF TIME OF COOS BAY OYSTER COMPANY AND JACK HAMPEL, AS AN INDIVIDUAL AND OWNER

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C. F. R., 385.214, I, Jack Hampel, an individual and owner of Coos Bay Oyster Company, respectfully move to intervene out of time in the May 21, 2013, application of the Jordan Cove Energy Project, L.P. and the June 6, 2013, application of the Pacific Connector Gas Pipeline, L. P. in the above-captioned dockets.

I. Identity and Contact Information

I ask that all communication in regards to this motion be addressed to the following:

Jack Hampel
Coos Bay Oyster Company
PO Box 5478
Charleston, Oregon 97420
[redacted]

II. Declaration of Interest

On May 21, 2013, Jordan Cove Energy Project, L.P. filed in FERC Docket No. CP13-483-000 an application under section 3 of the Natural Gas Act (NGA) and Parts 153 and 380 of the Commission's regulations, seeking authorization to site, construct and operate a natural gas liquefaction and liquefied natural gas (LNG) export facility on the bay side of the North Spit of Coos Bay in Coos County, Oregon, directly across from the Cities of North Bend, Coos Bay and the Southwest Oregon Regional Airport. The LNG Terminal would be capable of receiving natural gas via the Pacific Connector Gas Pipeline, liquefying it, storing it in its liquefied state in two cryogenic storage tanks, and loading the LNG onto ocean going vessels.

On June 6, 2013, Pacific Connector Gas Pipeline, L. P. filed an application under CP13-492-000 with FERC to construct and operate the Pacific Connector Gas Pipeline (PCGP) Project, a new 231.82-mile, 36-inch diameter interstate natural gas transmission system and related facilities. The proposed PCGP system will extend from the proposed Jordan Cove Liquefied Natural Gas (LNG) Terminal, being developed by Jordan Cove Energy Project, L.P. (JCEP), to interconnects with two interstate natural gas pipelines near Malin, Oregon. The PCGP is the proposed supply pipeline for the proposed Jordan Cove Terminal.

On December 18, 2014, I met with Representative Caddy McKeown and Michael Hinricks of the Jordan Cove Energy Project where I learned about the plans of the Pacific Connector Gas Pipeline and the close proximity of the proposed pipeline to our Silverpoint oyster beds. As we understand it, the line is proposed to run up the channel between ours (Silver point 3) and Clausen Oysters (Silver point 1) oyster beds.

Our concern is the effect that the construction of the Pacific Connector Gas Pipeline will have on our oysters along the proposed route through the Haynes Inlet on Coos Bay.

Our oysters are planted at the minus tide lines to utilize the mud flats as close to the channel as we can get. At certain minus tides, the channel may only be 100-200 feet wide. With the amount of mud and sand sediment that would be created within the close proximity of our beds, I believe we could suffer a devastating dead loss.

In the summer months, we set oyster larvae on shell and place them on pallets in bags that keep them up about a foot off the mud flats. This is done to keep them out of any silt or sediment while letting them grow through fall and winter for planting in the spring.

These larvae, when first set, are very small and very vulnerable. (Twelve million larvae equal about the size of a tennis ball).

When the oyster spat are planted in the spring (March-June), by removing them from the bags and pallets and cast directly onto the mud flats, they are approximately ¼ to ½ inch in diameter, and if you cover them with sediment, they will die!

I am also concerned about the bay water quality in this area during the construction time. The Oregon Department of Agriculture will surely be testing this water and if they have any concerns during this period, they will shut our harvesting down.

We need continual access to these beds both day and night. We work on the tides and they change daily.

Due to the fact that the Pacific Connector Gas Pipeline's current proposed route could destroy our oyster business, I move to intervene out of time in this proceeding. No other party has been willing or is able to adequately represent our interest in this proceeding and it is for this reason I wish to be made a party to this proceeding, with all the rights attendant to such status. The decision by FERC to allow this Motion/Notice of Intervention Out of Time would be in the public interest.

Dated this 28th day of February 2015.

__*/s/ Jack Hampel*______________________
Jack Hampel, Coos Bay Oyster Company

Exhibit 8

Clam Diggers Association of Oregon

Chuck Erickson, Director
2727 Stanton Street
North Bend, OR 97459

William Lackner, President
P.O. Box 746
Newport, OR 97365

February 21, 2014

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE
Washington, DC 20426

RE: Motion to Intervene Out of Time submitted by the Clam Diggers Association of Oregon on February 20, 2014, for FERC Dockets CP13-483-000 and CP13-492-000

Dear Secretary Bose:

After submitting our *Motion to Intervene Out of Time* yesterday it was brought to our attention that we had the wrong date listed under our Certificate of Service portion of that Motion. Please accept this corrected version of our *Motion to Intervene Out of Time* that corrects this error. The original Motion was served to everyone in the FERC Service List for FERC Dockets CP13-483-000 and CP13-492-000 on February 20, 2014, and this corrected *Motion to Intervene Out of Time* will also be served to everyone in the Service List for the Jordan Cove / Pacific Connector Project.

Sincerely,

Chuck Erickson
William Lackner

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

IN THE MATTERS OF

Jordan Cove Energy Project, L.P.) Docket CP13-483-000

Pacific Connector Gas Pipeline, L.P.) Docket CP13-492-000

CLAM DIGGERS ASSOCIATION OF OREGON MOTION TO INTERVENE OUT OF TIME

Pursuant to 18 C.F.R. 385.214, the Clam Diggers Association of Oregon, hereby respectfully moves to intervene in the Jordan Cove Energy Project and the Pacific Connector Gas Pipeline applications submitted to the FERC on May 21, 2013 and June 6, 2013.

I. Identity/Contact Information

We ask that all communication in regards to this motion be addressed to the following:

Chuck Erickson, Director
Clam Diggers Association of Oregon
2727 Stanton Street
North Bend, OR 97459
[redacted]

William Lackner, President
Clam Diggers Association of Oregon
P.O. Box 746
Newport, OR 97365
[redacted]

II. Declaration of Interest

On May 21, 2013, Jordan Cove Energy Project, L.P. filed an application under section 3 of the Natural Gas Act (NGA) and Parts 153 and 380 of the Commission's regulations, seeking authorization to site, construct and operate a natural gas liquefaction and liquefied natural gas (LNG) export facility (Liquefaction Project) on the bay side of the North Spit of Coos Bay in unincorporated Coos County, Oregon, to the north of the Cities of North Bend and Coos Bay.

On June 6, 2013, Pacific Connector Gas Pipeline, L.P. filed an application with FERC for approval to construct, own and operate a natural gas transmission pipeline in southern Oregon. The Pacific Connector pipeline would deliver approximately 1 billion cubic feet of natural gas per day to the Jordan Cove Energy Project export terminal at Coos Bay Oregon. There the natural gas would be cooled to form LNG for export from Jordan Cove's proposed export terminal.

The proposed LNG export project would require extensive dredging of the Coos Bay, including but not limited to; Channel Deepening and Widening, an LNG Marine Terminal Slip Dock and Access Channel ; and the construction of the Pacific Connector Gas Pipeline through the Coos Bay Estuary and Haynes Inlet. Due to contamination that has been found in Coos Bay sediments, this dredging will negatively impact clams in the Coos Bay both indirectly and directly as described below.

III. **Basis for Intervention**

My name is Chuck Erickson and I am the Director of the Clam Diggers Association of Oregon and have been a resident of Oregon for 58 years. We recently received records from my Oregon Public Records Request we made to Oregon International Port of Coos Bay and Oregon Department of Environmental Quality. Port released documents to us in 2014.

The following information has recently come to light.

In December 2, 1998 EPA and Oregon DEQ entered into a deferral agreement that non-compliance would be reported to the EPA concerning the clean-up of Charleston sediment contamination of hazardous substances (Tributyltin, metals, PAHs, PCBs) in Coos Bay near the proposed Jordan Cove Energy site.

In 2001 EPA Superfund Record of Decision 12.0 clearly states that bioaccumulation test were to be done two years after cleanup and annual monitoring of the sediments for five years. When this was completed the sediment quality was to be monitored at five year intervals.

In the public records emails we received from the Oregon International Port of Coos Bay and their agents, they clearly state that the annual and the five year tests were never done. The Port did not supply the bioaccumulation test results and we assume those were also never done. The Oregon Department of Environmental Quality failed to contact the EPA that the Port was non-compliant with their cleanup agreements. Emails I received late 2013 from Eugene DEQ stated they have never received any test results from Oregon International Port of Coos Bay. These facts also show that DEQ was also non-compliant with the Superfund Deferral agreement.

The records request we received included emails from the Port which show that Coos Bay sediment testing was finally done in 2012.The test results were provided to the Port in October 2013 by Geosyntec consultants. The Port did not release these documents to us until 2014.

These documents indicate heavy metals exceeding minimum requirements in the sediment composite test. The single samples tested were near maximum allowed for heavy metal. These test results also show the following contaminates: tributyltin, antimony, chromium, copper, mercury, nickel and zinc are still present in the sediments sampled. In these same requested emails there were references being made of using samples from other areas of the bay in order to close this matter.

Through our website and members we have learned that Geoduck clams have been taken by commercial and sport harvesters in Coos Bay. Pictures were posted on our website showing a Geoduck harvested. Through our research we found that these clams were present in historical times. Our organization contacted the Oregon Department of Fish and Wildlife Director Roy Elicker to list the Geoduck clams as threatened or endangered species. These clams are only found in limited numbers in Coos Bay and Netarts Bay. ODFW refused our request to list these last remaining stocks of clams. We believe that the planned facility at Jordan Cove LNG export is the reason for their refusal to take action to protect these resources. These remaining Coos Bay Geoduck clams may be the last surviving Geoducks in the State of Oregon.

The President of the Clam Diggers Association of Oregon, William Lackner, was shown pictures of clams by an Oregon Department of Fish and Wildlife employee at the Charleston Field Office. These pictures clearly showed deformed clams from Coos Bay. Mr. Lackner contacted the ODFW employee by email for copies of these photographs. The Charleston ODFW employee refused the request for copies of the photographs and stated they were his personal property.

Mr. Lackner has repeatedly made requests to Newport Oregon Department of Fish and Wildlife to implement an Invertebrate Species Plan for Oregon bays. The Clam Diggers association of Oregon has members along the entire coast of Oregon. Our members have observed clam die offs and crab die offs. When these were reported to the State of Oregon we were told the die offs were natural or they don't have people available to investigate.

Clam Diggers Association of Oregon has contacted the State of Oregon to report sewage spills in Oregon bays. The Oregon Department of Agriculture in Salem has refused to implement the sewage spill notification system to which they agreed. The State excuse is they do not have enough money.

Through our recent request for information from Eugene Oregon Department of Environmental Quality we have learned that DEQ sampling of Coos Bay 1995 dredging samples for contaminates were done incorrectly. Because DEQ did not know how to collect the samples correctly, contaminates like tributyltin could not be tested and all 14 loads of dredged materials failed to detect (TBT) tributyltin. Tributyltin is a known human health risk and can bio-accumulate in shell fish and finned fish.

We also learned from documents and recent communications that DEQ did not use scientific proven methods for detecting contaminates in Coos Bay sediments. DEQ failed to do tissue sampling on clams before and after dredging took place in Coos Bay. Because clams bio-accumulate toxic contaminates they are the litmus test if contaminates are present in sediments. This sample method is used worldwide by scientists who study the effects of environmental pollution in sediments. In other words, clams are the canaries of the coal mine.

DEQ did some limited testing of clams for contaminates in Coos Bay. From DEQ documents and communications we have learned that their sampling methods were less than scientific. DEQ never sampled the original 1970's area where baseline for contaminates were established. When DEQ did test, they never tested the same area again even though contaminates were present in high numbers for the clams sampled. DEQ did not follow scientific protocol by using baseline methodology for their tissue contaminates studies. It was also learned that the clams samples were not all sent to the testing lab as whole shell clams. The larger gaper clams were dissected and not sent whole. It was learned that some internal parts of the clam were not sent for testing. This may explain why the Gaper clams tested much lower than the softshell clams. This methodology of using two systems for sampling is less than scientific and could result in errors.

DEQ has informed the Clam Diggers Association that non source point benzo(a)pyrene levels have risen since the 1979 EPA study. This increase is noted in the Coos Bay Toxics Study. The sediment studies for Jordan Cove LNG have not included tissue sampling for clams. The methodology used by the Jordan Cove studies may contain errors for contaminates in Coos Bay sediments.

Due to the recent findings described above showing that sufficient studies have not been completed to date, and in an effort to protect Coos Bay clams, clam diggers and the interest of any and all citizens who may potentially ingest clams coming from the Coos Bay, the Clam Diggers Association of Oregon respectfully request to be made a party to this proceeding and be permitted to intervene in this proceeding with all the rights attendant to such status. No other party will or can adequately represent the Clam Diggers Association of Oregon and no prejudice to, or additional burdens would occur to existing parties as a result of the FERC permitting this intervention. Participation of the Clam Diggers Association of Oregon in this proceeding would be in the public interest.

CERTIFICATE OF SERVICE

We hereby certify that notice of this Motion to Intervene Out of Time will be served electronically or by first class mail to each person designated in the official service list compiled by the Commission in the above-captioned proceedings.

Sincerely,

Chuck Erickson
William Lackner
Dated this 20th day of February 2014

Exhibit 9

Potential Impact of Jordan Cove LNG Terminal construction on the Nursery Habitat of the Dungeness crab.

Salem, Oregon, January 14, 2019

Sylvia Yamada Ph.D.
yamadas@science.oregonstate.edu

The **Dungeness crab** (***Cancer magister***) supports an important commercial and sport fishery from Alaska to California. Total annual landings in recent years exceeded 25,000 tons (55 million pounds) (FAO statistics, 2012). In Oregon, the 2014 Dungeness fishing season yielded 14.4 million pounds, $50 million to crabbers and an estimated $100 million to the Oregon economy (Oregon Dungeness Crab Commission in Fisherman's News On line). *The Dungeness fishery is the most valuable commercial fishery in Oregon (Rasmusen 2013).*

The life cycle of Dungeness crab is complex, depending on both estuarine and near-shore habitats. Typically, mating occurs in shallow water, and females migrate offshore to brood and hatch their eggs. The early larval stages feed and rear in the near-shore water column, after which the final larval stage rides tidal currents back to shore and settles out in shallow estuarine habitats. The final larval stage molts into a ~5 -7 mm wide first crab stage. *The highest densities of juvenile Dungeness crabs are found in estuaries, which provide warm water, high biological productivity and protection from predators. Sand substrate and eelgrass beds are preferred habitat for these young crabs, which bury in the sand and hide in the eelgrass to escape predators.* Size measurements of crabs trapped at Russell Point in Coos Bay (below the Highway 101 McCullough Bridge) show that Dungeness crabs in their first two years of life (100 mm carapace width and smaller) are extremely abundant in the mid-to low intertidal areas such as pools and eelgrass beds (Figure 1).

In my research documenting the status of the non-native European Green crab in Coos Bay, I encounter young Dungeness crabs in all my study sites. I selected a sub-set of my sites closest to the proposed Jordan Cove Energy Project: the north and south sides of Trans Pacific Lane and the beach adjacent to the Roseburg Forest Product watchman's booth. The results from over 600 trap-days, show that young Dungeness crabs are consistently abundant from 2002 to 2014 at all sites, with an average catch of 15 per trap (Table 1). *These trapping results confirm the findings by Emmett and Durkin (1985) that estuaries are important nursery habitats for Dungeness crabs. This fact has to be kept in mind when a trench is dug In Haynes Inlet, the Trans Pacific Parkway is to be expanded and an upland area is cut out to create a berth for ocean-going vessels. Not only will the turbidity during the construction phase be of concern to the ecological community, the on-going dredging to maintain the berth and shipping channels will continue to be a disturbance to the ecosystem. It will result in habitat loss for native species, including the valuable Dungeness crab. In one study between 45 to 85 % of the Dungeness crabs died during a simulated dredging operation (Chang and Levings, 1978).*

Sylvia Yamada is a marine ecologist who has studied native crabs and the invasive European green crab in Oregon and Washington for over 20 years.

References:

Chang, B., Levings, C. 1978. Effects of burial on the heart cockle *Clinocardium nuttalii* and the Dungenes crab *Cancer magister*. *Estuarine, Coastal and Shelf Scie*nce. 7, 4009-412.

Emmett, R.L. and Durkin, J.T. 1985. The Columbia River Estuary: An Important Nursery for Dungeness Crabs, *Cancer magister*. *Marine Fisheries Review*. 47(3), 21-25.

Fisherman's News On line Sept 24, 2014 http://fnonlinenews.blogspot.com/2014/09/oregons-crabbers-riding-market-value.html

Rasmuson, L.K. 2013. The Biology, Ecology and Fishery of the Dungeness crab, *Cancer magister*. In Michael Lesser, editor: *Advances in Marine Biology*, Vol 65, Burlington: Academic Press, pp. 95-148. ISBN: 978-0-12-410498-3 Elsevier Ltd. Academic Press.

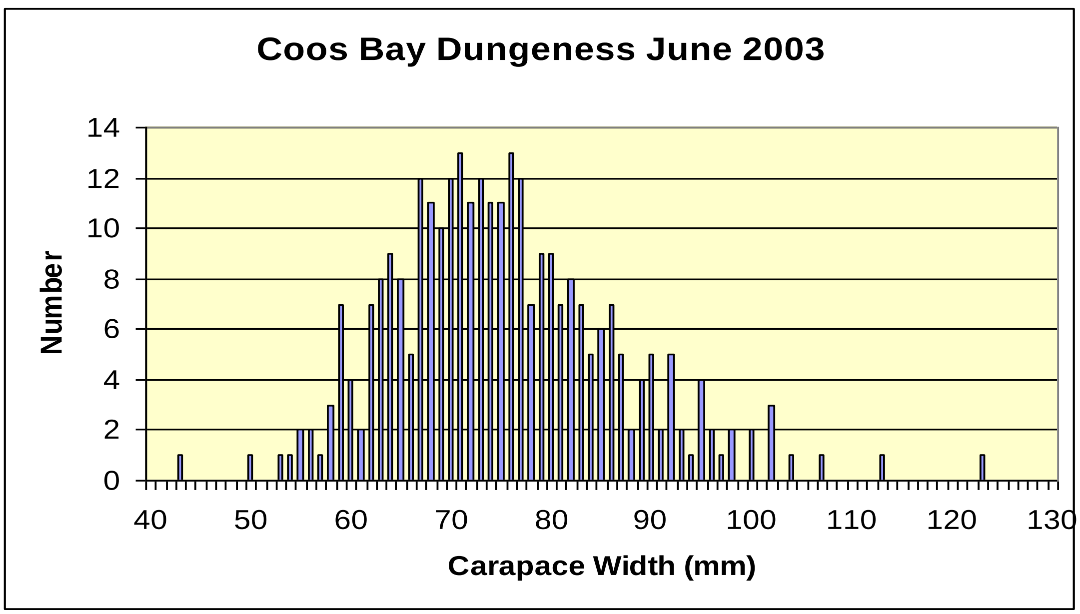

Figure 1. Size frequency distribution of Dungeness crabs trapped in pools and eelgrass at Russell Point, below the Highway 101 McCullough Bridge, in June 2003. Adult crabs are greater than 100 mm in carapace width. It is estimated that the first 2 year classes are represented.

Table 1. Trapping Data for study sites along Trans Pacific Lane and Roseburg Forest Product causeway from 2002-2014.

	Date	Trap Type	Zone	European green crab *Carcinus maenas*	Hairy shore crab *Hemigrapsus oregonensis*	Purple shore crab *Hemigrapsus nudus*	Dungeness crab *Cancer magister*	*Cancer magister* (Recruits <50mm)	Red rock crab *Cancer productus*	stag-horn sculpin	# Traps
Roseburg Lumber	6/25/2002	Fish	Site	0	0	0	45	0.5	0.1	0	10
Roseburg Lumber	6/16/2003	Fish	*low*	0	0	0	12.2	0	0.7	1.5	10
TransPacific S	7/10/2005	Fish	*low*	0	0	0	6.14	1.14	0	1.86	7
North	7/10/2005	Fish	*low*	0	0	0	0	5.7	0	1.1	10
South	3/25/2005	minnow	*Mid*	0	0	0	0	0	0	2.4	10
North	7/10/2005	minnow	*mid*	0	0.2	0	0	0.6	0	0.8	5
South	7/10/2005	minnow	*mid*	0	0	0	0	0.4	0	0.6	5
Trans-Pacific Bridge	9/1/2005	Fish	*Low*	0	0	0	6.6	0	3	1	5
	9/1/2005	Minnow	*high*	0	0	0	0.2	0	0	0.4	4
Trans-Pacific Ln.	6/8/2006	Fish	*Low*	0	0	0	4.9	0	0	2.6	10
	9/13/2006	Fish		0	0.4	0	0.2	0	0	0.2	5
	6/8/2006	Minnow	*high*	0	0	0	0.7	0	0	2.3	10
Trans Pacific Br.	9/13/2006	Minnow		0.2	0	0	0	0	0	0.2	5
TransPacific Ln. N	5/25/2007	Fish	Mid	0.5	0.2	0	1	0.1	0	0.8	10
	7/14/2007	Fish		0.4	1.47	0	23.53	0	0	0.2	15
	9/26/2007	Fish		0	0	0	4.75	0	0	0	8
TransPacific Ln. S	5/25/2007	Fish	Mid	0.09	0	0	0.82	0	0	0.36	11
	7/14/2007	Fish		0.27	0.07	0	9	0	0.07	1	15
	9/26/2007	Fish		0	0	0	2.71	0	0	0.14	7
TransPacific Bridge	5/25/2007	Fish	Mid	0	0	0	1.33	0	0	0	6
	9/25/2007	minnow	high	0	0	0	1.6	0	0	0.4	5
TransPacific Ln. N	6/18/2008	Fish	Mid	0.1	0.2	0	7.4	0	0	7.8	10
	6/19/2008	Fish		0	0	0	1.75	0	0	3.25	8
	9/18/2008	Fish		0	0.1	0	23.4	0	0	0.7	10
TransPacific Ln. S	6/18/2008	Fish	Mid	0.5	0	0	17.2	0	0	2.2	10
	6/19/2008	Fish		0.37	0	0	17.63	0	0	1.37	8
	9/18/2008	Fish		0.1	0	0	22.6	0	0	0.3	10
TransPacific Ln. N	7/8/2009	Fish	Mid	0.13	0	0	9.88	0	0	0.38	8

	7/9/2009	Fish		0.1	0.2	0	11.3	0	0	0.3	10
	07/0/09	Fish		0.1	0	0	11.7	0	0	0.5	10
TransPacific Ln. S	7/8/2009	Fish	Mid	0	0	0	24.38	0	0	0.25	8
	7/9/2009	Fish		0.1	0	0	30.2	0	0	0.9	10
	7/10/2009	Fish		0.4	0	0	16.6	0.1	0	0.5	10
	7/11/2009	Fish		0.4	0	0	13.1	0	0	2.7	10
TransPacific Ln. N	3/19/2010	Fish	Mid	0	0.4	0	0.7	0	0	0	10
	3/20/2010	Fish		0	0.1	0	0.1	0.2	0	0	10
	3/21/2010	Fish		0	0.3	0	0.3	0.4	0	0	10
	6/25/2010	Fish		0	0	0	35.7	0	0	1.1	9
	6/26/2010	Fish		0	0	0	75.9	0	0	0.4	10
TransPacific Ln. S	3/19/2010	Fish	Mid	0	0	0	1.9	0.9	0	0	10
	3/20/2010	Fish		0.1	0	0	1.7	0	0	0	10
	3/21/2010	Fish		0	0	0	2.5	0.1	0	0	10
	6/25/2010	Fish		0	0	0	90.6	0	0	0	10
	6/26/2010	Fish		0	0	0	69.9	0	0	1.6	20
TransPacific Ln. N	7/17/2011	Fish	Mid	0	0.6	0	4.73	0.27	0	0.73	15
	10/17/2011	Fish		0	0	0	5.3	0	0	0.2	10
TransPacific Ln. S	7/16/2011	Fish	Mid	0.03	0.09	0	1.5	0.06	0	1.53	34
	7/17/2011	Fish		0	0.13	0	2.07	0.47	0	1.2	15
TransPacific Ln. N	6/27/2012	Fish	Mid	0	0	0	89.2	0	0	0.4	5
TransPacific Ln. S	6/25/2012	Fish	Mid	0	0	0	9.75	0	0	0.75	12
	6/27/2012	Fish		0.11	0	0	5.2	0	0	0.67	9
TransPacific Ln. S	3/22/2013	Fish	Mid	0	0	0	1.75	0	0	0	20
	3/23/2013	Fish		0	0	0	6.79	0	0	0	19
	7/12/2013	Fish		0	0	0	7.37	0	0	1.6	30
	7/13/2013	Fish		0	0	0	5.24	0	0	1.48	25
TransPacific Ln N	7/12/2014	Fish		0	0	0	40.33	0	0	0.5	12
	7/13/2014	fish		0	0	0	24.9	0	0	0.4	12
TransPacific Ln. S	7/12/2014	Fish		0	0	0	47.27	0	0	0	15
	7/13/2014	fish		0	0	0	23.83	0	0	0	12
Average				0.068	0.075	0	14.955	0.067	0.065	0.874	
Total # Traps											649

Impact of Jordan Cove LNG Terminal
by Sylvia Yamada
Salem, Oregon January 15, 2019

- I have been studying crabs in Oregon estuaries, including Coos Bay, for over 20 years.
- I am concerned that the construction of the Jordan Cove Energy Project could impact important habitats for native species, including the Dungeness crab.
- The Dungeness crab fishery is the most valuable commercial fishery in Oregon. In a good year, landings yield 100 million $ to the Oregon economy.
- The highest numbers of juvenile crabs are found in soft sediments and eel grass beds of estuaries. This is where the young crabs find food and shelter from predators.
- In my study site along Trans Pacific Parkway, I have consistently trapped an average of 15 young Dungeness crabs per trap.
- The importance of this nursery habitats has to be kept in mind when
    - a trench is dug In Haynes Inlet,
    - the Trans Pacific Parkway is expanded and
    - an upland area is cut out to create a berth for ocean-going vessels.
- Not only will the turbidity during the construction phase be of concern to the ecological community, the on-going dredging to maintain the berth and shipping channels will continue to be a disturbance to the ecosystem.
- In a study, designed to simulated a dredging operation, between 45 to 85 % of the Dungeness crabs died.
- In summary, construction and maintenance of the Jordan Cove LNG Terminal will result in habitat loss for native species, including nursery habitat for the valuable Dungeness crab.

Exhibit 10

Oregon
Kate Brown, Governor

Department of State Lands
South Slough National Estuarine Research Reserve
P.O. Box 5417 | 61907 Seven Devils Road
Charleston, Oregon 97420
(541) 888-5558
FAX (541) 888-5559
www.oregon.gov/dsl/ss

RE: Questions and recommendations regarding the application for Coos Estuary Navigation Reliability Improvements (AM-18-011/RZ-18-007/HBCU-18-003 Jordan Cove Energy Project L.P)

To whom it may concern:

We understand that the application is for rezoning portions of 3 parcels of subtidal estuarine property (59-CA, 2-NA, 3-DA) to DDNC-DA in order to dredge for improved ship navigation.

We are particularly concerned with the potential impacts to eelgrass (*Zostera marina*) populations as eelgrass is an important habitat for many estuarine species and improves estuarine water quality. The following comments fit under CBEMP Policy 4: Resource Capability Consistency and Impact Assessment. Eelgrass habitat in the Coos Estuary has experienced a net loss since 2005 (from mapping/GIS methods) and abundance has declined more recently since 2016 (from intertidal field surveys).

Regarding our concerns we have questions and recommendations.

First, we have two questions regarding clarification of parcels in question.

1) Three parcels are listed in the narrative but four are shown in the maps. Why is 52-NA not included in the application narrative for rezoning?
2) Throughout the narrative the parcels are listed as 59-CA, 2-NA, 3-DA. However, on page 16 in the Response the parcels are listed as 59-CA, 3-NA, and 2-DA. Presumably this is a typo, but should be corrected.

Second, we are concerned about the potential presence of eelgrass in the areas to be dredged. The application classifies the areas to be dredged as “deep subtidal habitats” (exhibit 4: page 12) and cites Jefferts 1977 when stating that the substrate is mostly sand (exhibit 4: page 7). This survey is more than 40 years old and no source information for Jefferts 1977 is given in the application. It is unlikely that this survey applies directly to the specific areas intended for dredging. We do know that subtidal areas are important habitat for eelgrass and to our knowledge there have been no recent eelgrass surveys of the intended dredge or dredge-line areas (approximately 36.2 acres combined). Eelgrass is known to occur from depth ranges of 1.4 m to below -5.0 m MLLW in Pacific Northwest Estuaries (Puget Sound, Thom et al. 2008) and occurs in the primary channels of the South Slough estuary. Our examination of the selected sites using GIS indicates depth range starting from -5.5 to below -8.0 MLLW, suggesting eelgrass could be present within these sites. We recommend these areas be surveyed for eelgrass and the survey data be included in the application before this application for rezoning is considered. This could be done rapidly and cost effectively using an underwater camera and focusing on the shallowest areas and a number of randomly selected locations.

Third, the temporary dredge line will cross eelgrass habitat as it approaches APCO site 2 (inset Figure 1.3-1, Exhibit 5, page 2). We appreciate that the plan intends to reduce impact to eelgrass by constructing a temporary structure to span above the eelgrass beds (Exhibit 4: page 2). However, this includes driving 5-6 piles within the eelgrass beds and then removing them at the completion of the project, which would cause additional ongoing disturbance during the 3 years allotted to the project. Eelgrass is known to be sensitive to increases in turbidity and sediment, due to light requirements for photosynthesis (Thom et al., 2008). The application states that the location was chosen in the narrowest location in the eelgrass bed (Exhibit 4: page 2). This is obviously not correct as the figure itself shows decreased eelgrass to the west along the railroad (Figure 1.3-1, Exhibit 5, page 2). We recommend that this disturbance be prevented entirely by simply running the pipe alongside the Trans Pacific Railroad Bridge or choosing an alternative disposal site. If the route cannot be altered, we recommend considering methods for reducing impacts on eelgrass due to the disturbance from pile installation and removal and damage incurred during positioning and stabilization of the barge used for pile installation and removal.

Thank you for considering these clarifying questions and recommendations for project improvement.

Sincerely,

Shon Schooler, Ph.D.
Research Coordinator
South Slough National Estuarine Research Reserve
PO Box 5417
Charleston, OR 97420

Reference:
Thom, R.M., Southard, S.L., Borde, A.B., and Stoltz, P., 2008. Light requirements for growth and survival of eelgrass (*Zostera marina* L.) in Pacific Northwest estuaries. Estuaries and Coasts 31:969-980.

Exhibit 11

Dean Runyan Associates

Oregon Travel Impacts

Statewide Estimates

1992 - 2017p

June 2018

Prepared for the

Oregon Tourism Commission
Salem, Oregon

OREGON TRAVEL IMPACTS, 1992-2017p

STATEWIDE PRELIMINARY ESTIMATES
DETAILED COUNTY ESTIMATES
OVERNIGHT VISITOR VOLUME

June 2018

Prepared for

Oregon Tourism Commission
319 SW. Washington Street
Suite 700
Portland, Oregon 97204
503.967.1560
www.traveloregon.com

Prepared by

Dean Runyan Associates
833 SW Eleventh Avenue, Suite 920
Portland, Oregon 97205
503/226-2973
www.deanrunyan.com

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Executive Summary

This report provides detailed statewide, regional and county travel impact estimates for Oregon from 1992 to 2017. The report also provides average spending and volume estimates for overnight visitors for most counties. The estimates for 2017 are preliminary. Secondary impacts and travel industry GDP are provided at the state level.

Travel Spending, Employment and earnings continue to expand

The Oregon travel industry continued to exhibit strong growth in 2017, as all measures of travel activity were up over 2016.

- ***Spending.*** Total direct travel spending in Oregon was $11.8 billion in 2017. The annual increase from 2016 was 4.7 percent in current dollars. In real, inflation-adjusted, dollars travel spending increased by 3.2 percent. Visitor spending, excluding transportation, increased by 3.6 percent in current dollars. This is the eighth consecutive year of growth in travel spending following the recession.
- ***Travel Activity.*** An estimated 28.8 million overnight visitors traveled to Oregon destinations in 2017 (preliminary). This represents a 1.0 percent increase over 2016. Since 2010, overnight person-trips have increased by 2.2 percent per year. Domestic visitor air arrivals to Oregon (4.0 million) increased by 5.5 percent for the year. Room demand, as measured by STR, Inc., increased by 1.3 percent for the year.[1]
- ***Employment.*** Total travel generated employment was 112,200 in 2017. This represents a 2.2 percent increase over 2016, the seventh consecutive year of employment growth following the steep decline from 2008 to 2010. Employment has increased by 3.2 percent per year since 2010.
- ***Secondary Impacts.*** The re-spending of travel-generated revenues by businesses and employees generates additional impacts. In 2017, these secondary impacts were equivalent to 58,300 jobs with earnings of $2.8 billion. Most of these jobs were in various professional and business services.
- ***GDP.*** The Gross Domestic Product of the travel industry was $5.0 billion in 2017. Overall, the travel industry is one of the three largest export-oriented industries in rural Oregon counties (the other two being agriculture/food processing and logging/wood products).

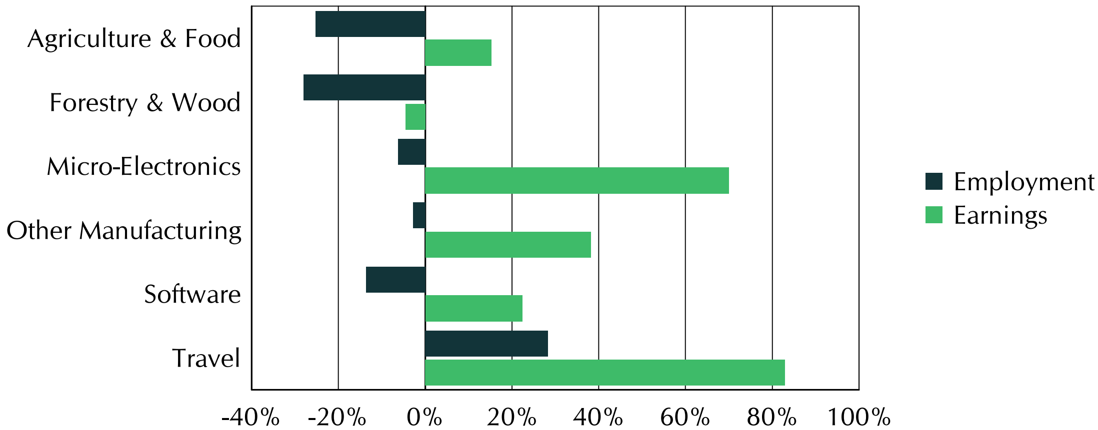
1. The STR reports were prepared for the Oregon Tourism Commission

The Oregon Travel Industry is A Leading Export-Oriented Industry

Travel and tourism is one of the most important ***"export-oriented"*** industries in Oregon. It is especially important in the non-metropolitan areas of the state, where manufacturing and traded services are less prevalent. Over the past decade, travel industry employment and earnings growth also compares favorably to other industries.

Change in Earnings and Employment (2003-2016)

Selected Export Oriented Industries



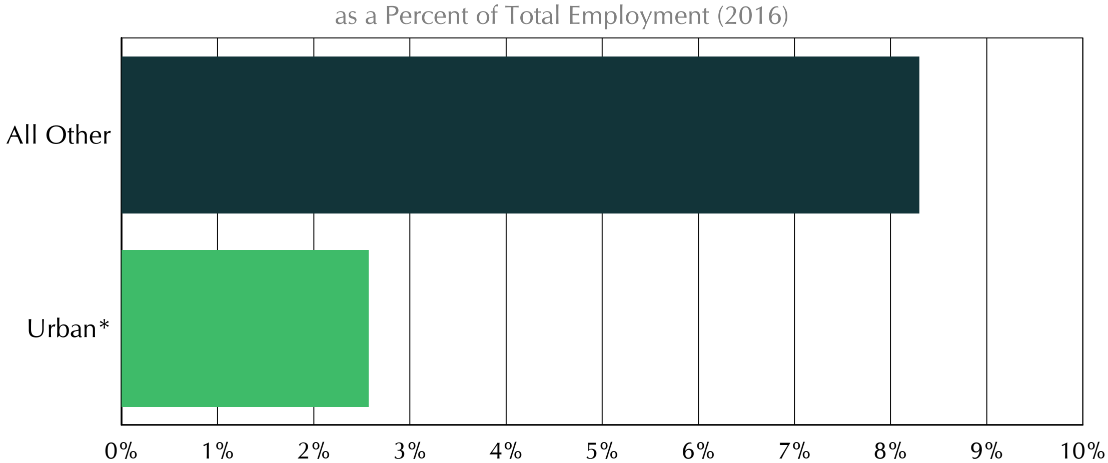
Note: The most current data is for 2016.

The Travel Industry Benefits All Regions of Oregon

Although most travel spending and related economic impacts occur within Oregon's urban areas, the travel industry is important throughout the state. In general, travel-generated employment is relatively more important in rural counties.

Travel Generated Employment

as a Percent of Total Employment (2016)



*The urban counties are Clackamas, Lane, Marion, Multnomah, and Washington. The most current data is for 2016.

Oregon Travel Impacts, 1992-2017

List of Tables & Figures

List Tables & Figures

List of Tables & Figures

Preface

The purpose of this study is to document the economic significance of the travel industry in Oregon and its thirty-six counties and seven tourism regions from 1992 to 2017. These findings show the level of travel spending by visitors traveling to and within the state, and the impact this spending had on the economy in terms of earnings, employment and tax revenue. Estimates of overnight visitor volume and average spending are also provided for all tourism regions and most counties. The estimates for 2017 are preliminary.

Dean Runyan Associates prepared this study for the Travel Oregon. Dean Runyan Associates has specialized in research and planning services for the travel, tourism and recreation industry since 1984. With respect to economic impact analysis, the firm developed and currently maintains the Regional Travel Impact Model (RTIM), a proprietary model for analyzing travel economic impacts at the state, regional and local level. Dean Runyan Associates also has extensive experience in project feasibility analysis, market evaluation, survey research and travel and tourism planning.

Many individuals and agencies provided information and advice for this report. The state agencies that provided essential information were the Parks and Recreation Department and the Department of Revenue. At the federal level, data was obtained from the U.S. Forest Service, the Department of Labor and the Bureau of Economic Analysis. Additionally, numerous local governments and visitor bureaus throughout Oregon provided information.

Finally, special thanks are due to Ladan Ghahramani, Research Manager, Michael Sturdevant, Director of Global Marketing Services , and Todd Davidson, Chief Executive Officer of Travel Oregon, for their support and assistance.

Dean Runyan Associates, Inc.
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Portland, OR 97205

503.226.2973
info@deanrunyan.com

I. U.S. Travel

Oregon Coast Travel Impacts and Visitor Volume

Travel Indicators

Visitor Spending Impacts

Amount of Visitor Spending that supports 1 Job	$87,612
Employee Earnings generated by $100 Visitor Spending	$31
Local & State Tax Revenues generated by $100 Visitor Spending	$4.26

Visitor Volume

Additional visitor spending if each resident household encouraged one additional overnight visitor (in thousands)	$22,174
Additional employment if each resident household encouraged one additional overnight visitor	253

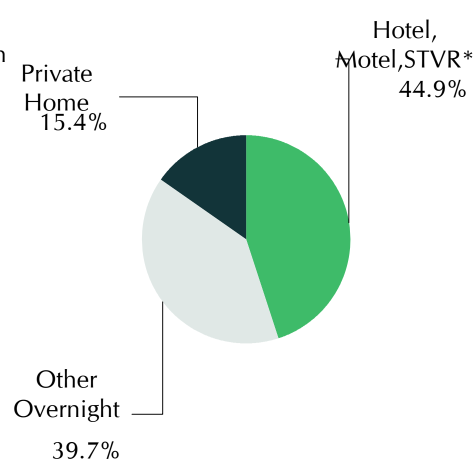
Visitor Shares

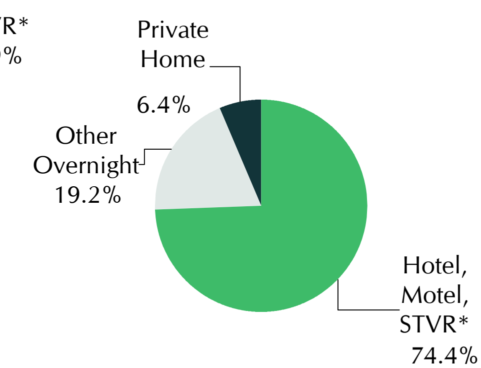
Travel Share of Total Employment (2016)*	18.5 %
Overnight Visitor Share of Resident Population (2017p)**	21.2 %

*Source: Bureau of Economic Analysis and Bureau of Labor Statistics. Estimates by Dean Runyan Associates.
**Annual Overnight Visitor Days divided by (Resident Population) *365.

Visitors who stay in private homes typically comprise the largest share of overnight visitor volume. Visitors who stay overnight in commercial lodging typically have the greatest economic impact. There is substantial variation among destinations, however. Most rural and suburban areas have high shares of private home visitation. Urban areas tend to have greater shares of hotel/motel stays.

Overnight Visitor Spending and Volume





	Person Trips (Thousands)	Person Nights (Thousands)	Visitor Spending ($Millions)
Hotel, Motel, STVR*	3,348	7,650	992
Private Home	728	2,624	86
Other Overnight	1,941	6,763	256
All Overnight	6,018	17,037	1,334

Note: Person Trips and Person Nights are in Thousands. Visitor Spending is in $Millions. Details may not round to total due to rounding

Oregon Coast
Direct Travel Impacts, 2010-2017p

							Ave. Annual Chg.	
Spending ($M)	**2010**	**2012**	**2014**	**2015**	**2016**	**2017**	**16-17**	**10-17**
Total (Current $)	1,500	1,592	1,801	1,872	1,943	1,985	2.2%	4.1%
Other	28	31	20	23	25	26	2.7%	-1.0%
Visitor	1,472	1,561	1,780	1,849	1,917	1,959	2.2%	4.2%
Non-transportation	1,291	1,347	1,562	1,664	1,740	1,768	1.6%	4.6%
Transportation	181	214	218	185	178	192	7.8%	0.8%
Earnings ($M)								
Earnings (Current $)	427	452	506	545	580	614	5.9%	5.3%
Employment (Jobs)								
Employment	19,690	19,670	20,830	21,540	22,320	22,710	1.7%	2.1%
Tax Revenue ($M)								
Total (Current $)	55	60	68	73	79	83	6.0%	6.1%
Local	20	20	24	27	28	30	4.5%	6.1%
State	36	40	43	46	50	54	6.9%	6.0%

Other spending includes resident air travel, travel arrangement and reservation services, and convention and trade show organizers. **Non-transportation visitor spending** includes accommodations, food services, retail, food stores, and arts, entertainment & recreation. **Visitor transportation spending** includes private auto, auto rental, other local ground transportation and one-way airfares.

Earnings include wages & salaries, earned benefits and proprietor income.

Employment includes all full- and part-time employment of payroll employees and proprietors.

Local tax revenue includes lodging taxes, auto rental taxes and airport passenger facility charges paid by visitors.

State tax revenue includes lodging, and motor fuel tax payments of visitors, and the income tax payments attributable to the travel industry income of businesses and employees.

Federal tax revenue includes motor fuel excise taxes and airline ticket taxes paid by visitors, and the payroll and income taxes attributable to the travel industry income of employees and businesses.

Oregon Coast

Travel Impacts, 2006-2017p

Total Direct Travel Spending ($Million)							
	2006	**2008**	**2010**	**2012**	**2015**	**2016**	**2017**
Destination Spending	1,436.6	1,525.1	1,472.2	1,561.5	1,849.1	1,917.4	1,959.2
Other Travel*	26.4	25.6	28.0	30.9	22.7	25.4	26.1
Total	**1,463.0**	**1,550.7**	**1,500.1**	**1,592.4**	**1,871.9**	**1,942.8**	**1,985.4**

Visitor Spending By Commodity Purchased ($Million)							
	2006	**2008**	**2010**	**2012**	**2015**	**2016**	**2017**
Accommodations	317.8	340.0	334.7	350.9	445.7	468.9	489.5
Food Service	360.0	386.9	393.3	413.4	532.4	566.6	579.3
Food Stores	141.5	152.4	146.4	157.1	186.7	188.7	186.3
Local Tran. & Gas	174.2	215.0	178.6	211.1	180.7	174.2	188.7
Arts, Ent. & Rec.	218.3	216.9	208.2	212.1	252.2	262.2	261.8
Retail Sales	220.3	209.6	208.1	213.9	247.5	253.2	250.5
Visitor Air Tran.	4.6	4.4	2.9	2.9	4.0	3.6	3.0
Total	**1,436.6**	**1,525.1**	**1,472.2**	**1,561.5**	**1,849.1**	**1,917.4**	**1,959.2**

Industry Earnings Generated by Travel Spending ($Million)							
	2006	**2008**	**2010**	**2012**	**2015**	**2016**	**2017**
Accom. & Food Serv.	275.7	304.1	294.7	313.9	391.1	416.5	446.4
Arts, Ent. & Rec.	62.2	71.3	64.4	65.8	71.0	74.6	76.3
Retail**	48.1	49.6	47.7	49.9	60.9	64.0	65.7
Ground Tran.	5.3	5.7	5.4	5.8	7.5	8.3	8.7
Visitor Air Tran.	1.6	1.6	1.7	2.1	3.3	3.6	3.6
Other Travel*	12.2	11.9	13.4	14.9	11.5	12.8	13.3
Total	**405.1**	**444.2**	**427.4**	**452.5**	**545.3**	**579.8**	**614.1**

Industry Employment Generated by Travel Spending (Jobs)							
	2006	**2008**	**2010**	**2012**	**2015**	**2016**	**2017**
Accom. & Food Serv.	13,140	13,710	12,850	12,860	14,330	14,900	15,350
Arts, Ent. & Rec.	4,060	4,430	4,070	3,970	4,000	4,090	4,050
Retail**	2,410	2,410	2,260	2,280	2,620	2,690	2,680
Ground Tran.	190	190	180	180	220	230	230
Visitor Air Tran.	40	40	30	40	60	60	60
Other Travel*	290	320	300	340	320	350	340
Total	**20,140**	**21,110**	**19,690**	**19,670**	**21,540**	**22,320**	**22,710**

Tax Receipts Generated by Travel Spending ($Million)							
	2006	**2008**	**2010**	**2012**	**2015**	**2016**	**2017**
Local Tax Receipts	18.4	18.3	19.5	20.1	27.3	28.3	29.6
State Tax Receipts	34.6	37.2	35.7	39.5	46.0	50.4	53.8
Total	**53.0**	**55.6**	**55.2**	**59.6**	**73.3**	**78.7**	**83.4**

Details may not add to total due to rounding. * Other Travel includes ground transportation and air travel impacts for travel to other Oregon visitor destinations and travel arrangement services.** Retail includes gasoline. Federal tax receipts not included.

Oregon Coast Visitor Spending and Visitor Volume

Visitor Spending by Type of Traveler Accommodation ($Million), 2017p

	2008	2010	2012	2014	2016	2017
Total Destination Spending	**1,525**	**1,472**	**1,561**	**1,780**	**1,917**	**1,959**
All Overnight	1,030	990	1,042	1,191	1,298	1,334
Hotel, Motel, STVR*	724	696	729	863	962	992
Private Home	78	76	83	84	84	86
Other Overnight	227	218	230	244	252	256
Day Travel	496	482	520	589	619	626
Day Travel	496	482	520	589	619	626

Average Expenditures for Overnight Visitors, 2017p

	Travel Party		Person		Party	Length of
	Day	Trip	Day	Trip	Size	Stay (Nights)
Private Home	$84	$304	$33	$117	2.6	3.6
Other Overnight	$126	$440	$38	$132	3.3	3.5
All Overnight	$216	$597	$78	$222	2.8	2.8

Overnight Visitor Volume, 2015-2017p

	Person-Nights (000)			Party-Nights (000)		
	2015	2016	2017	2015	2016	2017
Hotel, Motel, STVR*	7,455	7,751	7,650	3,049	3,170	3,129
Private Home	2,595	2,619	2,624	1,006	1,015	1,017
Other Overnight	6,703	6,796	6,763	2,011	2,038	2,030
All Overnight	16,753	17,166	17,037	6,067	6,223	6,175

	Person-Trips (000)			Party-Trips (000)		
	2015	2016	2017	2015	2016	2017
Hotel, Motel, STVR*	3,514	3,646	3,348	1,437	1,491	1,369
Private Home	756	727	728	292	281	282
Other Overnight	1,973	1,999	1,941	592	600	582
All Overnight	6,242	6,372	6,018	2,322	2,372	2,233

"Hotel, Motel, STVR" category includes all lodging where a lodging tax is collected except campgrounds. "Other Overnight" category includes campgrounds and vacation homes.

Coos County

County Travel Impacts and Visitor Volume

Visitor Spending Impacts

Amount of Visitor Spending that supports 1 Job	$81,129
Employee Earnings generated by $100 Visitor Spending	$28
Local & State Tax Revenues generated by $100 Visitor Spending	$3.68

Visitor Volume

Additional visitor spending if each resident household encouraged one additional overnight visitor (in thousands)	$4,522
Additional employment if each resident household encouraged one additional overnight visitor	56

Visitor Shares

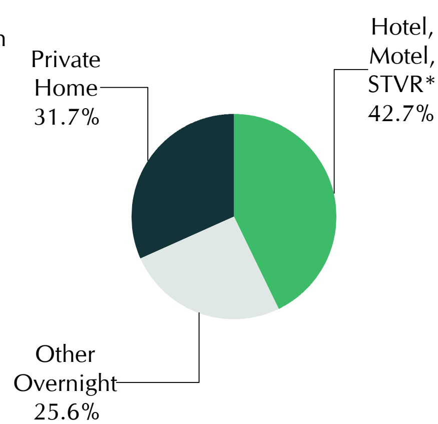
Travel Share of Total Employment (2016)*	10.5 %
Overnight Visitor Share of Resident Population (2017)**	11.0 %

*Source: Bureau of Economic Analysis and Bureau of Labor Statistics. Estimates by Dean Runyan Associates.
**Annual Overnight Visitor Days divided by (Resident Population) *365.

Visitors who stay in private homes typically comprise the largest share of overnight visitor volume. Visitors who stay overnight in commercial lodging typically have the greatest economic impact. There is substantial variation among destinations, however. Most rural and suburban areas have high shares of private home visitation. Urban areas tend to have greater shares of hotel/motel stays.

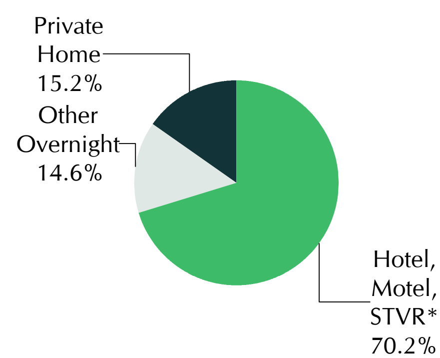
Overnight Visitor Spending and Volume

Person Nights



as a percent of total

Spending



as a percent of total

	Person Trips (Thousands)	Person Nights (Thousands)	Visitor Spending ($Millions)
Hotel, Motel, STVR*	579.7	1,096.4	121.2
Private Home	267.3	812.9	26.2
Other Overnight	203.4	657.6	25.3
All Overnight	1,050.4	2,567.0	172.7

Note: Person Trips and Person Nights are in Thousands. Visitor Spending is in $Millions. Details may not round to total due to rounding

Coos
Direct Travel Impacts, 2010-2017p

							Ave. Annual Chg.	
Spending ($M)	**2010**	**2012**	**2014**	**2015**	**2016**	**2017**	**16-17**	**10-17**
Total (Current $)	210.8	230.7	252.6	260.1	265.5	271.1	2.1%	3.7%
Other	11.9	12.6	11.2	9.4	9.1	10.0	9.7%	-2.5%
Visitor	198.9	218.0	241.3	250.8	256.4	261.1	1.8%	4.0%
Non-transportation	172.4	186.5	209.4	222.4	229.8	233.3	1.5%	4.4%
Transportation	26.4	31.5	31.9	28.4	26.6	27.8	4.4%	0.7%
Earnings ($M)								
Earnings (Current $)	56.3	60.4	66.6	72.0	76.5	79.0	3.3%	4.9%
Employment (Jobs)								
Employment	2,940	3,030	3,030	3,140	3,280	3,300	0.4%	1.6%
Tax Revenue ($M)								
Total (Current $)	6.5	7.3	7.9	8.4	9.0	9.5	5.6%	5.5%
Local	1.1	1.1	1.2	1.4	1.4	1.5	4.1%	3.9%
State	5.4	6.2	6.7	7.0	7.6	8.0	5.9%	5.8%

Other spending includes resident air travel, travel arrangement and reservation services, and convention and trade show organizers. **Non-transportation visitor spending** includes accommodations, food services, retail, food stores, and arts, entertainment & recreation. **Visitor transportation spending** includes private auto, auto rental, other local ground transportation and one-way airfares.
Earnings include wages & salaries, earned benefits and proprietor income.
Employment includes all full- and part-time employment of payroll employees and proprietors.
Local tax revenue includes lodging taxes, auto rental taxes and airport passenger facility charges paid by visitors.
State tax revenue includes lodging, and motor fuel tax payments of visitors, and the income tax payments attributable to the travel industry income of businesses and employees.
Federal tax revenue includes motor fuel excise taxes and airline ticket taxes paid by visitors, and the payroll and income taxes attributable to the travel industry income of employees and businesses.

Historical revisions have been made to correct for the assignment of visitor air travel to the other travel category total. This correction does not effect economic impact totals.

Coos County

Travel Impacts, 2006-2017p

Total Direct Travel Spending ($Million)	2006	2008	2010	2012	2015	2016	2017
Destination Spending	204.8	217.4	198.9	218.0	250.8	256.4	261.1
Other Travel*	13.2	14.9	11.9	12.6	9.4	9.1	10.0
Total	**218.0**	**232.3**	**210.8**	**230.7**	**260.1**	**265.5**	**271.1**

Visitor Spending By Commodity Purchased ($Million)	2006	2008	2010	2012	2015	2016	2017
Accommodations	42.7	44.7	40.7	45.3	55.5	58.8	61.5
Arts, Ent. & Rec.	36.1	35.9	33.1	34.8	39.8	40.7	40.6
Food Service	51.5	55.6	53.9	58.7	72.8	76.0	77.7
Food Stores	19.6	21.3	19.9	21.7	25.1	25.1	24.7
Local Tran. & Gas	23.7	29.6	23.5	28.6	24.4	23.0	24.8
Retail Sales	26.6	26.0	24.8	26.1	29.1	29.2	28.9
Visitor Air Tran.	4.6	4.4	2.9	2.9	4.0	3.6	3.0
Total	**204.8**	**217.4**	**198.9**	**218.0**	**250.8**	**256.4**	**261.1**

Industry Earnings Generated by Travel Spending ($Million)	2006	2008	2010	2012	2015	2016	2017
Accom. & Food Serv.	35.9	39.5	36.1	38.8	46.5	49.6	51.3
Arts, Ent. & Rec.	9.6	11.0	9.5	10.5	12.0	12.5	12.8
Ground Tran.	0.8	0.9	0.8	0.9	1.1	1.2	1.3
Other Travel*	3.5	3.5	3.8	3.8	4.8	5.2	5.5
Retail**	6.1	6.5	6.0	6.4	7.6	7.9	8.0
Total	**56.0**	**61.3**	**56.3**	**60.4**	**72.0**	**76.5**	**79.0**

Industry Employment Generated by Travel Spending (Jobs)	2006	2008	2010	2012	2015	2016	2017
Accom. & Food Serv.	1,930	2,010	1,700	1,750	1,860	1,950	2,000
Arts, Ent. & Rec.	770	840	830	870	830	860	820
Ground Tran.	30	30	30	30	30	30	30
Other Travel*	100	110	100	90	100	110	110
Retail**	300	310	280	290	320	330	330
Total	**3,140**	**3,300**	**2,940**	**3,030**	**3,140**	**3,280**	**3,300**

Tax Receipts Generated by Travel Spending ($Million)	2006	2008	2010	2012	2015	2016	2017
Local Tax Receipts	1.3	1.3	1.1	1.1	1.4	1.4	1.5
State Tax Receipts	5.5	5.9	5.4	6.2	7.0	7.6	8.0
Total	**6.9**	**7.3**	**6.5**	**7.3**	**8.4**	**9.0**	**9.5**

Details may not add to total due to rounding. * Other Travel includes ground transportation and air travel impacts for travel to other Oregon visitor destinations, travel arrangement services, and convention & trade show organizers.** Retail includes gasoline.

Historical revisions have been made to correct for the assignment of visitor air travel to the other travel category total. This correction does not effect economic impact totals.

Coos County Visitor Spending and Visitor Volume

Visitor Spending by Type of Traveler Accommodation ($Million), 2017p

	2008	2010	2012	2014	2016	2017
Total Destination Spending	**213.0**	**195.9**	**215.1**	**238.3**	**252.8**	**258.1**
All Overnight	**141.9**	**129.3**	**141.9**	**157.2**	**168.3**	**172.7**
Hotel, Motel, STVR*	94.5	83.9	93.7	107.1	117.3	121.2
Private Home	24.6	24.2	25.7	26.0	25.8	26.2
Other Overnight	22.8	21.2	22.5	24.1	25.1	25.3
Day Travel	**71.1**	**66.6**	**73.2**	**81.1**	**84.6**	**85.4**
Day Travel	71.1	66.6	73.2	81.1	84.6	85.4

Average Expenditures for Overnight Visitors, 2017p

	Travel Party		Person		Party	Length of
	Day	Trip	Day	Trip	Size	Stay (Nights)
Hotel, Motel, STVR*	$269	$510	$111	$209	2.4	1.9
Private Home	$83	$253	$32	$98	2.6	3.1
Other Overnight	$131	$425	$38	$124	3.4	3.2
All Overnight	$180	$431	$67	$164	2.7	2.4

Overnight Visitor Volume, 2015-2017p

	Person-Nights (000)			Party-Nights (000)		
	2015	2016	2017	2015	2016	2017
Hotel, Motel, STVR*	1,095	1,109	1,096	450	456	450
Private Home	815	816	813	319	319	317
Other Overnight	656	667	658	192	196	193
All Overnight	2,565	2,592	2,567	961	970	960

	Person-Trips (000)			Party-Trips (000)		
	2015	2016	2017	2015	2016	2017
Hotel, Motel, STVR*	579	586	580	237	241	238
Private Home	268	268	267	104	104	103
Other Overnight	203	206	203	59	60	60
All Overnight	1,050	1,061	1,050	401	405	401

"Hotel, Motel" category includes all lodging where a lodging tax is collected except campgrounds.
"Other Overnight" category includes campgrounds and vacation homes.

Exhibit 12

RON SADLER

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North Bend, Oregon 97459

ronsad@uci.net

Planning Department
Coos County Courthouse
250 N. Baxter
Coquille, Oregon 97423

May 21, 2010

<u>LAND USE HEARING (FILE # HBCU-10-01</u>

<u>SUPPLEMENTAL TESTIMONY</u>

I have previously submitted written and oral testimony in this case.

During the Applicant's Rebuttal phase at the hearing on May 20, a matter came up that I feel warrants further discussion.

A participant at the hearing had offered oral testimony regarding his concern that installing the pipeline across the floor of the bay might re-activate pollutants buried in the bottom sediments.

His concerns have merit.

Research has shown that Coos Bay contains a number of introduced contaminants, including several chlorinated hydrocarbons. Chlorinated hydrocarbons are extremely worrisome in that, once introduced into an ecosystem, they are not broken down by natural processes and persist in their original form almost indefinitely. While they are not metabolized and inactivated, they can be removed from cycling through the food chain by, for example, becoming sequestered and buried in bottom sediments. Significant disturbances of bottom sediments, such as by trenching and burying a new pipeline, release these contaminants to once again re-enter the food cycle where they essentially have the effect of increasing the dosage to which living elements are exposed.

For a more comprehensive and documented discussion of these points, please see my previous testimony in the Jordan Cove Marine Docking Berth land use hearing included herewith as Enclosure #1.

Reacting to these concerns during the Rebuttal phase, the Applicant's stated they would be sampling the sediments along the pipeline route across the bay. They stated that an unspecified standardized evaluation process would be used which apparently refers to the protocol used by the Corps of Engineers.

That is all well and good, but one thing is highly probable. The results of the testing will almost certainly show some level of contaminants occurring at sub-lethal doses.

It is at this point that the logic of attempting to complete the land use approval process in the absence of a viable Environmental Impact Statement begins to disintegrate.

Let's assume, for the sake of argument, the sediments show a few parts per billion (ppb) each of polychlorinated biphenyls (PCBs) and polycyclic aromatic hydrocarbons (PAHs). Apparently nothing to worry about, these are small amounts and any released contaminants would be washed away with the next outgoing tide. Based on the record currently before the Board of Commissioners, the decision would no doubt be to go ahead and approve the pipeline installation as this small amount of persistent organic pollutants recycling through the food chain should not cause any apparent bad effects.

If a viable EIS were available, in the section entitled "Affected Environment" (missing entirely, by the way, from the Jordan Cove FEIS), we would find that juvenile Chinook salmon currently swimming in the Coos Bay estuary carry 25 ppb of PCBs and 300 ppb of PAHs in their bodies. We would learn that juvenile salmon and their prey bioaccumulate chlorinated hydrocarbons whenever they become available in the food chain with detrimental effects on their immune systems which results in increased disease susceptibility (Enclosure 1). In addition, at some level, genetic effects begin to appear. In addition, rather than being flushed away on the next tide, we would learn that particles suspended in the water column in parts of Coos Bay can take as long as 48 days to be flushed from the estuary (Enclosure 1).

At this point, from a land use approval perspective, it would be apparent that a rubber stamp approval of the project would not be warranted, as the possibility exists the planned project could move us closer to a threshold which could initiate irreversible catastrophic impacts on the bay ecosystem. However, the unknown probability of this happening would cause a reluctance to cancel the project out of hand.

At this point, it would be logical to refer back to the EIS once again and turn to the sections on "Need for the project" (also missing from the Jordan Cove EIS) as well as the section which gives a balanced and complete side-by side comparison of the proposed project and all reasonable alternatives (yet again, missing from the Jordan Cove EIS).

The rationale of a logical land use decision could be developed as follows:

- If the need was dire and immediate, and if few viable alternatives were available, it would not be arbitrary or capricious to knowingly accept the environmental risks to the estuary and approve the pipeline in order to better serve the greater societal needs.

- If the need was speculative and future oriented, and if there were viable alternatives in place or readily available, it would not be worthwhile to risk the real possibility but uncertain probability of triggering catastrophic impacts to the estuarine ecosystem and the pipeline would not be approved.

In my estimation, the interplay of a valid and complete EIS within the County land use approval process is absolutely essential in this case given the importance and possible long-term implications of the decision to be made.

I understand the legal constraints placed on the Hearing Officer by the existing County land use approval process. I also understand this to be a somewhat arcane process probably inadequate to function adequately in today's managerial climate.

I find that the Oregon Progress Board essentially agrees with this premise: "The State's existing environmental data collection and management system must be improved to effectively measure ecological conditions, trends or risks. Measuring ecological conditions, trends, and risks is fundamentally different from the problems Oregon's environmental programs were initially established to address. Resolving them will require new approaches....." (Oregon State of the Environment Report 2000, Statewide Summary, page 3).

I ask that you apply your best creative efforts to find a way to postpone the land use approval decision until such time as it can be more fully and logically considered within the context of a viable and objective Environmental Impact Statement. I believe the environmental risks involved fully justify your efforts in this area.

Ron Sadler

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In the matter of: Coos County Land Use Hearing
Jordan Cove Marine Docking Berth

September 17, 2007
Coquille, Oregon

Testimony of Ron Sadler:

It is critical to remember, as was stated in a U.S. Department of Interior report, that Coos Bay is truly an ecosystem and one modification or activity could start a chain reaction which could affect the whole, resulting in severe damage to certain natural resources.[1]

The displacement, handling, and disposition of approximately 6,000,000 cubic yards of excavated and dredged material from the bottom and shoreline of the bay is certainly an activity that has great potential to do significant damage to marine life in the estuary, especially salmonid fish populations. This potential for damage is especially worrisome given what the sediments involved may contain.

Samples taken at various points in the Coos Bay estuary have shown concentrations of toxic materials in bottom sediments exceeding levels at which ecological effects are noted. These toxins include Tributyltin, arsenic, copper, lead, mercury, nickel, zinc, polycyclic aromatic hydrocarbons (PAHs), and polychlorinated biphenyls (PCBs).[2]

In addition, there are ongoing inputs of materials that may contribute to the accumulation of toxins in bottom sediments. In the year 2000, for example, there were inputs totaling 2,470 pounds of arsenic, chromium, zinc, copper, and mercury released in Coos County.[3] Further, the Coos Bay estuary receives unknown amounts of aliphatic organochlorines, chlorinated dibenzofurans, chlorinated phenols, and metabolites of each, as a by-product of the release of treated municipal wastewater. Looking further back in time, 40 years ago there was a pulp mill located on the bay at Empire. Its outfall of wastewater entered the bay untreated via a pipe located in the middle of the shipping channel. The resulting outflow resulted in a linear "dead zone" extending towards the mouth of Coos Bay. The types and amounts of toxins residing in the deep sediments at this location have not been investigated to my knowledge.

The various chlorinated organic compounds mentioned above are known as POPs – persistent organic pollutants. At the molecular level, they are extremely stable and

ENCLOSURE # 1

virtually indestructible by natural processes. In some instances, polymer chains may be broken by natural processes, but may recombine to form new compounds (metabolites) even more toxic than the originals.

Most appropriate to this discussion, then, is the fact that toxic material such as metals, PCBs, PAHs, etc. once released into the environment can remain unchanged for thousands of years. They are not biodegraded into more benign substances. They continue to cycle through the ecosystem raising havoc until they become no longer available to the flora and fauna through the process of sequestration.

In an estuarine ecosystem, the primary mechanism for sequestering toxins results in them being locked up by becoming buried in or attached to bottom sediments. There they remain out of reach of most organisms until some disturbance releases them to re-enter the food chain once again.

This is not a perfect process, however, as evidenced by conditions as they exist in Coos Bay today. Juvenile Chinook salmon in the Coos Bay estuary presently carry about 300 ppb of PAH metabolite concentrations in their bodies. They also carry about 25 ppb of PCB concentrations. As testimony to the longevity of these types of toxins, they also carry about 9 ppb of DDT concentrations, a full 30 years after its use was banned.[4]

It is well established that sediments in estuaries sequester and act as repositories for contaminants. It has also been shown that juvenile salmon and their prey bioaccumulate chlorinated and aromatic hydrocarbons, when they become available in the food chain, with detrimental effects on their immune systems which results in increased disease susceptibility.[5] Given current baseline loadings of toxins in juvenile salmon, how much room exists for additional inputs of toxins before critical thresholds are crossed?

The dynamics of tidal flows in estuaries are often viewed in simplistic terms. It is tempting to think of a cloud of murky water, with its associated toxins, created by dredging being carried out of sight and out of mind by the next out-going tide. This is not realistic, however. Studies have shown that a particle suspended in the water column in parts of Coos Bay can take as long as 48 days to be flushed from the estuary.[6]

Given the serious and potentially catastrophic effects that could negatively impact the salmonid productivity of the Coos Bay estuary, it appears premature and inappropriate to approve the construction of the marine docking berth at this time.

Several key elements of information essential to an informed and rational decision appear to be missing at this time. A viable decision process would require the following:

1. An intensive sampling of all areas proposed for dredging or excavation, to the full depth of planned disturbance, to determine the types and concentrations of all toxins expected in the spoils.

2. A detailed and explicit disposal and/or storage plan for all dredged and excavated material, with explicit requirements to prevent water or wind borne re-deposition in the estuary.

3. A risk assessment detailing an estimation of the net effects of unavoidable releases of sequestered toxins on salmonid productivity.

I ask that this information be gathered and analyzed before further action is taken on the marine docking berth proposal.

FOOTNOTES

1. USDI, "Natural Resources, Ecological Aspects, Uses and Guidelines for the Management of Coos Bay", L. B. Day, June, 1971, pg. 128.
2. NOAA, "Preliminary Natural Resource Survey, Coos Bay, December 12, 1997, pg. 11.
3. EPA, "Toxic Release Inventory, Coos County, Oregon", 2000
4. Dr. Mary Arkoosh, National Marine Fisheries Service, Newport, Oregon, 2000.
5. Dr. Mary Arkoosh, "Effect of Pollution on Fish Diseases: Potential Impacts on Salmonid Populations", Journal of Aquatic Animal Health, Vol. 10, June 1998, pp. 182-190.
6. Arneson, "Seasonal Variation in Tidal Dynamics, Water Quality and Sediments in the Coos Bay Estuary", OSU Masters Thesis, June, 1976.

1
2
3
4
5
6

Exhibit 13

WILDLIFE DIVISION
Regulating harvest, health, and enhancement of wildlife populations

Threatened, Endangered, and Candidate Fish and Wildlife Species

(T= Threatened, E= Endangered, C= Candidate, DPS= Distinct Population Segment)

Threatened, Endangered, and Candidate Fish and Wildlife Species in Oregon (pdf)

Common Name	Scientific Name	State Status*	Federal Status
FISH			
Borax Lake Chub	*Siphateles boraxobius*	T	E
Bull Trout (range-wide)	*Salvelinus confluentus*		T
Columbia River Chum Salmon	*Oncorhynchus keta*		T
Foskett Spring Speckled Dace	*Rhinichthys osculus* ssp		T
Green Sturgeon (Southern DPS)	*Acipenser medirostris*		T
Hutton Spring Tui Chub	*Siphateles bicolor* ssp	T	T
Lahontan Cutthroat Trout	*Oncorhynchus clarki henshawi*	T	T
Lost River Sucker	*Deltistes luxatus*	E	E
Lower Columbia River Chinook Salmon	*Oncorhynchus tshawytscha*		T
Lower Columbia River Coho Salmon	*Oncorhynchus kisutch*	E	T
Lower Columbia River Steelhead	*Oncorhynchus mykiss*		T
Middle Columbia River Steelhead	*Oncorhynchus mykiss*		T
Oregon Coast Coho Salmon	*Oncorhynchus kisutch*		T
Pacific Eulachon/Smelt (Southern DPS)	*Thaleichthys pacificus*		T
Shortnose Sucker	*Chasmistes brevirostris*	E	E
Snake River Chinook Salmon (Fall)	*Oncorhynchus tshawytscha*	T	T
Snake River Chinook Salmon (Spring/Summer)	*Oncorhynchus tshawytscha*	T	T
Snake River Sockeye Salmon	*Oncorhynchus nerka*		E
Snake River Steelhead	*Oncorhynchus mykiss*		T
Southern Oregon/Northern California Coast Coho Salmon	*Oncorhynchus kisutch*		T
Upper Columbia River Spring Chinook Salmon	*Oncorhynchus tshawytscha*		E
Upper Columbia River Steelhead	*Oncorhynchus mykiss*		T
Upper Willamette River Chinook Salmon	*Oncorhynchus tshawytscha*		T
Upper Willamette River Steelhead	*Oncorhynchus mykiss*		T

Warner Sucker	*Catostomus warnerensis*	T	T
AMPHIBIANS AND REPTILES			
Green Sea Turtle	*Chelonia mydas*	E	T
Leatherback Sea Turtle	*Dermochelys coriacea*	E	E
Loggerhead Sea Turtle	*Caretta caretta*	T	E
Olive Ridley Sea Turtle	*Lepidochelys olivacea*	T	T
Oregon Spotted Frog	*Rana pretiosa*		T
BIRDS			
California Brown Pelican	*Pelecanus occidentalis californicus*	E	
California Least Tern	*Sternula antillarum browni*	E	E
Marbled Murrelet	*Brachyramphus marmoratus*	T	T
Northern Spotted Owl	*Strix occidentalis caurina*	T	T
Short-tailed Albatross	*Phoebastria albatrus*	E	E
Streaked Horned Lark	*Eremophila alpestris strigata*		T
Western Snowy Plover	*Charadrius nivosus nivosus*	T	T (Pacific Coast population DPS)
Yellow-billed Cuckoo (Western DPS)	*Coccyzus americanus*		T
MAMMALS			
Blue Whale	*Balaenoptera musculus*	E	E
Canada Lynx	*Lynx canadensis*		T
Columbian White-tailed Deer (Columbia River DPS)	*Odocoileus virginianus leucurus*		T
Fin Whale	*Balaenoptera physalus*	E	E
Gray Whale	*Eschrichtius robustus*	E	
Gray Wolf	*Canis lupus*		E1
Humpback Whale	*Megaptera novaeangliae*	E	E
Killer Whale (Southern Resident DPS)	*Orcinus orca*		E
Kit Fox	*Vulpes macrotis*	T	
North Pacific Right Whale	*Eubalaena japonica*	E	E
Red Tree Vole (North Oregon Coast DPS)	*Arborimus longicaudus*		C
Sea Otter	*Enhydra lutris*	T	T
Sei Whale	*Balaenoptera borealis*	E	E
Sperm Whale	*Physeter macrocephalus*	E	E
Washington Ground Squirrel	*Urocitellus washingtoni*	E	
Wolverine	*Gulo gulo*	T	

* Listed under the Oregon Endangered Species Act (ORS 496.171 through 496.192)

1: The gray wolf is protected as endangered under the authority of the federal Endangered Species Act in Oregon west of highways 395, 78, and 95.

Revised June 11, 2018

Oregon Coast Coho

ESA Listing Status: *Threatened* on June 20, 2011 *250kb*; updated April 14, 2014 *503kb*

ESU Definition: This evolutionarily significant unit, or ESU, includes naturally spawned coho salmon originating from coastal rivers south of the Columbia River and north of Cape Blanco, and also coho salmon from one artificial propagation program: Cow Creek Hatchery Program (Oregon Department of Fish and Wildlife Stock #18).

Current Population Trends:

- Salmon Population Trend Summaries
- Salmon Population Summary Database
- 5-Year Salmon Status Review *1.2MB*

Critical Habitat: Designated Feb. 11, 2008 *1.5MB*

- Supporting Information

Protective Regulations: Issued Feb. 11, 2008 *1.5MB*

Coho Salmon Status Reviews

Coho Salmon Federal Register Notices

Coho Salmon Maps & GIS Data

ESA Chronology for Oregon Coast Coho

West Coast Region Home
About Us
What We Do
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Fish Passage
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Recent Stories
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How do I?

- Contact the West Coast Region
- Learn more about ESA Section 7 consultations
- Learn more about the Pacific Coastal Salmon Recovery Fund
- Log into my IFQ account
- Find a biological opinion
- Report a stranded or entangled marine mammal
- Report a violation
- Find grant opportunities

West Coast Region Home » Green Sturgeon

Green Sturgeon

Twenty seven species of sturgeons can be found in temperate waters of the Northern Hemisphere, two of which reside on the West Coast of North America: the green sturgeon (*Acipenser medirostris)* and the white sturgeon *(Acipenser transmontanus)*.

NOAA Fisheries received a petition in June 2001 from several environmental organizations requesting that the agency list the North American green sturgeon under the Endangered Species Act (ESA). On April 7, 2006, NOAA Fisheries listed the southern distinct population segment, or sDPS, of North American green sturgeon as threatened under the ESA. Critical habitat was designated on **October 9, 2009.** On June 2, 2010, NOAA Fisheries published final ESA protective regulations 4(d) for the southern distinct population segment of North American green sturgeon, and released a final environmental assessment analyzing the environmental impacts of these ESA Section 4(d) rules. The northern distinct population segment, or nDPS, of North American green sturgeon is a **species of concern** within the region.

Species Background

Biology

Life History

Threats

Critical Habitat

Status Reviews

Education

Identification Guide

Conservation Efforts & Research

Management & Policy

Final Recovery Plan, August 2018

- **Final sDPS Green Sturgeon Recovery Plan**
- **Appendix A - Final sDPS Green Sturgeon Recovery Plan**

Draft Recovery Plan, January 2018

- ***Federal Register* notice requesting comments on Draft sDPS Green Stugeon Recovery Plan**

ESA Listing

- ***Federal Register* Notice, April 7, 2006, Southern DPS**
  - **updated April 14, 2014**
- **References for Final Rule Listing, Southern DPS**
- **Final Green Sturgeon Listing Q & A**

Protective Regulations, ESA Section 4(d)

- **News Release**
- ***Federal Register* Notice**
- **Environmental Assessment**
- **Impact Review**
- **Flexibility Analysis**
- **References for 4(d) rule**

Eulachon

Eulachon are an anadromous forage fish and are endemic to the northeastern Pacific Ocean; they range from northern California to southwest and south-central Alaska and into the southeastern Bering Sea. The southern DPS of eulachon is comprised of fish that spawn in rivers south of the Nass River in British Columbia to, and including, the Mad River in California. Adult eulachon typically spawn at age 2-5 in the lower portions of rivers. Many rivers within the range of eulachon have consistent yearly spawning runs; however, eulachon may appear in other rivers only on an irregular or occasional basis. The spawning migration usually occurs between December and June.

If you have any questions about the recovery planning process or for more information, please contact Robert Anderson, 503-231-2226.

Recovery Planning

FINAL Recovery Plan for the Southern DPS of Eulachon September 2017

Notice of Intent to Prepare a Recovery Plan for the Southern DPS of Eulachon 78 *FR* 40104, July 3, 2013

DRAFT Eulachon Recovery Plan October 20, 2016

FR Notice October 20, 2016

Recovery Plan Outline

Listing Information

Eulachon Species Information

ESA Listing Status *Threatened* 75 FR 13012, March 18, 2010

Endangered and Threatened Wildlife; Final Rule to Revise the Code of Federal Regulations for Species under the Jurisdiction of the National Marine Fisheries Service April 14, 2014

Eulachon Critical Habitat 76 FR 65324, Oct 20, 2011

2016 5-Year Review Summary and Evaluation

2016 Status Review Update

Initiation of Eulachon 5-Year Status Review

2010 Eulachon Status Review

2008 Eulachon Status Review

Resources

Washington Department of Fish and Wildlife

http://wdfw.wa.gov/

http://wdfw.wa.gov/conservation/fisheries/smelt/

Oregon Department of Fish and Wildlife

www.dfw.state.or.us/

www.dfw.state.or.us/fish/oscrp/cri/publications.asp#Eulachon

California Department of Fish and Wildlife

www.wildlife.ca.gov/

file:///C:/Users/robert/Downloads/06_Anadromous%20Fish_092415[1].p

Department of Fisheries and Oceans, Canada

www.dfo-mpo.gc.ca/index-eng.htm

www.pac.dfo-mpo.gc.ca/science/species-especes/pelagic-pelagique/eulachon-eulakane-eng.html

Studies of Eulachon Smelt in OR and WA, 2014

Eulachon Newsletters

September 2014 Eulachon Newsletter

December 2014 Eulachon Newsletter

July 2015 Eulachon Newsletter

December 2015 Eulachon Newsletter

Biological Opinions

ESA-Listed Marine Mammals

NOAA Fisheries has listed 22 species of marine mammals under the Endangered Species Act, where 8 of those species are from the West Coast. We manage 7 different species of cetaceans (listed below) and Guadalupe fur seals. NOAA Fisheries' **Alaska Region** manages Steller sea lions. The Alaska Fisheries Science Center's **Marine Mammal Laboratory does research on Steller sea lions**.

Blue Whales

Fin Whales

Guadalupe Fur Seals

Central America **Humpback Whale** DPS * change in status, endangered as of October 2016

Mexico **Humpback Whale** DPS * change in status, threatened as of October 2016

Northern Pacific Right Whales

Western North Pacific Gray Whales

Sei Whales

Southern Resident Killer Whales

Sperm Whales

Steller Sea Lions * change in status, *delisted* as of December 2013

Sea Turtles

We share jurisdiction of marine turtles with the U.S. Fish & Wildlife Service. Sightings and strandings of turtles listed under the Endangered Species Act (ESA) in the region are rare, and there are no breeding beaches in California, Oregon, or Washington. However, encounters may occur. **Please report a dead, injured, or stranded sea turtle by calling: 1-866-767-6114.** Additional species information is provided below.

ESA-Listed Sea Turtles

Critical Habitat Designation for Pacific Leatherback Sea Turtles

- **News release**
- **Federal Register Notice**

Species in the Spotlight Initiative - Pacific Leatherback Sea Turtles

- **Five-Year Action Plan**

Point Reyes bird's-beak (*Cordylanthus maritimus* ssp. *palustris*)

ENDANGERED



Flowers (left), habit (center), and habitat (right) of Point Reyes bird's-beak. Photos by Melissa Carr. If downloading images from this website, please credit the photographer.

Family
Orobanchaceae

Taxonomic notes
Synonym: *Chloropyron maritimum* ssp. *palustre**

*Revised classification by Tank et al. (2009) based on recent molecular research of subtribe Castillejinae (Orobanchaceae).

This taxon was formerly included within the Scrophulariaceae.

Plant description
Point Reyes bird's-beak is a halophytic annual 10-20 (-30) cm tall, simple or sparingly branched with ascending lateral branches equal to or shorter than the central spike. The herbage is grayish green to glaucous, often purplish tinged, and villous to glabrescent. Leaves are oblong to oblong-lanceolate, 1-2.5 cm long and 0.3-0.7 cm wide, with a blunt to pointed apex. Flowers are arranged in dense spikes with oblong floral bracts bearing a pair of short teeth near the apex. The corolla is 1.8-2.5 cm long, the lower lip and pouch suffused with pinkish to purplish red, the galea pale cream to white. Capsules produce 10-20 seeds that are 0.2-0.3 cm long.

Distinguishing characteristics
Point Reyes bird's-beak shares the same coastal salt marsh habitat as *Cordylanthus maritimus* ssp. *maritimus* (*Chloropyron maritimum* ssp. *maritimum*), but the two taxa are geographically separated by over 100 air miles (160 km), with the latter species restricted to southern California. Point Reyes bird's beak is distinguished from *C. m.* ssp. *maritimus* by its simple or few-branched stem with branches equal to or shorter than the central spike, by its larger, broader leaves, denser and somewhat broader spikes, and larger bracts and flowers. Another subspecies, ssp. *canescens*, is a widespread species of the Great Basin associated with alkaline lakes and hot springs.

When to survey
Surveys for Point Reyes bird's-beak should be conducted when the species is flowering, from June to October.

Habitat
Point Reye's bird's-beak inhabits the upper end of maritime salt marshes at approximately 2.3-2.6 m (7.5-8.5 ft) above Mean Lower Low Water (MLLW, the mean height of water at the lowest of the daily low tides), in sandy substrates with soil salinity 34-55 ppt, and less than 30% bare soil in summer.

Point Reyes bird's-beak is a hemiparasite, forming root connections with host plants from which it derives some of its resources. Point Reyes bird's-beak is not host-specific, but standard hosts for the species probably include *Salicornia virginica*, *Jaumea carnosa*, *Distichlis spicata*, *Limonium californicum,* and *Deschampsia cespitosa*. Other associated species are *Cuscuta salina, Plantago maritima*, *Hordeum jubatum*, *Juncus gerardii*, *Castilleja ambigua* var. *ambigua*, *Spergularia macrotheca*, *S. canadensis*, *Atriplex patula*, *Carex lyngbyei*, *and Glaux maritima.*

Range
Point Reyes bird's-beak occurs along the Pacific Coast from Tillamook County in Oregon, south to Santa Clara County, California. In Oregon, the species is restricted to Netarts Bay, Yaquina Bay, and Coos Bay, with the majority of known occurrences located in Coos Bay.

Oregon counties
Coos, Lincoln, Tillamook

Federal status
Species of Concern

Threats
The primary threat to Point Reyes bird's-beak is habitat loss due to development. The species is also threatened by off-road vehicle use, water pollution, and habitat alteration due to invasion by non-native *Spartina densiflora*.

Did you know?
Research indicates that Point Reyes bird's-beak and other hemiparasites help reduce the abundance of competitive dominant plants, promote plant species diversity, and reduce root zone salinity stress in salt marsh communities.

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Exhibit 14

Natural Resources of Coos Bay Estuary

ESTUARY INVENTORY REPORT

Vol. 2, No. 6

OREGON

Fish & Wildlife

Prepared by

RESEARCH AND DEVELOPMENT SECTION
Oregon Department of Fish and Wildlife

for

Oregon Land Conservation and Development Commission

_1979_

FINAL REPORT

ESTUARY INVENTORY PROJECT
OREGON

PROJECT TITLE: Technical assistance to local planning staffs in fulfilling the requirements of the LCDC estuarine resources goal.

JOB TITLE: Natural resources of Coos Bay estuary

PROJECT PERIOD: February 1978 - June 1979

Prepared by: Cyndi Roye

Oregon Department of Fish and Wildlife
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Portland, Oregon 97208

The preparation of this document was financed in part by funds from the Oregon Land Conservation and Development Department and the Office of Coastal Zone Management, National Oceanic and Atmospheric Administration, U.S. Department of Commerce, and by the Oregon Department of Fish and Wildlife.

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PREFACE

This report is one of a series prepared by the Oregon Department of Fish and Wildlife (ODFW) which summarizes the physical and biological data for selected Oregon estuaries. The reports are intended to assist coastal planners and resource managers in Oregon fulfilling the inventory and comprehensive plan requirements of the Land Conservation and Development Commission's Estuarine Resources Goal (LCDC 1977).

A focal point of these reports is a habitat classification system for Oregon estuaries. The organization and terminology of this system are explained in volume 1 of the report series entitled "Habitat Classification and Inventory Methods for the Management of Oregon Estuaries."

Each estuary report includes some general management and research recommendations. In many cases ODFW has emphasized particular estuarine habitats or features that should be protected in local comprehensive plans. Such protection could be achieved by appropriate management unit designations or by specific restrictions placed on activities within a given management unit. In some instances ODFW has identified those tideflats or vegetated habitats in the estuary that should be considered "major tracts", which must be included in a natural management unit as required by the Estuarine Resources Goal (LCDC 1977). However, the reports have not suggested specific boundaries for the management units in the estuary. Instead, they provide planners and resource managers with available physical and biological information which can be combined with social and economic data to make specific planning and management decisions.

INTRODUCTION

Coos Bay, the estuary of the Coos River, is the site of a unique set of dynamic interactions involving its tributaries, the basin through which they flow, and the ocean (Fig. 1). In historic times man has altered conditions of the estuary more rapidly than expected in nature. Future actions will continue to modify the bay, and only carefully made decisions will insure that Coos Bay continues its history as a biologically productive multiple-use estuary.

Coos Bay has been classified as a deep-draft development estuary by LCDC (1977). Under Statewide Planning Goal 16 (LCDC 1977) the local comprehensive plan will designate estuarine areas as distinct water use management units. In a deep-draft development estuary such management units must include natural, conservation, and development units.

This report is a summary of available information for Coos Bay. It addresses the bay as a system, identifying processes occurring throughout the bay, and as a set of subsystems, smaller geographic areas which are functionally or physiographically distinct. Recommendations are made concerning certain areas or processes. The report is intended to provide information useful to planners, biologists, and citizens during the designation of management units and use policies.

THE COOS BAY ESTUARINE SYSTEM

Physical Characteristics

Dimensions

Several authors have used different methods in estimating the surface area of Coos Bay (Table 1).

Table 1. Reported surface areas of Coos Bay (Percy et al. 1974).

Reference	Surface area (acres)	Measured at	Tidelands		Submerged	
			Acres	Percentage	Acres	Percentage
Johnson 1972	10,973	HW				
"	8,242	MSL				
"	5,810	LW				
Marriage 1958	9,543	area affected by by tidal action	4,569	48		
Oregon Division of State Lands (DSL) 1973	12,380	MHW	6,200	50	6,180	50

DSL (1973) estimates that 6,200 acres (50% of the surface area) is submersible land (between high water and mean low water) and 6,180 acres (50%) is submerged land (below MLW). Using these figures, Coos Bay, although larger, compares closely to Tillamook Bay in ratio of submersible to submerged land (Table 2).

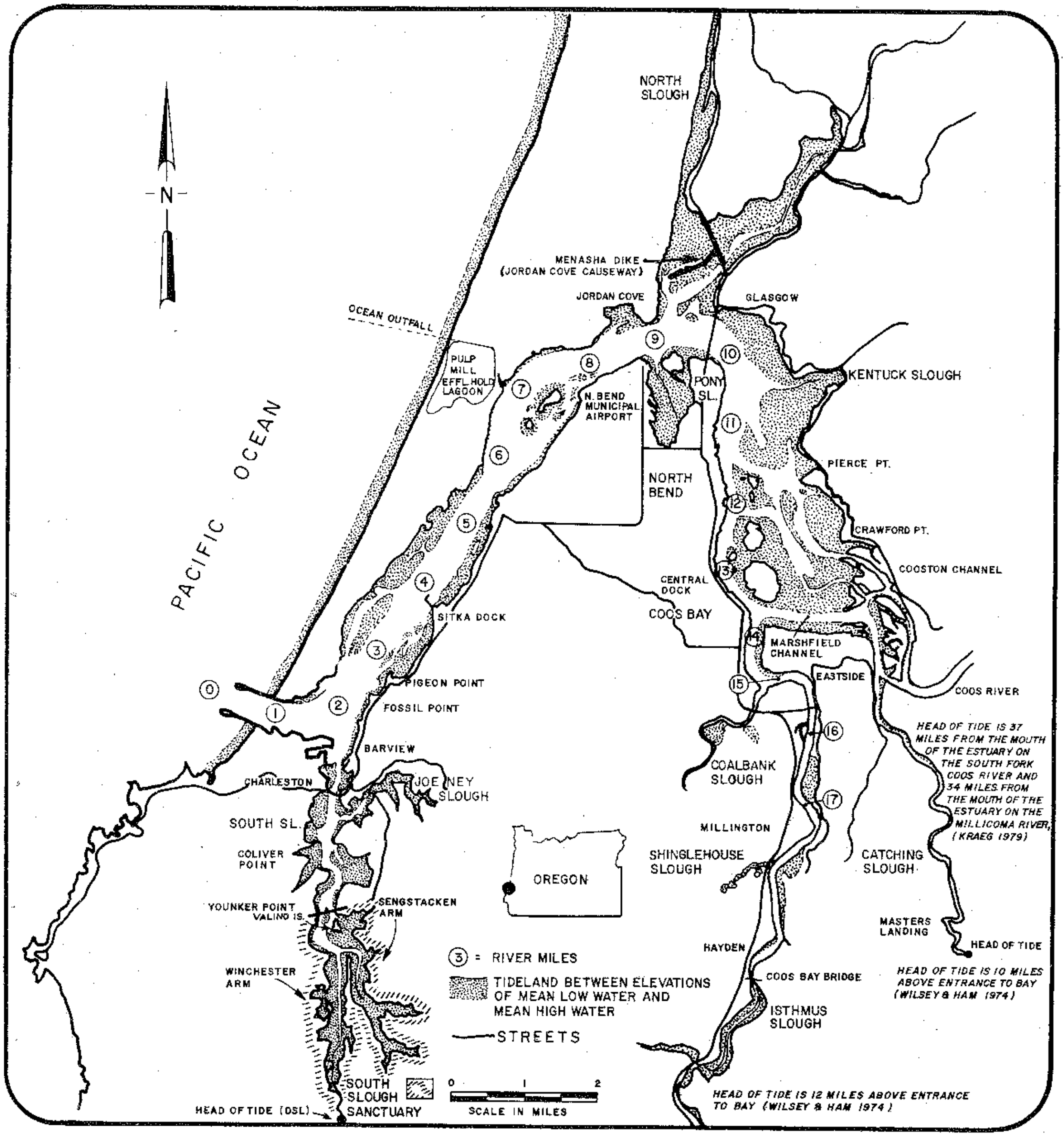

Fig. 1. Coos Bay estuary (base map from DSL 1973).

Table 2. Ratios of tideland (MHW to MLW) to submerged land (below MLW) (estimated from DSL 1973).

Sand Lake	3.0	Nehalem	0.87
Siletz	1.9	Alsea	0.84
Netarts	1.9	Coquille	0.64
Salmon River	1.6	Yaquina	0.53
Nestucca	1.4	Siuslaw	0.57
Necanicum	1.2	Columbia	0.35
Tillamook	1.0	Rogue	0.31
Coos Bay	1.0	Umpqua	0.25
		Chetco	0.13

Even the most extensive estimate of surface area (12,380 acres) covers only the area to mean high water. Much tidal marsh extends above this level and is therefore excluded in all available estimates. By including only the high marshes, at least 1,000 acres could be safely added to that estimate (Hoffnagle and Olson 1974).

Tributaries

About 30 tributaries enter Coos Bay from its 605 mi^2 drainage basin (Fig. 2) (Percy et al. 1974). The major tributary is the Coos River which is formed by the confluence of the Millicoma River and the South Fork Coos River. Head of tide extends up the South Fork Coos River approximately 32 miles from the mouth of the estuary and 34 miles from the mouth of the estuary up the Millicoma River (Kreag 1979). Other streams which contribute a much smaller amount of fresh water to the estuary enter through Catching, Isthmus, Pony, South, North, and Kentuck sloughs and Haynes Inlet. Gradients of the principal tributaries are slight for several miles allowing tidal effects to extend a considerable distance [Oregon State Water Resources Board (OSWRB) 1963]. Head of tide has been recorded for some of these slough systems, and in others the extent of salt water intrusion is limited by a tidegate, which acts as the effective head of tide under most conditions of flow. Information available on drainage areas of tributaries and location of heads of tide is summarized in Table 3.

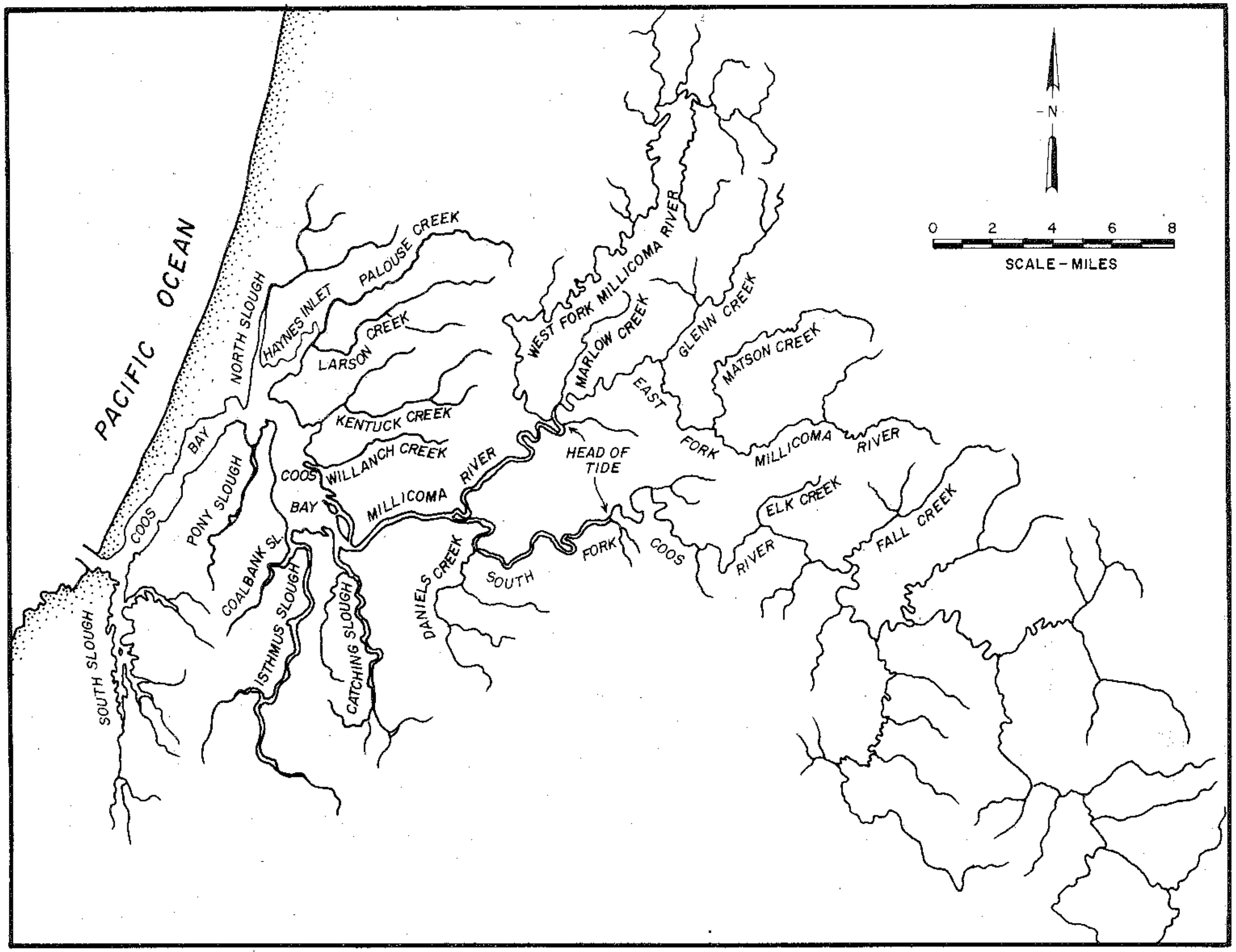

Fig. 2. Coos Bay drainage basin (USDI 1971).

Table 3. Drainage area and head of tide for Coos Bay tributaries.

Tributary	Drainage area (mi^2)	Head of tide (miles from entrance of tributary to main bay)
Coos River	415[a]	
Catching Sl.		10 mi[c]
Coalbank Sl.	6.2[a]	
Haynes Inlet	11[a]	
Isthmus SL		12 mi[c]
Kentuck	17[a]	
North	12.8[a]	
Willarch	7.8[a]	
South Sl.	26[b]	

[a] *OSWRB 1963*
[b] *Stevens, Thompson and Runyon, Inc. (STR) 1974*
[c] *Wilsey & Ham 1974*

Physiography

The physiography of Coos Bay is complex. From its mouth the narrow lower portion of the bay runs southwest to northeast to about river mile (RM) 9, measured from the mouth of the estuary. The main channel then swings to the south and the bay widens into an area of broad tidal flats. Sloughs branch off near the estuary mouth and at several locations in the upper bay. The Coos River enters the upper bay in its southeast corner about 17 mi from the mouth of the estuary. Johnson (1972) states the width at the mouth is 2,060 feet, and the average width of the bay at low tide is 1,200 feet.

Currently the U. S. Army Corps of Engineers (USACE) maintains a dredged ship channel from the entrance to RM 15 (Isthmus Slough). The channel is 45 ft deep and 700 ft wide at the entrance bar and decreases to 35 ft deep and 300 ft wide at RM 1. These dimensions continue to RM 9. From there the channel is 35 ft deep, 400 ft wide to RM 15. Two wide turning basins and an anchorage basin are located at North Bend, near the mouth of Coalbank Slough, and at RM 5.5 respectively. Shallower channels are also dredged by the USACE in the Coos River, the South Fork Coos River, the Millicoma River, and in South Slough connecting Charleston boat basin to the Coos Bay channel. Private concerns maintain a channel in Isthmus Slough to RM 17 (USACE 1976).

The physiography of the Coos estuary has been significantly altered by man. Prior to alterations, the channel across the bar at the entrance to Coos Bay was 10 ft deep and 200 ft wide (USACE 1975). The channel wound to the north with a depth of about 11 ft and width of 200 ft to the town of North Bend, then gradually decreased in width to 50 ft and in depth to 6 ft at Marshfield. Shoals were numerous.

Extensive filling and diking in the main bays, sloughs, and tributaries have changed the form and consequently the function of the estuary. Channel shifts and areas of accelerated erosion and deposition have been noted

(Dicken et al. 1961; Aagard et al. 1971). Other major alterations include the North and South jetties, the Charleston breakwater, and the Charleston small boat basin.

Bottom topography

Coos Bay shares several features with other drowned river valley estuaries. It has a "V"-shaped cross section, a relatively shallow and gently-sloping bottom, and a fairly uniform increase in depth toward the mouth (Baker 1978 [citing Schubel 1971]). NOS charts provide soundings in the navigable portions of the estuary (NOS 1978). Soundings of the bay following completion of the USACE Deep-Draft Navigation Project are available from the Portland District Engineer.

Bottom topography of South Slough can be determined from soundings made in 1977 (USACE 1977). Topography of most other shallow portions of the bay is less well known. Contours showing tidal levels such as MLLW and ELW are generally unavailable.

Water discharge

Fresh water inflow into the Coos estuary is measured only on the West Fork of the Millicoma River. Estimates of total fresh water flow at the mouth are made from extrapolations of these data. Estimated average annual discharge at the mouth of Coos Bay is 2.2 million acre-feet of fresh water (Percy et al. 1974). Using this figure as an average, a yearly maximum of 3,044,000 ac-ft and minimum of 1,560,000 ac-ft may be estimated from data presented in Percy et al. (1974) for the mouth.

Records from 1933-63 show that January is the wettest month at North Bend, averaging 9.9 in of precipitation, and July is the driest with an average 0.38 in (USACE 1975). According to USACE (1975) freshwater inflow may vary from 100,000 cubic feet per second (cfs) in winter to 100 cfs in summer. Arneson (1976) measured an even lower inflow of 35.3 cfs during September of 1973.

Runoff follows the pattern of precipitation. Soils provide a minimum of water retention, and snowfall is light so that a significant snow pack does not form (OSWRB 1963). Figure 3 suggests a one month lag in discharge response to precipitation.

Range of tide

The USACE (1978) states that mean tidal range is 6.7 ft above mean lower low water (MLLW) at the entrance to Coos Bay and 6.9 ft above MLLW at the city of Coos Bay. Predicted extreme range is 10.5 ft above MLLW. Extreme low water (ELW) is predicted to be -3.0 ft below MLLW.

Tidal range predictions are made by the National Oceanic and Atmospheric Administration (NOAA) and are based on data taken over 40 years ago (Arneson 1976). Arneson found that measured ranges at the entrance were slightly greater than predicted ranges for all seasons, although the error was usually

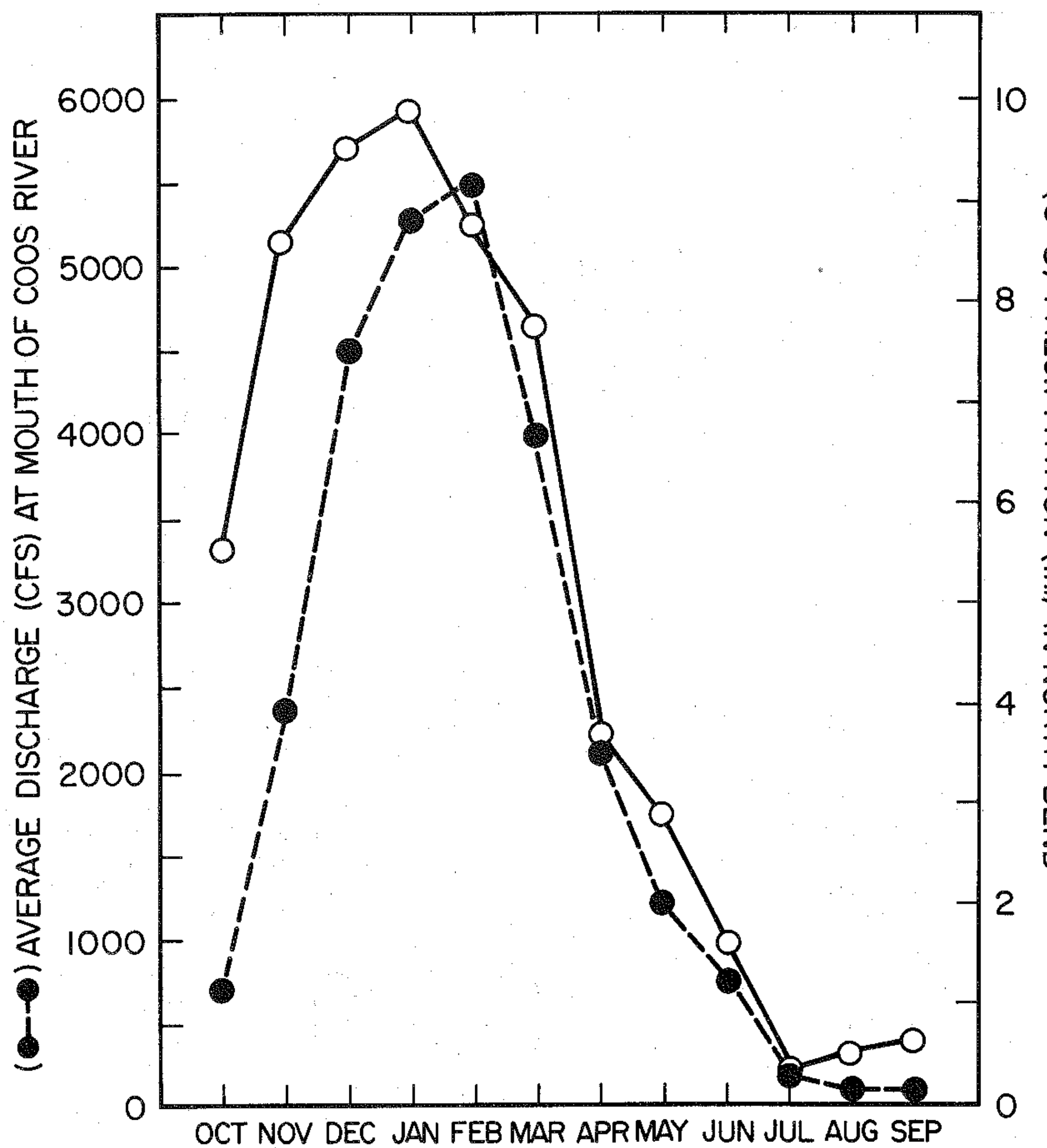

Fig. 3. Precipitation in North Bend (USACE 1975) and average monthly discharge of Coos River at the mouth (OSWRB 1963).

less than 15% . At the city of Coos Bay, Arneson (1976) consistently measured higher tidal ranges than those predicted by NOAA. He states that unusually high ranges may be attributed to river flow.

Arneson (1976) hypothesizes that tidal ranges greater than predicted mainly resulted from fill placed in the bay. Large fills have been placed on the tidelands of the upper bay, near the airport, and at Eastside since the predictions were made. Although the channel was deepened concurrently, the resulting cross-section may be more hydraulically efficient so that dampening of the tidal wave is less (Arneson 1976). The effect of further channel deepening has not been assessed.

Tidal prism

Johnson (1972) based his calculation of the tidal prism of Coos Bay (1.86×10^9 ft^3) on a mean tide range of 5.2 ft multiplied by a mean surface area between high and low water of 10,973 acres. The accuracy of these figures may be questionable. Compared to values for other Oregon estuaries shown in Table 4, Coos Bay is most similar to Tillamook Bay in volume of saltwater exchange.

Table 4. Coos Bay tidal prism compared with selected Oregon estuaries.[a]

Estuary	Tidal prism (ft^3)	Ratio of other estuaries to Coos Bay
Coos Bay	1.86×10^9*	1.0
Tillamook	2.49×10^9	1.3
Umpqua	1.18×10^9*	0.6
Yaquina	8.35×10^9*	0.45
Alsea	5×10^8*	0.3
Nehalem	4.28×10^8*	0.2
Siletz	3.5×10^8	0.2
Netarts	3.3×10^8	0.2
Siuslaw	2.76×10^8	0.2
Nestucca	1.8×10^8*	0.1
Coquille	1.32×10^8	0.07
Sand Lake	8.2×10^7	0.4

[a] *Values indicated by * are from Johnson (1972). All other estimates are calculated by Starr (1979) from DSL (1973).*

Time of tide

Both the high and low tides occur progressively later upbay from the mouth. Lag time at some locations seems to vary with seasonal changes in river flow (Arneson 1976). Arneson's study shows that lag times are variable and difficult to predict for different locations in the estuary.

Arneson (1976) compared his tidal measurements to predictions made by NOAA. For the mouth he discovered actual tides to be within 20 minutes of predications 80% of the time and to generally be earlier than predicted. At Coos Bay tides occurred considerably earlier than predicted. Only 25% of measured tides were within 20 minutes of NOAA predictions.

Arneson suggests the earlier tides at Coos Bay could be attributed to increases in mean channel depth that have occurred subsequent to the tidal predictions. Shallow wave theory predicts that the tidal wave should move faster at increased depth. Measurements have not been made since completion of channel deepening associated with the Deep-Draft Navigation Project. This further depth increase could allow the tidal wave to travel even faster.

Tidal circulation

The USACE (1975) states that the average tidal current at Coos Bay is 2.0 knots (3.4 ft per sec) and that flood currents of 3.5 knots (5.9 fps) have been reported. Arneson (1976) mentions that ebb currents as high as 5.0 knots (8.4 fps) have been measured, although maximum ebb measured during his study was 2.4 knots (4.0 fps).

Arneson (1976) studied the relationships of flow and velocity to maximum and minimum tidal heights to determine the character of the tidal wave. His data (Table 5) reveal that the wave is neither a true standing nor progressive wave. The tide resembles a cooscillating wave in which the tidal wave is reflected at the head of the estuary and the resulting tidal motion is the sum of the incident and reflected waves. However, studies of tidal ranges and lag times of high and low water as one progresses up the mouth show that the cooscillation theory does not strictly define Coos Bay. The complex geometry of the bay and the fact that one may consider tributaries both as sources and as inertial forces contributes to this complexity (Arneson 1976). The response of the tidal phenomena to further changes in estuarine geometry is difficult to predict.

Mixing

Burt and McAllister (1959) used a salinity gradient approach to describe mixing in Coos Bay. They classified the bay as well mixed for all months except November, when the estuary was partly mixed. They also specified a secondary classification of partly mixed for January, March, and June. Arneson (1976) applied the salinity gradient approach and the approach developed by Simmons (Dyer 1973), which uses a ratio of river flow to tidal prism, to data which he collected in 1973 and 1974. Results are shown in Fig. 4.

Both the flow ratio and salinity gradient methods classify the entire estuary as one mixing type. Arneson (1976) used salinity profiles to depict conditions along the main channel of the bay (Fig. 4). He finds a consistent change in mixing patterns occurring between RM 14 and 15 in Marshfield Channel, not far from the entrance of Coos River into the wide, shallow tidal flat area of the bay. It also appears that RM 8-9 is a zone of change. This may also be related to shape changes that occur there.

Table 5. Flow and velocity phase results (Arneson 1976).

		Phase lag following low or high water[a]						
		Entrance (RM 1.06)		Coos River (RM 15)		Isthmus Slough (RM 14.22)		
Date	Tide	Flow	Velocity	Flow	Velocity	Flow	Velocity	Range (m)
Sept. 12, 1973	Flood	78°	78°	148°	126°	156°	129°	1.79
(Summer)	Ebb	87°	81°	100°	130°	--	--	-1.82
Dec. 18, 1973	Flood	--	--	--	--	--	--	1.33
(Fall)	Ebb	81°	87°	--	--	90°	49°	-2.15
Mar. 22, 1974	Flood	--	--	113°	95°	128°	--	1.71
(Winter)	Ebb	84°	78°	124°	156°	92°	112°	-1.89
June 11, 1974	Flood	114°	127°	168°	122°	--	--	1.71
(Spring)	Ebb	88°	90°	168°	162°	88°	74°	-1.07

[a] *360° = 1 tidal cycle of 12.42 hours*

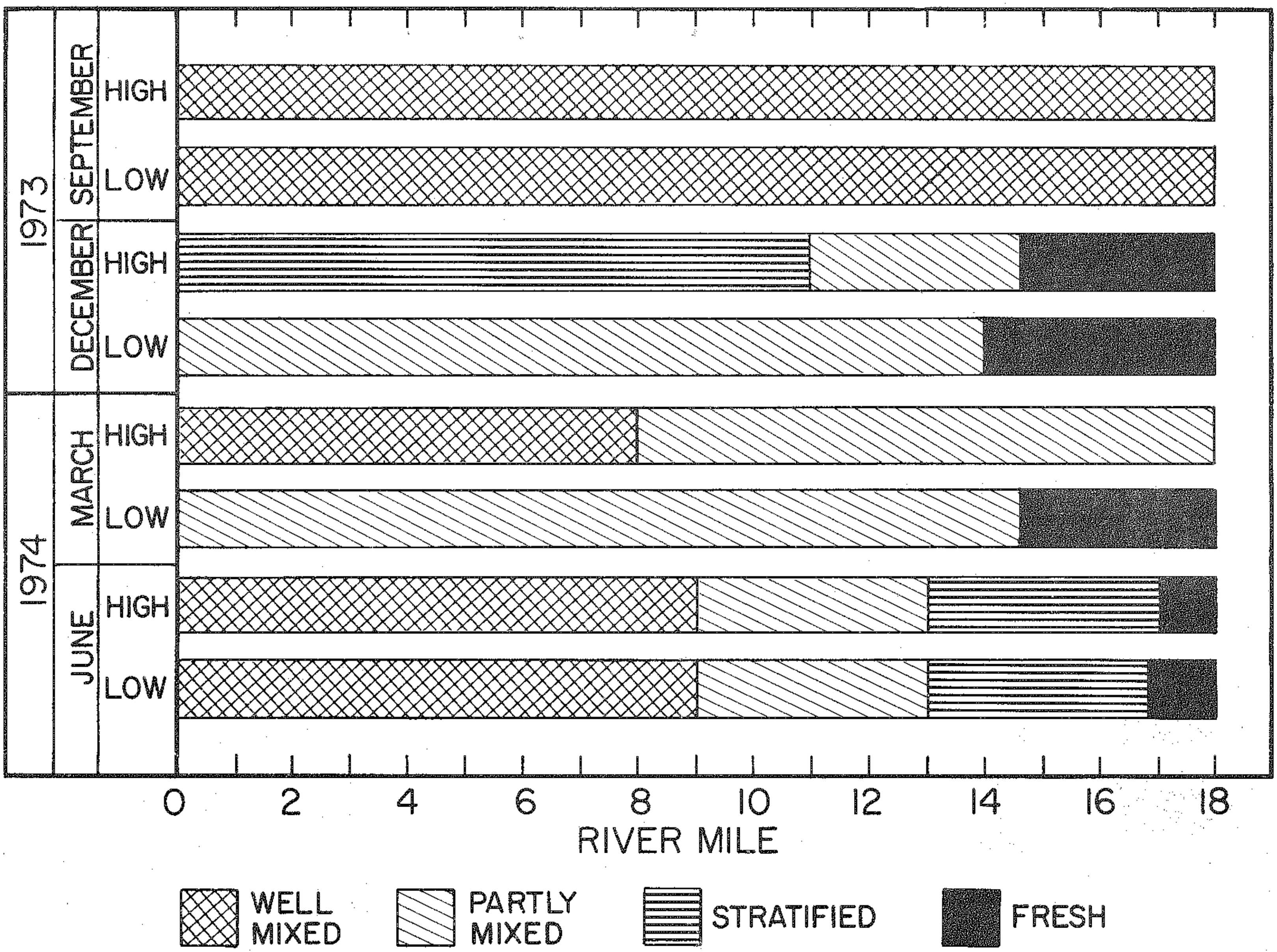

Fig. 4. Coos Bay mixing characteristics (Arneson 1976).

Flushing

Using the modified tidal prism method Arneson (1976) calculated flushing times for several points in the estuary (Table 6). His calculations for a point 27 miles from the mouth of the estuary ranged from 13.4 days at a time of high river flow and tidal range to 48.5 days at low flow and low tidal range. Although these estimates are based on only a few measurements, they demonstrate that flushing takes a number of days even under optimum flow.

Table 6. Calculated flushing rates using the modified tidal prism method (Arneson 1976).

Date	Tidal Range (ft)	Flow (cfs)	Flushing time (days)		
			RM 7.6	RM 17.3	RM 27.0
Sept. 13, 1973	7.9	28	9.7	22.9	40.3
Dec. 19, 1973	5.9	3,814	6.2	11.8	13.4
Mar. 23, 1974	7.2	1,074	8.2	14.4	15.9
June 12, 1974	3.3	431	19.0	41.3	48.5

Temperature

The temperature of Coos Bay undergoes both seasonal and diurnal fluctuations. Fresh water inflow and tidal currents are the main factors affecting temperature distribution in the estuary (Arneson 1976). Coastal upwelling causes offshore surface temperatures to be coldest during summer (Bourke et al. 1971). River temperatures are coldest in winter and warmest during summer and fall (Arneson 1976). DEQ (1978) data show that temperatures in the estuary have reached extremes of 35.6°F and 73.4°F. Seasonal temperature fluctuations are greater upbay than near the mouth of the estuary, reflecting that fluctuations in tributary temperatures are more extreme than those of the ocean.

Arneson (1976) plotted temperature vs RM for the data he collected in 1973 and 1974 (Figs. 5 and 6). His data show large longitudinal variations in September and June when entering fresh water was warmest. June data also show vertical gradients because a greater amount of fresh water was entering at that time. High tide profiles each show a significant increase at RM 8, which Arneson attributes to solar heating of the shallow water over the large tideflats of the upper bay.

In December and March the ocean and entering fresh water were nearly the same temperature so profiles were almost identical. DEQ (1978) data show that fresh water temperatures may be much colder than ocean temperatures. Different profiles would be expected under those conditions.

In summer, low streamflows and poor circulation cause high temperatures in some areas of the bay (STR 1974). High temperatures physiologically stress aquatic life. STR (1974) list high temperature as a water quality problem in Coos River, Millicoma River, North Slough, Catching Slough, and Isthmus Slough.

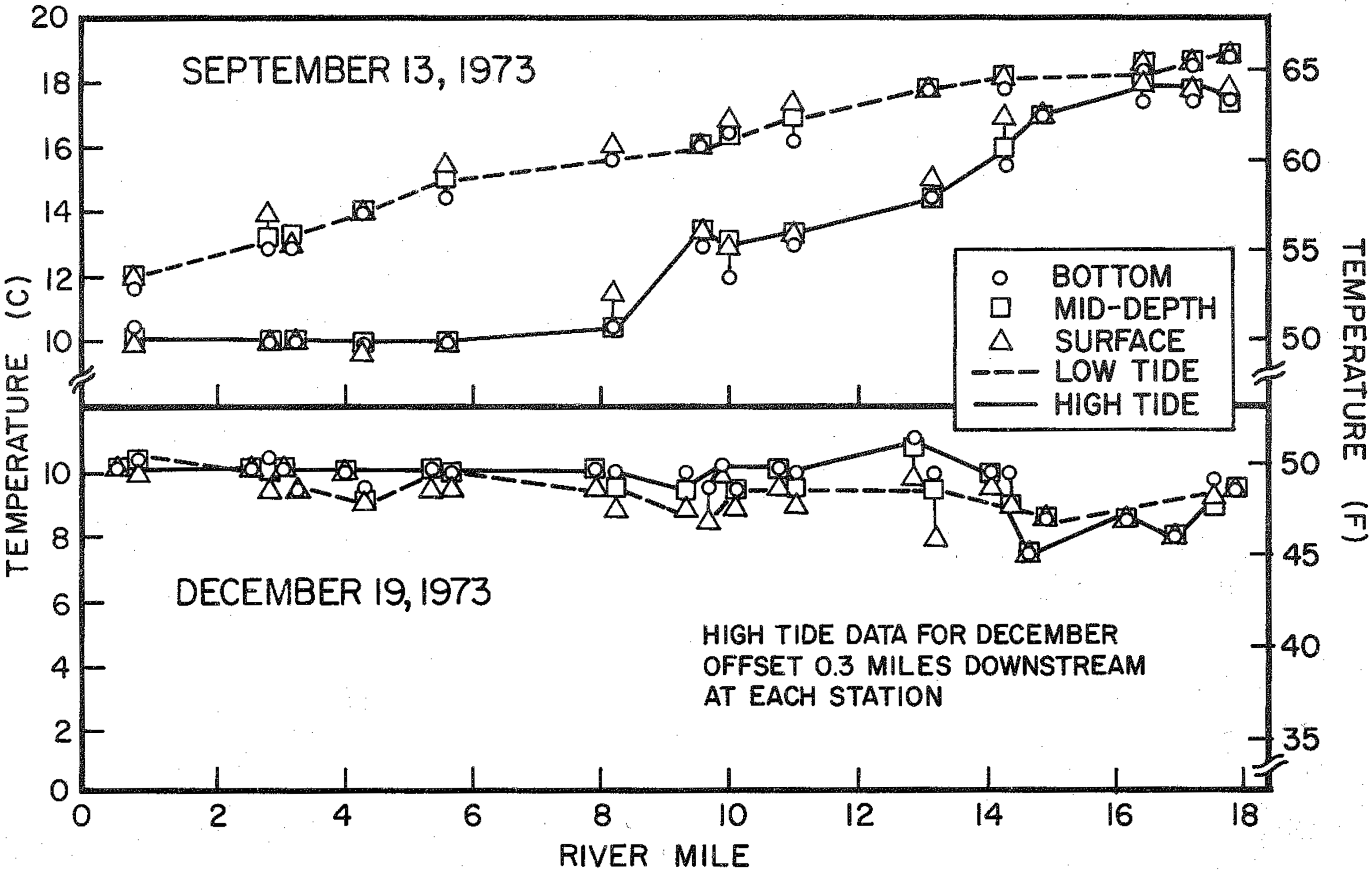

Fig. 5. Temperature vs. river mile, Coos Bay, September 13 and December 19, 1973 (Arneson 1976).

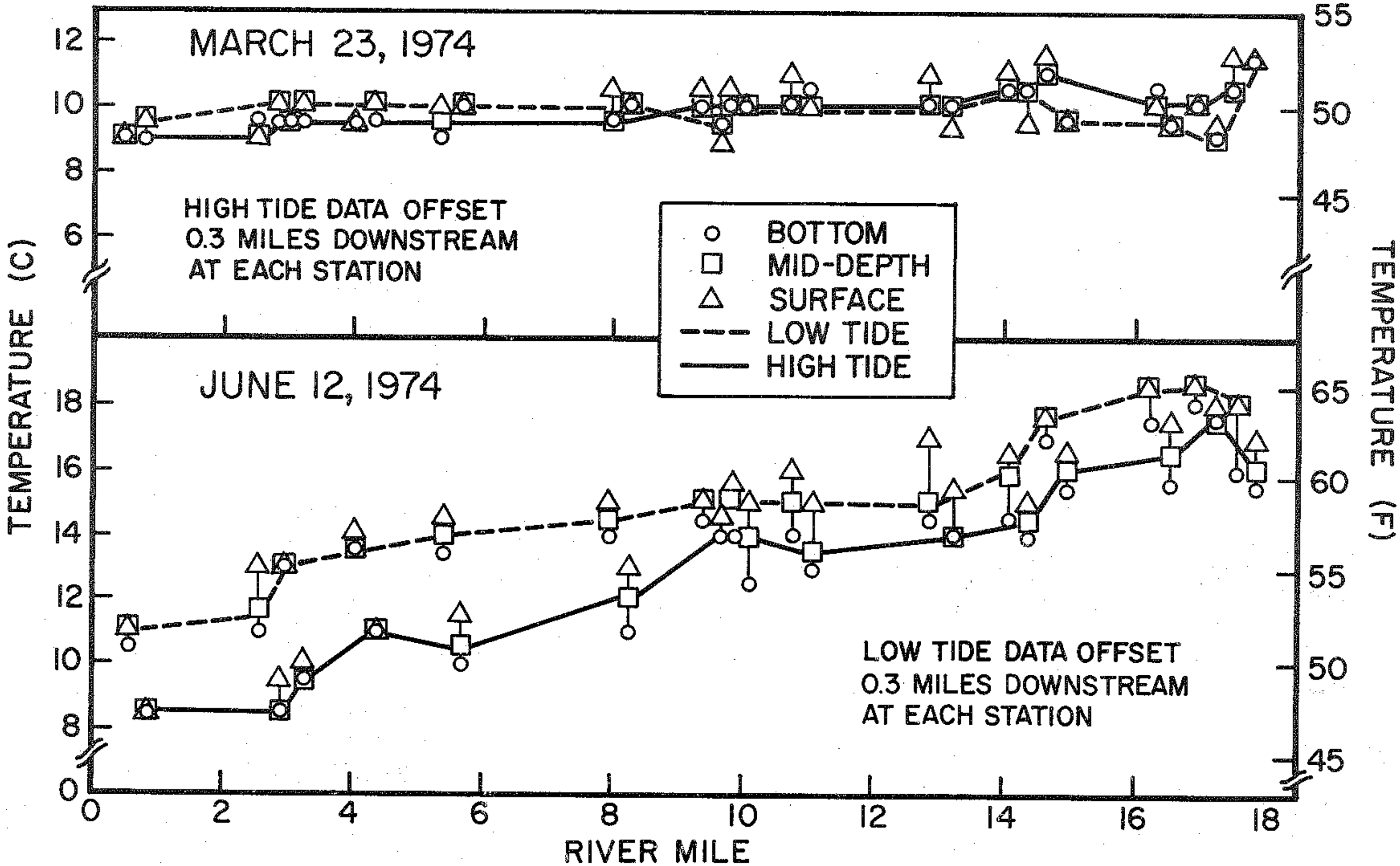

Fig. 6. Temperature vs. river mile, Coos Bay, March 23 and June 12, 1974 (Arneson 1976).

Dissolved oxygen

Dissolved oxygen (DO) is measured by DEQ as part of their regular water quality monitoring program. Others who have measured DO in conjunction with specific projects include Arneson (1976), STR (1974), and Slotta et al. (1973).

DEQ data show DO levels below the 6 mg/l standard occasionally at various locations in the bay (DEQ 1978). Measurements below standards were more frequent above RM 13 and in Isthmus Slough. STR (1974) data generally concur. Arneson (1976) sampled seasonally in 1973 and 1974. His limited data show that DO concentrations were slightly higher in December and March than in June and September. Lowest levels were recorded from Isthmus Slough. DO concentrations below the standard can kill resident fish and invertebrates and prevent migrants from utilizing the area.

Arneson (1976) mentions that DO depressions during fall have been attributed to low fresh water inflow and waste loading caused by offshore upwelling of low DO water and input of organic material, such as seafood industry waste water and bark from stored logs.

Arneson (1976) also noted supersaturation in the Coos River and in Catching Slough during June which he attributes to photosynthetic activity. Arneson attributed supersaturation observed near the mouth in December to reaeration aided by wave action.

Turbidity

Arneson (1976) found, with only a few exceptions, that low tide turbidity levels were higher than high tide levels. He interpreted this to mean that the primary cause of turbidity in Coos Bay is the sediment carried in by fresh water entering the bay. High tide turbidities increase from the mouth upstream during all seasons although this increase is very slight during times of low runoff.

USACE (1975) states the average turbidity in the bay ranges from 20 to 49 Jackson Turbidity Units. Slotta et al. (1973) found that below RM 12 dredging does not significantly increase turbidities. Above RM 12 post-dredging levels of 500 JTU have been recorded. North Slough and the area near Empire Mill are mentioned by the USACE (1975) as areas of high turbidity. Discharge of industrial waste water is listed as a probable cause of these high turbidities by STR (1974). USACE (1975) states that highest turbidity levels measured by STR in 1972 were 2,400 JTU during high tide at the site of log-dumping operations at the Empire Mill. The clearest waters were found at the entrance and near North Bend (USACE 1975).

DEQ standards specify that no more than a 10% cumulative increase in natural turbidities is allowed except for certain DEQ approved limited duration activities (OAR 340-41-325).

Coliform

DEQ has measured fecal coliform counts which exceed standards for commercial shellfish growing areas occasionally below RM 8.75 in the bay and frequently above this point. Counts exceeding general standards are frequent above RM 11.5. With a few exceptions, coliform counts in South Slough have been within shellfish area standards. STR (1974) has measured counts above the standard upbay of Jordon Point in the main bay, in North Slough, Isthmus Slough, and Catching Slough. The bay has been closed to commercial shellfish harvest above Sitka Dock by the State Health Division (Osis and Demory 1976).

Major causes of high coliform counts include improper disinfection of sewage plant effluents, inadequate subsurface disposal systems, and livestock (STR 1974).

Sediments

Coos Bay is an aggrading system--more sediment enters the bay than is removed by natural forces (USACE 1975). Prior to the channel deepening for the Deep-Draft Navigation Project, an annual average of 1.65 million yd^3 of material was removed from Coos Bay by the USACE (1976) to maintain navigation channels.

Sediments entering the bay include

1. materials, primarily silts, derived from erosion of the drainage basins of tributary streams;
2. marine sands carried into the bay by littoral drift;
3. dune sands which are blown into the bay even though the dunes have been partially stabilized by vegetation;
4. sands from wind erosion of the sandstone cliffs of the lower bay and South Slough.

The material from the entrance to RM 12 is predominantly fine sand. No shift to smaller grain size has been observed in that section following dredging. From RM 12 to RM 15 channel, sediments are primarily silts, clays, and organic fines, and the composition shifts to smaller grain sizes after dredging. Above RM 15 sediments are silty (USACE 1975).

Sedimentation is controlled by hydrology. Arneson (1976) has applied the concept of realms of deposition used by Kulm and Byrne (1976) for Yaquina Bay to the Coos. He hypothesizes a marine and a transition realm extends to RM 12 and a fluviatile realm exists above RM 12. Percy et al. (1974) estimate an average of 72,000 tons of sediment enters the bay from its drainage basin annually.

Known areas of sediment deposition in Coos Bay include the entrance to Charleston Channel, the area adjacent to disposal islands west of the North Bend Airport, Jordan Cove, east of the upper Coos Bay Channel, and at the mouths of Pony Slough, North Slough, and Haynes Inlet (USACE 1976).

In the lower portions of Coos Bay, material removed from the channel is deposited in in-bay disposal sites. During recent years the amount of material has been constant and shoaling has recurred at the same sites. USACE (1976) hypothesizes that a semi-closed sediment transport system has been operating from RM 2 to RM 12. Sediments originating upstream of RM 15 were thought to have been trapped between RM 12 and RM 15 where the channel was dredged by the Corps. Sediments from the ocean were thought to accumulate mainly below RM 2. Below RM 2 and RM 12 sediments were thought to result from redistribution of existing sediments in a cycle of removal of material from the channel, disposal of dredged material adjacent to the channel, and gradual infilling of the channel (USACE 1976). Effects of channel deepening on this sytem are unknown.

Most studies of the sediment chemistry of Coos Bay have been related to dredging and disposal of dredged material (STR 1972; Slotta et al. 1973; Arneson 1976). STR (1972) determined that sediments below RM 10 met standards for inwater disposal, whereas all materials above RM 10 failed to meet those standards. Above RM 10 volatile solids increased (Arneson 1976). USACE (1975) found the area above RM 12 in the estuary exceeded EPA standards for grease and oil, volatile solids, nitrogen, and phosphorus.

Biological Characteristics

The biology of Coos Bay has been the subject of numerous studies, including those by individual students and classes at Oregon Institute of Marine Biology (OIMB), by OSU students and faculty, and by ODFW personnel. Most of the studies are descriptive in nature. Quantitative studies of productivity and population dynamics are generally lacking.

Phytoplankton

The USACE (1975) has summarized work done by several authors on the summer phytoplankton of Coos Bay (Kilburn 1961; Ednoff 1970; Ide 1970; McGowan and Lyons 1973). Diatoms are the principal members of Coos Bay's planktonic flora. There appears to be a continuum of species from the ocean to the upper bay containing two species assemblages and a transition zone. The transition zone lies between RM 5 and 9 and is an area of high species diversity and productivity (McGowan and Lyons 1973). *Chaetoceros, Skeletonema,* and *Thalassiosira* predominate in the lower bay, while *Melosira* and *Skeletonema* are found in the upper bay.

OIMB is currently taking quantitative measurements of phytoplankton in South Slough. Preliminary results indicate definite seasonal and tidal changes in species composition.

Macroalgae

The algal flora of Coos Bay is not well described. Most of the existing information is derived from qualitative studies by Sanborn and Doty (1944) and OIMB (1970). The USACE (1975) states that attached algae are probably found throughout the bay on solid substrates and that very few marine algae are restricted to the bay environment and not found in other locations along the Pacific Coast.

The greatest variety of algal species is found near the mouth of the estuary where hard substrates providing significant attachment sites and moderate wave action support a flora similar to that of the protected outer coast (Sanborn and Doty 1944). Along the main channel there is a change from a strictly marine to a brackish water flora.

Small subtidal kelp (*Nereocystis leutkeana*) beds are located in the lower sections of the estuary, and free-floating, seasonally occurring mats of green algae sometimes cover large areas of the upper bay (Ednoff 1970).

Productivity studies of the algae of Coos Bay have not been done.

Seagrasses

Two seagrasses occur in Coos Bay--eelgrass (*Zostera marina*) and ditchgrass (*Ruppia* sp.) (USACE 1975). Approximately 1,400 acres of lower intertidal and shallow subtidal tideflats are covered by eelgrass meadows (Akins and Jefferson 1973). Large contiguous beds of eelgrass occur in the lower and upper bay, in North and South Sloughs, and in Haynes Inlet. George M. Baldwin and Associates et al. (1977) state that the eelgrass meadows of the upper bay are among the largest in the state. In the lower reaches of the estuary eelgrass often occurs in pure stands, whereas in upper, less saline, areas it is often accompanied by ditchgrass.

Tidal marsh

Tidal marsh generally occurs from lower high tide inland to the line of non-aquatic vegetation and includes both salt marsh and tidally influenced fresh marsh. The U.S. Department of the Interior (USDI 1971) states that marsh vegetation in Coos Bay developed where broad, low gradient flats of soft sediment were not too strongly stressed by waves or currents. Large present day marshes are located at the mouth of Coos River and in the slough systems--North Slough, Pony Slough, Kentuck Inlet, Isthmus Slough, and Coalbank Slough. Fringing marshes have developed along the shoreline of the main channel near Empire, around the spoil islands of the lower and upper bay, and along the undisturbed shorelines of South Slough.

Using a classification adapted from Jefferson (1975) and estimating an error of less than 10%, Hoffnagle and Olson (1974) calculated the marsh acreage of Coos Bay (Table 7). Akins and Jefferson (1973) have given a figure of 2,738 ac. of marsh for Coos Bay.

Table 7. Area of Coos Bay marshes (Hoffnagle and Olson 1974).

Marsh type	Area (acres)
Low silt marsh	71.6
Low sand marsh	289.1
Immature high marsh	1000.5
Mature high marsh	97.5
Sedge marsh	353.5
Bullrush and sedge marsh	149.8
Surge plain	285.0
Total undiked marsh	1951.9
Total diked marsh	2942.9

Prior to human alterations of the estuary and its drainage basin, vast marshes occupied the upper bay and slough systems. Hoffnagle ad Olson (1974) estimate that 90% of the salt marshes of this estuary have been diked or filled to accomodate expansion of industry or residential areas and for agriculture and for dredged material disposal sites. Eilers (1974) indicates that of the 14 estuaries examined, Coos Bay marshes have been the most severely disturbed by human activities.

Marsh species and types present in Coos Bay resemble those found in other Oregon estuaries to the north and in the Coquille to the south. Akins and Jefferson (1973) noted that south of the Coquille there is a distinct change in vegetation and marsh types.

Hoffnagle et al. (1976) studied six marsh sites in Coos Bay. The group estimated those marshes produced over 1,050,000 gm/acre/year of plant material and considered this figure to be an underestimate. Their data suggest higher marshes are more productive than lower marshes. Bullrush and sedge were found to be particulary productive species. Productivity alone may be insufficient evidence to judge the importance of a marsh. The palatability of marsh plants to consumer organisms and the importance of the plant to detritus production are examples of other considerations (Hoffnagle et al. 1976).

According to Hoffnagle and Olson (1974), "The salt marsh and bacterial and clinging forms associated with its detritus comprise a base of production for the Coos Bay Estuary, providing food and habitat for commerical fish, bivalves, crab, birds, and mammals, and life in Coos Bay in general." The marsh serves as a buffer between shorelands and estuarine waters, preventing or minimizing erosion, flooding, and pollution. Jefferson (1974) indicates that flooding poses a greater potential hazard to shorelands because vast areas of Coos Bay marshes have been diked. Areas constructed on filled marsh are the most susceptible to flooding.

Zooplankton

McGowan and Lyons (1973) directed a short sampling program during the summer of 1973. Their data show a decreasing number of zooplankton taxa along the axis of Coos Bay with increasing distance from the ocean. The lower bay appeared to have a species assemblage which included neritic zooplankters carried in by tidal action and resident species which maintained reproductive populations. Peak zooplankton numbers occurred near Empire in an area of high chorophyll values. Different species were found in the upper bay and in Coos River.

Quantitative information on Coos Bay zooplankton is sparse, and seasonal species distributions are unknown.

Invertebrates

A wide variety of ecological niches are available to invertebrates in the Coos Bay estuary. Differing substrates provide a range of attachment sites and sediments in which to burrow from the solid rock of Fossil Point to the silty, highly organic mud of Isthmus Slough. In addition to substrate variations, differing salinities, temperatures, dissolved oxygen, and other physical factors provide even more variation in conditions.

Subtidal invertebrate populations of the dredged ship channel have been studied by Parr (1974), Slotta et al. (1974), and Jefferts (1977). Jefferts (1977) found the channel infauna of the lower portions of the estuary to be more diverse than that of the upper bay channel. Species of the upper bay, such as the polychaete *Streblospio benedicti*, are generally widespread and opportunistic. Parr (1974) hypothesizes that the fauna of the upper channel are adapted to dredging and that the "weed" species occurring there require frequent disturbance to maintain their competitive advantage.

A qualitative overview of the intertidal macroinvertebrates in Coos Bay was conducted by OIMB in 1970. Many other workers have concentrated on certain taxa or on limited geographic areas of the bay. Distribution of *Corophium*, an important crustacean in the diet of salmonids and other fishes, is shown in Fig. 7. ODFW has surveyed intertidal clam and shrimp distribution in some areas and is completing surveys in other areas (Gaumer 1978) (Fig. 8-15). Hartmann and Reish (1950 described the annelid fauna of the bay with notes on distribution, and Queen (1930) studied the decapod crustaceans of the bay.

Commercially and recreationally harvested invertebrates include several species of clams, the Dungeness and red rock crabs, oysters, bay mussels, ghost shrimp, kelp worms, and mud shrimp.

Clams. Principal species of clams harvested in Coos Bay are gapers (*Tresus capax*), cockles (*Clinocardium nuttallii*), butter clams (*Saxidomus giganteus*), littlenecks (*Protothaca staminea*), softshell clams (*Mya arenaria*), and razor clams (*Siliqua patula*). Of these, all but the softshell clams are restricted in distribution to areas below the railroad bridge (RM 9). These clam species are all filter feeders. Salinity, substrate, and water circulation probably play significant roles in limiting distribution (USACE 1975).

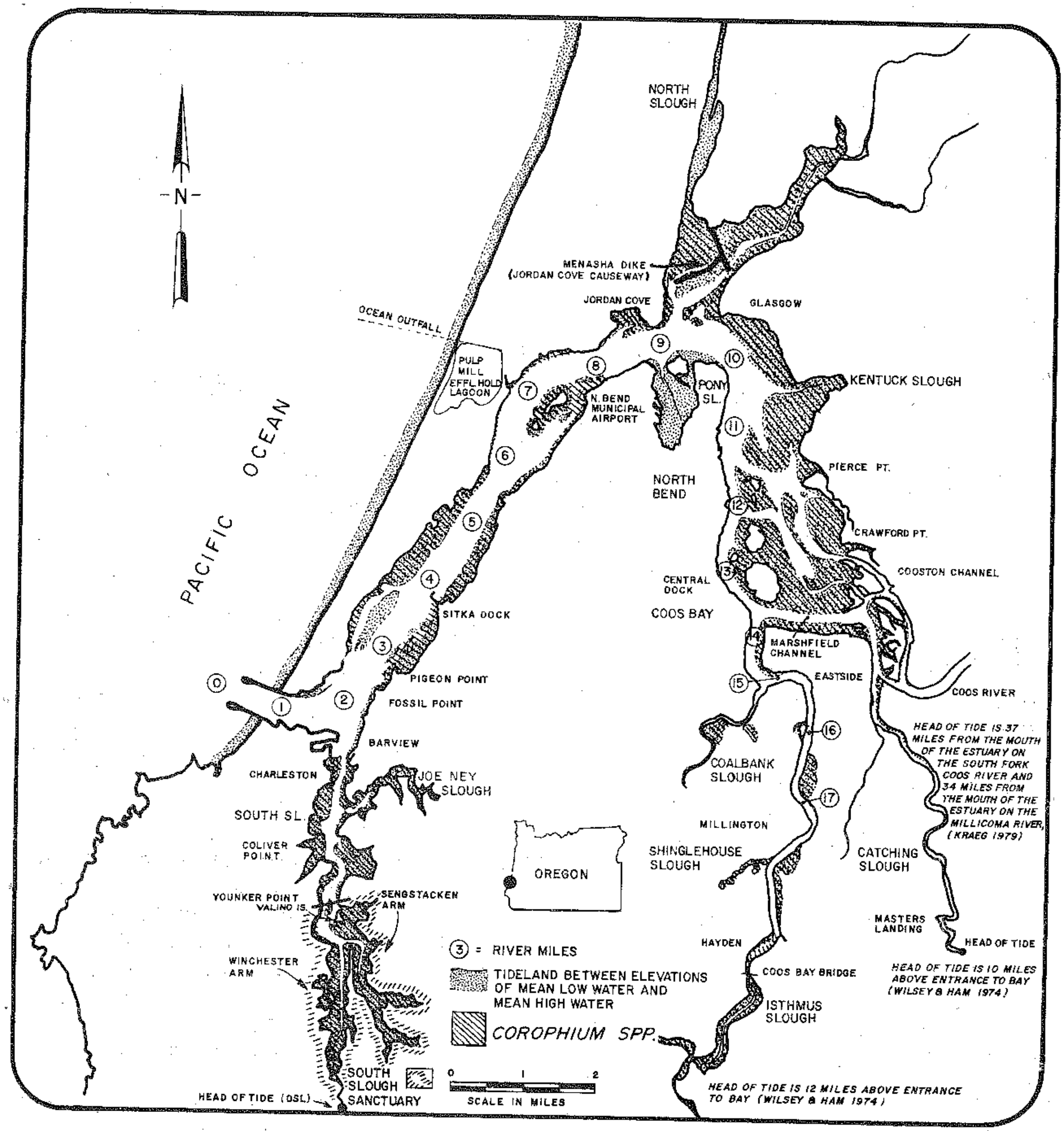

Fig. 7. *Corophium* distribution in Coos Bay (Coos Bay Planning Department 1979).

Fig

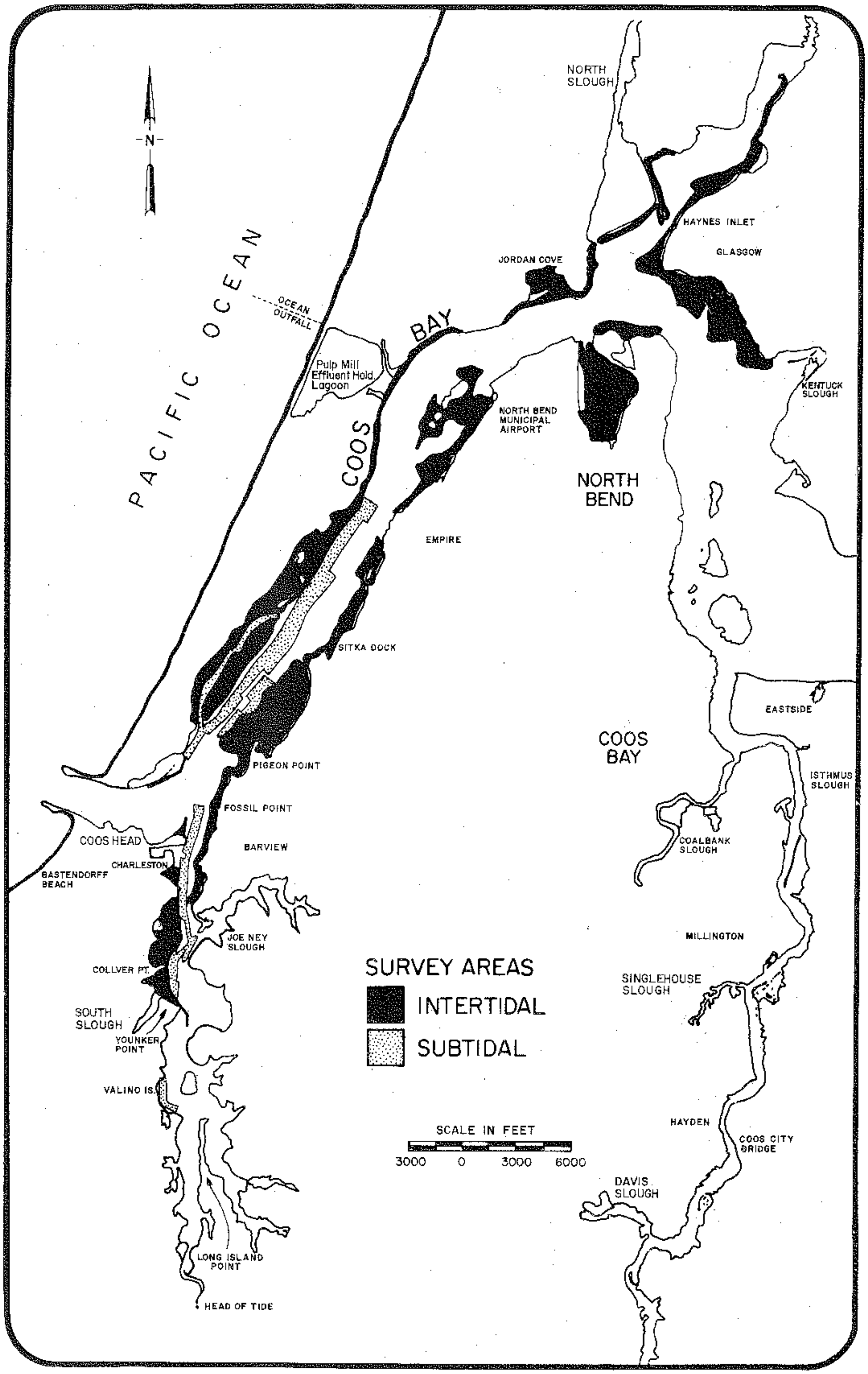

Fig. 8. Areas surveyed for clam and shrimp distribution (Gaumer 1978).

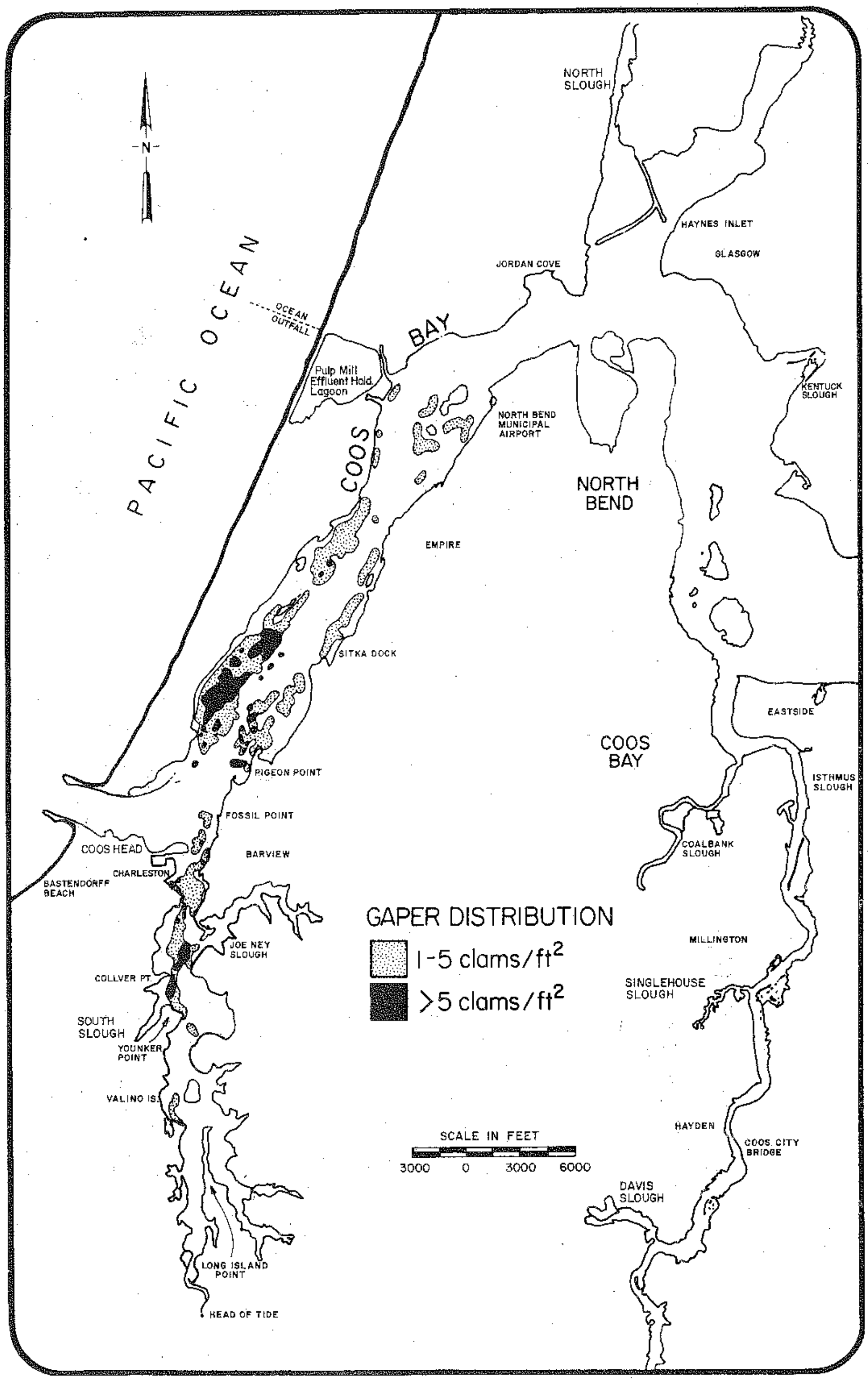

Fig. 9. Gaper distribution in Coos Bay (Gaumer 1978).

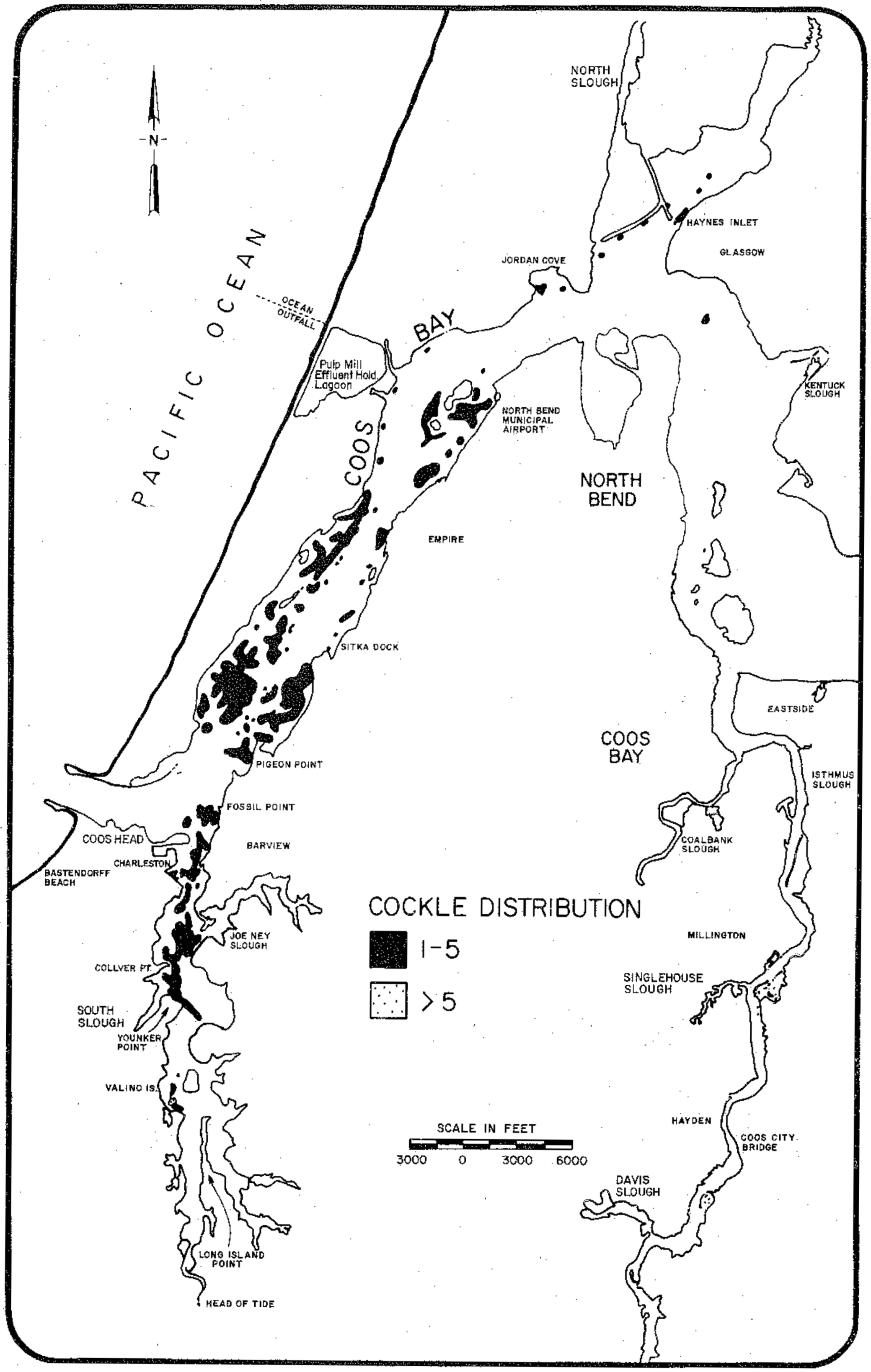

Fig. 10. Cockle distribution in Coos Bay (Gaumer 1978).

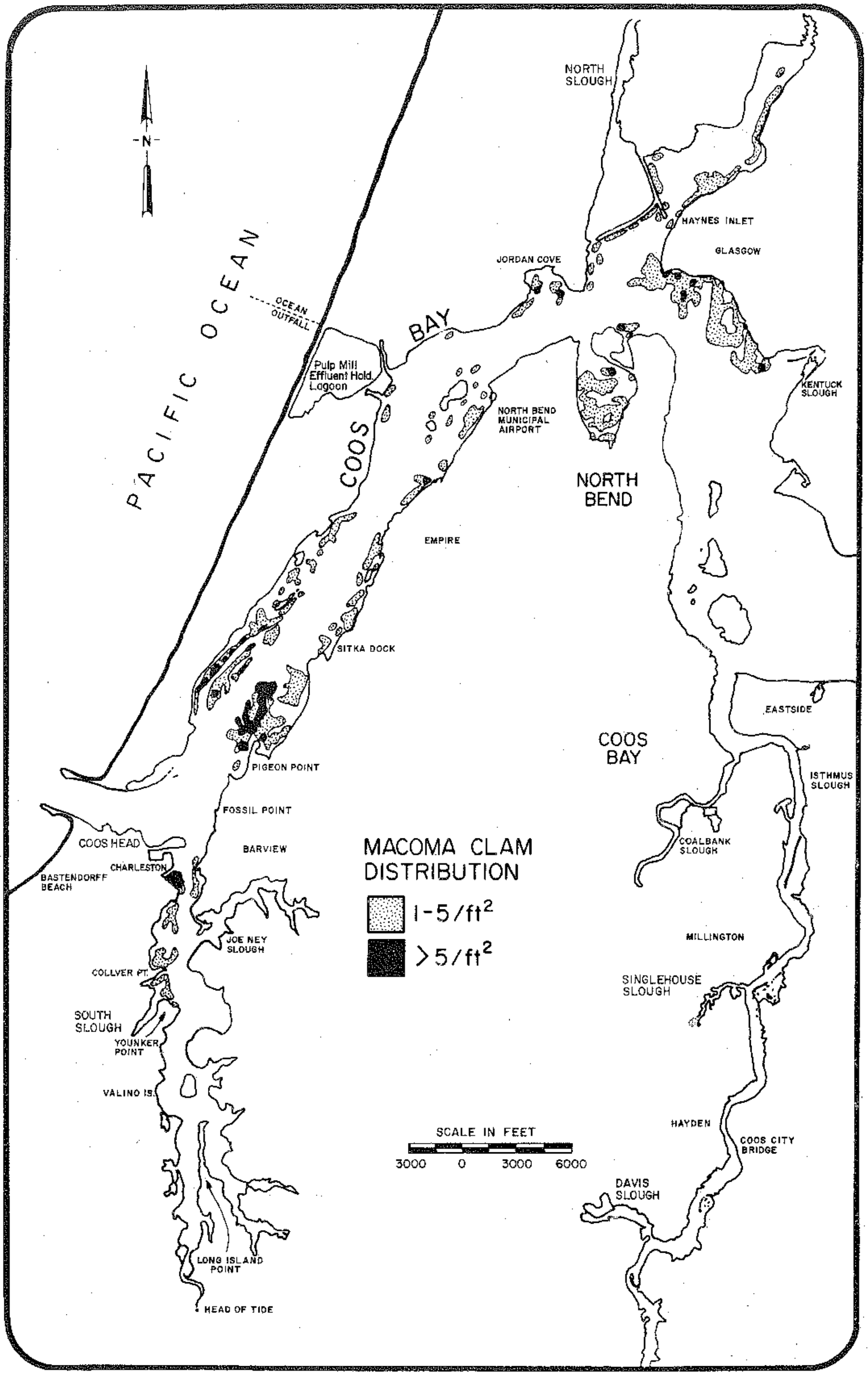

Fig. 11. *Macoma* (*Macoma irus*, *M. nasuta* and *M. balthica*) distribution in Coos Bay (Gaumer 1978).

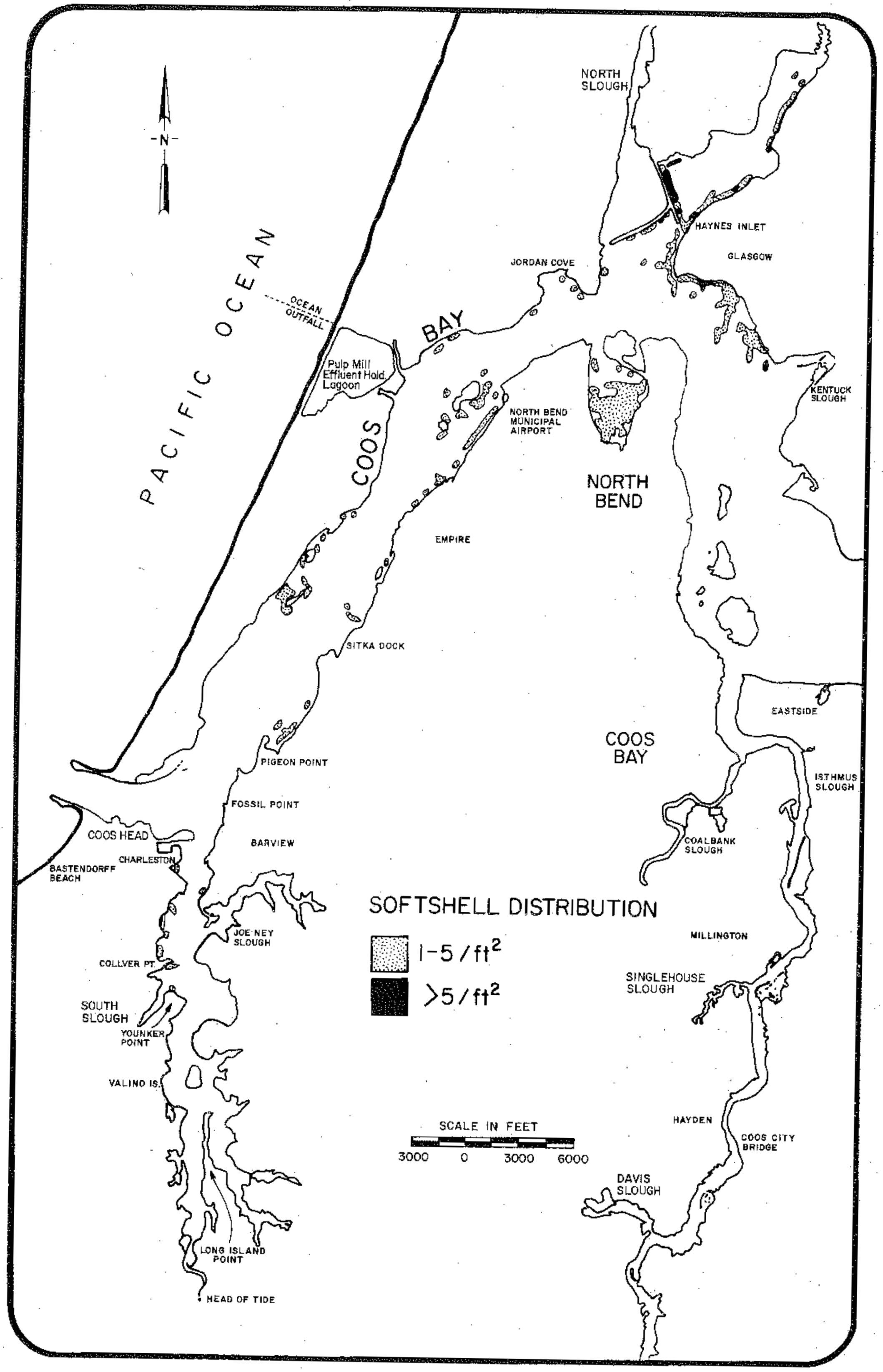

Fig. 12. Softshell distribution in Coos Bay (Gaumer 1978).

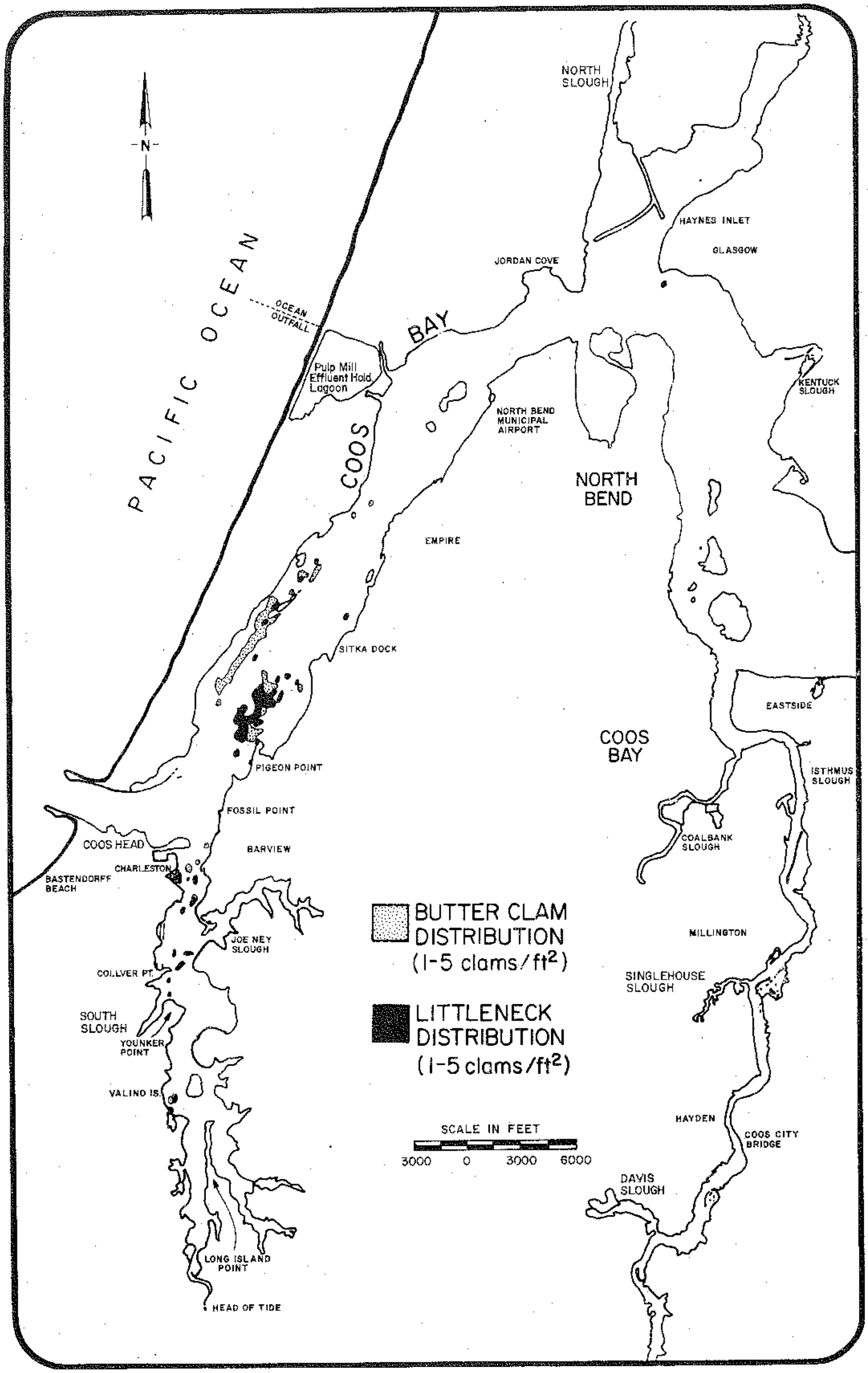

Fig. 13. Butter clam and littleneck distribution in Coos Bay (Gaumer 1978).

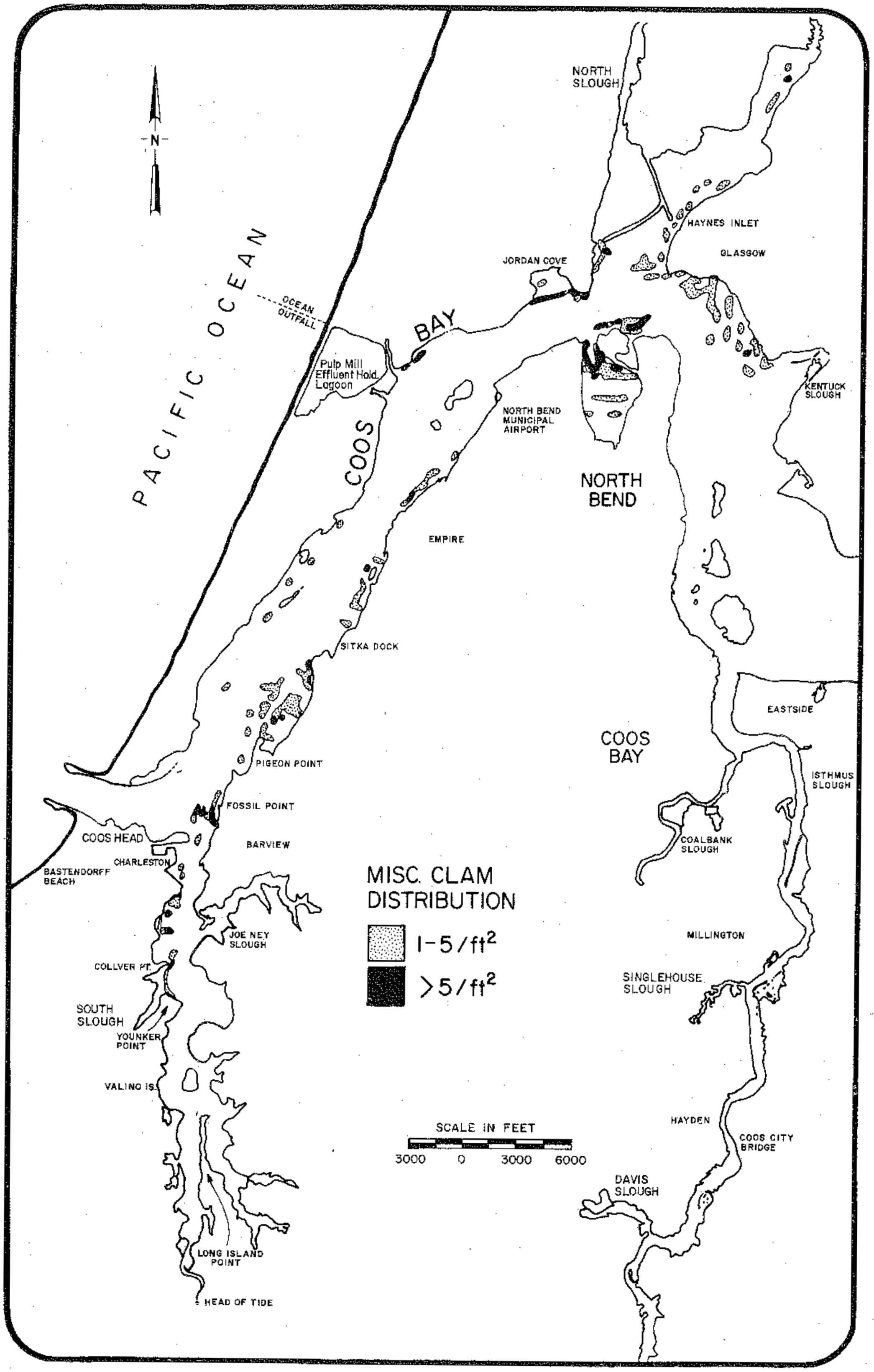

Fig. 14. Miscellaneous clam (California softshell, bodega, paddock, jackknife and rockclams) distribution in Coos Bay (Gaumer 1978).

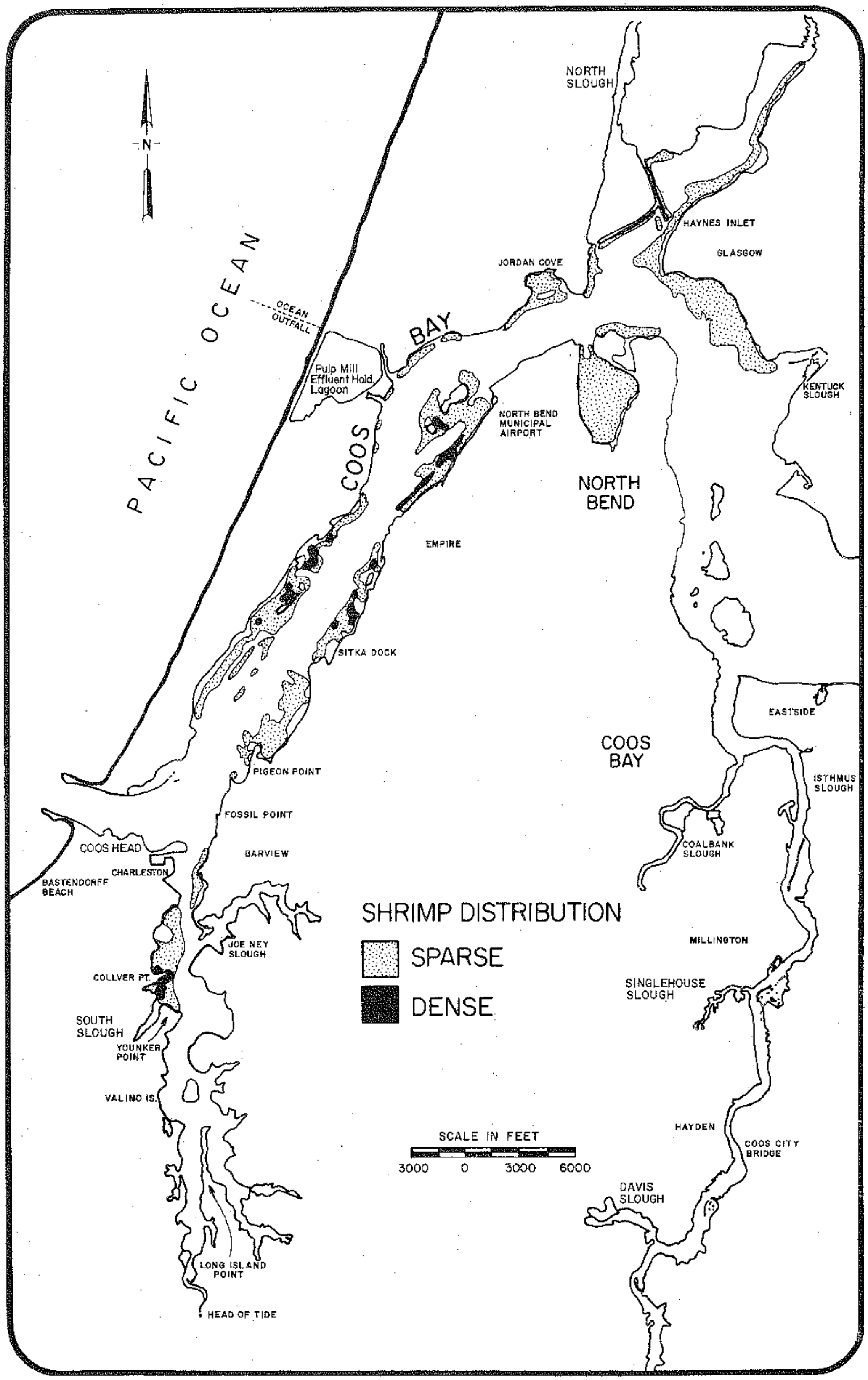

Fig. 15. Shrimp distribution in Coos Bay (Gaumer 1978).

Preliminary ODFW studies indicate that Coos Bay has extensive subtidal clam beds, including large beds of gapers and cockles (Gaumer and Lukus 1976). Principal beds are in the lower bay and lower South Slough. In 1976 one subtidal bed was investigated by ODFW to determine the feasibility of a commercial clam fishery (Gaumer and Halstead 1976). The 48-acre bed off Pigeon Point contained approximately 26.4 million clams, principally gapers and Irus clams (*Macoma inquinata*). Mean size of butter, cockle, littleneck and gaper clams was larger for each species than in a similar study in Yaquina Bay (Gaumer and Halstead 1976). A commercial harvest of 55,482 lb of gapers was taken from the Coos Bay site in 1975-76.

A 1971 estuarine resource use survey (Gaumer et al. 1973) showed that the greatest numbers of clams were taken from tideflats adjacent to North Spit and Pigeon Point and the flats just south of Charleston bridge. Menasha Dike, which separates North Slough from the main bay ranked second. Of the areas surveyed, the Menasha Dike above the railroad bridge was the principal site of softshell clam harvest. Some resource use information on major recreational clam species is contained in Table 8.

Table 8. Clam catch by tideflat users, 1971 (Gaumer et al 1973).

Clam species	Number taken	% of invertebrate tideflat catch	Primary digging area	Secondary digging area
Gaper	107,907	35.3	North Spit	Pigeon Point
Cockle	53,250	17.5	Charleston Flat	North Spit
Butter	53,288	17.4	Pigeon Point	North Spit
Softshell	45,101	14.8	Menasha Dike	North Bend
Native littleneck	15,482	5.1	Pigeon Point	Boat Basin

Razor clams maintain a fluctuating population on a wave-washed sand spit immediately north of the Charleston breakwater where they are taken recreationally (USACE 1978).

Crabs. Both Dungeness (*Cancer magister*) and red rock (*C. productus*) crabs are taken recreationally in Coos Bay. In 1971 crabs accounted for over 80% of the recreational boat fishing catch with Dungeness crabs alone accounting for 76.7% of the catch (Gaumer, Demory, and Osis 1973). Dungeness crabs are also fished commercially within Coos Bay. In-bay crab landings fluctuate, as do those of the ocean, but an average of 11,441 lb were landed from Coos Bay in 1971-74 (personal communication, Darrel Demory, ODFW, May 8, 1979). Of the 31,000 lb landed from Oregon bays in 1977, Demory (personal communication) estimates that 15,000-18,000 lb were from Coos Bay.

Both species of crabs are found subtidally throughout the bay (USACE 1975). Waldron (1958) states that Dungeness crabs have a preference for sandy or muddy bottoms, although they may be found on almost any bottom. Gaumer et al. (1973) found the lower bay to be the primary site of recreational crab fishing.

Fish Commission of Oregon studies (Waldron 1958) have shown that while crabs do move between bays and the ocean, and from bay to bay, 84% of the crabs tagged in bays were recovered within four miles of the tagging site.

The importance of the estuary as rearing ground for crabs is not understood (USACE 1975). Large numbers of crab larvae (megalops) are found in Coos Bay in late spring and early summer and are also found offshore at that time of year (Waldron 1958). Samll (0.8-2 in) Dungeness crabs are found abundantly in the upper reaches of the estuary. Hunter (1973) has shown that small Dungeness crabs seem to be more tolerant of low salinities than are large individuals.

Several other crab species inhabit the bay including the freshwater crab (*Rhithropanopeus harrissi*) of the upper bay and the shore crabs (*Pachygrapsus crassipes* and *Hemigrapsus nusus*) of rocky intertidal areas.

Oysters. While native oysters (*Ostrea lurida*) no longer inhabit Coos Bay, Pacific oysters (*Crassostrea gigas*) are grown commercially in the bay. All existing Coos Bay oyster leases are in South Slouth (Fig. 16). In 1976, 144.08 acres of oyster ground were leased in Coos Bay. About 40% (57 ac.) were actually in production at that time. Osis and Demory (1976) listed a potential ground acreage of 525 ac and indicated that siltation problems account for much of the land remaining unused. Excessive fresh water and heavy siltation sometimes cause oyster mortality in Coos Bay during winter.

The potential oyster culture area of Coos Bay extends upstream from the mouth to the lower reaches of Haynes and North Sloughs, but high bacterial counts have forced closure of commercial areas above Sitka Dock. Jambor and Rilette (1977) note the area open to oyster harvest is only about one-half of the useable oyster tideland.

According to Jambor and Rilette (1977), DEQ officials state that because high bacterial counts in Coos Bay are mainly caused by dairy and wild animal stocks, little improvement is expected. Purification of shellfish grown in polluted waters (depuration) may be one way to increase acreage in Coos Bay used for commercial oyster culture (ODFW 1976; Jambor and Rilette 1977). However, other factors such as existing clam beds and navigation rights may limit expansion of oyster culture.

Other invertebrates. Other invertebrates taken by recreationists in Coos Bay include ghost shrimp (*Callianassa californiensis*), and mud shrimp (*Upogebia pugettensis*), kelp worms (*Nereis* spp.) (Fig. 15) (Gaumer et al. 1973), and lug worms (*Abarenicola pacifica*) (personal communication, Reese Bender, ODFW, March 10, 1979). These organisms are frequently used as bait. The shrimp are primarily taken from tideflats of the lower bay while the worms are harvested in greatest abundance from Menasha Dike (Gaumer et al. 1973).

Fish

At least 66 species of fish are known to use the Coos Bay estuary (Cummings and Schwartz 1971). Fish distribution has been studied during summer months (Cummings and Schwartz 1971; Ednoff 1970) and seining efforts by ODFW in 1977 and 1978 have added further information regarding seasonal use of the bay (personal communication, Reese Bender and Bill Mullarkey, ODFW, April 4, 1979)

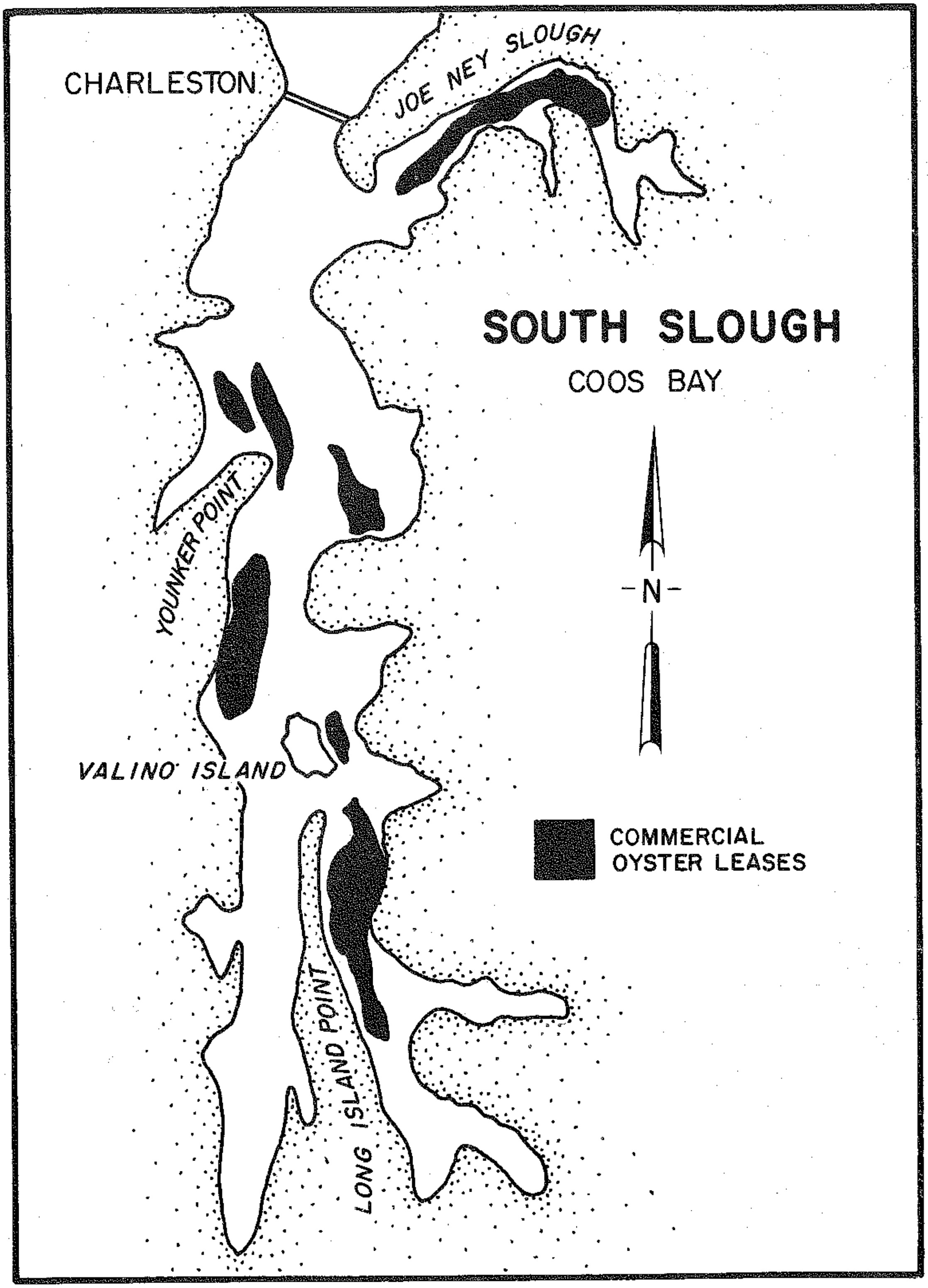

Fig. 16. Commercial oyster leases in Coos Bay (Jambor and Rilette 1977).

(Table 9), but documentation of the use of specific areas and habitats by fish species is lacking.

The greatest variety of species is found in the lower parts of the estuary (Cummings and Schwartz 1971), while the greatest numbers of fish, captured during the same sampling program, were taken near the mouth of the Joe Ney Slough and just west of Jordan Point (Hostick 1975). One might expect those species requiring high salinities to reach the upper most extent of their ranges in the bay during summer and those species requiring low salinities to extend further downbay during periods of high runoff.

The Coos system supports stocks of fall chinook salmon, coho salmon, steelhead, and searun cutthroat trout. Chum salmon are seen occasionally. Records show that a sizeable population of fall chinook salmon once inhabited the Coos system (Cleaver 1951). Gillnet catches declined from an average of 200,000 lb between 1923 and 1930 to 36,000 lb between 1930 and 1940. After the building of splash dams on the South Fork Coos River in 1941, the population declined substantially (personal communication, Al McGie, ODFW, January 17, 1979). Since removal of the dams in 1957, the population has recovered so that now approximately 5,000 chinook spawn in Coos River and its tributaries (personal communication, Bill Mullarkey, ODFW, April 14, 1979). Based on historic records, a spawning population of at least 12,000 chinook is possible when the recovery of spawning grounds and reaccumulation of spawning gravel is complete (personal communication, Mullarkey). Information on salmonids is summarized in Table 10.

In 1978 anglers caught 1,145 chinook and 24,000 coho salmon in the ocean sport fishery offshore from Coos Bay. In late summer chinook and coho are caught from the jetties. A boat fishery develops in late August in the upper bay and river and continues through the fall. In 1977, a year of drought, 604 salmon over 24 inches were caught in the Coos and Millicoma rivers, and Bender (pers. comm.) estimates another 600 jacks may have been caught. A cutthroat fishery of unknown catch also occurs in the river.

Three private hatcheries have obtained permits from ODFW for salmon release/ recapture operations (Table 11). ODFW has begun an evaluation of the private hatchery programs in Coos Bay to determine the periods and areas of residence and food habits of hatchery and wild salmonids.

Coos Bay also supports a large population of striped bass. Commercial fishing for bass has been closed in Coos Bay since 1975, but prior to the 60s, the striped bass fishery on the Coos was surpassed on the West Coast only by that of the Sacramento River in California (Hutchison 1962). Currently an active sport fishery occurs on a population of unknown size. Stripers are taken throughout the year at various places in the bay. Upriver migration of striped bass occurs in several runs from May until July. After spawning the fish move back into the bay to feed, seeking the deeper holes and channel. Although a few may go to the ocean, most of the fish probably stay in the bay all year (personal communication, Al McGie, ODFW, July 10, 1979). Young fish appear to stay upriver until the end of their first year of life.

Table 9. Distribution of fish species by subsystem (Cummings and Schwartz 1971; Hostick 1975, and Mullarkey and Bender 1979).

Species	Subsystem[a]								
	Marine (RM 0-3)	Lower Bay (RM 3-9)	Upper Bay (RM 9-17)	Riverine (RM 17-30)	South Slough	North Slough	Haynes Inlet	Isthmus Slough	Catching Slough
Leopard shark *(Triakis semifasciata)*	X								
Longnose lacetfish *(Alepisaurus richardsoni)*	X								
White seabass *(Cynoscion nobilis)*	X								
Pomfret *(Brama rayi)*	X								
Redtail surfperch *(Amphistichus rhodoferus)*	X								
Wolf-eel *(Anarrhichthys ocellatus)*	X								
Copper rockfish *(Sebastodes caurinus)*	X								
Rock greenling *(Hexagrammos superciliosus)*	X								
Tidepool sculpin *(Oligottus maculosus)*	X	X							
Mosshead sculpin *(Clinocottus globiceps)*	X								
Fluffy sculpin *(Oligottus snyderi)*	X								
Tubenose poacher *(Pallasina barbata)*	X								
Longnose skate *(Raja rhina)*	X	X							
Whitebait smelt *(Allosmerus elongatus)*	X	X							

Table 9. Continued.

Species	Subsystem[a]								
	Marine (RM 0-3)	Lower Bay (RM 3-9)	Upper Bay (RM 9-17)	Riverine (RM 17-30)	South Slough	North Slough	Haynes Inlet	Isthmus Slough	Catching Slough
Eulachon *(Thaleichthys pacificus)*	X	X							
Penpoint gunnel *(Apodichthys flaridus)*	X	X							
Pacific sandlance *(Ammodytes hexapteros)*	X	X							
Bocaccio *(Sebastodes paucispinis)*	X	X		X					
Cabezon *(Scorpaenichthys marmoratus)*	X	X		X					
Tubesnout *(Aulorhynchus flaudius)*	X	X		X					
Spiny dogfish *(Squalus acanthias)*	X	X	X						
White sturgeon *(Acipenser transmontanus)*	X	X	X						
Northern anchovy *(Engraulis mordax)*	X	X	X	XXF					
Longfin smelt *(Spirinchus dilatus)*	X	X	X						
Pacific tomcod *(Microgadus proximus)*	X	X	X						
Surf smelt *(Hypomesus pretiosus)*	X	X	X	F					
Striped seaperch *(Embiotoca lateralis)*	X	X	X	XX					
Walleye surfperch *(Hyperprosopon argenteum)*	X	X	X	XXF					
White seaperch *(Phanerodon furcatus)*	X	X	X	XX					

Table 9. Continued.

Species	Subsystem[a]								
	Marine (RM 0-3)	Lower Bay (RM 3-9)	Upper Bay (RM 9-17)	Riverine (RM 17-30)	South Slough	North Slough	Haynes Inlet	Isthmus Slough	Catching Slough
Pile Perch *(Rhacochilus vacca)*	X	X	X	XX					
High cockscomb *(Anoplarchus purpurescens)*	X	X	X						
Arrow goby *(Clevelandia ios)*	X	X	X						
Pacific pompano *(Palometa simillima)*	X	X	X						
Black rockfish *(Sebastodes melanops)*	X	X	X	XX					
Kelp greenline *(Hexagrammos decagrammus)*	X	X	X	XX					
Lingcod *(Ophiodon elongatus)*	X	X	X	XX					
Padded sculpin *(Artedius fenestralis)*	X	X	X						
Buffalo sculpin *(Enophys biason)*	X	X	X						
Sand sole *(Psettichthys melanostichus)*	X	X	X						
Pacific lamprey *(Lompetra tridentata)*	X	X	X	X					
Green sturgeon *(Acipenser medirostris)*	X	X	X	X					
American shad *(Alosa sapidissima)*	X	X	X	X	XF	X		X	XX
Pacific herring *(Clupea harengus pallasi)*	X	X	X	X	X			X	
Chum salmon *(Oncorhynchus keta)*	X	X	X	X					

Table 9. Continued.

	Subsystem[a]								
Species	Marine (RM 0-3)	Lower Bay (RM 3-9)	Upper Bay (RM 9-17)	Riverine (RM 17-30)	South Slough	North Slough	Haynes Inlet	Isthmus Slough	Catching Slough
Coho salmon *(Oncorhynchus kisutch)*	X	X	X	X	F				
Chinook salmon *(Oncorhynchus tsawytcha)*	X	X	X	XF	XF				
Cutthroat trout *(Salmo clarki)*	X	X	X	XF					
Rainbow trout *(Salmo gairdneri)*	X	X	X	X					
Topsmelt *(Atherinops affinis)*	X	X	X	X	XX		X	XX	
Bay pipefish *(Syngnathus griseolineatus)*	X	X	X	X	X		X		
Striped bass *(Roccus saxatilis)*	X	X	X	X					
Shiner perch *(Cymatogaster aggregata)*	X	X	X	XE	XXE	X	X	XX	X
Silver surfperch *(Hyperprosopon ellipticum)*	X	X	X	XE	XXF			XX	
Snake prickleback *(Lumpenus sagitta)*	X	X	X	X	XX			X	
Saddleback gunnel *(Pholis ornata)*	X	X	X	X					
Pacific staghorn sculpin *(Leptoccotus armatus)*	X	X	X	XF	XXF	X	X	XX	XX
Speckled sanddab *(Citharichthys stigmaeus)*	X	X	X	X	XX				
English sole *(Parophrys retulus)*	X	X	X	X	XX				
Starry flounder *(Platichthys stellatus)*	X	X	X	XF	XF	X	X	X	XX

Table 9. Continued.

Species	Subsystem[a]								
	Marine (RM 0-3)	Lower Bay (RM 3-9)	Upper Bay (RM 9-17)	Riverine (RM 17-30)	South Slough	North Slough	Haynes Inlet	Isthmus Slough	Catching Slough
Bay goby *(Lepidogobius lepidus)*		X	X						
Threespine stickleback *(Gasterosteus aculeatys)*		X	X	XF			X	XX	XX
Prickly sculpin *(Cottus asper)*		X	X	X					
Redside shiner *(Richardsonius balteatus)*				X	F				
Speckled dace *(Rhinichthys osculus)*				X					
Largescale sucker *(Catostomus machrochelius)*				X					

[a] *Pony Slough not included in sources used.*
X= species present according to summer sampling by Cummings and Schwartz (1971).
F= species present in ODFW 1977 seine samples. Applies only to South Slough and Riverine because data from other areas was combined by authors.

Table 10. Salmonid use of Coos Bay (Thompson etal 1972; Bender and Mullarkey 1979).

Species	Estimated population	Time of spawning migration	Spawning peak	Juvenile use of estuary	State releases
Fall chinook salmon	5,000	Sept.-Jan.	Nov.	Feb.-Oct.	--
Coho salmon	8,300	Oct.-Feb.	Dec.	Mar.-Jun.	--
Chum salmon	incidental				
Steelhead	5,000	Nov.-Apr.	Jan.-Mar.	Mar.-Jun.	100,000
Cutthroat trout	3,500	Aug.-Jan.	unknwon	entire yr.	10,000

Table 11. Private hatchery permits for Coos Bay (Cummings 1977).

Hatchery	Total permit	Permits by species		
		Chinook	Coho	Chum
Weyerhaeuser	40,000,000	10,000,000	10,000,000	20,000,000
Anadromous	10,000,000	5,000,000	5,000,000	
Calvin Heckard				5,000,000

Shad are fished commercially in Coos Bay from April 20 to June 21. A five-year (1973-77) average of 19,310 lbs of shad was taken from Coos Bay. Sport fishermen take shad from the South Coos River and Millicoma River from mid April through June by trolling from boats.

Shad tagged in the Coos River have been recovered from the Umpqua and Coquille rivers, but evidence suggests each of these rivers supports its own population of shad (Mullen 1974). Mullen (1974) estimated from tagging studies a population of over 50,762 shad in the Coos River system. However, shad too small to be caught in the gillnets were not included in the estimate.

Shad enter the bay from the ocean in the spring months and start to appear in the commercial gill net fishery when it opens in April. Spawning usually occurs in May and June in upper tidal areas of the Coos and Millicoma rivers. Juvenile shad rear in the Coos and Millicoma rivers throughout the summer. Shad begin to appear in seine hauls in lower Coos Bay during August (pers. comm., Bender). Most of the juveniles enter the ocean in the fall.

In 1978 a conservative estimate of 145 tons of herring spawned in Coos Bay between 0.6 and 13.7 miles from the mouth (Miller and McRae 1978). Spawning occurs from January through April, and herring remain in the bay through summer (pers. comm., Bender). Three areas heavily used during the 1978 spawn were Fossil Point (eelgrass, algae, rocks), lower North Spit (eelgrass), and the Ford Dock near Jordan Cove (pilings) (Miller and McRae 1978). Jackson (1979) observed heavy spawns on lower North Spit, south of Clam Island in 1979. It is possible that timing of the herring spawn is influenced by freshwater runoff so that spawning occurs farther downbay during high runoff periods (Miller and McRae 1978).

Shiner perch, redtail surfperch, striped seaperch, black rockfish, and kelp greenling are among the other fish inhabiting the bay in large numbers which are taken by sport anglers (Gaumer et al. 1973).

Distribution maps for major species have been prepared by the Coos County Planning Department.

Mammals

Resident marine mammals in the estuary are limited to the harbor seal (*Phoca vitulina*) and the harbor porpoise (*Phocoena phocoena*) (personal communication, Mike Graybill, OIMB, March 15, 1979). Approximately 120 harbor seals haul out in the Pigen Point area of Coos Bay. They use the bay for feeding, primarily on bait fish such as herring and eulachon, and have been sighted in both the upper and lower bay. There is evidence that lower North Spit serves as a pupping area (pers. comm., Graybill). Harbor porpoises live in the lower estuary where they are seen frequently from RM 1 to 3.

Non-resident marine mammals occasionally sighted in the bay include California sea lions (*Zalophus californianus*), Stellar sea lions (*Eumetopias jubata*), and rarely California gray whales (*Eschrichtius gibbosu*) and killer whales (*Orciniis orca*).

River otters are common in the Coos and Millicoma rivers (pers. comm., Bender) and have been seen in the Crawford Point area (pers. comm., Graybill) and in South Slough (Magwire 1976a). The population size is unknown.

A variety of mammals are found in Coos Bay salt marshes. Raccoon, bobcat, muskrat, mink, weasel, fox, coyote, black-tailed deer (Magwire 1976a), and striped skunk (Pinto 1972) are found in the salt marshes, and beaver are found in areas of inflowing fresh water (Magwire 1976a). The marsh is only part of the range of animals, and their abundance depends primarily on how remote and undisturbed the community is (Magwire 1976a).

The major small mammals of the marshes are vagrant shrews and deer mice. The deer mouse is most abundant in the high marsh and tends to remain close to the terrestrial environment, while the shrew uses lower marshes and is often near logs or debris. Other species of mice, shrews, voles, and the black rat use the marshes in lesser numbers. These small mammals serve as primary and secondary consumers in the terrestrial food chain (Magwire 1976a).

Birds

Although a thorough study of the use of the estuary by bird populations has not been published, observations by individuals and groups provide information on seasonal use and abundance of bird species at Coos Bay. USACE (1975) abstracted a list of birds using the bay from information published by U.S. Department of the Interior (1971). Magwire (1976a) has summarized observations by Wampole (1959), Fawver and Wampole (1971), McGie (1976), and Richer (1976). Table 12 presents a compilation of this information. In addition, a census of birds of the greater Coos Bay area is made each December by the local chapter of the National Audubon Society.

Table 12. Bird use of Coos Bay estuary (key on p. 46).

Species	Subsystems: Marine & Lower Bay	Subsystems: Upper Bay	Subsystems: Riverine	Habitats: Channel	Habitats: Unconsolidated Shores & Flats	Habitats: Rocky Shores	Habitats: Tidal Marsh	Coos Head W	Coos Head S	Fossil Point to Pigeon Point W	Fossil Point to Pigeon Point S	Empire W	Empire S	Pony Slough W	Pony Slough S	Haynes Inlet W	Haynes Inlet S	Metcalf *Salicornia* Marsh W	Metcalf *Salicornia* Marsh S
Arctic loon (*Gavia arctica*)	FWSp			U				0	U	C	U	U						C	
Red-throated loon (*G. stellata*)	FWSP			U				0	0			0				0	0	0	
Red-necked grebe (*Podiceps grisegena*)	FWSp			U						0		C		0					
Brown pelican (*Pelecanus occidentalis*)	F			U				0	0										
Brandt's cormorant (*Phalacrocorax penicillatus*)	Res			C															
Pelagic cormorant (*P. pelagicus*)	Res			C				A	A	0	0	0				0	0		
Black brant (*Branta nigricans*)	Sp			A[1]	A[1]			0		A	A	R				A		U	
Harlequin duck (*Histrionicus histrionicus*)	FWSp			R		R		0	R					R		R			
Oldsquaw (*Clangula hyemalis*)	W			R				0	R										
Common scoter (*Oidemia nigra*)	W			U								R							
Surf scoter (*Melanitta perspicillata*)	FWSp			A				A	U	A	C	A	A	U	U			A	A
Red-breasted merganser (*Mergus serrator*)	FWSp			U				0	0	U		C	U	U		U			
Surfbird (*Aphriza virgata*)	FWSp					C		C	0										
Ruddy turnstone (*Arenaria interpres*)	M					U							R						

Table 12 continued.

Species	Subsystems			Habitats				Subsystems or Specific Areas											
	Marine & Lower Bay	Upper Bay	Riverine	Channel	Unconsolidated Shores & Flats	Rocky Shores	Tidal Marsh	Coos Head		Fossil Point to Pigeon Point		Empire		Pony Slough		Haynes Inlet		Metcalf *Salicornia* Marsh	
								W	S	W	S	W	S	W	S	W	S	W	S
Red phalarope (*Phalaropus fulicarius*)	M			R															
Northern phalarope (*Lobipes lobatus*)	M			C										R					
Glaucous-winged gull (*Larus glaucescens*)	FWSp			C								C				O			
Herring gull (*L. argentatus*)	FW			U				O				A	A	C					
California gull (*L.californicus*)	FW			U										R					
Mew gull (*L. canus*)	FWSp			C				C	U			C	O	C	O				
Heerman's gull (*L. heermanni*	SF			C				O	U								O		
Bonaparte's gull (*L. philadephia*)	M			C				C	U				O		O		O		
Blacklegged kittiwake (*Rissa tridactyla*)	FWSp			R				O	O										
Caspian tern (*Hydroprogne caspia*)	M			U					R						R				
Common Murre (*Uria aalge*)	Res			A				U	A			O	U		U				
Marbled Murrelet (*Brachyramphus marmoratum*)	Res			R						C		C		C		U		C	C
Horned grebe (*Podiceps auritus*)	FWSp	FWSp		C															
American wigeon (*Mareca americana*)	W	W		A	A		A							A		A			

Table 12 continued.

Species	Subsystems: Marine & Lower Bay	Subsystems: Upper Bay	Subsystems: Riverine	Habitats: Channel	Habitats: Unconsolidated Shores & Flats	Habitats: Rocky Shores	Habitats: Tidal Marsh	Coos Head W	Coos Head S	Fossil Point to Pigeon Point W	Fossil Point to Pigeon Point S	Empire W	Empire S	Pony Slough W	Pony Slough S	Haynes Inlet W	Haynes Inlet S	Metcalf *Salicornia* Marsh W	Metcalf *Salicornia* Marsh S
Black-bellied plover (*Squatarola squatarola*)	FWSp	FWSp			C		C	R						C	U			R	
Semi-palamated plover (*Charadrius semipalmatus*)	M	M			C							U		U	U				
Snowy plover (*C. alexandrinus*)	Res	Res			R														
Whimbrel (*Numenius phaeopus*)	F	F			U														
Spotted sandpiper (*Actitus macularia*)	F	F				U			O						U				
Dunlin (*Erolia alpina*)	WSp	WSp			A			O	O	C	O	C	C	A	A			O	O
Sanderling (*Crocethia alba*)	FWSp	FWSp			C							C	C	O					
Baird's sandpiper (*Erolia bairdii*)	F			F	R														
Western sandpiper (*Ereunetes mauri*)	FWSp	FWSp			A														
Least sandpiper (*Erolia minutilla*)	FWSp	FWSp			A														
Willet (*Catoptrophorus semipalmatus*)	M	M			U		U												
Western gull (*Larus occidentalis*)	Res	Res		A						C		C		U		C	U	C	C
Common tern (*Sterna hirundo*)	M	M		U					R						R				
Pigeon guillemot (*Cepphus columba*)	S	S		C				U	A		U		U		U				C

Table 12 continued.

Species	Subsystems				Habitats			Subsystems or Specific Areas											
	Marine & Lower Bay	Upper Bay	Riverine	Channel	Unconsolidated Shores & Flats	Rocky Shores	Tidal Marsh	Coos Head		Fossil Point to Pigeon Point		Empire		Pony Slough		Haynes Inlet		Metcalf *Salicornia* Marsh	
								W	S	W	S	W	S	W	S	W	S	W	S
Common loon (*Gavia immer*)	FWSp	FWSp	FWSp	C				A	C	C	O	C	O	C	O	C	O	C	
Pied-billed grebe (*Podiceps dominicus*)	W	W	W	R				O	R					O		O	O	U	
Western grebe (*Aechmophorus occidentalis*)	FWSp	FWSp	FWSp	C															
Double-crested cormorant (*Phalacrocorax auritus*)	FWSp	FWSp	FWSp	C				C	U	A		U		C		O	O	U	
Common goldeneye (*Bucephala clangula*)	W	W	W	C			U	O				U		R		U		R	
Bufflehead (*B. albeola*)	W	W	W	C				O		C		U		C		C		C	
Marsh hawk (*Circus cyaneus*)	Res	Res	Res				U		O					O					
Bald eagle (*Haliaeetus leucocephalus*)	Res	Res	Res				R	R	R							R			
Red-tailed hawk (*Buteo jamaicensis*)	FWSp	FWSp	FWSp				U												
Great Blue heron (*Ardea herodias*)	Res	Res	Res		U		C	U	U	U	U	U		C	C	C	C	C	C
Green heron (*Butorides virescens*)	Res	Res	Res		U		U								O				
American coot (*Fulica americana*)	FWSp	FWSp	FWSp	A			A	U	O	C	C	C	C	A		A		O	
Killdeer (*Charadrius vociferus*)	Res	Res	Res		C			U	U	U		C	C	C	C	U			
Belted kingfisher (*Megaceryle alcyon*)	Res	Res	Res	C								U	U	C	C			C	C

Table 12 continued.

Species	Subsystems: Marine & Lower Bay	Subsystems: Upper Bay	Subsystems: Riverine	Habitats: Channel	Habitats: Unconsolidated Shores & Flats	Habitats: Rocky Shores	Habitats: Tidal Marsh	Coos Head W	Coos Head S	Fossil Point to Pigeon Point W	Fossil Point to Pigeon Point S	Empire W	Empire S	Pony Slough W	Pony Slough S	Haynes Inlet W	Haynes Inlet S	Metcalf *Salicornia* Marsh W	Metcalf *Salicornia* Marsh S
Whistling swan (*Olor columbianus*)		W					R							R					
Canada goose (*Branta canadensis*)		M					R	O											
Pintail (*Anas acuta*)		FW		A										A	C	A			
Gadwall (*A. strepera*)		FW					U							A					
Shoveler (*Spatula clypeata*)		FW		U	U									C					
Green-winged teal (*Anas carolinensis*)		FW		C	C									A	C	A	O		
Redhead (*Aythya americana*)		W		C										O					
Canvasback (*A. valisineria*)		W		C										A		C			
Blue-winged teal (*Anas discors*)		M		R															
Snowy egret (*Leucophoyx thula*)		W					R							R					
Virginia rail (*Rallus limicola*)		SpSF					U												
Long-billed curlew (*Numenius americanus*)		M			R		R							U					
Marbled godwit (*Limosa fedoa*)		FW			U									O					
Greater yellowlegs (*Totanus melanoleucus*)		FWSp			U									C	O				

Table 12 continued.

	Subsystems				Habitats			Subsystems or Specific Areas											
Species	Marine & Lower Bay	Upper Bay	Riverine	Channel	Unconsolidated Shores & Flats	Rocky Shores	Tidal Marsh	Coos Head		Fossil Point to Pigeon Point		Empire		Pony Slough		Haynes Inlet		Metcalf *Salicornia* Marsh	
								W	S	W	S	W	S	W	S	W	S	W	S
Lesser Yellowlegs (*Totanus flavipes*)		M(F)			R														
Short-billed dowitcher (*Limnodromus griseus*)		M			U									C	C		O		
Long-billed dowitcher (*L. scolopaceus*)		M(F)			R														
Pectoral Sandpiper (*Erolia melanotos*)		M(F)					R							R					
Knot (*Calidris canutus*)		M			U		U												
American bittern (*Botaurus lentiginosus*)		Res	Res				R												
Common egret (*Casmerodius albus*)		FWSp	FWSp				C							U					
Black-crowned night heron (*Nycticorax nycticorax*)		FWSp	FWSp		U														
Sora rail (*Porzana carolina*)		SpS	SpS				R												
Common snipe (*Capella gallinago*)		Res	Res		U		U							U					
Ring-billed gull (*Larus delawarensis*)		FWSp (Res)	FWSp (Res)		C							C	C	C	C	U	U		
Mallard (*Anas platrhynchos*)			FW	A	C		C							A	C	A			
Ring-necked duck (*Aythya collaris*)			W	R										R					
Common merganser (*Mergus merganser*)			Res	U												R			

Table 12 continued.

Species	Subsystems				Habitats			Subsystems or Specific Areas											
	Marine & Lower Bay	Upper Bay	Riverine	Channel	Unconsolidated Shores & Flats	Rocky Shores	Tidal Marsh	Coos Head		Fossil Point to Pigeon Point		Empire		Pony Slough		Haynes Inlet		Metcalf *Salicornia* Marsh	
								W	S	W	S	W	S	W	S	W	S	W	S

Key:

Seasonal Use:

F Fall
W Winter
Sp Spring
S Summer
M Migrant
Res Resident
(Res) Some residents

Abundance:

A = Abundant
$\geq$ 50/day/observer

C = Common
10-49/day/observer

U = Uncommon
0-9/day/observer

R = Rare
$\leq$ 5/day/observer
(includes very rarely sighted species)

Key:

Seasonal Use:

W = Oct. - Mar.
S = Apr. - Sept.

Abundance:

A = Abundant
$\geq$ 50/day/observer

C = Common
1-50/day/observer

U = Uncommon
Not seen each day

O = Occasional

R = Rare
Not seen every year

[1] *Eelgrass beds*

Table 12 continued.

Species noted by Magwire 1976 but not by USACE 1975	C H		F Pt, P Pt		Emp		P Sl		H I		MM	
	W	S	W	S	W	S	W	S	W	S	W	S
Yellow-billed loon *(Garia adamsii)*		R										
Eared grebe *(Podiceps caspicus)*		O	C		O		O	O	C	O	C	
Emperor goose *(Anser albifrons)*											R	
White-fronted goose *(Philacte canagica)*							R					
European wigeon *(Mareca penelope)*							R					
Hooded merganser *(Lophodytes cucullatus)*									R			
Turkey vulture *(Cathartes aura)*	O	U						O				
Osprey *(Pandron haliaetus)*		O						O	O			
Black oystercatcher *(Haematopus bachmani)*	U	O										
Wandering tattler *(Heteroscelus incanun)*	U	O										
Rock sandpiper *(Erolia ptilocnemis)*		O										
Forster's tern *(Sterna forsteri)*		R										
Common crow *(Corvus brachyrhychos)*					C	C	C	C	C	C	C	C

Coos Bay is located in the Pacific Flyway for migratory waterfowl. USDI (1971) lists marshes, tideflats, and open water as prime bird habitats with some birds relying entirely on one habitat type and others using a variety of habitats.

Ducks, geese, loons, gulls, murres, and terns use the open water for resting but are commonly found near food sources in shallow water (USDI 1971). Thompson, Smith, and Lauman (1972) state mallard, pintail, wigeon, and coot are the most abundant waterfowl of the area. Surf and white-winged scoters are also found in large numbers. Waterfowl are abundant in November through March with peak populations occurring in December. USDI (1971) states that Coos Bay has 575,000 waterfowl-use days annually and 1,350 hunter-use days. The protected Pony Slough and Haynes Inlet areas receive particularly heavy use by waterfowl.

COOS ESTUARINE SUBSYSTEMS

The Coos Bay estuary can be divided into marine, bay, riverine and slough subsystems based on sediments, habitats, and geographic location (Fig. 17). Physical and biological characteristics of each subsystem are a result of the relative influence of ocean water, river water, and currents. Although the subsystems do not function independently, a separate discussion of each of the subsystems is used in considering management options.

Marine Subsystem

The marine subsystem is defined as the area between the mouth of the Coos Bay estuary and RM 2.5 (Fig. 17). The vigorous wave action it experiences helps to create and maintain the unique habitats found in this subsystem.

Alterations to the marine subsystem have been numerous. The natural channel across the Coos Bay bar averaged 10 ft in depth and 200 ft in width. The first alteration was a half-tide jetty just upbay from Fossil Pt. constructed in 1880 (USACE 1973). The North Jetty was constructed in the 1890s and reconstructed in the late 1920s, when the South Jetty was built (Lizarraga-Arciniega and Komer 1975). The entrance channel has recently been dredged to 45 ft deep and 700 ft wide at the outer bar and gradually decreases to 35 ft deep and 300 ft wide at RM 1. Previously, the depth was maintained at 40 ft over the entrance bar and 30 ft at RM 1 (USACE 1975).

The entrance channel is exposed to high waves generated by local coastal storms and swells from Pacific Ocean storms (USACE 1973). Waves up to 27 ft occur during major storms (USACE 1973). Mean tidal range at the bar is 6.7 ft with predicted extremes of 10.5 ft above MLLW and 3 ft below MLLW.

During 1973-74, high tide salinities at the mouth ranged from 30.5 ppt at the surface in December to 33.9 ppt at both surface and bottom in June (Arneson 1976). Even during periods of high runoff, high tide salinity at the mouth is similar to that of the ocean. Low tide extremes of 13.0 ppt at the surface in December and 3.33 ppt in September demonstrate the dilution effect of high runoff (Arneson 1976). Vertical salinity profiles from 1973-74 show the mouth was well mixed in June and September, stratified at high tide and partially

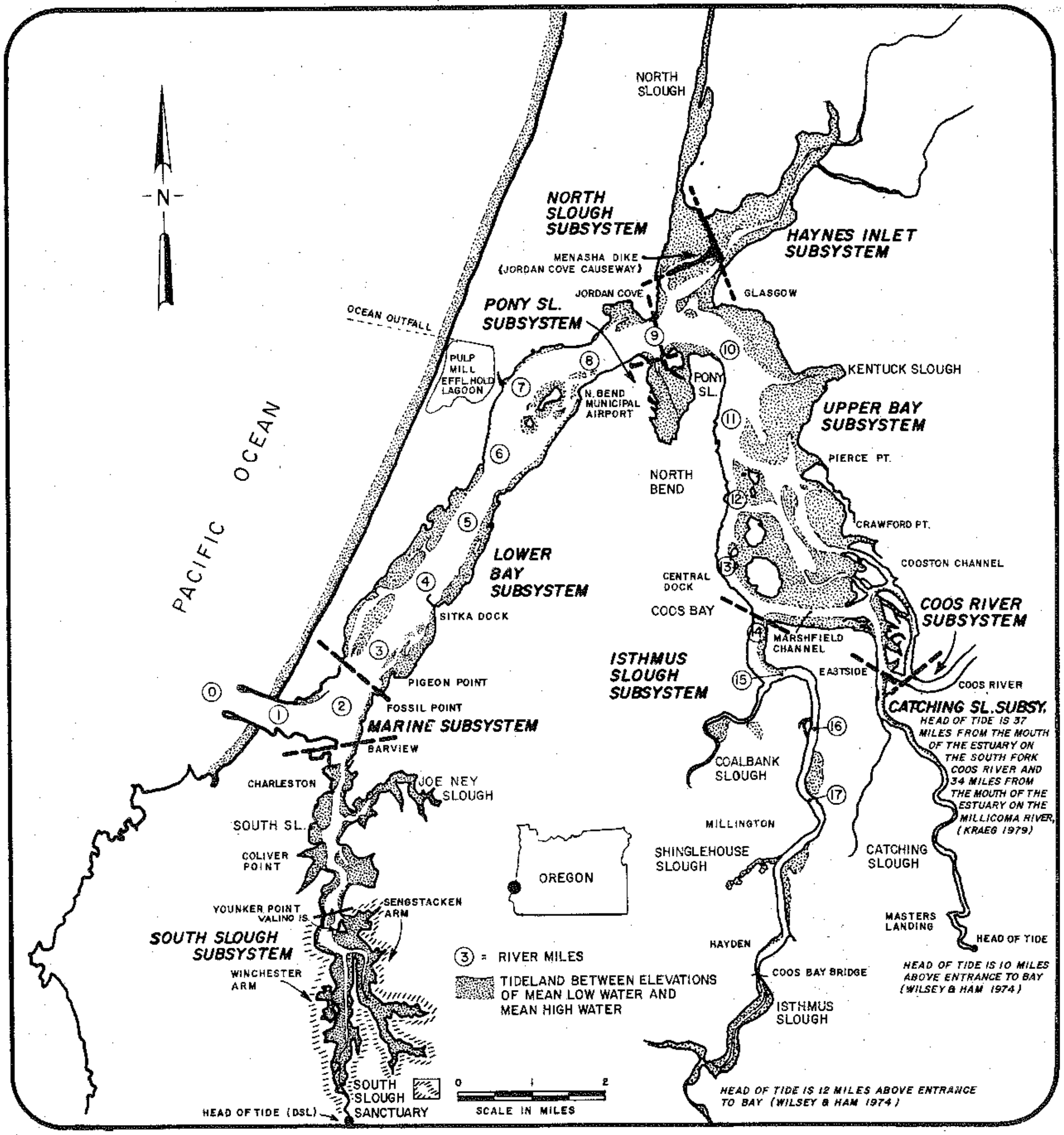

Fig. 17. Coos Bay estuarine subsystems.

mixed at low tide in December, and well mixed at high tide and partially mixed at low tide in March (Arneson 1976).

In general, the water quality of the marine subsystem is good. Temperature generally is similar at high tide to that of offshore waters and may be somewhat influenced by the temperature of the inflowing river waters at low tide (Arneson 1976). Low dissolved oxygen has occasionally been measured by DEQ near the mouth, and a DO depression was also observed by Arneson (1976) during his fall low tide measurements. Waste water from seafood processing which is discharged subtidally into the marine subsystems and upwelling of offshore waters low in dissolved oxygen may be contributing factors to low DO near the mouth (Arneson 1976).

Dredging records show that most of the materials removed from the entrance are clean sands, probably of marine origin (USACE 1975). Dredged material from this area is normally disposed at sea. Spoil from the Charleston area to about RM 10 is disposed in the estuary. The shorelines to the north and south of the entrance advanced following construction of the jetties, probably as an adjustment to a new equilibrium in an area that is experiencing no net north-south sand transport along the beaches (Lizarraga-Arciniega and Komar 1975).

Habitats and species

The marine subsystem has an exceptional diversity of habitats, including sand, cobble, boulder, and bedrock shores; sand and sand-mud flats; algal beds on unconsolidated bottoms and on bedrock; eelgrass; and subtidal unconsolidated bottom (Fig. 18).

Habitats of the north shore of the marine subsystem include the artificial boulder shores of the jetty, a narrow cobble shore, sandy shores and flats, and a flat of sand-mud substrate (Fig. 18). Little is known of the biology of this area. Seining studies have shown large numbers of Pacific herring, surfsmelt, whitebait smelt, shiner perch, and silver surfperch in the area (Hostick 1975). Feeder coho salmon have been found using the sandy area just inside the jetty. This area is just below a very productive portion of the lower bay subsystem and the salmon may be feeding on material carried in the water column as it ebbs from the productive flats (personal communication, Bill Mullarkey, ODFW, May 15, 1979).

The south shore habitats of the marine subsystem include jetty boulders, bedrock shores below the cliffs of Coos Head, small sandy shores, the boulders of the Charleston breakwater, and a transient sand bar west of the Charleston channel (Fig. 18).

The area north of the Charleston breakwater is inhabited primarily by a few species of molluscs and annelids. The sand bar west of the Charleston channel contains the only in-bay population of razor clams on the southern Oregon coast. This clam bed is heavily used by recreational diggers (USACE 1978). USACE has proposed an extension of the Charleston breakwater near the sand spit to stabilize the Charleston channel. The Corps Environmental Impact Statement for this project (USACE 1978) states the clam population will survive the planned modification.

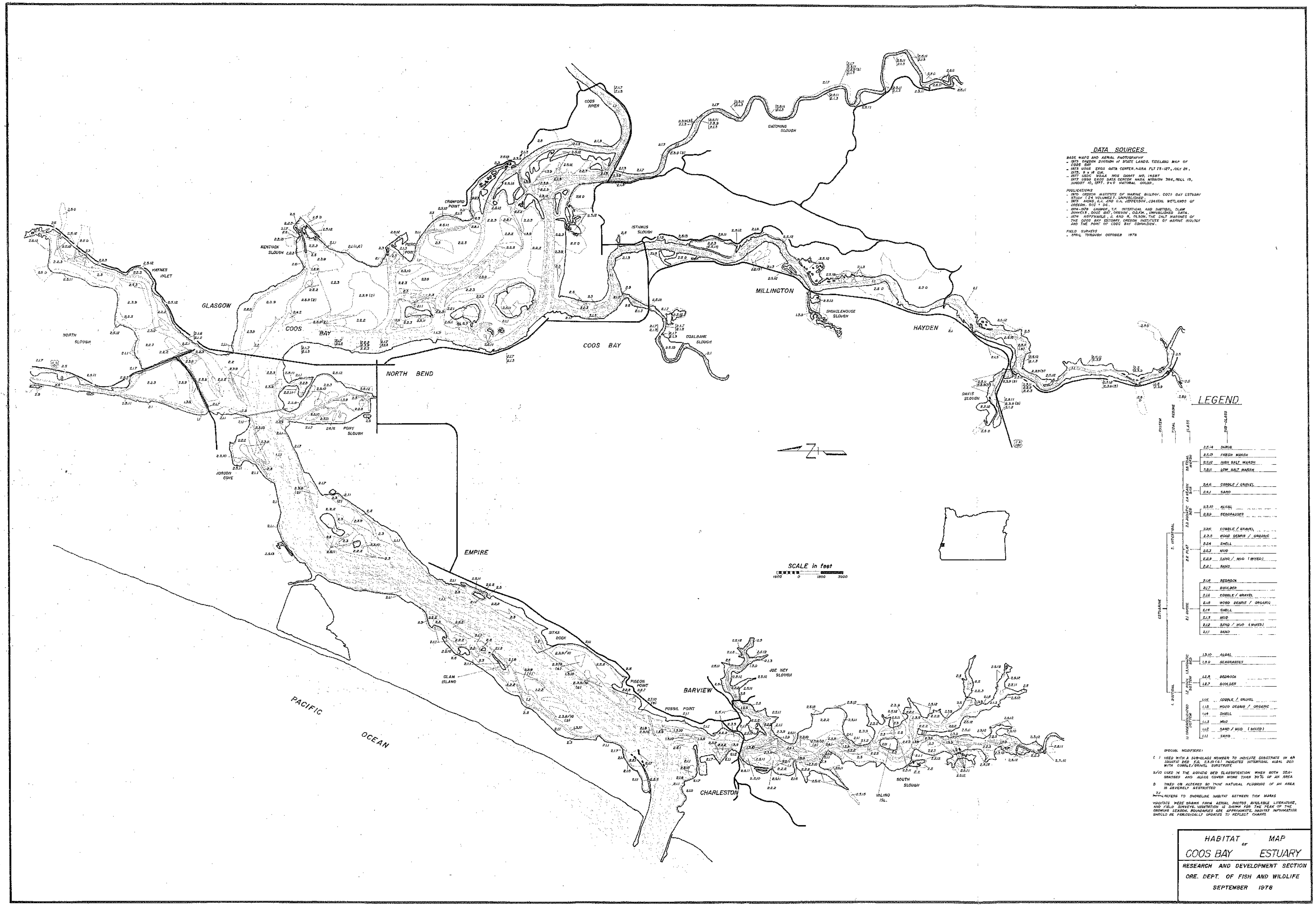

Fig. 18. Habitat map of Coos Bay.

The eastern shore of the marine subsystems has the largest naturally occurring rock habitat in the estuary. This high salinity, protected bedrock is unique to the Coos Bay marine subsystem and is rare in other Oregon estuaries. Over 40 species of plants and 100 species of animals inhabit this area in a community that resembles typical protected outer coast algal and invertebrate communities (Rosenkeetter et al. 1970). Green, brown, and red algae are well represented in the flora of Fossil Pt. (Sanborn and Doty 1944). Sponges, sea anemones, hydroids, and ribbon worms are found in this area (USACE 1975). Certain groups of annelids (sabellids, serpulids, syllids, and phyllodocids), grazing gastropods, carnivorous snails, and nudibranchs are also common.

Small kelp (*Nereocystis leutkeana*) beds occur in the tidal area just north of Coos Head, north of Charleston breakwater, and southward of Fossil Pt.

During the summer sampling, certain fishes were found only in the marine subsystem (Table 9) (Hostick 1975). These fish are commonly associated with open coastal waters. The apparent restriction of these species to the marine subsystem may be due to physiological tolerances or preference for rocky habitat. Almost all other species recorded in the estuary occur in the marine subsystem at some time during the year as residents or migrants (Cummings and Schwartz 1971).

A substantial percentage of the 1978 Pacific herring spawn in Coos Bay occurred on the rocks, algae, and eelgrass of the Fossil Pt. area (Miller and McRae 1978).

The South Jetty is a popular area for sport angling and offers the most varied species to shore fishermen (Gaumer et al. 1973). Redtail surfperch, striped seaperch, Pacific tomcod, starry flounder, and kelp greenling were the most frequently taken fish (Gaumer et al. 1973). A small fishery for chinook and coho salmon occurs from the jetties in late summer. Black rockfish, Pacific tomcod, coho salmon, and Dungeness crab are taken in large numbers in the marine subsystem by boat anglers.

Within Coos Bay, brown pelican, harlequin duck, oldsquaw, surfbird, and blacklegged kittiewake, yellow-billed loon, black oystercatcher, wandering tattler, rock sandpiper, and Forster's tern have been observed only in the marine subsystem (Table 12). Common murres and pigeon guillemots are most abundant in the bay at Coos Head (pers. comm., McGie). Bald eagle and osprey are occasionally sighted (pers. comm., McGie). Pelagic cormorant are abundant at Coos Head, and a nesting population of 12 to 15 pairs occurs on the cliffs there (Graybill 1978). Belted kingfisher and rough winged swallows also nest along the cliffs at Coos Head.

Recommendations

The marine subsystem of Coos Bay contains unique habitats not found in other sybsystems of the estuary and infrequently occurring in other Oregon estuaries. Fossil Pt. is the only naturally occurring rock in the bay exposed to vigorous wave action. Within the area are a biologically significant algal bed and subtidal kelp bed. It provides habitat for diverse invertebrates and fishes and an important spawning site for herring. It is also a valuable scenic and open-space resource. Only those low intensity uses which will not substantially alter these existing habitats and species should be permitted.

The cliffs of Coos Head, which provide nesting areas for pelagic cormorants, kingfishers, and swallows, and the tidal sand flat west of Charleston channel, whch has the only in-bay population of razor clams on the south coast, should be protected in order to maintain the diversity of habitats within Coos Bay and among Oregon estuaries.

Use policies of the marine subsystem should strive to protect water quality. It may be appropriate to restrict discharge of effluent at low tide during times of low river flow or high water temperature.

Lower Bay Subsystem

The lower bay subsystem extends along the main channel from RM 2.5 to the railroad bridge at RM 9 (Fig. 17). Although still under considerable oceanic influence, it is not as strongly affected by wave action as is the marine subsystem.

Salinity extremes recorded by DEQ in this subsystem were 34.0 ppt and 10.7 ppt at a station 1/4 mile north of Pigeon Point, compared to 34.2 ppt and 3.7 ppt at a station 1/4 mile west of the railroad bridge. During 1973-74 surface salinity from RM 2.9 to RM 8.3 at one time differed as little as 0.3 ppt at high tide during periods of low flow to as much as 14.4 ppt at high tide during periods of high flow (Arneson 1976). Surface salinity changed from 24.7 ppt to 11.5 ppt between high and low tides during high flow at RM 2.9 (Arneson 1976).

Salinity gradients indicated the lower bay was well mixed at times of low flow. During high flow the subsystem was stratified at high tide and partly mixed at low tide. During intermediate flows (March), it was partially mixed at low tide and well mixed at high tide.

Dissolved oxygen levels measured at DEQ monitoring stations in the lower bay have been above the minimum standards required for estuarine waters during the 70s (DEQ 1978). However, one sample taken near a log dump in Empire showed very low DO and high turbidity (STR 1974, USACE 1975).

Coliform counts exceeding standards for commercial shellfish harvest and even exceeding general health standards have frequently been measured at DEQ Station 6, 1/4 mile west of the railroad bridge (DEQ 1978). Counts exceeding standards at other DEQ stations in the lower bay are infrequent. Two sewage treatment plants discharge waste from the east side of the lower bay near Empire and near Pony Slough.

Pollutants discharged in the lower bay may not be rapidly flushed through the estuary. Flushing times ranged from 6.2 days in December to 19 days in June 7.6 miles from the mouth (Arneson 1976).

The sediments of the lower bay are predominantly marine sands (Arneson 1976) and probably include sands blown into the bay from the dunes.

Habitats and species

Subtidal habitats of the lower bay include the unconsolidated bottom of the dredged ship channel and adjacent area and aquatic beds in shallower areas (Fig. 18). The substrate is primarily sand (USACE 1975, Jefferts 1977). Shell and wood mixed with sand have also been reported at RM 7, 8, and 9 (Jefferts 1977).

The major alteration to the subtidal lower bay is channel dredging and associated in-bay spoil disposal. Disposal sites for the recently completed deep draft dredging project were adjacent to the channel at about RM 3, between RM 4 and 5, just below RM 6, and between RM 8 and 9.

Biological information on the subtidal lower bay is incomplete. Jefferts (1977) has examined infauna of the dredged ship channel, and ODFW has surveyed clam populations of some subtidal areas (Gaumer 1978).

Surveys west of the channel between RM 4 and 6 show scattered distributions of gaper and cockle clams and densities of 1-5 clams/ft^2 (Figs. 9 and 10) (Gaumer 1978). Butter clams were found in only a few locations in the survey area (Fig. 13) (Gaumer 1978). A 48 ac subtidal area off Pigeon Point was thoroughly surveyed to evaluate its potential for commercial clam harvest (Gaumer 1976). Population estimates for that bed were 5,648,700 gapers, 202,200 cockles, 843,000 littlenecks, and 809,200 butters (Gaumer and Halstead 1976). The bed produced a commercial gaper harvest of 11,931 lb in 1977 and 27,505 lb in 1978.

The infauna of the lower bay dredged channel has numerous species representing many groups of animals (Jefferts 1977). The fauna is more diverse and less likely to be composed of cosmopolitan species than the upper reaches of the dredged channel. Both numbers of species and numbers of individuals were found to decrease with depth in the sediment. Jefferts (1977) concluded that dredging has a relatively minor influence on the fauna of the lower reaches of the estuary, which primarily reflect the coarse sediment type rather than the effects of mechanical disturbance.

The intertidal habitats of the west side of the lower bay include large aquatic beds, sand-mud flats, sand shores, and small marshes (Fig. 18). Between RM 2.5 and 6, flats prevail. From RM 6 to RM 8 there is a narrow sand shore, and between RM 8 and 9 lies Jordan Cove with its flats, aquatic beds, and fringe of marsh.

The southwestern portions of the lower bay has been altered through the disposition of dredge spoils which form "Clam Island" and which have raised some of the shoreline above tidal level. The eelgrass beds are quite extensive and the flats are probably the most productive clamming areas in the bay. Gaper clams occur in densities of greater than 5/ft^2 over much of the area (Fig. 9) (Gaumer 1978). Cockles, butter clams, and native littlenecks are also widely distributed over the flats but occur in lesser density than the gapers (Figs. 10 and 13). Softshell clams are not found in the southernmost flat but occur from Clam Island northward (Fig. 12) (Gaumer 1978).

The southern flat was by far the most prolific site for recreational gaper harvest during a 1971 ODFW survey (Gaumer et al. 1973). Substantial numbers of cockles and butter clams were also taken there.

Above RM 6 the narrow sandy shore drops off quickly into the subtidal zone. Current through this portion of the bay is swift and scours the shores so that attached vegetation is absent. Five pile dikes were placed along this shore to retard erosion and prevent further curvature of the ship channel (USACE 1973). While this area appears barren in comparison to the flats to the south, it is an important feeding area for Englis sole, topsmelt, surfsmelt, herring, northern anchovy, and coho and chinook salmon (pers. comm., Mullarkey). Many of these fish feed on material in the water column from productive areas adjacent. Gut content analysis of salmon seined in sandy areas during August 1978 showed larval fishes were the main diet during the period sampled (pers. comm., Bender).

Jordan Cove lies between RM 8 and 9. Recreationally important clams are scarce, but ghost shrimp occur in moderate density over the entire area of flats and aquatic beds (Fig. 15). Softshell clams are sparsely distributed around the edges of the flats, and smaller species of clams are scattered across the cove (Gaumer 1978).

Just west of the railraod bridge at Jordan Point is a sandy area where ODFW repeatedly seines large numbers of fish (pers. comm., Bender and Mullarkey). The site was highest in numbers of individuals and second in numbers of species taken during seining efforts in 1970 (Hostick 1975).

Below Sitka Dock on the east side of the lower bay, there are broad algal and eelgrass beds on a sand-mud substrate with three large areas of cobble, where dredeged materials have been deposited. The cobbles form a habitat that is unique in the bay and may add niches for colonization by marine life. A high density of marine species, primarily rockfish, have been consistently found there in recent ODFW surveys (pers. comm., Bender).

Gaper clams are much less dense here than on the west side of the bay (Gaumer 1978), but the area provided recreational diggers with the second highest number of gapers taken in 1971 (Gaumer 1973). Butter clams are found among the cobbles of the spoil site (Gaumer 1978), and the Pigeon Point flat was by far the most productive butter clam area in 1971 (Gaumer 1973). Pigeon Point was also the prime site for the harvest of littleneck clams (Gaumer 1973). Ghost shrimp are also common in the area (Gaumer 1978).

The large eelgrass beds of the Pigeon Point area are of particular significance in providing food for migratory black brant. Harbor seals use one of the spoils disposal sites as a haul out area (pers. comm., Graybill). A historic seal haul out area is also located on the western shore of the lower bay just below the Ore-Aqua salmon ranching facility.

The tideflat habitats near Sitka Dock were significantly degraded by waste discharge from the Coos Head Pulp Mill which operated until 1971. Biological productivity has been increasing since closure of the mill (George M. Baldwin and Associates et al. 1977). A dense eelgrass meadow has become established southwest of the mill site, and gaper, tellen (*Tellina* sp.), cockle, *Macoma* spp., and softshell clams occur there (George M. Baldwin and Associates et al. 1977). Studies of the recovery of the flat have not been undertaken. The area is under private ownership and is not available to the public for recreation.

North of Sitka Dock, ghost shrimp, tellens, *Macoma* spp., and softshells inhabit the sand-mud flats and eelgrass beds. Flats there provided the greatest number of ghost shrimp to diggers of the areas surveyed in 1971 but were used much less heavily than the Pigeon Point flats (Gaumer 1973). Limited access and the clam distribution may influence the use pattern.

The narrow north shore of Empire, which is affected by storage of logs at the Cape Arago Lumber Company Mill, gradually widens into the broad complex of flats, aquatic beds, and small marshes southwest of North Bend Municipal Airport (Fig. 18). Qualitative studies show that the area is inhabited by softshell clams, tellens, *Macoma* spp., and polychaete worms (Figs. 12, 14, and 11). A quantitative study of the area has recently been completed and will be available through LCDC (Gonor 1979).

Several fish species are found in the lower bay nad marine subsystems (Table 9). Other species, such as English sole are most abundant in the lower bay, although they may be found further upbay. Sampling during the summer of 1970 showed that juvenile chinook salmon and lingcod were most common at lower bay sites (Hostick 1975; Cummings and Schwartz 1971).

Most of the fish species of Coos Bay use the flats of the lower bay at some time during the year (Cummings and Schwartz 1971). Habitat has considerable bearing on types of fish present. Vegetated areas appear to exhibit greater species diversity and are preferred by surfperch, pipefish, snake prickleback, gunnel species, and starry flounder (pers. comm., Mullarkey). Many of the species are found in greatest numbers over the sandy substrates (pers. comm., Mullarkey).

The aquatic beds adjacent to the North Spit, the Roseburg Lumber Co. dock, and the aquatic beds of Jordan Cove on the west side of the lower bay and the aquatic beds to the north and south of Sitka Dock are prime herring spawning areas (Jackson 1979; Miller and McRae 1978).

A salmon release-recapture facility (Oregon Aqua Foods) is located at about RM 5.5 on the west side of the bay. Another facility, Anadromous Inc., is located at Jordan Pt. at the extreme eastern border of the lower and upper bay subsystems (Fig. 17).

The lower bay was by far the most popular boat angling area in surveys conducted in 1971 (Gaumer et al. 1973). Dungeness crabs represented 80% of the catch. Black rockfish, red rock crab, perch species, and kelp greenling were also taken in large numbers (Gaumer et al. 1973).

Most of the bird species of Coos Bay may be found in the lower bay, and several species have their prime distributions in the lower bay and marine subsystems (Table 12). The more abundant of these birds include Brandt's cormorants, pelagic cormorants, black brant, surf scoters, northern phallaropes, western gulls, glaucous-winged gulls, mew gulls, Heerman's gulls, Bonaparte's gulls, and common murres. A variety of migrant and wintering shorebirds feed on the exposed intertidal mud flats.

Recommendations

The lower bay between RM 2.5 and RM 5 is an area of exceptional natural productivity and a prime aesthetic and recreational resource. The tideflats, eelgrass, and algal beds along the western shore of this region should be considered as major tracts, which require inclusion in a natural designation as described by the LCDC Estuarine Resources Goal (1977).

Although the sandy shore between RM 6 and 8 on the western side of the bay appears unproductive because it does not have attached vegetation, it is a valuable habitat for certain species of fish. Any development occurring there should preserve the sandy substrate and water quality of the area. Use of pilings may be appropriate in the area unless subsequent reduction in current velocity changes the quality of the substrate.

Sitka Dock at about RM 3.8 is located along the eastern shore of the productive lower bay. The adjacent area was formerly degraded by waste discharges, but some evidence suggests that the nearby tidal flats are recovering. Upland uses near the Sitka Dock area are primarily residential. The location of the dock within a prime natural and recreational resource area makes the area unsuitable for industrial development, but water-dependent recreational development would appear to be appropriate.

A public boat ramp, fish processing plant, oil company docks, and a mill are located on the eastern shore at Empire. These developments contribute to degradation of the habitats. Habitat restoration or further development for water-dependent uses, preferably constructed on pilings, are possibilities for this area.

The large flats southwest of the North Bend Airport and the Jordan Cove area should be considered major tracts and protected accordingly (LCDC 1977).

In-bay spoiling of material dredged from the channel between RM 3 and RM 10 should be discontinued. This activity reduces the tidal prism and further increases filling of the estuary, which is already accelerated from upstream activities. Habitat is irreversibly lost, even with mitigation. Suitable areas should be located for upland or offshore spoil disposal.

Upper Bay Subsystem

In the upper bay subsystem Coos Bay broadens into a complex of wide shallow tidal flats adjacent to the main dredged ship channel (Fig. 18). It extends from the railroad bridge at RM 9 to the southeastern corner of Bull Island at RM 17 (Fig. 17).

Massive alterations have occurred in the upper bay. The dredged ship channel runs along the west side of the bay, and industrial activity for the Port of Coos Bay is centered there. The channel between RM 9 and the mouth of Isthmus Slough is 35 ft deep and 400 ft wide. A turning basin 35 ft deep, 800 ft wide, and 1000 ft long is at RM 12. Filling of tidelands has occurred along the western shore, south of Marshfield Channel at Eastside, and on the major tideflats, where dredged materials form several spoil islands. Much of the filling has occurred to dispose dredged material and to provide sites for industrial development. The upper bay also receives industrial wastes and is a site of log storage and handling.

The upper bay receives freshwater inflow from Coos River, Catching, Isthmus, Kentuck, and North sloughs, and Haynes and Willanch inlets. Measurements at the mouth of Kentuck Slough indicate salinity extremes of 33.7 ppt and 3.0 ppt, while extremes measured at the mouth of Marshfield Channel were 33.7 ppt and 0.5 ppt (DEQ 1978). The organisms of the upper bay are exposed to low salinity during freshets, but the water is saline during low flows.

Extreme tidal currents of 4 ft/s have been measured at North Bend, and mean currents are about 1 ft/s (Aagard et al. 1971). Mean seaward velocity of river dishcarge passing a cross section between North Bend and Pierce Pt. is less than 0.1 ft/s at times of low runoff and 3-4 ft/s during peak runoff. Seaward ebbs of 6-8 ft/s during periods of high runoff have been predicted (Aagard 1971).

Wave development over the tideflats of the upper bay is limited by the short fetch and shallow water. Before recent channel deepening, phase changes indicated high dampening of the tidal wave in the upper bay as tidal energy was spent in turbulent mixing over the wide tideflats (Blanton 1964). Mixing in the main bay was probably sufficient so that stagnation causing anoxic conditions did not occur in the main bay (Aagard et al. 1971). The effect of recent channel deepening on tidal circulation has not been evaluated.

Sediments of the upper bay main channel are sandy from RM 9 to RM 10.5, shell from RM 10.5 to RM 12, and mud from RM 12 to RM 15 (USACE 1975). The main channel adjacent to Coos Bay is the area of most active deposition of river sediments (Aagard et al. 1971). Prior to channel deepening, RM 12-15 have been dredged every three years with an average of 450,000 yd^3 of sediment removed annually (USACE 1976). Sediments removed from the main channel above RM 12 do not pass EPA pollution standards for in-water disposal of materials. The sediments of the upper bay tidal flats are primarily silty with some areas of sand near the spoils islands. Wood debris overlies the sediments in many areas (Ednoff 1970).

During the past century the Coos River has changed its course through the upper bay (Aagard et al. 1971). Formerly the main flow of the river was east of Bull Island. At the northern end of Bull Island, it bifurcated into the East Channel and the main Marshfield Channel. At that time, Catching Slough had a large tidal prism and strong tidal flushing.

Splash damming, log transportation, and dredging have increased the size of the channel to the south of Bull Island (the Cutoff) so that it now carries the main flow of the river. As recently as 1970 the channel northwest of Bull Island has been deepening and eroding the tip of the island. From 1944 to 1970 the Cooston and East channels have been stable with minimal channel migration and sedimentation (Aagard et al. 1971). The tendency for channel migration does exist, and changes in hydrographic conditions, such as major dredging projects, may have unpredicted effects on shifting river channels.

Elutriate tests of core and water samples indicate that the main ship channel above RM 12 is polluted (USACE 1976). Coliform counts at DEQ stations in the upper bay during the 70s have frequently been higher than general standards for estuarine waters. In the main shipping channel, the frequency of violations increased from the station at the mouth of Kentuck Slough to the station at the mouth of Marshfield Channel (DEQ 1978). Dissolved oxygen less than the 6 ppm standard for estuarine waters was also measured with increasing frequency (DEQ 1978). STR (1974) attributed coliform problems to the presence of municipal sewage treatment plants and DO problems to municipal sewage treatment plants, industrial wastes, and log storage.

Habitats and species

Subtidal areas of the upper bay include the deep draft dredged ship channel; the shallowly dredged Marchfield, Cooston, and East channels; and the smaller channels draining the tidal flats (Fig. 18). Most of the information available on the upper bay subtidal concerns the dredged ship channel. The ship channel presents an altered environment for colonization by estuarine species. Maintenance dredging, propellor wash, and anchor drag frequently resuspend sediments so that little attached vegetation can grow (Parr 1974).

The benthic fauna of the dredged channel represents a community that has become adapted to the stresses of frequent sediment disruption (Parr 1974). Patches of substrate missed during dredging may be important to re-establishment of benthic organisms (Slotta et al. 1974).

Streblospio benedicti, an annelid, is the dominant organism in the upper bay subtidal area (Parr 1974; Jefferts 1977). Species most frequently encountered by Parr (1974) were

Annelids:

Streblospio benedicti
Pseudopolydora kempi
Polydora ligni
Eteone lighti
Capitella (capitata) ovincola
Notomastus (Clistomastus) tenuis
Glycinde armigera

Bivalves:

Macoma inconspicua
Clinocardium nuttallii
Mya arenaria
Modiolus sp.

Pycnogonids:

Achelia nudiuscula
Achelia chelata

Amphipods:

Corophium salmonis
Corophium spinicorne
Anisogammarus ramellus

These taxa are frequently reported in the literature to be associated with polluted environments (Parr 1974). Jefferts (1977) postulated that in the upper reaches of the estuary, the high water, organic content of the sediment, and the reduced grain size have a deleterious effect on faunal diversity and depth of distribution of organisms in the sediment.

Distribution of fish and of mobile invertebrates, such as crabs, in the dredged channel has not been adequately studied. Seining near the channel in 1970 revealed that shiner perch, silver surfperch, American shad, and English sole use the area in addition to a number of less freqeuntly captured species. More silver surfperch were captured per haul at this location than in other seining sites on the estuary.

Anglers catch pile perch, striped seaperch, and white seaperch from the Coos Bay waterfront (Gaumer et al. 1973). Thirty-eight species of fish have been recorded using the upper bay during the summer (Cummings and Schwartz 1971). Many of the fish probably feed over the tidal flats and congregate in the channels at low tide.

The intertidal area of the upper bay is composed of broad, shallow tidal flats, eelgrass beds, and tidal marshes (Fig. 18). George M. Baldwin and Associates et al. (1977) calculated that tidal flats composed predominantly of mud occupied about 4.5 mi^2. Sand occurs near the spoil islands, and wood debris is common on the southern portion of the flats. A huge eelgrass-tide-flat complex stretches from the Jordan Cove causeway south to the Marshfield Channel. The northern two-thirds of this area is an extensive eelgrass meadow, the largest in Coos Bay and one of the largest in Oregon (George M. Baldwin and Associates et al. 1977). Development has altered intertidal habitats along the shoreline of Coos Bay and North Bend. Studies of invertebrate distribution and abundance have not been conducted.

At least 10 species of annelids, 10 species of molluscs, and 13 species of crustaceans have been recorded from the muddy upper bay tidal flats (USACE 1975). The sea hare (*Aglaja diomeda*) has been recorded in the bay only from upper bay eelgrass beds, and the distribution of the freshwater crab is the upper bay and riverine areas.

The only clam taken recreationally which inhabits the upper bay in large numbers is the softshell, although small cockles have also been reported there. Lugworms and ghost shrimp are the other upper bay invertebrates sought by recreationists. McConnaughey et al. (1971) divided the tidal flats and eelgrass beds into four smaller subunits in their study. Biomass results of the most common species are summarized in Table 13. Animals were the most diverse and abundant within the dense eelgrass beds. Softshells and Dungeness crabs were found in much greater concentrations in the dense eelgrass, but certain invertebrates, such as the ghost shrimp and the false mya (*Cryptomya californica*) preferred sandier substrates and areas of less eelgrass.

Log storage over the flats and channels of th upper bay is common. Log storage areas have been mapped by the Coos County Planning Department. A DEQ study (Zegers 1978) of the impact of logs grounding on tideflats at low tide included sampling sites in the Cooston Channel of the upper bay. There was a large reduction in the number of total organisms (including annelids, arthropods, and molluscs) per unit area in grounding areas compared to adjacent control sites.

It is possible to cultivate oysters (*Crassotrea gigas*) in the upper bay, but commercial harvest there is prohibited because of poor water quality.

The upper bay tidal flats are an important feeding area for shad and striped bass (Cummings and Schwartz 1971). Adult shad may spend several weeks there, and bass can be found there most of the year. Juvenile salmonids also use the area for feeding. Among the most numerous fish found in the upper bay were shiner perch, silver surfperch, shad, topsmelt, starry flounder, and English sole (Hostick 1975).

Table 13. Average sample composition (g/m^2) of most common macrofaunal invertebrates in upper bay tidal flats and eelgrass beds (McConnaughey et al. 1971)

Organism	Subunit I	II	III	IV
Mya arenaria	3.02	0.97	17.28	39.20
Tellina salmonea	1.69	3.95	2.02	2.27
Macoma baltica	0.71	1.95	0.91	0.61
Others	0.77	0.07	4.51	0.65
Clam Total	6.19	6.94	24.72	42.73
Nereis brandti	1.25	2.89	1.60	5.42
Heteromastus f.	2.26	2.48	1.88	2.49
Eteone lighti	0.53	1.04	1.62	1.08
Others	0.87	0.66	1.04	1.91
Worm Total	4.91	7.07	6.14	10.90
Corophium s.	0.71	2.62	2.05	3.53
Anisogammarus c.	0.24	0.00	0.05	0.32
Haustorius sp.	0.01	0.01	0.03	0.01
Others	0.10	0.00	0.00	0.05
Amphipod Total	1.06	2.63	2.13	3.91
Cancer magister	0.00	0.00	0.00	1.55
Callianassa c.	0.34	0.00	1.56	0.00
Tectibranch (?)	0.07	0.16	0.01	0.49
Biomass Total	12.97	16.75	34.72	59.85
Number of Samples	38	16	9	11

I. Near spoil islands, sandy substrate, high elevation
II. Mud without eelgrass
III. Areas with sparse to medium density eelgrass
IV. Areas with dense eelgrass covering.

The upper bay has not been studied as a discrete unit with regard to bird use. Western grebes, pintails, canvasbacks, buffleheads, killdeer, snipe, sandpipers, sanderlings, dunlins, herring gulls, and Bonaparte's gulls were among the more abundant birds sighted in the area during the 1977 and 1978 Audubon Christmas Bird Counts. Graybill (1978) noted a particularly large population of sandpipers on the flats of the upper bay.

In general, the upper bay intertidal area is inhabited by fewer species than either the lower bay or marine subsystems. Jefferts (1977) states "The number of species present in a community is roughly inversely proportional to the degree of environmental uncertainty." The physiological stresses of salinity and temperature fluctuations in the upper bay as well as the presence of pollution and mechanical disturbance tend to produce a community that is physically controlled. Although fewer species are present in such a community, individuals may be numerous, occur in high biomass, and be important to the overall estuarine food chain. For example, *Corophium spinicorne*, the dominant upper bay amphipod, is abundant and is important in the diet of juvenile salmonids during their seaward migration (personal communication, Paul Reimers, ODFW, March 18, 1979).

Present marshes of the upper bay subsystem are located along the eastern side of the bay at the mouths of Kentuck Slough and Willanch Inlet, on the Coos River delta islands and adjacent shores, on the northeastern portion of the Eastside peninsula, and on the spoil islands east of the main ship channel (Fig. 18). Acreage of upper bay undiked marshes was estimated by Hoffnagle and Olson (1974):

Low sand marsh	46.3
Low silt marsh	3.8
Sedge march	22.1
Immature high marsh	416.4
Mature high marsh	44.8

Most of the marsh area of Kentuck and Willanch inlets has been lost through diking (Johannessen 1961, Hoffnagle and Olson 1974). Original diking along the upper portion of Kentuck Inlet was extended and a bridge and tidegate installed. Marsh rapidly invaded the tideflat below this diking (Johannessen 1961). The diked area is currently used for a golf course. In Willanch Inlet about 100 acres have been diked and are used for agriculture, leaving only about 6 acres as marsh (Hoffnagle and Olson 1974).

Extensive marshes currently exist in the Coos River delta and on the shore across the East Channel. Marshland there has increased since the 1800s (Johannessen 1961), probably because of increased siltation (Hoffnagle et al. 1976). The marshes are primarily immature high marsh with *Deschampsia caespitosa, Carex lyngbyei,* and *Triglochin maritima* the dominant plants (Hoffnagle et al. 1976).

The marsh along the shore east of the delta islands was studied by Hoffnagle et al. (1976). The site showed rapid increase in biomass from April to a maximum in June. This site was second in net primary productivity of six marshes studied in Coos Bay with a productivity of 1007.85 g/m^2/yr.

Invertebrates of the Bull Island study site included the sea anemone (*Nematostella* sp.), polychaetes, crustaceans, and molluscs. The number of species reported was intermediate between a site in lower South Slough and one in North Slough (Hall 1976). Fish taken from the site include shiner perch, Pacific staghorn sculpin, starry flounder, gunnel, bay pipefish, and coho salmon. The most common birds noted were the great blue heron, barn swallow, long-billed marsh wren, and song sparrow (Magwire 1976).

In the vicinity of Eastside, diking began before 1980 (Johannessen 1961). About half of the mature high marsh remaining in Coos Bay is in Eastside (Hoffnagle and Olson 1974). Low sand marshes have colonized the edges of these islands (Hoffnagle and Olson 1974).

Losses of marshland in the upper bay have been extensive. Large areas of Kentuck and Willanch inlets, at Graveyard Pt., on the Eastside peninsula, and near sea level in the cities of Coos Bay and North Bend have been diked or filled for agriculture, industry, and dredge spoil disposal.

Recommendations

The marshes of the Coos River delta islands constitute major tracts of salt marsh, which should be included in a natural management unit as required by the Estuarine Resources Goal (LCDC 1977).

The entire eastern side of the upper bay from Jordan Point to Bull Island and west to the shipping channel is a vast complex of flats, marshes, and eelgrass beds, providing valuable habitat and a rich source of organic material for the entire estuary. George M. Baldwin and Associates et al. (1977) note "the condition of this area is critical for the overall production of the Coos Bay Estuary. Because of its biological importance, the area as a whole should be considered environmentally sensitive." The area should be managed as a single ecological unit. It definitely encompasses major tracts of tideflat and seagrass as discussed in the LCDC Estuarine Resources Goal (1977) and should be managed accordingly.

The tidal flats of the upper bay are feeding grounds for fish, including the anadromous salmonids, striped bass, and American shad. Productivity of these flats should be maintained and increased through restoration of their surface area, including removal of stored logs which ground on the flats.

Habitats along the main channel adjacent to the cities of Coos Bay and North Bend have been altered. Water-dependent uses in these areas are appropriate. Unnecessary pilings should be removed and water quality should be considered in future development. The Cooston Channel is a main artery for the passage of fish between the river and ocean. It should remain unobstructed.

South Slough Subsystem

South Slough enters the main body of Coos Bay near Coos Head, less than 2 mi from the estuary mouth (Fig. 17). It may have once been a separate estuary with its own opening to the ocean. The slough has a drainage basin of 26 mi^2 (STR 1974). Because of its proximity to the ocean, South Slough receives more marine influence than the other slough subsystems. Its north-south orientation makes it particularly susceptible to strong north-northwest winds.

The slough bifurcates into the western Winchester arm and the eastern Sengstacken arm. Major tributaries include Joe Ney and Day creeks from the east; John B. and Talbot creeks, which flow into the Sengstacken arm; and Winchester Creek, which flows into the Winchester arm.

The upper reaches of South Slough (Fig. 17) have been set aside as a research sanctuary to preserve an unaltered site for studies to improve our ability to properly manage estuarine systems. The South Slough Sanctuary was the first of its kind in the nation.

Fresh water inflow into the slough has not been measured directly. Freshwater runoff from the South Slough drainage basin has been estimated from the precipitation and runoff measured in two nearby drainage basins (Harris et al. 1979). Monthly average values ranged from 6 cfs in August to 232 cfs in February. Monthly extremes of 1 cfs and 445 cfs were estimated. Further calculations yielded a representative tidal prism of 3.3×10^8 ft^3 and implied that mixing is thorough and flushing of fresh water is rapid (Harris et al. 1979). Salinity gradients for stations at the mouth of the slough and at Younker Pt. also show the lower slough is well mixed throughout the year (Arneson 1976).

A breakwater separates South Slough from the main body of Coos Bay. A project to extend the jetty to provide additional protection to boats moored in the Charleston boat marina is currently underway. A 10-ft deep, 50-ft wide channel is maintained between the main bay channel and the Charleston Bridge. The Charleston Small Boat Basin is also dredged to dimensions of 500 ft x 900 ft in lower South Slough (USACE 1978). Studies of bottom topography have been conducted by USACE (1978) and a mathematical model, verified by field measurements, of tidal elevations, current velocities, and circulation in South Slough under calm wind and wave conditions has been constructed (USACE 1978). Bathymetric charts are on file at the offices of the South Slough Estuarine Sanctuary. Although DEQ maintains 11 water quality stations in South Slough, most of them are in the lower portion of the slough. Stations have recently been established farther up the slough in conjunction with the South Slough Estuarine Sanctuary, so comparisons should soon be possible.

At the entrance to South Slough, DEQ (1978) has measured salinity extremes of 35.3 ppt and 14.6 ppt. Extremes 0.3 miles south of Collver Pt. were 33.3 ppt and 6.3 ppt. The data suggest that highly saline water extends far into the slough at periods of low flow and that water at the head is fresh at times of high flow.

Dissolved oxygen at the stations monitored by DEQ is generally above minimum standards for estuarine waters (DEQ 1978). Arneson's data (1976) show slight depressions in DO at Younker Pt. in March and at the Charleston Bridge in December relative to surrounding stations.

Several coliform measurements greater than 70 mpn have been taken by DEQ (1978) within the Charleston Small Boat Basin and at the Joe Ney Slough Bridge. Recent work by Plotnick (1979) suggests that improper disposal of sewage from boats may be a problem in the boat basin. Septic tank leakage from dwellings not yet hooked up to the Charleston sanitary district sewage disposal system are another source of coliform. Sampling for coliform in the upper reaches of the slough has only recently begun. Counts in the Sengstacken arm are within standards for shellfish harvest, while those in the Winchester arm often exceed those standards. Livestock waste may elevate coliform counts in the upper reaches of the slough (personal communication, Delane Munson, Manager of South Slough Sanctuary, February 15, 1979).

An examination of the sediment characteristics of volatile solids, Kjeldahl nitrogen, grease and oil, and total sulfides showed that, although the outer boat basin is more exposed to flushing action, it is more highly polluted than the inner basin (Slotta and Noble 1977).

South Slough is an area of sediment deposition. Sediment movement is generally seaward and deposition occurs where movement is obstructed, such as at Valino Island and in regions of large cross sectional area (Baker 1978).

Strong winds may be a factor in sediment resuspension in South Slough as wave bases disturb the bottom (Baker 1978).

Baker (1978) found that most of the sediments of South Slough are a mixture of medium to fine sand eroded from the terrace shorelands and coarse to medium silt from fluvial input. Silty sands are the dominant sediment type over tideflats and in the channels toward the head of the slough. The uppermost reaches are generally silt. Organic content of slough sediments ranged from 0.00 ppt in channel sands to 19.77 ppt in tideflat silts (Baker 1978).

Drainage from Joe Ney Sanitary Landfill was reported to have been increasing sedimentation in South Slough, but recent measures seem to have alleviated the problem (pers. comm., Munson). Logging activities have occurred in the drainage basin which may have obscured the effects of the landfill.

Habitats and Species

The habitats of South Slough show the most variation of any slough subsystem within Coos Bay (Fig. 18). The marine influence, the coarse sediments found in the lower portions of the slough, and the relatively undisturbed nature of the upper portion provide habitats for more species of invertebrates and fish than are found in the other slough subsystems.

South Slough has a irregular shoreline, which leads to a high shoreline to surface area ratio. The area has many diverse habitats. Below the Charleston Bridge are flats of mixed substrate, intertidal and subtidal eelgrass beds, riprapped shores, sandy shores, and only a small amount of marsh. Between the bridge and Valino Island are, in addition to most of the above habitats, a small amount of bedrock shore, sandy bars, and much larger marshes. Above Valino Island the substrate becomes more silty and marshes are more prominent. Eelgrass in the channels extends far up the slough.

Because of the proximity to the ocean and its varied habitats, the number of species inhabiting South Slough is high. Ednoff (1970) recorded more total species from the mud in South Slough than in any other portion of the bay. Polychaetes and molluscs were most diverse in South Slough, but crustaceans were most diverse in the lower bay.

A rich intertidal infauna was also found by Jefferts (1977), who recorded 26 polychaetes, 10 bivalves, 4 harpacticoid copepods, and 7 amphipods. Jefferts' uppermost South Slough station had the lowest diversity of any station sampled. This station was in a backwater with a high concentration of volatile solids, a high water content in the substrate, and was dominated by a few opportunistic species. In these respects, it resembled stations in the upper bay, although the faunal assemblage was different.

Most clambeds used by recreational diggers in South Slough are north of Valino Island. Gaper, butter, cockle, littleneck, and softshell clams are taken from the tide flats. Four South Slough sites provided a total of 22.6% of the marine animals taken by tideflat users in Coos Bay in a 1971 survey (Gaumer et al. 1973). While the clam bed just south of the Charleston Bridge provided the greatest number of clams of the South Slough flats surveyed, the flat just south of the existing boat basin (the Charleston Triangle) had the highest catch per unit effort (Gaumer 1973). Clam resources of this flat have been surveyed in greater detail (Gaumer 1978). Estimates of the populations of recreationally harvested clams occurring there are 1,333,000 gapers, 348,000 cockles, 289,000 native littlenecks, 119,000 butters, and 50,000 softshells. Estimate of the total clam population was 10,078,000 (Gaumer 1978).

Of major significance is the use of South Slough for commercial oyster culture. The only oyster leases in Coos Bay are on South Slough. Leases are scattered on Joe Ney Slough and South Slough proper, except for the Winchester arm (Fig. 16). Oysters can be grown in areas throughout the estuary, but health restrictions due to poor water quality prohibit commercial oyster leases in most of the estuary.

Many of the 995 acres of undiked tidal marsh in South Slough are fringing marshes at scattered points along the slough's edges, especially in inlets and coves (Hoffnagle and Olson 1974). The largest expanses of marsh are found at the heads of various inlets and on the flats just south of the Charleston Bridge and just south of Valino Island. Low sandy marsh and immature high marsh are the major marsh types of the slough (Hoffnagle and Olson 1974).

Several areas in South Slough are reverting to marsh following the breaching of dikes or as a result of tidegate failure. Regions at the head of the Winchester arm are inundated only during high water or very high tides as a result of tidal damming of streams. These areas are termed "surge plain marshes" by Hoffnagle and Olson (1974).

The only area of bullrushes in South Slough is along part of the north bank of Joe Ney Slough (Hoffnagle and Olson 1974). At the head of Joe Ney Slough is a large, tidegated freshwater marsh with dense stands of cattail (*Typha latifolia*) (Hoffnagle and Olson 1974). Studies of this marsh site as a potential mitigation site for alterations in other portions of the estuary have been conducted and results will be available from LCDC (Gonor et al. 1979).

Two South Slough marshes of differing character were studied in detail by Hoffnagle et al. (1976). The marsh site at the upper end of the slough was vegetated primarily by *Carex lyngbyie* and *Distichlus spicata*. Its net primary productivity was estimated at 764.81 $g/m^2/yr$. A low sandy marsh in the Henry Metcalf Estuarine Preserve just south of the Charleston bridge was the other study site (Hoffnagle et al. 1976). The marine influence experienced by this marsh is probably responsible for the diversity of species observed there. Bird observations near the Metcalf marsh are summarized in Table 12.

As in other portions of the bay, the habitats of South Slough have been altered by human use. The lower slough has been a site of rapid change accompanying a growing fishing industry. The construction of the Charleston Breakwater, dredging of the channel and of the small boat basin, and filling of adjacent tidelands have all occurred within the past 25 years. In the middle and upper slough, oyster culture has added a habitat to the intertidal area. Although there have been splash dams and dikes in the upper slough, recent developments have been few.

Recommendations

While generally one would choose to concentrate development in the lower South Slough, certain features of the area deserve special attention. Of 6,200 acres of submersible land in Coos Bay, 6% of the clams harvested were from the 11.5 ac area frequently referred to as the "Charleston Triangle". Because of the density of clam populations at this site and its recreational value, it should be protected. The flats south of Charleston Bridge on the west bank also receive heavy recreational use.

Generally, the diversity of organisms present in lower South Slough and the recreational capacity of the area suggest maintaining as much diversity of habitats and uses as possible. On the east side of the lower slough is the Barview State Wayside, an areas used by recreationists. The site should be maintained for these uses.

The values of South Slough marshes accrue primarily because of the long involuted shore and many fringing marshes. Development should be planned to leave the marshes undisturbed. Although individual marshes are small, the total marsh area makes a significant contribution to the primary productivity of the estuary. The low sandy marsh just south of the Charleston Bridge on the Metcalf Preserve is the closest marsh to the mouth of the bay and is a unique habitat as a marsh under marine influence.

South Slough is the only area within Coos Bay where legal commercial oyster harvest currently takes place. That use must be carefully protected. Oyster land and water quality should be protected for oyster growth. Proper sewage disposal and management of upland uses to minimize sedimentation are particularly important for oyster production.

There are several sites in South Slough appropriate for restoration, including formerly diked areas in the upper slough and in Joe Ney Slough. Habitat improvements should be considered on the east side of the channel from north of Peterson's Seafoods to the mouth of Joe Ney Slough, where discharge of sewage and industrial pollutants has occurred.

The use of Sough Slough Sanctuary an an unaltered site for research presupposes that it will remain undeveloped and its habitats and water quality will be protected. South Slough is very directly influenced by marine waters that enter through the mouth of the bay and slough and flow through the extensive development in the Charleston area. It is imperative that existing uses and new development north of the sanctuary not degrade the water quality of the sanctuary. Approval of new development north of the South Slough should be contingent upon evidence that the development will not adversely impact the water quality of the sanctuary.

Pony Slough Subsystem

Pony Slough branches south from the main bay between RM 8 and 9. Formerly a triangular embayment, its shape has been altered by filling. Presently a narrow mouth gradually opens into a wide tidal flat which is divided by a channel. The slough is about 1 mile long and the widest point is slightly more than 1/2 mile.

Hydrological studies of Pony Slough are limited. Freshwater discharge from Pony Creek is controlled at dams on Upper and Lower Pony reservoirs. Since 1975, USCS has monitored water discharge below the lower reservoir. Records for Water Year 1976 show a total freshwater discharge of 3,010 ac-ft. Flow ranged from a minimum of 0.08 cfs in May, June, July, and September and to a maximum of 26 cfs in December (USGS 1977). Summer mean flow was between 0.27 and 1.42 cfs, and the winter mean was between 4.33 and 13.6 cfs. Water discharge doesn't necessarily coincide with precipitation because of the controlling dams.

Information regarding salinity is limited to a single set of samples taken during August 1970. These measurements showed salinities in the main channel were 30.6 ppt at the mouth and 27.9 ppt at the Virginia Blvd. Bridge on an incoming tide and 23.4 ppt at the mouth and 5.5 ppt at the bridge on the outgoing tide (Horstmann et al. 1970). This demonstrates that considerable variation can occur over one tidal cycle. Interstitial salinities fluctuate less, and standing water on the marsh may become hypersaline because of evaporation (Horstmann et al. 1970).

The sediments of Pony Slough tidal flats are mostly mud and mixed sand-mud near the channels and marsh edges (Horstmann et al. 1970). A reducing layer at depths varying from 0.2 to 11.8 in was present over most of the slough area sampled.

Water quality of Pony Slough has not been examined. Domestic waste and waste water from an adjacent car wash enter the slough. In the spring of 1970, a large accidental discharge of raw sewage entered the slough from a nearby waste treatment plant (Horstmann et al. 1970). The effects of this discharge have not been studied.

Pony Slough has a long history of human alteration. Filling for the Southern Pacific Railroad began in 1917 in the northeastern section of the slough. During World War II, 240 ac. were filled for the North Bend Municipal Airport. In 1958 filling for Pony Village shoping center began, and in 1960 filling occurred north of Virginia Street in North Bend. The southeastern portion of the slough is bordered by residences, the southern side by commercial enterprises, and the North Bend Municipal Airport lies along the western border (Fig. 17). A public boat launch is located near the mouth on the western side. Several waste outfalls empty into the slough.

Habitats and Species

Habitats of Pony Slough include subtidal areas with unconsolidated bottoms and eelgrass and intertidal mud flats, sand-mud flats, eelgrass beds, algal beds and marshes (Fig. 18).

Benthic diatoms were ubiquitous on Pony Slough tideflats and are probably a major source of productivity (Horstmann et al. 1970). Mats of green algae (*Chaetomorpha cannabinna* and *Rhizoclonium* spp.) covered large areas of the tidal flats. Blue-green algae were noted on the eastern edges of the mud flats, and brown algae (*Fucus* sp.) was present on hard substrates and in the marshes.

Dense eelgrass is distributed along the intertidal area near the slough entrance and through part of the main channel. The various types of plant communities in Pony Slough show that the area remains an important producer of organic material for Coos Bay despite extensive alterations by filling. Fringes of high marsh also occur on the east and west margins of the slough and an expanse of low sand marsh occurs on the west side (Hoffnagle and Olson 1974). Most of the marsh vegetation lies between 5.5 and 7.5 ft above MLLW (MacDonald 1967).

The plant community of the low marsh at Pony Slough is composed primarily of *Salicornia virginica* and *Distichlis spicata* (Hoffnagle et al. 1976). *Deschampsia caespitosa* and *Spergularia marina* were also noted (Hoffnagle et al. 1976). These plants evidence a change in species composition since Johannessen studied the marsh 1961. He recorded *Scirpus validus* as a significant member of the flora and did not record any *Distichlis spicata* (Johannessen 1961).

The Pony Slough marsh increases in biomass from April to July (Hoffnagle et al. 1976). Net primary productivity was lower than that of North and South slough marshes probably because of the perennial *Saliconria virginica*, which has high biomass but a low rate of production. The marshes of Pony Slough were the lowest in elevation of the marshes studied by Hoffnagle et al. (1976). Dead standing shoots disappeared quickly probably because of the frequency of inundation. *Salicornia*, although lower in productivity, is an important detritus source, and its woody perennial form stabilizes soil (Hoffnagle et al. 1976).

The Pony Slough mud flat is populated primarily by burrowing mudflat organisms (Hoffnagle et al. 1970). *Corophium spinicorne*, an important amphipod in the diet of juvenile salmonids, is widely distributed over Pony Slough tideflats. Lugworms, ghost shrimp, and clams (*Mya arenaria, Cryptomya californica*) also occur, often in very high densities (Horstmann et al. 1970). Dungeness crabs are found in lower intertidal and subtidal areas. Tideflat users harvest softshell clams and ghost shrimp at Pony Point to the west of the entrance to Pony Slough, but this accounted for only a small percentage of tideflat use on Coos Bay (Gaumer et al. 1973).

Most sampling for fishes in Pony Slough has been by otter trawl because the soft muddy substrate makes beach seining difficult. However, ODFW has seined in the lower slough for the past three years. Eleven species occur in Pony Slough (Rousseau 1972). The slough is an important striped bass feeding area. Adult striped bass feed over much of the tideflats at high tide and move in and out of the slough with the tides. Pony Slough is a popular bass angling area from May through September.

Over 100 species of birds use Pony Slough. The slough harbors the largest concentrations of wintering birds in the estuary (Rousseau 1972). Peak numbers of 7,000-9,000 wigeon and other waterfowl and shorebirds have been noted (Rousseau 1972). Thornburgh (1979) conducted weekly surveys from June 1978 to June 1979 (Table 14).

The protection from southerly winter storms offered by the sheltered Pony Slough is probably a major reason for its heavy use by waterfowl. ODFW manages Pony Slough as a refuge, where hunting is prohibted.

Table 14. Peak counts of birds occurring in Pony Slough between June 1978 and March 1979 in numbers greater than 100 per observation period (Thornburgh 1979).

	Number	Time of observed peak
Dabbling Ducks		
American Wigeon	3,526	Nov.
Pintail	1,943	Jan.
Green-winged Teal	872	Dec.
Gadwall	330	Jan.
Shoveler	209	Jan.
Diving Ducks		
Canvasback	648	Dec.
Plovers		
Killdeer	204	Jan.
Semipalmated Plover	177	July
Black-bellied Plover	151	Mar.
Medium-sized Waders		
Dowitch	220	Sept.
Sandpipers		
Dunlin	2,808	Nov.
Western Sandpiper	1,577	Sept.

Recommendations

Pony Slough is a very important striped bass feeding area in Coos Bay. It is an area of high plant and animal productivity and a critical waterfowl and shorebird habitat, which harbors the largest concentrations of wintering birds in the estuary. The entire slough should be managed as a single unit. Most of Pony Slough is a major tract of intertidal land as described in the LCDC Estuarine Resources Goal (1977) and should be managed accordingly.

In its present condition Pony Slough provides valuable and scenic open space and natural resources to the urban North Bend area and could be used in satisfying state land use Planning Goal 5 (LCDC 1977).

North Slough Subsystem

North Slough extends approximately 3 mi north from the main body of Coos Bay at RM 9 (Jefferson 1975). The slough has a watershed of 8,190 ac (OSWRB 1963). Freshwater inflow from North Creek has not been measured. Although there is a tidegate at the slough's north end, near Highway 101, it may be too high in elevation to provide good flood drainage relief (OSWRB 1963). Upland plants are found adjacent to the channel before the slough crosses under Highway 101 (Hoffnagle and Olson 1974). The lands to the east of the highway are tidegated and diked but may be of sufficient elevation to be unaffected by salt water (Hoffnagle and Olson 1974).

The hydrography of North Slough has not been studied. The Jordan Cove Causeway separates the slough from full exposure to the main bay. The dike system undoubtedly reduces tidal circulation in the slough and may be accelerating sediment deposition. The Southern Pacific railroad bed parallels the western perimeter and acts as a dike, separating the slough from the dunes and forming a barrier between salt and fresh water marshy areas.

Sediments of North Slough are fine silts and broken shells (STR 1974). Sand from the dunes is also carried into the slough by the wind. These sands sometimes clog the channel at the tidegate (OSWRB 1963). Derelict logs occur on both sides of the slough and wood chips are found under the mud surface near the mouth (Baker et al. 1970).

Water quality samples are limited to a single set of samples taken in the summer of 1971 (STR 1974). Results showed high temperatures, high coliform counts, and excessive turbidity. Temperature problems were thought to occur because of low summer stream flows and incomplete mixing. Livestock and log storage were possible sources of turbidity, and livestock waste was thought to account for the high coliform counts. Log storage no longer takes place in North Slough. A municipal water treatment plant is located on North Slough, but wastes are not discharged into the slough from this plant.

The invertebrates of North Slough tidal flats include the molluscs *Mya arenaria, Crytpomya californica, Tellina salmonea, T. Buttoni, Macoma nasuta,* and *M. balthica* (Baker et al. 1970). Softshell clams and *T. salmonea* are widely distributed in the lower, broader regions of the slough. *C. californica, Macoma nasuta* and *T. Buttoni* are found near the causeway. *Macoma balthica* is found in the narrower portion of this area. The softshell clam is the only mollusc taken by recreational diggers in this area. The Jordan Cove Causeway yielded by far the most softshell clams to recreationists in Coos Bay of areas surveyed in 1971 (Gaumer et al. 1973).

Other invertebrates with wide distributions on North Slough flats include spionid worms, (*Eteone* spp.), ribbon worms (*Paranemertes* spp. and *Cerebratulus* spp.), lugworms, bamboo worms (*Heteromastes* spp.), amphipods (*Corophium* spp.), crangonid shrimp (*Crago* spp.) (USACE 1975), and Dungeness crab (Baker et al. 1970). Ghost shrimp are found only near the causeway, and shore crab (*Hemigrapsus oregonensis*) are associated with the riprap shores. Ghost shrimp and lugworms are collected from North Slough flats by recreationists.

American shad, shiner perch, staghorn sculpin, and starry flounder were found during 1970 sampling in the slough (Cummings and Schwartz 1971). Boat and shore angling for striped bass occurs in the slough May through September. There is an upstream fishery for coho salmon which spawn in North Creek (pers. comm., Bender and Mullarkey).

Large numbers of dunlin have been observed on North Slough tideflats, and North Slough has been identified as a great blue heron feeding area (McMahon 1974). North Slough is a major feeding and resting area for redheads and other ducks.

Of particular significance in North Slough are the marshes. Large, intact, diverse marshes occur there (Akins and Jefferson 1974). Jefferson (1975) described the marshes of North Slough as the "most complete and diverse mosaic of salt marsh plant communities in all stages of succession and with ecotones to freshwater, forest, and sand dunes."

Marsh acreage mapped by Hoffnagle and Olson (1974) included 7 ac. of immature high marsh, 138.5 ac. of sedge marsh, 18 ac. of bullrush-sedge marsh and 23 ac. of low sand marsh. Of six sites studied on Coos Bay, the site on North Slough, which was an almost pure stand of *Scirpus validus*, had the highest standing crop and net primary productivity (Hoffnagle et al. 1976). The plant *Cordelanthus maritima*, which is rare in Oregon, is found within the immature high marsh of North Slough (Hoffnagle and Olson 1974). *Cotula coronopifolia*, an introduced species which thrives in areas of wood and bark accumulation, is quite common (Hoffnagle et al. 1976).

Shiner perch and staghorn sculpin were found adjacent to North Slough marshes. Harpacticoid copepods, insect larvae, small bivalves and *Corophium* spp. were major items in their diet (Hoffnagle et al. 1976).

In addition to barn swallows, long-billed marsh wrens, and song sparrows, the uncommon Virginia rail has been sighted in North Slough marshes and nesting areas for this bird were observed there by Magwire (1976b).

Recommendations

The marshes of North Slough represent major tracts as described in the LCDC Estuarine Resources Goal (1977) and should be protected (Jefferson 1975). Because these diverse marshes have remained relatively unaltered, they could serve as valuable research natural areas for baseline studies of natural processes in undisturbed ecosystems. They are particularly well suited to studies of dune encroachment, impacts of drift logs, and recovery from log storage (Jefferson 1975).

North Slough includes suitable sites for habitat restoration. Removal of derelict logs would increase the surface area available for estuarine production.

Placement of culverts beneath the Jordan Cove Causeway would increase tidal circulation to North Slough and might reverse the accelerated sediment accretion.

Haynes Inlet Subsystem

Haynes Inlet extends about 2-1/2 mi northeast from its entrance into Coos Bay just east of North Slough (Fig. 17). It has a watershed of 7,120 ac (OSWRB 1963), which is drained by Larson and Palouse creeks.

Haynes Inlet was once broad at its mouth, gradually narrowing to a system of narrow, meandering channels at its head. Larson and Palouse creeks once contained large tidal marshes and had substantial tidal prisms. Currently the mouth has been greatly restricted by the Highway 101 causeway. Marshlands on both major creeks have been diked for agricultural use, and stream flows are controlled by tidegates, which reduce the total tital prism of the inlet.

Hydrological studies of freshwater inflow and tidal circulation have not been made. Data on the water quality of Haynes Inlet is lacking, and only minimal biological information is available.

Habitats of Haynes Inlet include subtidal channels with unconsolidated bottoms; intertidal flats of sand, mud, and sand-mud mixed; eelgrass beds; low marsh; high marsh; and sand shores (Fig. 18).

In a brief qualitative survey, invertebrates of the Haynes Inlet mudflats were similar to those recorded in North Slough included (Rischen and Danielson 1970). Additional species not recorded in North Slough included several species of amphipods and the nudibranch *Hermissenda crassicornis*. The California papershell, *Lyonsia californica*, has not been recorded elsewhere in Coos Bay. An oyster farm operated there before construction of the Highway 101 Causeway. The presence of shells suggest that cockles once inhabited the sea.

Fish seined in Haynes Inlet include threespined stickleback, shiner perch, topsmelt, bay pipefish, staghorn sculpin, and starry flounder, all species with wide distributions in Coos Bay (Hostick 1975) (Table 9). Bender (pers. comm.) noted that large numbers of anchovies occur near the mouth of the inlet in September and October. Boat angling for striped bass is popular in Haynes Inlet in May through September. Shiner perch, pile perch, and striped seaperch are also taken there by shore anglers. Larson and Palouse creeks are both productive coho and steelhead streams (pers. comm., Bender). Larson Creek is used to chart coho population trends in coastal streams. It has the highest number of spawning coho of the 3 creeks surveyed by ODFW in the Coos system. A sport fishery for coho develops in October and continues until the end of steelhead season (pers. comm., Bender).

Haynes Inlet is heavily used by waterfowl. The most abundant winter species include black brant, American wigeon, ruddy duck, American coot, pintail, greenwinged teal, and mallard (Magwire 1976b). Few species appear to use the area in summer, but great blue heron are common (Magwire 1976b) and use the inlet as a feeding area (McMahon 1974).

Several hundred acres of salt marsh have been diked for agricultural use in Haynes Inlet (Hoffnagle and Olson 1974). About 150 acres of marsh remain, including immature high marsh, sedge marsh, bullrush-sedge marsh, and one of the few areas of low silty marsh mapped in Coos Bay (Hoffnagle and Olson 1974).

The watershed of Haynes Inlet has a fairly high level of both agriculture and logging (Wilsey and Ham 1974). Other human uses of the slough and adjacent uplands include a small mill and log dump, residences, light commercial use near the mouth, and a boat launch and wayside (Wilsey and Ham 1974).

Recommendations

Haynes Inlet was classlified as an area of moderate marine biological value and high terrestrial biological value by Wilsey and Ham (1974). Of particular significance are the salt marshes of the upper end of the inlet, which are listed by Jefferson (1975) as an area that should be protected for primary production in Coos Bay.

The Highway 101 causeway has changed tidal circulation within Haynes Inlet and may be contributing to accelerated accretion. It may be advisable to increase ciruclation with the main bay through a system of culverts. Leaking tidegates, especially the one controlling the entrance to Larson Creek, have necessitated recent diking to protect agricultural land from salt water intrusion. Dike material should be obtained from upland sources rather than from the adjacent channel to protect water quality and bottom characteristics, which are important for anadromous fish using these streams.

Isthmus Slough Subsystem

Isthmus Slough is a very long, narrow body of water which enters the upper southwest corner of Coos Bay at about RM 13.8 (Fig. 17). Head of tide is about 12 mi up the slough (Wilsey and Ham 1974). The drainage area of Isthmus Slough is 32 mi^2 (Arneson 1976), and major tributaries include Coalbank Slough, Shinglehouse Slough, Davis Slough, and Noble Creek.

In Isthmus Slough the deep draft navigation channel extends to RM 15 at a depth of 35 ft and width of 400 ft. Near the mouth of Coalbank Slough a turning basin has recently been enlarged to 700 ft by 1,000 ft. Major shipping activities occur in this area of the bay. A shallower channel 22 ft deep and 150 ft wide extends from RM 15 to Millington at RM 17. It is privately maintained and used primarily for log transport (USACE 1976).

Freshwater flow has been calculated for Isthmus Slough using drainage basin area and precipitation averages (Arneson 1976). In 1973-74 minimum flow was estimated at 1.4 cfs in September 1973 and maximum flow at 304 cfs. Extreme salinities of 30.6 ppt and 4.7 ppt have been measured at the Eastside Bridge over the slough. Salinities at the Coos City Bridge measured 30.2 ppt and 0.3 ppt (DEQ 1978). Downstream from Eastside a minimum salinity of 0.2 ppt has been measured, which probably indicates the influence of fresh water from Coos River.

Salinity profiles show Isthmus Slough to be well mixed at essentially all times of the year (Arneson 1976). In December, when some portions of the estuary were stratified, Isthmus Slough was well mixed at high tide and essentially fresh water at low tide (Arneson 1976). The well mixed condition of the slough may be attributed to limited freshwater inflow (Arneson 1976), even though diking has greatly reduced the tidal prism in the slough (Aagard 1971). Water temperatures as low as 46.4°F have been recorded in Isthmus Slough, while maximum temperatures of 73.4°F have occurred at upstream stations (DEQ 1978).

Isthmus Slough receives heavy industrial use for shipping, waste disposal, and log handling and storage. These uses combined with minimal flushing (Arneson 1976) and low freshwater inflow cause dissolved oxygen to be lowest in

Isthmus Slough of the stations measured in Coos Bay (DEQ 1978). DEQ data show that DO improved from 1974 to 1978, but measurements less than the minimum standards for estuarine waters still occur(DEQ 1978). USACE (1976) reports Isthmus and Coalbank sloughs are moderately to heavily polluted according to EPA standards.

High coliform counts have been recorded in Isthmus Slough. Of the stations measured by DEQ, the most frequent and severe violations occurred in Coalbank Slough and downbay from Coalbank (DEQ 1978). At the upper stations coliform less frequently exceeded standards for general health but was often over the maximum for commercial shellfish harvesting areas.

Sediments of Isthmus Slough are river-born silts (Arneson 1976). Although winter freshets do aid flushing, the slow currents of the slough and general lack of fresh water inflow contribute to the deposition of fine material (Arneson 1978). Wood chips and bark also occur in the substrate of much of the slough. Anerobic sediments are found in most areas (Thompson 1971).

Habitats and Species

The habitats of Isthmus Slough are predominantly the unconsolidated bottom in the channel, muddy shores which are sometimes covered by eelgrass beds, and marshes (Fig. 18). Log rafts are often stored and ground along the tidal flats. Consequently, the exact location of aquatic beds and marshes is subject to change as vegetation is removed and reestablishes itself.

A survey of organisms of Isthmus Slough, primarily those of the tidal flats, was conducted by Thompson (1971). Algae noted in the slough include the green (*Enteromorpha tubulosa*), reds (*Gracilaria* spp., *Antithamnion* spp., *Platythamnion* spp., *Polysiphonia* spp., and *Gigartina* spp.), and the brown (*Fucus* spp.). *Ruppia* is found in increasing abundance in aquatic beds toward the southern end of the slough in less saline water.

Invertebrates primarily include crustacean arthropods and polychaete worms. Only six molluscs are recorded from Isthmus Slough. The softshell clam is the only species taken recreationally. Historical notes show softshells were once more abundant than at present (Thompson 1971).

The arthropods found in the slough are the shrimp *Crago franciscorum* and the crabs *Cancer magister, Rhithropanopeus harrisii,* and *Hemigrapsis oregonensis* (Thompson 1971). At least eight species of amphipods and isopods are also found. The amphipods were primarily in channels under algae, and in eelgrass beds. *Anisogammarus confervicolus* became less dense with increased temperature and decreased salinity. *Corophium* spp. were found farther into freshwater than *Anisogammarus*.

The most abundant polychaete worms were the nereids, *Nereis brandti* and *N. limnicola*. *Heteromastis filiformis* and *Capitella (Capitata) ovincola* were found in reducing layers, and ampharetids and spionids were found throughout the slough. Many of the annelids found have been termed pollution indicators.

At least 11 species of fish have been seined from Isthmus Slough (Table 9).

Adult coho salmon have been seined in Coalbank Slough, and a spawning run of coho occurs in tributaries of Isthmus Slough and in Davis Slough (pers. comm., Mullarkey and Bender).

Historically Isthmus Slough has been used by striped bass which tend to seek out deep holes and channels (pers. comm., Bender). Isthmus Slough was a prime striped bass fishing area until low DO and chemical wastes apparently prevented all use of the slough by striped bass. Conditions have improved somewhat and bass are again showing up. Several age classes of stripped bass have been found south of Davis Slough which have not recently been seen in other portions of Coos Bay (pers. comm., Mullarkey and Bender). It is possible this area is critical to the bass at certain stages of their life cycle (pers. comm., Bender). In February and March striped bass fishing is popular from the banks of Isthmus Slough.

Many of the marshes in Isthmus Slough have been eliminated by diking, filling, and log storage. In Coalbank Slough alone, marshes occupied 597 ac. in 1892, and now only 57.0 ac. remain (Hoffnagle and Olson 1974). The major marshes of Isthmus Slough occur along its banks and in Coalbank, Shinglehouse, and Davis sloughs. Marshes of Coalbank Slough include a 25 ac. marsh separated from the channel by a dike with culverts and a 35 ac. marsh partially bordered by an old dike. These marshes have characteristics of sedge marshes and immature high marshes, but *Carex lyngbyei* is the dominant species present (Hoffnagle and Olson 1974).

Along the main channel of Isthmus Slough south of the mouth of Coalbank Slough lies the estuary's largest expanse of low silty marsh, which is returning to its former state after being diked (Hoffnagle and Olson 1974). Sedge and immature high marshes occur along the main Isthmus Slough channel south of the silty marsh, and bullrush-sedge marsh occurs at the south end of Isthmus Slough (Hoffnagle and Olson 1974). Sedge marshes occur in Shinglehouse Slough, and Davis Slough has marshes of bullrush and sedge. Total undiked marsh acreage of Isthmus Slough and its tributaries is 431.8 ac., which contains 62.8 ac. of sedge marsh, 64.6 ac. of low silt marsh, 219.0 ac. of immature high marsh, and 85.4 ac. of bullrush and sedge marsh.

Recommendations

Hoffnagle and Olson (1974) estimated that 90% of the total acreage of Coos Bay marshes have been lost to filling or other causes since 1892. It is therefore critical that remaining marsh lands be protected from filling and diking in order to maintain habitat diversity in the estuary, as well as the flow of organic material to and from marsh communities. Significant tracts of salt marsh remain in Coalbank and Shinglehouse sloughs and should be preserved for primary production (Jefferson 1975).

Much of Isthmus Slough can be considered degraded habitat, and restoration measures should be undertaken to restore water quality and biological production. The acreage of tide flats impacted by grounding log rafts should be minimized. Log rafts should be removed from intertidal areas wherever feasible. The inventory of logs stored in the slough at any given time and the length of residence of stored logs should not exceed the minimum levels required to keep pace with mill production. All unused pilings, derelict logs, and wood debris should be removed. Breaching of several partially diked areas of Isthmus Slough should improve circulation, water quality, and the flow of materials between these areas and the other portion of the subsystem. The 35-ac. marsh in Coalbank Slough and the low silty marsh east of the channel just south of Eastside should also be considered for restoration through dike removal.

Increased circulation to the 25-ac. Coalbank Slough marsh should be considered to improve the exchange of organic materials with the remainder of the estuary.

Davis Slough and the section of Isthmus Slough above it should remain free of log storage or other uses which would further degrade water quality in the subsystem. Log storage has been gradually phased out in upper Isthmus and Davis sloughs, and during the same period water quality has improved significantly. This recovery and the poor circulation in these upper reaches suggest the area may be particularly important in maintaining the water quality of Isthmus Slough.

Catching Slough Subsystem

Catching Slough enters the main body of Coos Bay just west of the mouth of Coos River (Fig. 17). It is fed by several small streams and is about 10 mi long from its mouth to its head (Wilsey and Ham 1974).

In the late 1800s, Catching Slough was an area of vast tidal marshes and a large tidal prism. Strong tidal flushing was responsible for maintaining depths of 18 to 20 ft at the confluence of the Catching Slough channel and the Marshfield Channel. By the 1940s diking of Catching Slough for agricultural purposes had decreased tidal transport and velocity through Marshfield Channel (Aagard 1971).

Little is known of the physical or biological processes of Catching Slough. Freshwater inflow is unmeasured, but STR (1974) state that because of low summer flow, tidal circulation during summer in Catching Slough is a simple exchange of water from the main bay.

In a single series of summer water quality samples, high temperatures, probably resulting from low summer flows, were noted (STR 1974). Fecal coliform increased from the mouth toward the head of the slough (STR 1974) and could be expected to be greater at times of high runoff.

Habitats of Catch Slough include the subtidal channel, narrow muddy shores, eelgrass or ditchgrass beds, fringing tidal marshes, and rip-rapped shores (Fig. 18). Typically these habitats occur in narrow bands zoned from lowest to highest as listed. The tidal marshes are the only Catching Slough habitat that have been studied.

Tidal marshes of Catching Slough once totalled 1,600 ac., but through extensive alterations for agricultural use, only fringing marshes of bullrush and sedge totalling less than 50 ac. remain (Hoffnagle and Olson 1974).

Distribution of invertebrates in Catching Slough has not been studied. Large numbers of juvenile American shad have been seined from Catching Slough

(Hostick 1974). Coho salmon and steelhead spawn in the upper reaches of the slough (pers. comm., Mullarkey and Bender). Other fish seined from the slough include species with wide distributions in the upper bay and sloughs, such as shiner perch, staghorn sculpin, threespine stickleback, starry flounder, and bay pipefish (Cummings and Schwartz 1971). Water in the upper part of the slough apparently is sufficiently fresh to maintain significant numbers of largescale suckers. Recent gill netting surveys by ODFW have shown the area is also used by striped bass.

Recommendations

Materials needed for dike repair should be obtained from upland sources rather than by dredging in the slough. Dredging can convert productive intertidal areas into less productive subtidal habitats and degrade surrounding habitats. Consideration should be given to restoring a portion of the large amount of diked tidal land to estuarine production. Derelict pilings previously used for log storage should also be removed.

Catching Slough supports good runs of coho salmon in Catching, Selander, and Wilson creeks. Recent sampling suggests the slough may also be an important area for 5- and 6-year-old striped bass. Isthmus Slough is the only other area where concentrations of this age group of striped bass have been found, but Isthmus Slough may be unsuitable for the fish during the summer due to low DO. Water quality in Catching Slough should be maintained and improved for fish and other organisms dependent upon the area. Catch Slough has good potential for recreational fishing, and public use may be improved with increased access.

Coos Riverine Subsystems

There are several riverine subsystems in the Coos Bay estuary, including the Coos and the South Fork Coos rivers and Millicoma river, which enters the Coos River. Tidewater extends more than 11 mi upstream from the boundary of the upper bay subsystem (Fig. 17) on the South Fork Coos and 10.6 mi upstream on the Millicoma River (Wilsey and Ham 1974).

The riverine subsystems provide important fish habitats. Shad are entirely dependent on the area during the first 6-12 months of life and part of their second year. Coho and steelhead can be found in the spring enroute to their spawning grounds. The Coos system is a major freshwater rearing area for chinook, especially during their first year. Juvenile cutthroat also rear in the system, and adults return in late summer to spawn. The lower portions are also used by starry flounder and staghorn sculpin. Prickly sculpin and shiner perch occur in the upper portions. Other species found in the riverine subsystems include red-sided shiners and largescale suckers. Shiner perch and largescale suckers are important forage fish for striped bass (pers. comm., Bender).

This section of the estuary is a popular fishing area for shad (May-July), striped bass (year-round), cutthroat (August-October), coho and chinook (September-November), and steelhead (November-March). Commercial shad fishing takes place on the lower Millicoma, South Fork Coos, and throughout the Coos River.

Recommendations

Generally there is little specific information on other biological and physical characteristics of the riverine subsystems. The habitat map (Fig. 18) does not depict habitats far beyond the upper bay subsystem. However, the Coos riverine subsystems are similar to the tidewater areas of other coastal rivers, and many of the same general considerations should be made in developing management strategies.

The Coos Bay riverine subsystems should be managed as units to prevent the piecemeal destruction of shoreland habitats. Riprap, bulkheads, and docks can destroy riparian vegetation, which is important for fish and terrestrial animals. Docks can reduce the productivity of aquatic plants by shading. Riparian vegetation should be protected as suggested in the implementation of the LCDC Coastal Shorelands Goal (LCDC 1977). New homes and other structures should be placed a sufficient distance from the shore so that bank stabilization measures are not required. This will also help reduce flooding and erosion caused by encroachment into the floodway fringe. Non-structural solutions to erosion and flooding are also encouraged in the LCDC Coastal Shorelands Goal. Bank stabilization should only be allowed as part of an overall stream corridor management plan.

Dredging during July and August will have the least detrimental impact on the riverine fisheries. Spawning and larval development of shad and striped bass occur in the spring (April-June). After September, the tidewater sections are used extensively for sport fishing.

Pollutants discharged into the riverine sections of estuaries can be particularly detrimental to estuarine water quality since flushing times are extremely long much of the year, and all material from the upper estuary may affect the rest of the system downstream. Adequate waste treatment facilities are needed to prevent pollution of the riverine subsystem. Particular care must be excercised to prevent oxygen depletion and high water temperatures, which can stress fish, and to maintain minimum stream flows. Logging and other activities which cause erosion within the riverine subsystems and in the upper watershed should be carefully regulated to prevent rapid filling, which has occurred in many Oregon estuaries as a result of these activities.

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Exhibit 15

Exhibit 16

Oregon Shorebird Festival
Bird List
Compiled from all field trips
August 26-28, 2011

Loons and Grebes
Red-throated Loon
Pacific Loon
Pied-billed Grebe
Western Grebe
Red-necked Grebe

Pelagic and Herons
Black-footed Albatross
South Polar Skua
Northern Fulmar
Pink-footed Shearwater
Sooty Shearwater
Buller’s Shearwater
Fork-tailed Storm-Petrel
Brown Pelican
Brandt's Cormorant
Double-crested Cormorant
Pelagic Cormorant
Great Blue Heron
Great Egret
Snowy Egret
Black-crowned Night Heron

Waterfowl
Canada Goose
Mallard
Northern Pintail
Cinnamon Teal
American Wigeon
Gadwall
Ring-necked Duck
Harlequin Duck
Surf Scoter
Hooded Merganser
Bufflehead
Ruddy Duck

Birds of Prey
Turkey Vulture
Osprey
Northern Harrier
Red-shouldered Hawk
White-tailed Kite
Sharp-shinned Hawk
Cooper’s Hawk
Bald Eagle
Peregrine Falcon

Rails & Bitterns
American Bittern
American Coot
Sora

Marsh and Shorebirds
Virginia Rail
Black-bellied Plover
Pacific Golden-Plover
Semipalmated Plover
Snowy Plover
Killdeer
Black Oystercatcher
Spotted Sandpiper
Baird’s Sandpiper
Western Sandpiper
Least Sandpiper
Dowitcher Sp.
Greater Yellowlegs
Lesser Yellowlegs
Whimbrel
Marbled Godwit
Wandering Tattler
Black Turnstone
Surfbird
Sanderling
Wilson’s Snipe
Red-necked Phalarope
Red Phalarope
*Red-necked Stint

Gulls, Terns & Alcids
Parasitic Jaeger
Long-tailed Jaeger
California Gull
Glaucous-winged Gull
Heermann's Gull
Sabine's Gull
Western Gull
Ring-billed Gull
Caspian Tern
Arctic Tern
Common Murre
Pigeon Guillemot
Marbled Murrelet
Cassin’s Auklet
Rhinoceros Auklet
Tufted Puffin

Pigeons and Doves
Mourning Dove
Band-tailed Pigeon
Rock Pigeon
Eurasian Collared-dove

Owls
Great Horned Owl

Hummingbirds
Anna's Hummingbird
Rufous Hummingbird

Kingfisher
Belted Kingfisher

Woodpeckers
Downy Woodpecker
Hairy Woodpecker
Northern Flicker
Pileated Woodpecker

Flycatchers
Black Phoebe

Corvids
Steller's Jay
American Crow

Swallows
Purple Martin
Barn Swallow

Chickadees & Bushtits
Black-capped Chickadee
Chestnut-backed Chickadee
Bushtit

Wrens
Bewick’s Wren
Marsh Wren

Kinglets
Golden-crowned Kinglet

Bluebirds & Thrushes
American Robin
Swainson’s Thrush

Babblers
Wrentit

Starlings
European Starling

Waxwings
Cedar Waxwing

Warblers
Common Yellowthroat
Wilson’s Warbler

Tanagers
Western Tanager

Sparrows
Spotted Towhee
Savannah Sparrow
Song Sparrow
White-crowned Sparrow

Blackbirds
Red-winged Blackbird
Brewer's Blackbird
Brown-headed Cowbird

Finches
House Finch
American Goldfinch
Lesser Goldfinch
House Sparrow

Exhibit 17

http://www.cbc.ca/news/canada/new-brunswick/7-500-songbirds-killed-at-canaport-gas-plant-in-saint-john-1.1857615

7,500 songbirds killed at Canaport gas plant in Saint John

Migrating birds, some possible endangered species, flew into gas flare

CBC News Posted: Sep 17, 2013 1:24 PM AT ; Last Updated: Sep 18, 2013 7:48 AM AT

About 7,500 songbirds, possibly including some endangered species, were killed while flying over a gas plant in Saint John late last week, officials have confirmed.

It appears the migrating birds flew into the gas flare at Canaport LNG between Friday night and Saturday morning, said Fraser Forsythe, the company's health, safety, security and environmental manager.

The birds were drawn to the flame like moths, an extremely unusual event, according to Don McAlpine, the head of zoology at the New Brunswick Museum.

"They would circle in around that and of course with a large flame like that and high temperatures, they wouldn't need to get terribly close to become singed or burned."

The weather conditions were foggy and overcast at the time, which may have contributed to the incident, said McAlpine.

Not much is known about how such birds navigate at night, but officials believe they are attracted to light, particularly red or flashing lights, he said.

The flare tower at the Canaport liquefied natural gas receiving and regasification terminal is about 30 metres tall and the size of the flame varies, depending on weather conditions. It is typically higher amid low-pressure systems.

Flaring is part of the standard operation at the east side plant, located on Red Head Road, and is designed as a safety release system. It is used to maintain normal operating pressure by burning off small amounts of excess natural gas.

An estimated 6,800 birds were killed, while several hundred more were injured and had to be put down. "There were too many birds to count," said McAlpine.

"A crude estimate at this stage suggests about 7,500 birds died," he said. "There's certainly more than 5,000 and probably less than 10,000 birds affected."

McAlpine is still examining several hundred of the dead birds, which are being stored in a freezer, to try to identify their species.

There were a large number of red-eyed vireos, several types of warblers, including parula, black-and-white, magnolias and redstarts, as well as a few thrushes and rose-breasted grosbeaks, he said.

It's possible there may have also been some endangered species, such as the olive-sided flycatcher and Canada warbler, which are on the federal government's species at risk registry, said McAlpine.

"There are some flycatchers involved, but I haven't identified them yet. There's very few. Likewise with the Canada warbler, I haven't seen any yet, but it doesn't mean they're not there."

Many of the birds were badly burned, but some appeared completely unscathed, said McAlpine. He suspects they became disoriented and hit the tower or the ground, but several have been sent to the Atlantic Veterinary College in Prince Edward Island for necropsies to determine if there were any underlying conditions or external factors that may have contributed to the bird deaths.

The affected birds, which are mostly insect-eating, spend their summers in New Brunswick nesting and breeding before heading to Mexico, Central and South America for the winter, he said.

Staff 'reduced to tears'

Canaport LNG employees were devastated when they discovered the dead and injured birds piled up around the base of the plant's flame on Saturday morning, said Forsythe.

"We've got people that are pretty well reduced to tears here," he said.

"It has really struck home to our employees here and they've expressed a lot of remorse to me that this would happen. It's a very unexpected event," Forsythe said, adding it was the first incident of this type at the plant.

Cleanup efforts continued into Tuesday, said Forsythe.

Staff alerted the provincial Department of Environment, the Canadian Wildlife Service and the Atlantic Wildlife Institute in Sackville about the incident immediately, he said.

Barry Rothfuss, executive director of the Atlantic Wildlife Institute, said they are still busy dealing with the "carnage."

But they hope to be able to determine the cause and make recommendations to prevent a similar occurrence. "That's going to take some time," he said.

"I don't think it could have been necessarily perceived and accidents like this do happen and so it's a learning experience for all of us," Rothfuss added.

McAlpine said there is not a lot of information about bird mortalities involving flare towers.

"There's been a recognized need recently for further monitoring of this kind of thing," he said.

Still, McAlpine, said it's important to put the incident in perspective, noting an estimated one billion birds in the U.S. are killed every year from human causes.

"Although this is certainly a tragic event and it's shocking to see 7,500 dead birds, it’s a drop in the bucket in terms of the number of birds that are killed from human actions every year," said McAlpine.

The leading cause of death is birds flying into tall office buildings, while house cats rank third, he said.

Canaport LNG, owned by Repsol and Irving Oil Ltd., lists bird monitoring as among its environmental and reporting activities on its website.

Migratory birds have been considered in previous environmental impact assessments at the terminal.

In March 2012, Canaport LNG announced plans for a $43-million upgrade to make the facility more efficient and cut down on flaring.

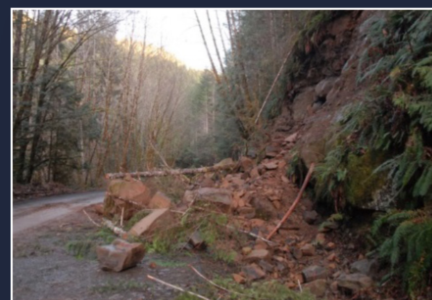
Exhibit 18

Geology of the Coos Estuary and Lower Coos Watershed

Clw DATA SOURCE

Summary:

- *Tectonic interactions between the Pacific, Gorda, Juan de Fuca, and North American plates, and the Juan de Fuca and Gorda oceanic ridges are the source of incremental , long-term coastal uplift and infrequent earthquakes when coastal lands suddenly subside.*
- *Tectonic processes, along with long-term cyclical changes in climate and related glacial spread and retreat, have created the bedrock and soil formations found in the project area.*



Landslide along the Smith River in the Oregon coast range.

Local geologic formations are revealed at Coos Head.

What's happening?

This summary describes local geology (e.g., soil and bedrock types), in the context of larger geological processes (e.g., plate tectonics) in four sections:

1. Plate Tectonics – which examines interactions between continental plates, faults, and folds, as well as earthquakes and tsunamis affecting the project area;
2. Geologic Formations – which describes the project area's geologic formations, superficial deposits, and geologic age;
3. Soils – which provides information on soil types within the project area; and
4. Landslides – which describes areas within the project area most at risk for landslides and debris flows.

These four sections are followed by a Background section which provides more in-depth information for each of the sections in this data summary.

Plate Tectonics

Plate Movement: The underlying geology of the Coos estuary and surrounding watershed results from the tectonic interactions between the Pacific, Gorda, Juan de Fuca, and North American (i.e., North American continent) tectonic plates, and oceanic spreading from two ridges (Juan de Fuca and Gorda) (Figure 1)(see also Geology Terminology sidebar). Large-scale plate movements (e.g., slip of the Juan de Fuca plate along the Blanco Transform Fault, and subduction of the Juan de Fuca plate beneath the North American plate) have been coupled with localized sea floor spreading along two ridges: the Gorda Ridge at a rate of 2.3-5.5 cm (0.9-2.2 in) per year, and the Juan de Fuca Ridge at a rate of 4.0 cm (1.6 in) per year (Komar 1997; Clague 1997). Along the Oregon coast, pressure from these tectonic movements of the earth's crust have resulted in the folded and warped outer continental shelf margin and cycles of long-term, incremental uplift of the coastal lands followed by rapid subsidence events (i.e., earthquakes)(Rumrill 2006).

Stratigraphic (i.e., study of rock layers) investigations of rock outcroppings by Nelson et al. (1996, 1998) and analysis of the composition and age of buried microfossils indicate that the South Slough tidal basin has undergone catastrophic subsidence of 0.50-1.0 m (1.64-3.28 ft) at least three times over the past 4,000 years, and possibly as many as nine times.

Geology Terminology

Tectonic Plate – The rigid outermost shell of the planet (crust and upper mantle), is broken into major (e.g., continental plates) and minor tectonic "plates".

Ocean Ridge – Underwater mountain range formed by rising magma in a zone on the ocean floor where two tectonic plates are moving apart.

Subduction Zone – An area where two tectonic plates converge causing one plate to slide beneath the other.

Cascadia Subduction Zone – The area where the Juan de Fuca Plate slides beneath the North American Plate.

Faults – Fractures in the earth's crust caused by compression, tensional, or shearing forces, often associated with the boundaries between tectonic plates.

Slip or Strike-slip Fault – Vertical fractures in the earth's crust where the blocks of land have mostly moved horizontally.

Paleoseismic Faults – Faults that were the source of significant earthquakes (magnitude 6.0 or greater) in the past 1.6 million years

Sources: USGS 2014a; DOGAMI 2009; PNSN n.d.

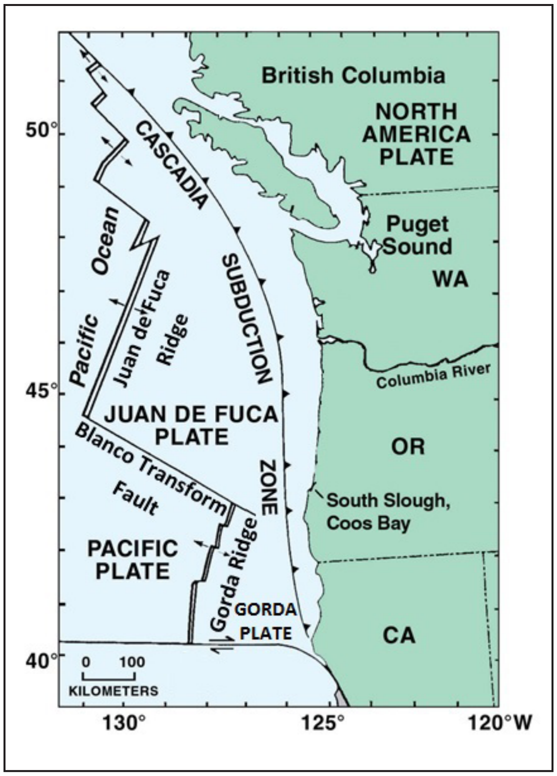


Figure 1: Tectonic components (ridges and plates) in the Pacific Northwest. Arrows on ridges indicate direction of spread. Cascadia Subduction Zone is where the Juan de Fuca Plate is pushed under the North American Plate. Amended from Rumrill 2006

<u>Faults and Folds</u>: The chief geological feature of the Coos estuary is the South Slough Syncline, which is an asymmetric fold with steep sandstone and shale on its western side and gently sloping marine terraces on its eastern side, all of which are offset by several minor cross faults (Rumrill 2006; McInelly and Kelsey 1990)(Figure 2). According to Rumrill (2006), "South Slough marks the point where the Cascadia fold and thrust belt comes onshore; north of Coos Bay most compressional structures occur offshore on the continental shelf and slope".

Paleoseismic faults in the project area – or faults that were the source of significant earthquakes (magnitude 6.0 or greater) in the past 1.6 million years – were found almost exclusively in the South Slough subsystem (Figure 2). Similarly, nearly all non-paleoseismic faults and folds in the project area are found

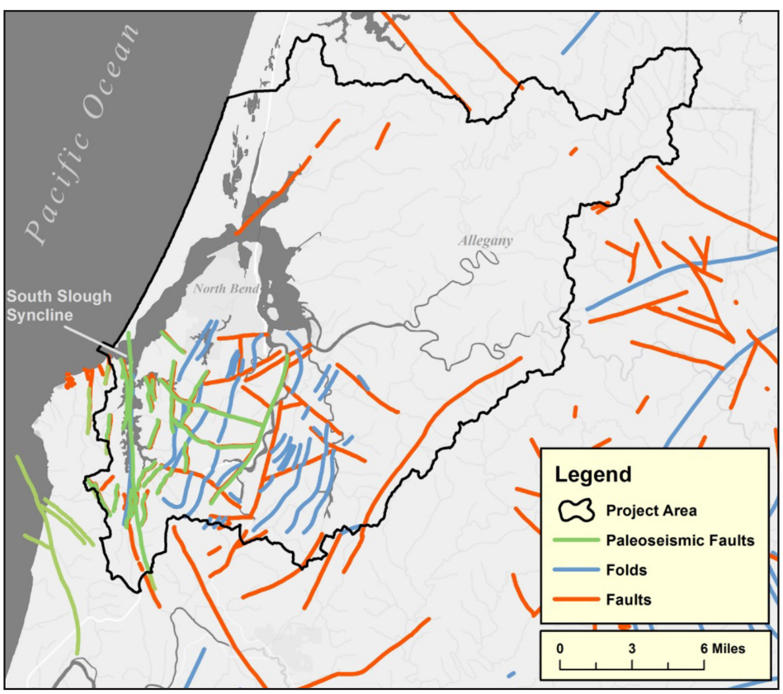


Figure 2: Faults and folds occurring within project boundaries. Paleoseismic faults are highlighted, designating faults that were the source of significant earthquake (6.0 or greater) in the past 1.6 million years. Data: USGS 2005; DOGAMI 2009.

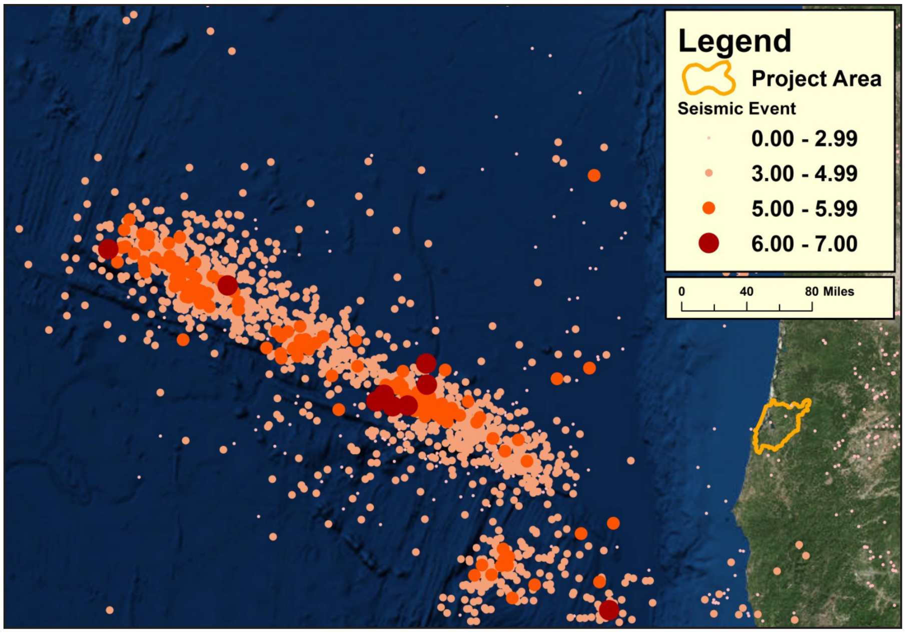


Figure 3: Seismic events between 1969 and 2015.
Data USGS 2015

Year	Month	Magnitude	Depth	Latitude	Longitude
1991	July	6.9	11	42.182	-125.641
1985	March	6.5	10	43.51	-127.561
2008	January	6.3	13	43.785	-127.264
2003	January	6.3	10	44.284	-129.024
1994	October	6.3	20	43.515	-127.427
2000	June	6.2	10	44.513	-130.081
1981	November	6.2	10	43.542	-127.706
2000	January	6.1	10	43.649	-127.257
2012	April	6.0	8	43.584	-127.638

Table 1: Seismic events (between 1969 and 2015) with magnitudes 6.0 or higher. Depth is kilometers below the earth's surface. Data USGS 2015

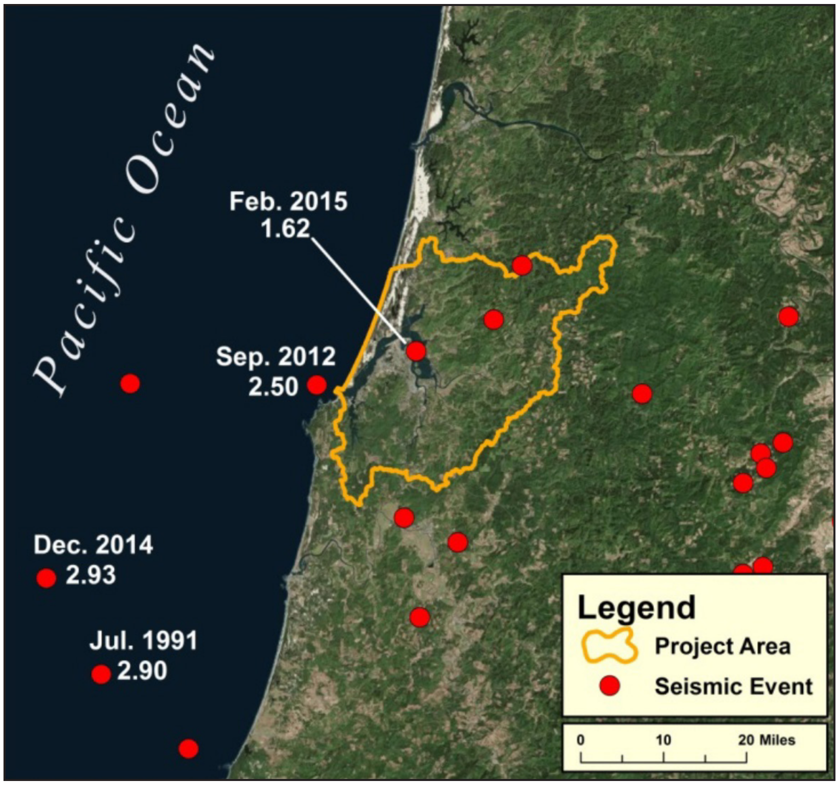


Figure 4: Seismic events (occurring between 1969 and 2015) closest in proximity to the project area. Dates and strength of the highest magnitude events are labeled. Data USGS 2015

in its southern portions (i.e., South, Isthmus and Catching Slough subsystems).

Earthquakes and Tsunamis: Of the over 2,100 earthquakes measured off the Oregon coast since 1965, only nine have been a magnitude 6.0 or higher (Figure 3). The strongest of these (magnitude 6.9) occurred in July 1991 (Table 1). The average magnitude of all earthquakes during that time period was 3.5 and the average depth was 10.7 km (6.6 mi) below the earth's surface. Many earthquakes were concentrated around the Blanco Transform Fault. In contrast, only a few earthquake events were located in close proximity to the project area and those were much smaller in magnitude during the same time period (Figure 4). The largest of these closer proximity earthquakes (2.5 magnitude) occurred just off Cape Arago in September 2012.

Stratigraphic investigations conducted over the past few decades have provided evidence that much of the Pacific Northwest coast has experienced significant (magnitude greater than 8) Cascadia megathrust earthquakes and accompanying tsunamis repeatedly over the past 5,500-6,500 years. These earthquakes occurred every 500-600 years on average (varying from a few hundred years to almost 1,000 years)(Kelsey et al. 2002; Witter et al. 2003). For example, soil cores provide evidence for historically reoccurring rapid coastal subsidence events. Cores taken from current-day tidal marshes in the project area show ancient marsh soils (full of organic materials such as march plant roots) abruptly buried by fine intertidal mud when the coastal land mass rapidly subsided during historic earthquakes. Often these abrupt transitions in the soil cores include a coarse sandy layer full of woody debris deposited during earthquake-generated tsunamis.

The most recent Cascadia megathrust earthquake (magnitude 9) and tsunami on the Oregon coast (including the Coos estuary) occurred on January 29, 1700, caused by a sudden slip of the Juan de Fuca plate beneath the North America plate along the 1,000 km (621 mi) long Cascadia subduction zone (Satake et al. 1996; Rumrill 2006). This caused the land mass to subside an estimated 0.6 m (2.0 ft) (Leonard et al. 2004). Estimates of subsidence from future mega-thrust earthquakes in Coos Bay range from 0-1.5 m (0-4.9 ft) (Leonard et al. 2004) while maximum subsidence, modeled for this area, could be as high as 2 m (7 ft)(Witter et al. 2011). According to Rumrill (2006), "the probability of a future earthquake and coastal subsidence event is conservatively estimated at 10-20% within the next 50 years (or 20-40% within the next 100 years)".

Lately, seismic activity along the subduction zone appears to have fallen off, leaving the zone "eerily quiet" (Banse 2014). Quoted in several northwest media outlets in December, 2014, Doug Toomey, a geophysics professor at the University of Oregon, said, "all of Cascadia is quiet. It's extraordinarily quiet when you compare it to other subduction zones globally" (Banse 2014). In 2011, Toomey and other scientists began the Cascadia Initiative, a four-year study in which seismometers were deployed at 160 sites along the entire Cascadia subduction zone to help determine what that silence means. If they find the boundary between the two plates is fully locked, pressure will continue to build until another serious earthquake occurs. "If it is completely locked, it means [the Cascadia subduction zone] is increasingly storing energy and that has to be released at some point." (Toomey, on Banse 2014).

Geologic Formations and Deposits

Tyee and Coaledo formations make up the vast majority of the underlying bedrock in the project area (71% combined)(Figure 5). Both formations are sandstones with minor siltstone embedded within (Beaulieu and Hughes 1975)(see definitions in sidebars and in Table 2). Landforms surrounding most of the South Slough shoreline and eastern portions of the lower bay are composed primarily of marine terrace deposits (Figure 5). The remainder of the lower bay is made up of eolian deposits (wind-generated deposits: in this case, dune sand) and beach deposits, while alluvial deposits (river-formed) are found under and along each major tributary to the Coos estuary. Man-made fill deposits can be found under most of the project area's low-lying urban centers.

The Coos Bay Coal Field (oriented north to south and roughly 30 mi long by 12 mi wide, overlaps the Coaledo formation), lies under North Bend, Coos Bay, Isthmus Slough and Catching Slough (and their tributaries), and the Lower Coos River, and extends down to the Coquille River (DOGAMI n.d.)(Figure 5). From the late nineteenth century through the mid-twentieth century extensive coal mining and geologic testing occurred in the Coos

Geologic Formation

A geological formation is a rock unit that is distinctive enough in appearance that a geologic mapper can tell it apart from the surrounding rock layers. It must also be thick enough and extensive enough to plot on a map.

Source: Wilkerson 2001

Geologic Deposits

Geologic deposits (superficial) are recent (quaternary: 2.6 million years old or less) unconsolidated sediments, soil or rocks added to a landform, generally named according to their origin (e.g., beach deposit, landslide deposit). Older deposits are referred to as bedrock.

Source: Wikipedia 2015b

Sandstone

Sandstone (sometimes known as arenite) is a medium-grained sedimentary rock composed primarily of minerals or rock grains cemented together.

Siltstone

Siltstone is sedimentary rock made up of cemented together silt particles, similar to shale, but does not demonstrate fissility (breaking along planes into sheets).

Source: USGS 2014b

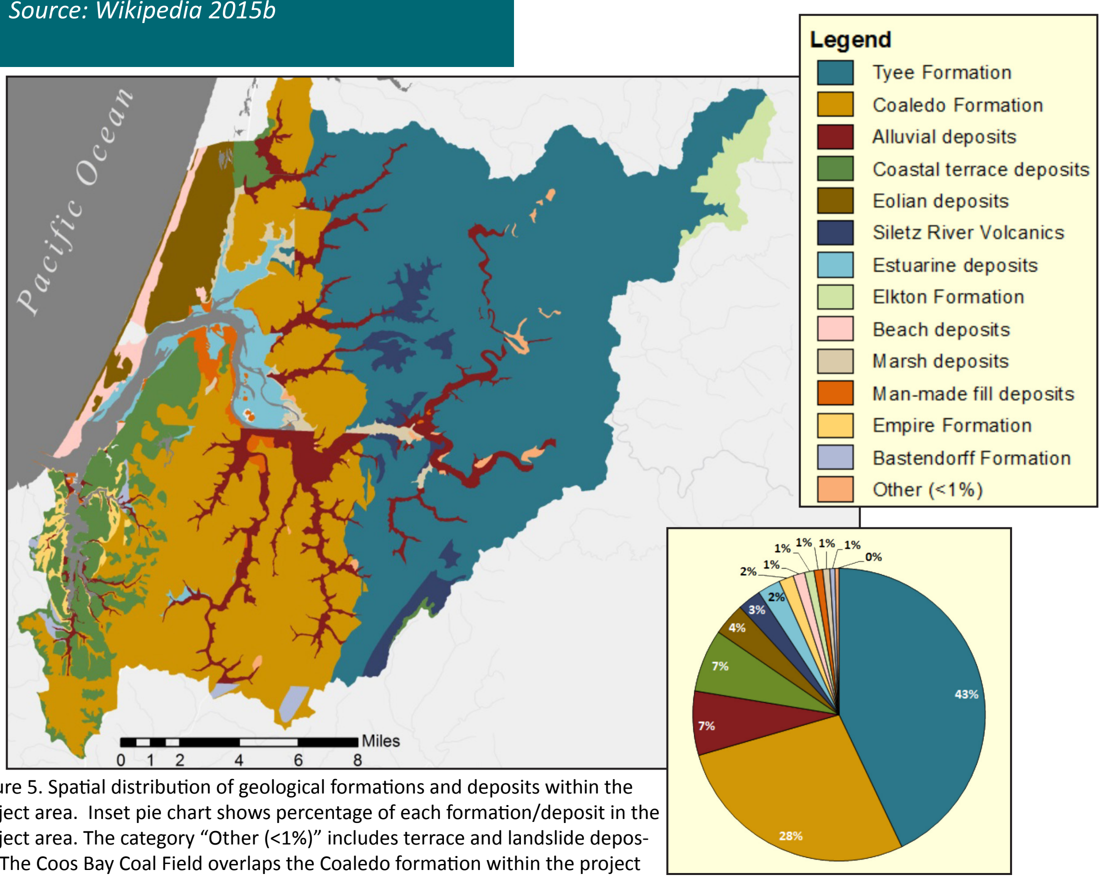


Figure 5. Spatial distribution of geological formations and deposits within the project area. Inset pie chart shows percentage of each formation/deposit in the project area. The category "Other (<1%)" includes terrace and landslide deposits. The Coos Bay Coal Field overlaps the Coaledo formation within the project area, but the coal field is not shown in its entirety. Data: DOGAMI 2009

Geologic Unit	Bedrock Description	Age	Structure
Alluvial deposits	Silt, sand, and gravel filling channels of present day streams/rivers.	Quaternary	
Bastendorff Formation	3,000 ft of shale and siltstone with thin (50') sandstone	Late Eocene	Major synclines
Beach deposits	Fine-grained sand	Holocene-present	
Coaledo Formation	Coarse to fine-grained cross-bedded, deltaic sandstone and minor siltstone	Late Eocene	Moderately to tightly folded with steep dips
Coastal terrace deposits	Compact, horizontally bedded, deeply weathered silt, sand and clay	Quaternary	
Elkton Formation	Thousands of feet of clayey siltstone with minor beds of	Mid-Eocene	Gently folded and
Empire Formation	Thick sandstone beds with very minor quantities of siltstone	Pliocene	Gently dipping folds
Eolian deposits	Fine-grained sand	variable	
Estuarine deposits	Horizontally bedded sand, silt, and clay, rich in organic material	Holocene-present	
Landslide deposits*	Unstratified mixture of bedrock fragments	Holocene	
Man-made fill deposits	Dredge spoils, sand, silt, clay, woodchips	<100 years	
Marsh deposits	Horizontally bedded sand, silt, and clay, rich in organic material	Holocene-present	
Siletz River volcanics*	Basaltic pillow lava flows composed of basaltic siltstone, sandstone, tuff and conglomerate. Originated from oceanic crust.	Eocene	
Terrace deposits	Sand, silt, clay gravel, cross-bedded	Quaternary	
Tyee Formation	Thousands of feet of thick-bedded sandstone and minor rhythmically bedded siltsone	Mid-Eocene	Gently folded

Table 2: Descriptions of geological formations and deposits in the project area. Source: Beaulieu and Hughes 1975; except those marked with an asterisk* sourced from USGS 2014b

Bay Coal Field. Nearly 2.5 million tons of coal were extracted from this coal field between 1882 and 1918 (Duncan 1953; DOGAMI n.d.). Mining ceased in the 1920's primarily due to competition from California fuel oils and higher grade coal from Utah and Wyoming (Duncan 1953; DOGAMI n.d.). Although coal mining no longer occurs in the project area, in the mid-2000s, portions of the coal field were explored to determine its potential for natural gas production using hydraulic fracturing techniques.

Geologic Age of the Project Area

The project area is composed of bedrock formed in the Cenozoic era (65 million years ago-present), most of which was created during its Eocene epoch (Figure 6; Table 3).

According to Rumrill (2006), sandstone, siltstone, and shale were deposited deep in the Pacific ocean and in shallow coastal waters over the past 50 million years, from the Eocene epoch through the Quaternary period. During the marine regression in the middle to late Eocene epoch (38-45 million years ago), sea level dropped, which allowed Coos Bay to emerge as a distinct, wave-dominated (as opposed to river-dominated) deltaic coastal basin.

Beginning in the middle Eocene epoch (about 40-48 million years ago), sediments that largely form the present-day bedrock were laid down during repeating marine transgressions (period of high sea level) and regressions (period of low sea level)(Rumrill 2006). These fluctuations were caused primarily by

Geological Time Scale

Span of time since the Earth's creation, divided by major geological events, strata composition, or radiometric dating. Eon is the largest division, followed by Era, Period, Epoch and finally Age.

Source: Wikipedia 2015a

cyclical changes in climate that led to advances and retreat of continental glaciers, and subsequent rise and fall of sea level. These periods of major seal level fluctuations caused the continental shoreline to migrate back and forth tens of kilometers between the sea level extremes.

For example, beds of siltstone, mudstone, and sandstone formed in the middle Coaledo Formation beds (see "Formations" above) were laid down in deeper coastal waters during a marine transgression, while upper Coaledo beds (siltstone, mudstone, coal, and conglomerate) were deposited in shallow water during a subsequent regression (Rumrill 2006).

According to Rumrill (2006), absence of sediments for nearly 30 million years, dating from the Oligocene and early Miocene (8-36 million years ago), indicates a significant period of non-deposition, probably related to a combination of the onset of "tectonic plate deformation along the Cascadia subduction zone", glacial advance, and periods of low sea level. Rumrill (2006) discusses another gap of about four million years long occurring 6-2 million years ago, separating older formations

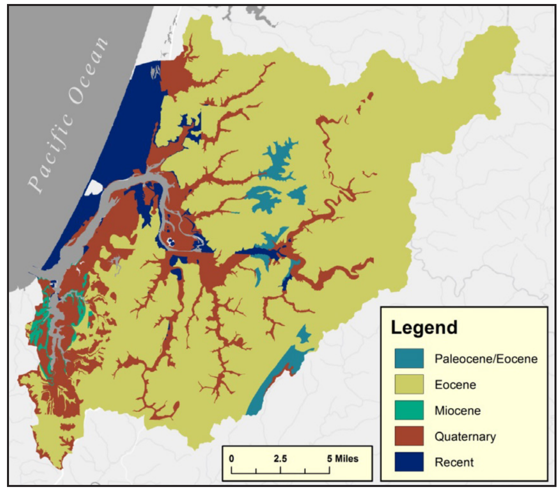


Figure 6: Spatial distribution the project area's geologic time scale. Legend ordered from oldest to most recent. Data: DOGAMI 2009

Era	Period	Epoch	Geologic Age (million years ago)
Cenozoic	Quaternary	Holocene	0.01-present
		Pleistocene	2.6-0.01
	Neogene	Pliocene	5.3 - 2.6
		Miocene	23.0-5.3
	Paleogene	Oligocene	33.9-23.0
		Eocene	56.0 -33.9
		Paleocene	65.0-56.0

Table 3: Definition of geological ages in the Cenozoic era.

such as the Miocene epoch's Empire formation from more recent Pleistocene marine terraces and Holocene estuarine and sand deposits.

Soils

This section discusses soil types found in the project area. Definitions of soil types discussed in this section can be found in Table 4.

Estuarine Soils

Sediments in the estuarine tidal channel vary from coarse-grained sand to fine-grained sand, silt and clay (Rumrill 2006). See "Sediment Composition" summary in "Chapter 10: Sediment" for more detail on estuary sediments.

Tide flat sediments are primarily open sand flats and mudflats, which are composed of Udorthents, a combination of sand, silt, mud or organic materials, largely devoid of emergent vegetation (Haagen 1989). Mudflats typically occur in regions of the estuary that experience low tidal energy while sand flats occur in areas of high tidal energy (Rumrill 2006).

In the South Slough estuary, sand flats frequently occur on the inside of major bends in the tidal channel. These sand flats frequently have sand ripples or waves, the patterns of which are directly related to water velocity (Rumrill 2006).

According to Rumrill (2006) tidal beaches within South Slough are generally steep (9-15% slope) and sediments increase in mean grain size with depth, and decrease in mean grain size along the estuarine gradient (i.e., sediment is more fine further away from the mouth of the estuary). Most beach sediments are well-sorted. The decrease in mean sediment grain size along the estuarine gradient (from the high-energy estuary mouth to the low-energy upper estuary) is most likely a result of the gradual decrease in velocity of tidal currents, which in turn reduces their capacity to carry larger sediment particles (Arkett 1980, in Rumrill 2006).

Tidal Wetland Soils

Soils in the tidal wetlands of the Coos estuary are predominately Fluvaquents-Histosols, which, typical of permanently or frequently saturated soils, are particularly rich in organic matter (Haagen 1989).

Rumrill (2006) described surface soils within South Slough riparian areas, forested wetlands, and emergent freshwater marshes as typically sandy loams, also rich in organic matter.

Soil Complex

Soil complex is defined as two or more soils which are so integrated that they cannot be separated at the map scale.

Soil Association

Soil association is defined as two or more soils that are intricately mixed but could still be separated at the map scale (although it's not practical to do so).

Source: Haagen 1989

Soils	Abridged Definition (Haagan 1989)
Bandon Sandy Loam	Deep, well drained soils, with a thick (1") covering of organic litter, found on dissected marine terraces. Top 5" is dark gray/brown sandy loam, followed by 25" dark red/brown sandy loam subsoil, 13" pale brown cemented sandy material and a substratum of yellow/brown loam.
Bullards-Bandon-Blacklock	Loamy and sandy soils derived from marine sediment and found on marine terraces.
Bullards (58%)	See Bullards Sandy Loam above
Bandon (20%)	See Bandon Sandy Loam above
Blacklock (18%)	Poorly drained, nearly level (0-3%) soils on depression areas of marine terraces. Black fine sandy loam surface (9") soil, with upper subsoil (2") black mucky loam, and lower subsoil (37") with a yellow/brown cemented sand. Base substratum is light olive/red or brown sand.
Bullards Sandy Loam	Deep, well drained soils, with a thick (3") covering of organic litter, found on dissected marine terraces. Surface soil (7") is dark gray/brown sandy loam, with 34" dark red/brown gravelly sandy loam subsoil beneath, under which is yellow/brown sand.
Coquille-Nestucca-Langlois	Poorly drained, silty and clayey soils found on flood plains; formed from alluvial processes.
Coquille (22%)	See Coquille Silt Loam below.
Nestucca (19%)	Poorly drained soils found in depressions with mottled dark brown silt loam on the surface (14"). Subsoil is mottled dark gray/brown silty clay loam (26"). Substratum is mottled olive brown silty clay.
Langlois (14%)	Very poorly drained soils found in depressions and old tide flats. A thick (5") dark gray/brown peat layer sits atop surface soils. Surface soils are mottled dark gray/brown silty clay loam (10") and dark gray/brown silty clay upper subsoil (20") with dark gray clay lower subsoil (60").
Other minor soils (45%)	Combination of minor elements.
Coquille Silt Loam	Deep, poor draining soils, found primarily on flood plains (formed from alluvium). Thick (14") surface layer is dark gray/brown silt loam with gray/olive silty clay loam subsoil. Substratum is dark gray silty clay loam.
Dement Silt Loam	Deep, well drained soils derived from silt or sandstone, frequently found on ridgetops. Surface is dark gray/brown silt loam (7"), followed by red/brown silty clay loam subsoil (38"). Under this is found weathered sedimentary rock.
Dune Land	Shifting fine and medium grained sand, extremely permeable.
Dune Land-Waldport-Heceta	Sandy soils found on sand dunes and deflation plains.
Dune Land (30%)	See Dune Land above
Waldport (29%)	Found on stabilized sand dunes (leeward side of deflation plains). Surface 4" is dark gray/brown fine sand with dark yellow/brown fine sand beneath.
Heceta (18%)	Deep poorly drained soils found in deflation plains and depressions between dunes. Surface layer (4") is dark gray/brown fine sand with mottled gray/brown sand beneath.
Other minor soils (23%)	Combination of minor elements.
Fluvaquents-Histosols Complex	Level (slope ≤ 1%) tidelands of bays, inlets and estuaries
Fluvaquents (50%)	Covered by mean high water. Layers of mineral and organic material in varying thicknesses. Surface layer is generally sandy, silty or clayey depending on tidal currents.
Histosols (40%)	Covered by mean higher high water. Thick (16") organic layer over alternating layers of mineral and organic matter.
Geisel Silt Loam	Deep, well drained soil found on side slopes, derived from sedimentary rock. Surface layer is dark red/brown silt loam (4" thick). Upper subsoil (26") is dark red/brown silt loam and silty clay loam, while lower subsoil (24") is dark red/brown silty clay. Weathered siltstone forms base rock.
Milbury-Bohannon-Umpcoos Association	Moderately deep and shallow, gravelly loamy soils, derived from sedimentary rock
Milbury (40%)	Derived from sandstone, moderately deep well drained soil with very gravelly black sand loam on surface (10") and dark gray brown very cobbly loam subsoil (26"). These sit atop consolidated sandstone.
Bohannon (27%)	Moderately deep, well drained soil derived from arkosic sandstone. Surface (11") is very dark brown loam and gravelly loam; subsoil is dark yellow/brown gravelly loam (20"). Base substratum is weathered fractured sandstone.
Umpcoos (22%)	Shallow, well drained soils derived from sandstone, found on rock outcrops and ridgelines. Surface (3") is dark gray/brown very gravelly sand loam. Subsoil is brown very gravelly sandy loam (13"). Hard sandstone is underneath.
Other soils (11%)	Combination of minor elements.
Millicoma-Templeton Complex	Found on ridgetops and side slopes
Millicoma (55%)	Deep well drained, derived from sandstone. Surface layer is very dark/gray brown gravelly loam (18") with very gravelly dark brown loam subsoil (17"). Underneath that is partially weathered sandstone.
Templeton (25%)	Deep well drained, derived from sandstone. Surface layer is very dark brown silt loam (16") with red/brown/yellow silty clay loam subsoil (26"). Weathered fractured siltstone is under that.
Salander and other soils (20%)	Salander - see Salander Silt Loam below; small areas of clay loam or soils with ≤ 35% rock fragment.
Preacher-Blachly Association	Found on broad ridgetops and benches.
Preacher (50%)	Found in concave areas, deep, well drained soil derived from arkosic sandstone. Surface is organic litter (4") with dark gray/brown loam (14"). Subsoil is dark yellow/brown clay loam (34"). Base substratum is yellow brown clay loam.
Blachly (35%)	Deep, well drained soil, derived from basalt or sedimentary rock. Surface is red/gray or dark red/brown silty clay loam (7"). Upper subsoil (45") is dark red or yellow/red silty clay; lower subsoil (8") is yellow/red silty clay loam.
Bohannon, Digger (15%)	See Bohannon in Milbury-Bohannon-Umpcoos above.
Preacher-Bohannon Loams	Deep gravelly and loamy soils found on broad ridgetops, benches and steep side slopes.
Preacher (50%)	See Preacher in Preacher-Blachly Association above.
Bohannon (30%)	See Bohannon in Milbury-Bohannon-Umpcoos above.
Milbury, Digger, Blachly (20%)	Milbury - see Milbury-Bohannon-Umpcoos above. Blachly - see Preacher-Blachly Association above. Digger soil is moderately deep well drained derived from sedimentary rock. Organic layer (1") thick on top has dark brown gravelly loam (6") underneath. Upper subsoil (3") is dark yellow/brown gravelly loam; bottom 18" is brown very gravelly and cobbly loam. Base rock is brown extremely cobbly loam (4") with weathered, fractured sandstone beneath.
Rinearson Silt Loam	Deep, well drained soil, found on ridgetops and side slopes, derived from sedimentary rock. Surface soils are dark red/brown silt loam (6"). Upper subsoil (12") is dark/red brown silt loam; lower subsoil (24") is red/brown silty clay loam. Base substratum is weathered sandstone.
Salander Silt Loam	Deep, well drained soil, found on side slopes, derived from sedimentary rock. Surface layer (26") and top layer of subsoil (14") is dark red/brown silt loam. Lower subsoil (25") is dark red/brown silty clay loam.
Templeton Silt Loam	Deep, well drained soil, found on ridgetops and benches, derived from sedimentary rock. Surface layer is very dark brown silt loam (16") with red/brown/yellowish red silty clay loam subsoil (26"). Soft weathered fractured siltstone makes up the base substratum.
Udorthents	Level (slope ≤ 1%) flood plains, marshes, and tidal flats on major water bodies (including filled and leveled areas). Soils are a mixture of sand, silt or clay materials; dredge spoils also consist of dune sand and wood chips.
Wintley Silt Loam	Deep well drained souls found on high terraces, derived from alluvial processes. Surface is topped with 1" undecomposed organics, followed by 4" dark brown silt loam. Upper subsoil (12") is dark brown silty clay loam; lower subsoil (31") is brown silty clay and silty clay loam. Base substratum is dark yellow/brown very gravelly loam.

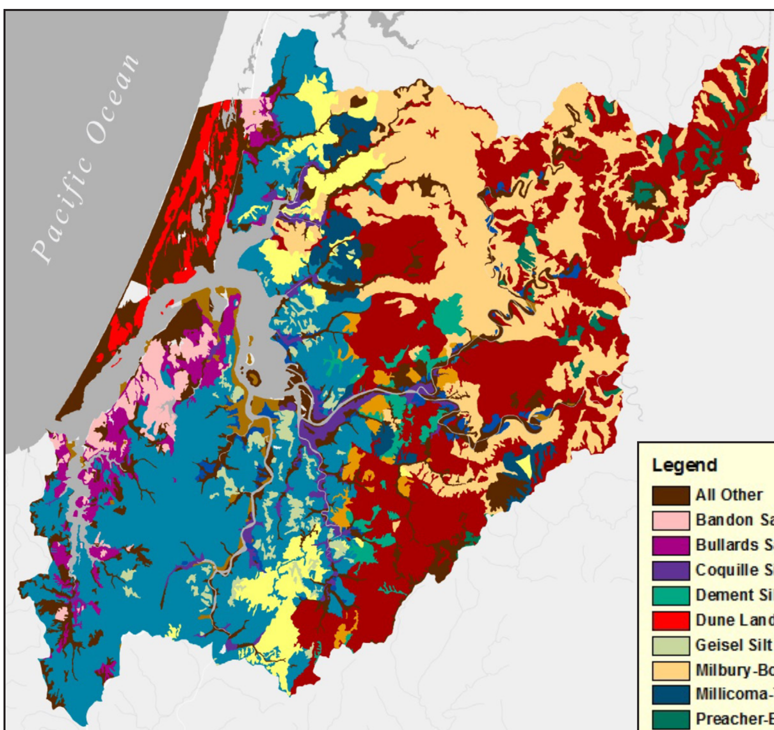
Table 4: Most common soil types, soil complexes, and soil associations found in the project area.

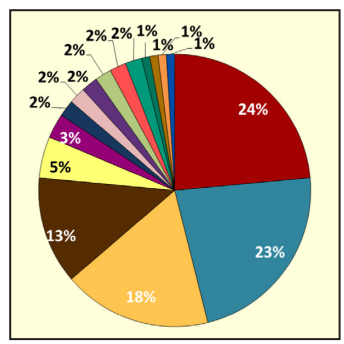
Dune Soils

The Coos Bay Dune Sheet is a mass of sand that extends, unbroken but for the mouths of rivers and streams, from Haceta Head to Cape Arago, making it the largest dune sheet in North America and the only 'oblique-ridge dune' in the world (Cooper 1958; Crook 1979). Dune lands in Coos County are generally made up of DuneLand-Waldport-Heceta soil types. Extensive portions of the dunes have been stabilized by plantings of the invasive European beachgrass (*Ammophila arenaria*), which began in 1910 (for more information on this, see "Vegetation" summary in "Chapter 18: Non-Native/Invasive Spp.").

Upland and Lowland Soils

Fifteen principle soil types are found in the lower Coos basin (Figure 7). Of those, three predominate and are found in distinctly different areas of the landscape. Most common are Preacher-Bohannon loams (24% of total soil cover), found in a patchy, north-south oriented band of uplands east of the bay, along the western slopes and foothills of Blue Ridge, and in the Millicoma highlands. Templeton silt loam (23% of soil cover) extends from the uplands of the South Slough basin east through the drainages of Isthmus and Catching Sloughs, across the highlands of Pony Creek Reservoir, along the eastern slopes of Coos Bay and across the uplands between North





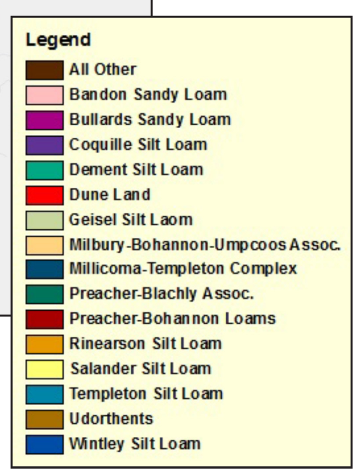


Figure 7: Distribution of different soil types in the project area. Inset pie chart shows percentage of each soil type that makes up the project area. Soil types for both figures were grouped by series (e.g., Bandon Sandy loam 0-7% slopes and Bandon Sandy Loam 7-12% slopes were grouped as Bandon Sandy Loam). Data: USDA 2000

Slough and Haynes Inlet. The Milbury-Bohannon-Umpcoos association (18% of cover) is interspersed with the Preacher-Bohannon series in the upper watershed.

Except where otherwise noted, the following soil descriptions for several major sub-basins, are taken from an assessment of Coos estuary tributary basins conducted by the Coos Watershed Association (CoosWA 2006).

North Slough

North Slough differs in its soils from other sub-basins in that it is dominated by the very soft, highly erosive sandstones of Dune Land-Waldport-Heceta and Bullards-Bandon-Blacklock soils.

Palouse and Larson Sloughs

Three general soil types dominate the Palouse and Larson Slough sub-basin: Dune land-Waldport-Heceta, which is common to dune areas, Templeton and Salander loams, common to the lowland area, and Milbury-Bohannon-Umpcoos, found in the uplands.

Kentuck Slough

Soils in the Kentuck Slough sub-basin consist of Templeton and Salander loams in the lowlands, and Preacher-Bohannon loams in the uplands. The headwaters of Kentuck Creek are on the Milbury-Bohannon-Umpcoos soil type.

Willanch Slough

General soil types in the Willanch Slough sub-basin are Templeton and Salander loams (lowlands) and Preacher-Bohannon loams, (uplands).

Echo Creek

The Echo Creek sub-basin hosts three general soil types: the Coquille-Nestucca-Langlois soil, found in level areas, areas along the bay, and Coos River; Templeton and Salander loams (lowlands), and the Preacher-Bohannon loams (uplands).

Lower Millicoma and South Fork Coos Rivers

According to CoosWA (2008), Preacher-Bohannon loams are the most prevalent soils in Lower Millicoma and South Fork Coos River sub-basin. Other soils include Milbury-Bohannon-Umpcoos on steep slopes and poorly draining, clay Coquille-Nestucca-Langlois soils along floodplains.

South Slough

Haagen (1989) shows the primary soils in this sub-basin as Templeton loams, with some Bullards-Bandon-Blacklock group.

Landslides

According to Wang et al. (2002), Oregon economic losses due to landslides exceed $10 million/year. In years with heavy storm events, losses can exceed $100 million. These losses are expected to increase as the state's human population increases, expanding current land uses.

Landslides occur frequently in the Coos region, as they do throughout much of the central Coast Range. The Oregon Department of Geology and Mineral Industries (DOGAMI) has compiled an inventory of historic landslide locations, which helps identify areas potentially prone to future land failures (Figure 8).

Oregon Department of Forestry (ODF) developed debris flow (a type of landslide – see Background below) hazard maps, based on slopes derived from USGS digital elevation models. Slopes >40% and an area greater than 150,000 ft^2 were considered moderately hazardous. Tyee Formation slopes >65% over an area of 100,000 ft^2 or >60% for more than ⅓ the total basin area were considered a high risk for debris flows. Other formations were considered a high risk if they had a slope >70% and an area exceeding 150,000 ft^2 or ¼ total basin area. Extreme hazard values were assigned to locations where debris flows have occurred frequently over the past 35 years.

Areas of high and moderate debris flow risk have been mapped for the project area using these data (Figure 9). The hills east of the main Coos estuary are at considerably higher risk for debris flow occurrences than lands closer to the ocean. In fact, the Coos River subsystem has the highest percentage of both high (9.5%) and moderate (18%) lands at risk for debris flow events (Figure 10). When taken as a whole, 33% and 12% of the entire project area is at moderate and high risk, respectively, for debris flows.

Background

Plate Tectonics

Rumrill (2006) describes the Coos estuary as being formed by the interactions of “several coastal geomorphic processes in the recent geologic past” (thousands to tens of thousands of years ago), including “slow coastal uplift and sudden subsidence” (driven by tectonic movement of offshore crustal plates); “regional transgression and regression of the sea as a result of ice-age glacial advance and retreat”; and “fluvial erosion of a major riverine drainage system caused by differential coastal uplift”.

Folds and faults

Long-term seismic shifting of the North America and Juan de Fuca plates contributed to east-west compression that formed the South Slough syncline and other folds throughout the southern Oregon coastal region. Folding and faulting cause different areas of the coast to rise at different rates, significantly altering the topography of the Coos drainage basin (Kelsey et al. 2002). For example, before the creation of the current coastal terraces (which were created by folding and faulting processes), the Coquille River drained into the Pacific Ocean through Isthmus and South Sloughs (Baldwin 1945; Nyborg 1993 as cited in Rumrill 2006). Evidence of this can be seen along several outcrops in the South Slough where Pleistocene alluvial floodplain materials (including aquatic invertebrate fossil assemblages) are identical to those found at the mouth of the Coquille River (Nyborg 1993 as cited in Rumrill 2006).

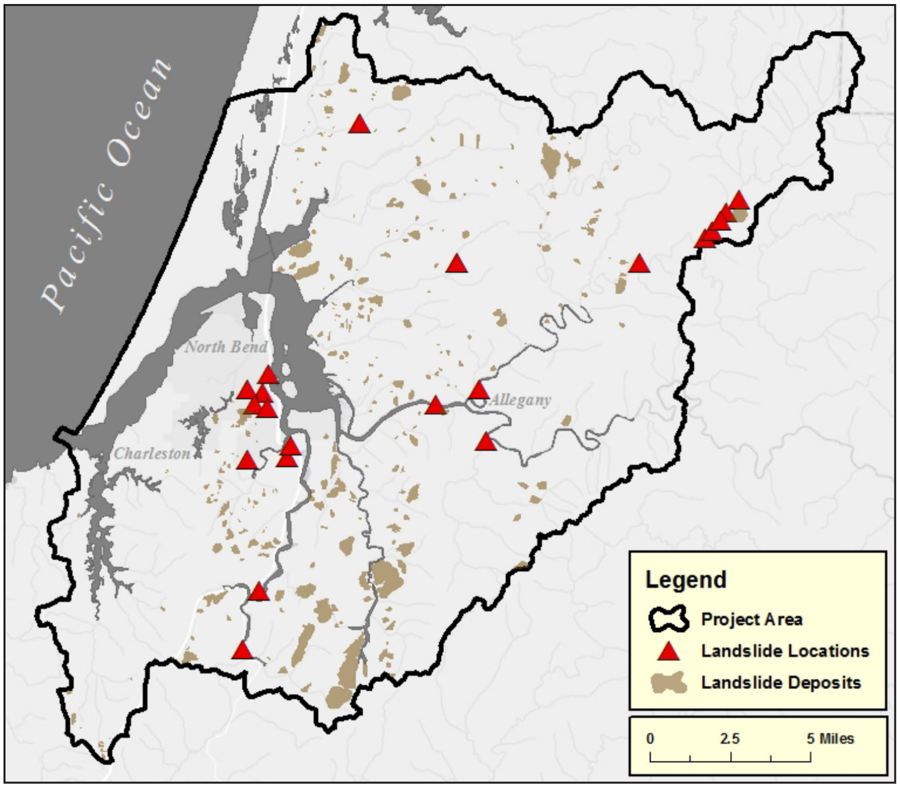


Figure 8: Inventory of historic landslides (1849-2013), identifying landslide-prone areas, which may be susceptible to future landslides. Landslide deposits include debris flow fans and talus extent. Data: DOGAMI 2014

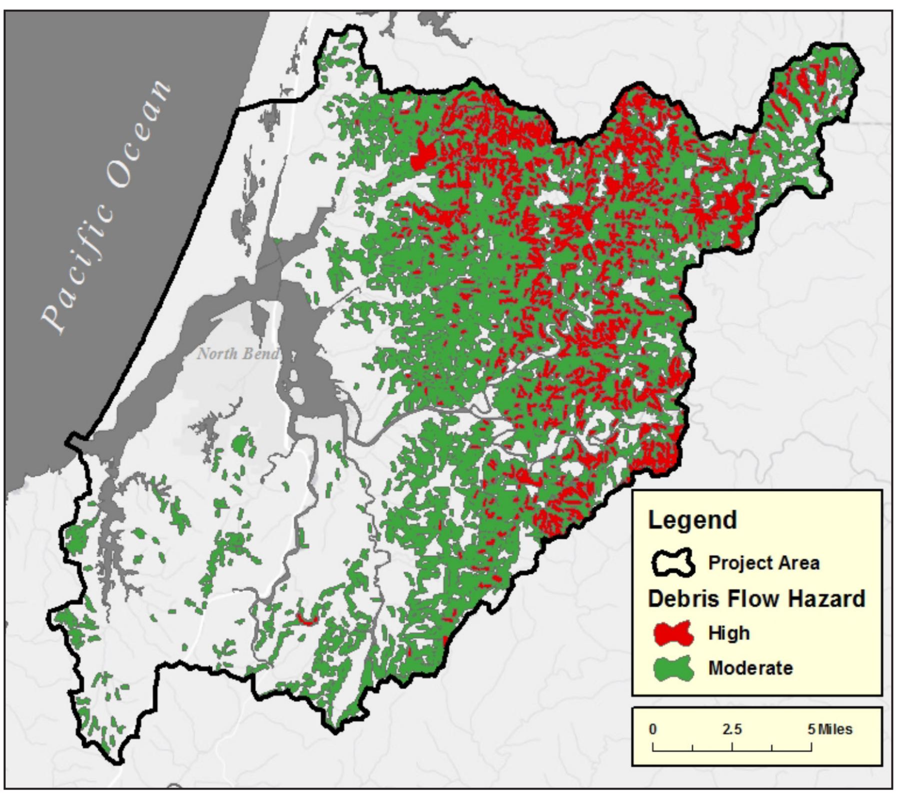


Figure 9: Distribution of lands that are highly or moderately at risk of debris flows in the project area. Data: ODF 2000.

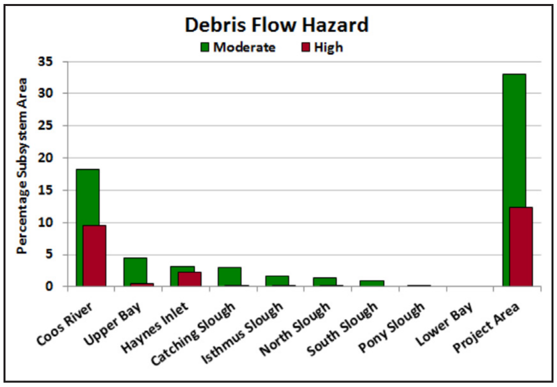


Figure 10: Percentage of each subsystem and entire project area that is at high and moderate risk for debris flow. Data: ODF 2000.

Other evidence of subduction processes were described by Witter et al. (2003), who found that stepped marine terraces occurring in the hills surrounding the Coos estuary are a result of ocean-derived sediments scraped off the Juan de Fuca plate as it slid down under the North American Plate.

Earthquakes

Pressure that accumulates in the earth as a result of forces and movements of plates is released episodically during earthquakes. Three types of earthquakes affect coastal Oregon: Cascadia megathrust, deep intraplate, and crustal earthquakes (see sidebar). The most frequently occurring of these are crustal earthquakes, which occur along active fault lines (Rumrill 2006). Seismic studies conducted near the Coos estuary's Jordan Cove indicate fewer deep intraplate earthquakes occur in the Coos Bay area compared with areas to the north and south (GRI 2013). The largest earthquakes in our area tend to occur along the Cascadia Subduction Zone boundary and can cause sudden coastal subsidence of from 0.5-2 m (1.64-6.56 ft)(Darienzo and Peterson 1990 as cited in Rumrill 2006).

According to NOAA's Pacific Northwest Seismic Network (PNSN n.d.), the Cascadia Subduction Zone is locked by friction at depths shallower than 30 km (16.6 mi). Strain continues to build slowly as the tectonic forces act (including expansion at the Juan de Fuca Ridge). Eventually, when the frictional strength is exceeded, the plates will slip past each other, causing a megathrust earthquake. The fault's frictional properties change with depth, such that immediately below the locked part is a strip (called the transition zone) that slides slowly and slips a few centimeters every year or so. These small slips relieve the stress on the plate boundary in one location, but add to the stress on the fault elsewhere. Below the transition zone geodetic evidence suggests that the faults slide continuously and silently past one another.

Tsunamis

Tsunamis are triggered when the elevation of the coastal margin suddenly changes, displacing a large volume of water. Tsunami waves propagate rapidly through the open ocean and can reverberate throughout the entire Pacific Ocean basin in the 24-hour period following a sufficiently strong earthquake. In the Pacific Ocean, tsunamis move at speeds of ~435 mph, losing little energy as they travel (Petroff n.d.).

Geologists examined sediments deposited in the Coquille River estuary (Witter et al. 2003) and those of coastal lakes (Kelsey et al. 2005)

Local Earthquake Types

Cascadia Megathrust – The most powerful recorded earthquakes in the area (magnitude 8-9 or higher), Cascadia megrathrust earthquakes are caused the by sudden release of built-up energy when the Juan de Fuca Plate (locked against the North American Plate) is suddenly released and the plates slip past each other.

Deep Intraplate – Deep intraplate earthquakes occur when the Juan de Fuca plate cracks as it is bent deep underneath the North American Plate (at depths from 30-70 km [19-43 mi]). Deep intraplate earthquakes occur about every 30 years at magnitudes as high as 7.5. Because they usually occur under the Cascade and Coastal ranges, these earthquakes can be the most damaging to population centers.

Crustal – Crustal earthquakes occur on shallow faults (to 35 km [22 mi] deep) in the North American Plate and are relatively common off the southern Oregon coast (maximum magnitudes <7).

Earthquake Magnitude (i.e., strength), originally based on the Richter Scale but now based on the moment magnitude scale (MMS), quantifies the energy released by an earthquake.

Sources: PNSN n.d.; DOGAMI 1996

for evidence of periodic tsunamis, and to improve their understanding of the impact of movements and interactions of crustal plates of the Cascadia Subduction Zone on the landforms and elevation of the southern Oregon coast, including the Coos estuary. Witter and colleagues traced 12 cycles of uplift and subsidence in the record of low-lying forests and tidal wetlands over the last 6,700 years while Kelsey and colleagues found a record of repeated local tsunamis in the sediments of Bradley Lake in Curry County.

Soils

Tidal Areas

According to Rumrill (2006), tide flats in the Coos estuary likely formed during the past 1,000-2,000 years as estuarine sediment eroded from marine terraces, filling in the Coos estuary tidal basin and creating the tide flats we see today.

Other sources of tide flat sediments are terrestrial runoff, oceanic deposition, and biotic material (Rumrill 2006). For example, much of the mud, silt, and clay within the estuarine tidal basin enters South Slough from Coos Bay and the nearshore Pacific Ocean during flood tides (Wilson 2003 in Rumrill 2006).

Sand flats are created largely from land sources, including erosion of nearby cliffs, then transported by high velocity tidal currents (Rumrill 2006).

Tide flats are often highly channelized with shallow drainage channels, which facilitate a continued cycle of erosion and deposition as sediments are re-suspended, transported, and deposited with every tidal cycle (Rumrill 2006).

Tidal Wetlands

Tidal wetland soils can inform us about sea level rise rates. For example, Rumrill (2006) explains that “Prevalence of peat layers in the upper 1.0-1.5 m (3.28-4.92 ft) of sediment cores taken from brackish marshes in many parts of the Coos estuary suggests a reduction in the rate of sea-level rise or an increase in the rate of sedimentation over the past 1,000-1,500 years”.

Landslides

Landslides are typically triggered by heavy rain. Less commonly they are caused by earthquakes, road construction, rapidly melting snow, or a combination of these and other events (DOGAMI 2008).

A particularly damaging landslide is known as a debris flow. A debris flow (synonymous with mudslide, mudflow, or rapidly moving landslide) is a fast moving (exceeding 30 mph) mixture of water, rock, soil, and vegetation. Debris flows begin as small landslides, and then, upon entering a steep sloping stream channel, gain momentum and more debris, until they finally end as massive deposits at the outlet of the channel (DOGAMI 2008; ODF 2012).

Debris flows can travel long distances, sometimes scour the channel down to bedrock, and frequently cause major structural damage to houses and roads. They are extremely hazardous, especially in populated areas (Robison et al. 1999; ODF 2012). It should be noted, however, that debris flows also deliver large wood to streams where they add complex structure that provide high quality fish habitat (ODF 2012).

In 1996, two very large storms severely affected western Oregon, one of which was a 100-year rain event that set an all-time one-day precipitation record at North Bend (6.67 inches in 24 hrs)(Robison et al. 1999). Both storms triggered large numbers of landslides in western Oregon, prompting ODF to take a closer look at activities, such as forest-road building and logging, that were thought to play a role in landslides. This report (Robison et al. 1999) examined eight locations affected by these two storms and found that lands with the highest hazards for landslides were found on slopes >70-80% steepness (depending on surface geology and landform). For example, Tyee Core formations are very susceptible to debris flows generally due to steep slopes, shallow low-cohesion soils, with an impermeable layer beneath. Lands with moderate hazard were found on slopes 50-70%. In addition, concave shaped landforms with large drainage areas were most frequently associated with landslides.

Robison et al. (1999) determined that forest cover and time since last timber harvest also influenced landslide occurrence, with lands 0-10 years post-harvest being most susceptible to landslides. However, forest stand age did not appear to affect the size of landslides.

Further, road-associated landslides were found to be four times larger (volume of earth moved) than landslides not occurring near roads. Landslides associated with abandoned logging roads ("legacy" roads) were smaller in size than those associated with active logging roads. Roads where drainage water was diverted (e.g., culvert or other relief structure), had higher landslide occurrences if the water exited on fill slopes. Roads carved out of slopes often deposit excavated fill on the downslope edge of the road, further influencing landslide hazards.

Rain-induced landslides are also thought to be more frequent during La Niña years, when the Pacific Northwest experiences increased storminess, increased precipitation and more days with measurable precipitation (UO 2012; NOAA 2002).

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Exhibit 19

News and Research Communications

13-year Cascadia study complete – and earthquake risk looms large

08/01/2012

CORVALLIS, Ore. – A comprehensive analysis of the Cascadia Subduction Zone off the Pacific Northwest coast confirms that the region has had numerous earthquakes over the past 10,000 years, and suggests that the southern Oregon coast may be most vulnerable based on recurrence frequency.

Written by researchers at Oregon State University, and published online by the U.S. Geological Survey, the study concludes that there is a 40 percent chance of a major earthquake in the Coos Bay, Ore., region during the next 50 years. And that earthquake could approach the intensity of the Tohoku quake that devastated Japan in March of 2011.

"The southern margin of Cascadia has a much higher recurrence level for major earthquakes than the northern end and, frankly, it is overdue for a rupture," said Chris Goldfinger, a professor in OSU's College of Earth, Ocean, and Atmospheric Sciences and lead author of the study. "That doesn't mean that an earthquake couldn't strike first along the northern half, from Newport, Ore., to Vancouver Island.

"But major earthquakes tend to strike more frequently along the southern end – every 240 years or so – and it has been longer than that since it last happened," Goldfinger added. "The probability for an earthquake on the southern part of the fault is more than double that of the northern end."

The publication of the peer-reviewed analysis may do more than raise awareness of earthquake hazards and risks, experts say. The actuarial table and history of earthquake strength and frequency may eventually lead to an update in the state's building codes.

"We are considering the work of Goldfinger, et al, in the update of the National Seismic Hazard Maps, which are the basis for seismic design provisions in building codes and other earthquake risk-mitigation measures," said Art Frankel, who has dual appointments with the U.S. Geological Survey and the University of Washington.

The Goldfinger-led study took four years to complete and is based on 13 years of research. At 184 pages, it is the most comprehensive overview ever written of the Cascadia Subduction Zone, a region off the Northwest coast where the Juan de Fuca tectonic plate is being subducted beneath the continent. Once thought to be a continuous fault line, Cascadia is now known to be at least partially segmented.

This segmentation is reflected in the region's earthquake history, Goldfinger noted.

"Over the past 10,000 years, there have been 19 earthquakes that extended along most of the margin, stretching from southern Vancouver Island to the Oregon-California border," Goldfinger noted. "These would typically be of a magnitude from about 8.7 to 9.2 – really huge earthquakes.

"We've also determined that there have been 22 additional earthquakes that involved just the southern end of the fault," he added. "We are assuming that these are slightly smaller – more like 8.0 – but not necessarily. They were still very large earthquakes that if they happened today could have a devastating impact."

The clock is ticking on when a major earthquake will next strike, said Jay Patton, an OSU doctoral student who is a co-author on the study.

"By the year 2060, if we have not had an earthquake, we will have exceeded 85 percent of all the known intervals of earthquake recurrence in 10,000 years," Patton said. "The interval between earthquakes ranges from a few decades to thousands of years. But we already have exceeded about three-fourths of them."

The last mega-earthquake to strike the Pacific Northwest occurred on Jan. 26, 1700. Researchers know this, Goldfinger said, because written records in Japan document how an ensuing tsunami destroyed that year's rice crop stored in warehouses.

How scientists document the earthquake history of the Cascadia Subduction Zone is fascinating. When a major offshore earthquake occurs, Goldfinger says, the disturbance causes mud and sand to begin streaming down the continental margins and into the undersea canyons. Coarse sediments called turbidites run out onto the abyssal plain; these sediments stand out distinctly from the fine particulate matter that accumulates on a regular basis between major tectonic events.

By dating the fine particles through carbon-14 analysis and other methods, Goldfinger and colleagues can estimate with a great deal of accuracy when major earthquakes have occurred over the past 10,000 years.

Going back further than 10,000 years has been difficult because the sea level used to be lower and West Coast rivers emptied directly into offshore canyons. Because of that, it is difficult to distinguish between storm debris and earthquake turbidites.

"The turbidite data matches up almost perfectly with the tsunami record that goes back about 3,500 years," Goldfinger said. "Tsunamis don't always leave a signature, but those that do through coastal subsidence or marsh deposits coincide quite well with the earthquake history."

With the likelihood of a major earthquake and possible tsunami looming, coastal leaders and residents face the unenviable task of how to prepare for such events. Patrick Corcoran, a hazards outreach specialist with OSU's Sea Grant Extension program, says West Coast residents need to align their behavior with this kind of research.

"Now that we understand our vulnerability to mega-quakes and tsunamis, we need to develop a culture that is prepared at a level commensurate with the risk," Corcoran said. "Unlike Japan, which has frequent earthquakes and thus is more culturally prepared for them, we in the Pacific Northwest have not had a mega-quake since European settlement. And since we have no culture of earthquakes, we have no culture of preparedness.

"The research, though, is compelling," he added. "It clearly shows that our region has a long history of these events, and the single most important thing we can do is begin 'expecting' a mega-quake, then we can't help but start preparing for it."

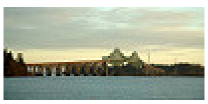
STORY BY:

Mark Floyd,
541-737-0788

SOURCE:

Chris Goldfinger, 541-737-5214

AVAILABLE PHOTO(S):
(click to download)



Coos Bay bridge

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Exhibit 20

The Oregon Resilience Plan

Reducing Risk and Improving Recovery for the Next Cascadia Earthquake and Tsunami

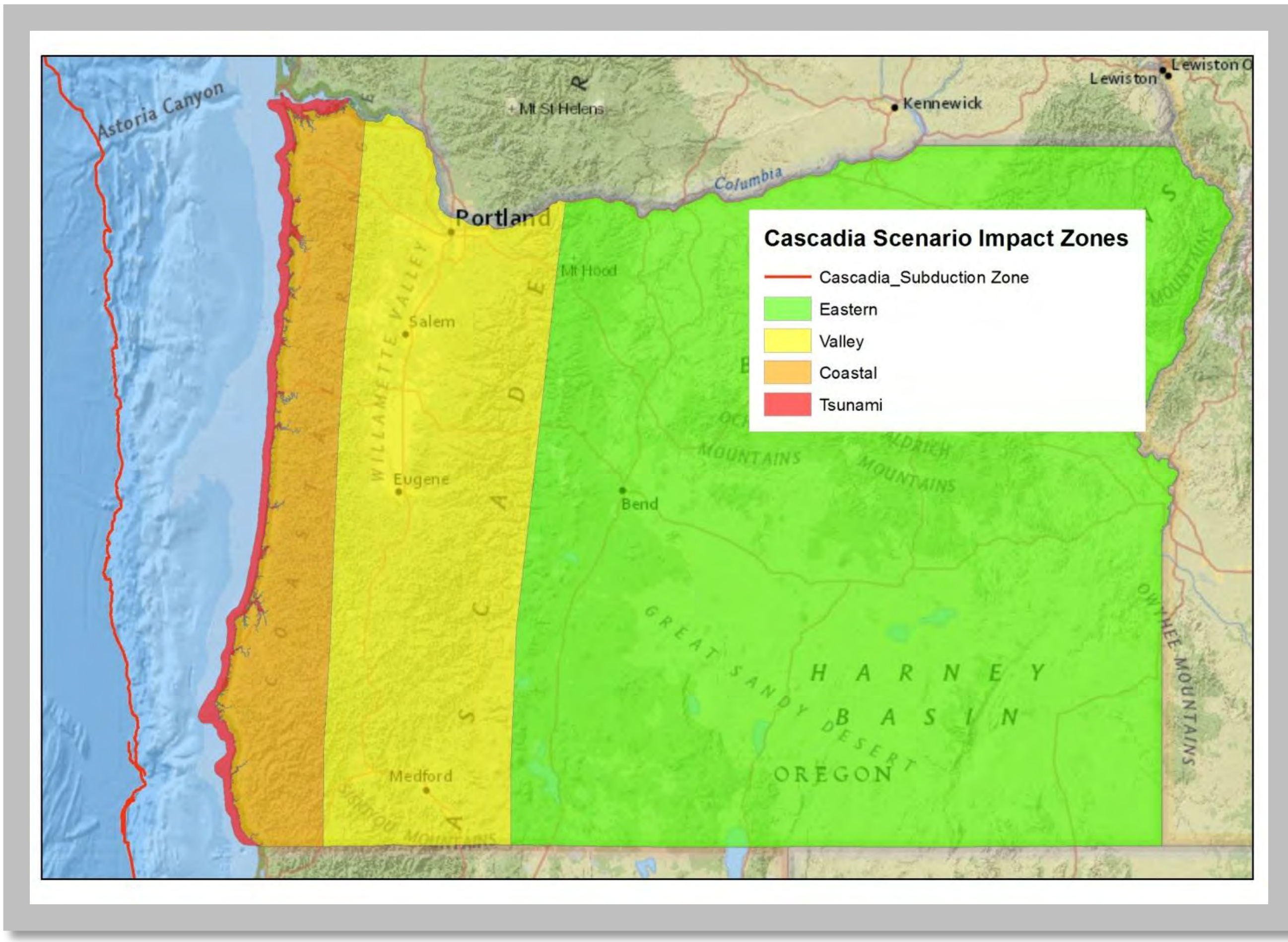
Report to the
77th Legislative Assembly

from
Oregon Seismic Safety Policy
Advisory Commission (OSSPAC)

Salem, Oregon
February 2013

Executive Summary

Very large earthquakes will occur in Oregon's future, and our state's infrastructure will remain poorly prepared to meet the threat unless we take action now to start building the necessary resilience. This is the central finding of the *Oregon Resilience Plan* requested by Oregon's 76th Legislative Assembly.



Impact zones for the magnitude 9.0 Cascadia earthquake scenario. Damage will be extreme in the Tsunami zone, heavy in the Coastal zone, moderate in the Valley zone, and light in the Eastern zone.

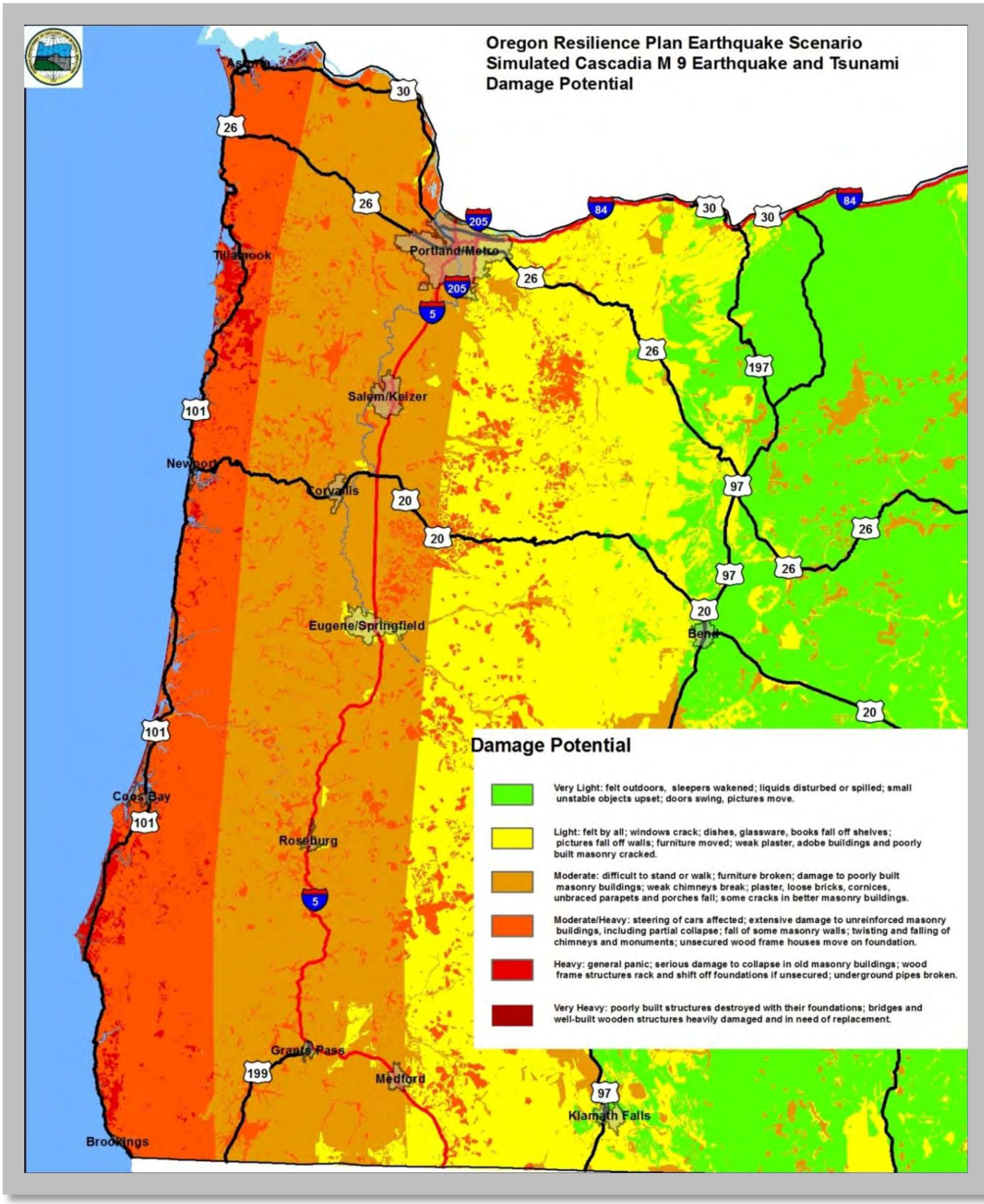


Figure 1.4: Simulated shaking for the magnitude 9.0 Cascadia scenario.

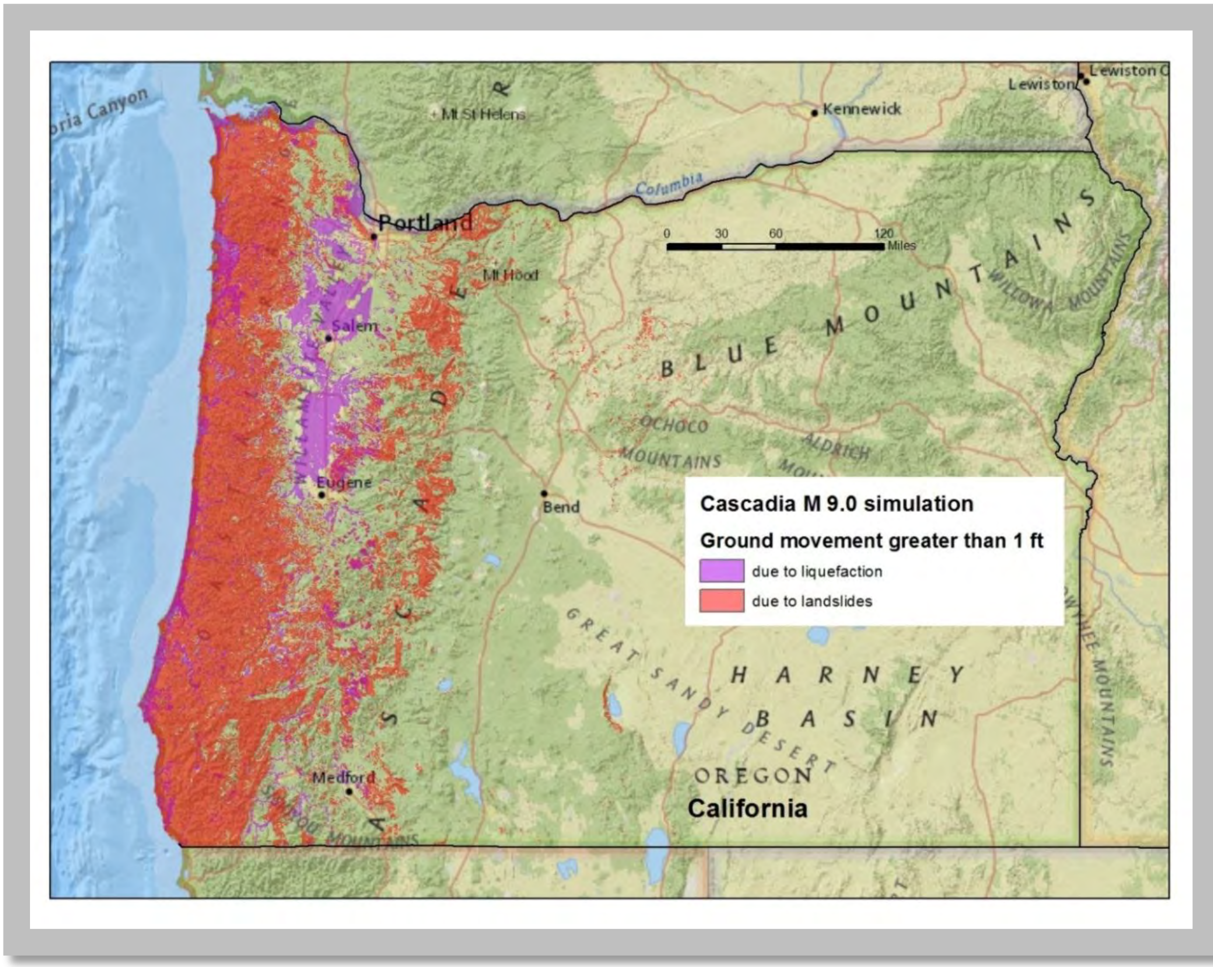


Figure 1.6: Ground failure and movement for the magnitude 9.0 Cascadia earthquake scenario. Colored areas could experience more than one foot of ground movement due to earthquake-induced landslides in steep areas and liquefaction failure in lowlands. Both forms of ground failure can cause severe damage.

The amount of tsunami inundation that would be experienced along the coast due to the scenario magnitude 9.0 earthquake is quite variable and depends on local topography. Large parts of many low-lying communities, such as Warrenton, Seaside, Rockaway Beach, and Neskowin (see Figure 1.7), will be inundated.

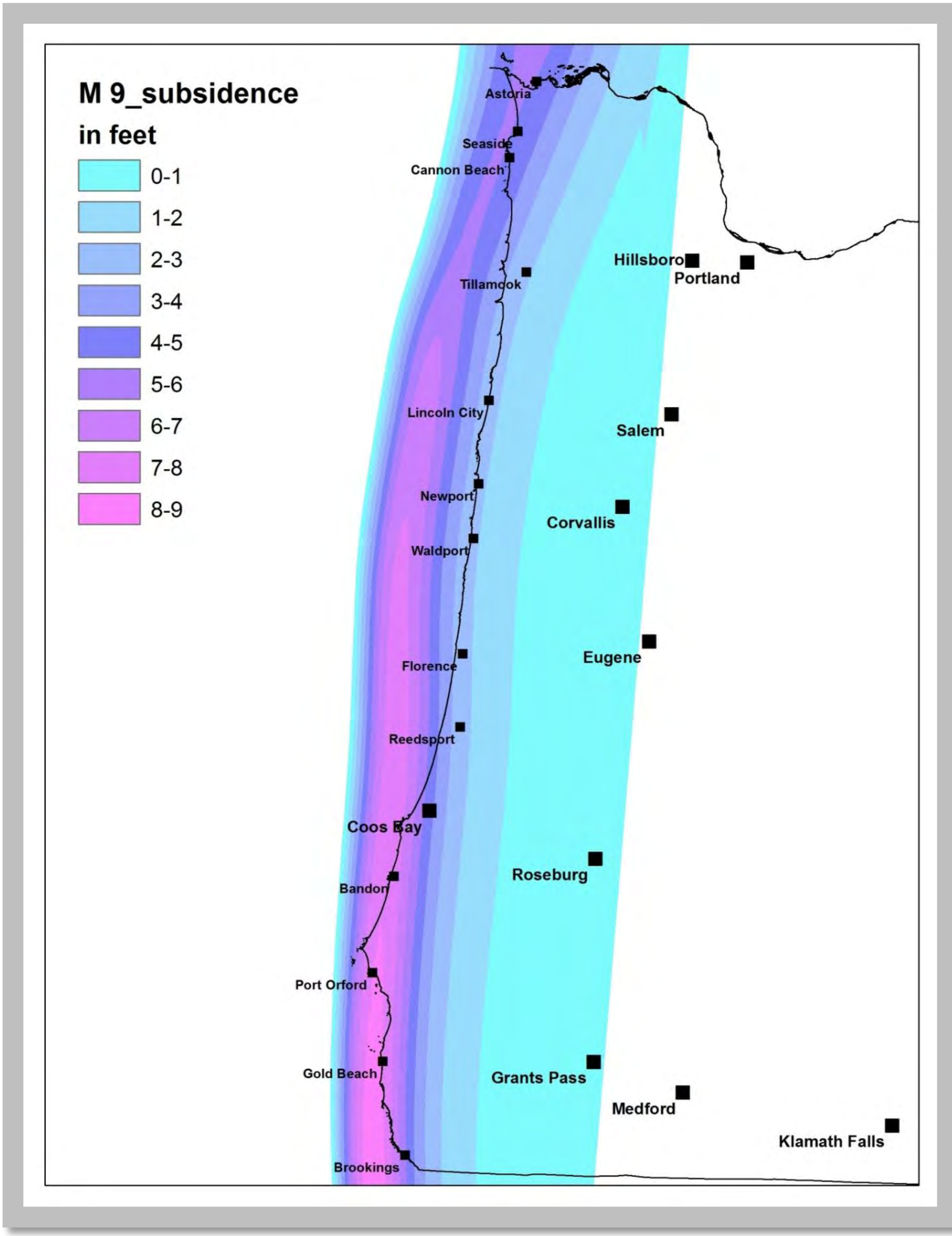


Figure 1.8: Estimated permanent land subsidence from the scenario magnitude 9.0 earthquake for the Oregon Coast. Subsidence would occur during the earthquake.

Exhibit 21

Alan Trimble, Ph.D.
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October 5, 2011

Andrew Stamp
Hearings Officer
c/o Coos County Planning Department
225 N. Adams Street
Coquille, Oregon 97423

Dear Mr. Stamp:

At the request of Mark Chernaik, expert for Citizens Against LNG, I was asked to answer the following questions (in red) relating to the surveying of Olympia oysters in Haynes Inlet.

Q1. Could you describe your qualifications for answering the following questions? How many years have you studied the biology of Olympia oysters? What peer-reviewed scientific publications about the biology of Olympia oysters have you authored?

I have been involved in research on Ostrea lurida since 2001, with my first professional presentation at the 2003 national meeting of the Estuarine Research Federation titled: "What prevents recovery of native oysters (Ostreola conchaphila) in Willapa Bay, Washington." This talk was prior to genetic work that refined our current understanding of taxonomy of the genus Ostrea. I have been involved in six publications that relate to this species since that time:

THE WILLAPA BAY OYSTER RESERVES IN WASHINGTON STATE: FISHERY COLLAPSE, CREATING A SUSTAINABLE REPLACEMENT, AND THE POTENTIAL FOR HABITAT CONSERVATION AND RESTORATION, Dumbauld Brett R.; Kauffman Bruce E.; Trimble Alan C.; et al., JOURNAL OF SHELLFISH RESEARCH Volume: 30 Issue: 1 Pages: 71-83

EVALUATION OF OLYMPIA OYSTER (OSTREA LURIDA CARPENTER 1864) STATUS AND RESTORATION TECHNIQUES IN PUGET SOUND, WASHINGTON, UNITED STATES, White Jacqueline M.; Buhle Eric R.; Ruesink Jennifer L.; et al., JOURNAL OF SHELLFISH RESEARCH Volume: 28 Issue: 1 Pages: 107-112

THE NEARLY FORGOTTEN OYSTER: OSTREA LURIDA CARPENTER 1864 (OLYMPIA OYSTER) HISTORY AND MANAGEMENT IN WASHINGTON STATE, White Jacqueline; Ruesink Jennifer L.; Trimble Alan C., JOURNAL OF SHELLFISH RESEARCH Volume: 28 Issue: 1 Pages: 43-49

FACTORS PREVENTING THE RECOVERY OF A HISTORICALLY OVEREXPLOITED SHELLFISH SPECIES, OSTREA LURIDA CARPENTER 1864, Trimble Alan C.; Ruesink Jennifer L.; Dumbauld Brett R., JOURNAL OF SHELLFISH RESEARCH Volume: 28 Issue: 1 Pages: 97-108

Changes in productivity associated with four introduced species: ecosystem transformation of a 'pristine' estuary, Ruesink JL; Feist BE; Harvey CJ; et al., MARINE ECOLOGY-PROGRESS SERIES Volume: 311 Pages: 203-215

Introduction of non-native oysters: Ecosystem effects and restoration implications, Ruesink JL; Lenihan HS; Trimble AC; et al., ANNUAL REVIEW OF ECOLOGY EVOLUTION AND SYSTEMATICS Book Series: Annual Review of Ecology Evolution and Systematics Volume: 36 Pages: 643-689

Q2. What documents have you examined about the potential impacts of the proposed pipeline on Olympia oysters in Haynes Inlet in Coos Bay?

I have reviewed two documents provided by Dr. Chernaik:

1) Pacific Connector Gas Pipeline: Olympia Oyster Survey, authored by Bob Ellis/Ellis Ecological Services,Inc., dated September 13, 2011
2) Report on the Potential Impacts of the Pacific Connector Gas Pipeline on the Olympia oyster (Ostrea lurida) and the "resource productivity" of Haynes Inlet, authored by Mark Chernaik, Ph.D, dated September 2011

Q3. Can you explain the concept of "microclimate" and how location within an estuary determines the viability of an individual or clutch of Olympia oysters? Why might there be substantial mortalities associated with relocating Olympia oysters even a few hundred feet to a higher elevation, as the pipeline company is proposing?

One of the most important principles in Ecology (the scientific study of the abundance and distribution of organisms) is that locations are different. This principle is true at all scales; Africa is not equivalent to North America, and the inside of a person's mouth does not support the same biological community as their palms. Tideflats are inherently complex three dimensional ecosystems. The distribution and abundance of organisms on and within tideflats is not uniform in space and time. Tidal inundation (water cover), temperature, mobile predators, sediment and porewater chemistry (to list but a few factors) all vary in substantial ways throughout each estuary. Hence, each location throughout each tideflat has it's own unique "microclimate" of conditions.

Adult oysters are found in locations where the historical combination ("microclimate") of these factors have allowed the long term survival of juveniles which settled out of the plankton; oysters are not inherently mobile as adults –they generally remain fixed to the hard surfaces they selected as planktonic settlers.

While tideflats (and lawns, for that matter) can appear uniform to our eye, (I think "indistinguishable" is the word used in the first report listed above), simple measurements can reveal local differences which can be critically important to particular organisms.

The most informative measure of local and historical conditions as they relate to *Ostrea lurida* is the presence/absence of adults. It is ecologically safe to say that locations containing oysters are different than locations that don't. The challenge to ecologists is to determine the mechanism driving the difference – and that process must be done experimentally, not simply by observation and correlation.

While it is trivial to suggest that moving existing oysters from locations where they currently exist to locations where they don't is sufficient to preserve them, this isn't a fact based on solid evidence. In fact, substantial evidence exists that moving oysters (and other organisms) increases mortality rates; hundreds of millions of *Ostrea lurida* adults have been moved within and between estuaries since the 1850's, (see Collins, 1892 and Townsend, 1896 as examples) with the vast majority of events resulting in massive mortalities.

There is no guarantee that transplanting existing oysters between locations in Haynes Inlet will result in equivalent or improved survival and fitness (reproductive success in making offspring which survive to produce offspring) to leaving them in the places where they currently exist. Transplantation is not a proven mechanism for mitigation in oysters in general or *Ostrea lurida* in particular.

Q4. Why might protection of subtidal populations of Olympia oysters be more important to the overall goal of recovery than intertidal populations? Can you comment on the pipeline company?s conclusion, based on its survey results and prevailing sediment characteristics, that the subtidal presence of Olympia oyster in the pipeline right-of-way is unlikely?

The study in question found no oysters in the subtidal samples and concluded that presence of oysters in that right of way is unlikely. This is a reasonable guess based on the data available but it is not a fact.

Correlations used as proof of presence/absence of organisms in particular locations are very dangerous.

This method is not acceptable where species listed under the ESA are a factor, and should only be accepted for what they are – simple, inexpensive sampling.

The samples were not continuous or exhaustive (cost and time are always factors) so individuals could easily have been missed. Therefore, there is no basis for concluding that Ostrea lurida does not and could not exist in these locations – that would require both exhaustive sampling and experimental tests placing both known settlement substrate (adult shell) and adults in replicated plots and monitoring recruitment and survival.

We do know that all species of the genus *Ostrea* are particularly sensitive to extremes of temperature (both hot and cold) and are therefore primarily found in submerged locations as adults. Historically, the most productive farmed areas of Puget Sound for *Ostrea lurida* were diked to hold 8-12" of water over the oysters at all times to minimize the potential effects of exposure. We also know that substantial subtidal populations of *Ostrea lurida* continue to exist in Willapa Bay and are likely the primary source of larvae in the plankton each year. We consider the intertidal populations to be "fringe" because they are small, highly dispersed (so fertilization is difficult), and they are subject to much higher risk of mortality from environmental exposure.

Q5. Can you explain the concept of "recruitment sink"? Why might it be harmful to seed Haynes Inlet with Pacific Oyster shells, as the pipeline company is proposing?

A recruitment sink is a location where juveniles of a species settle and ultimately die before producing viable offspring (their fitness is zero.) This can occur when the juveniles are "fooled" by habitat/conditions which appear favorable and they make an irreversible choice to settle there, thereafter being exposed to less favorable conditions. This can occur in oysters when settlement substrate (hard surfaces like shell or rock) is artificially placed in locations where it did not occur naturally over evolutionary time. An example would be placing Pacific Oyster (*Crassostrea gigas*) shell in the intertidal areas of tideflats. This substrate was never present in US estuaries prior to introduction from Japan in the 1920's, is similar enough to *Ostrea lurida* shell to facilitate settlement of juveniles, and can be placed in totally inappropriate locations (too high and exposed to cold/heat, too unstable and exposed to drifting/sedimentation etc.) This substrate can be dangerous because it persists for decades, provides novel habitat for other (introduced, invasive) fouling species, and can attract Ostrea lurida larvae to settle in locations where they will die at higher rates than they might in more "natural" locations.

Q6. Can you describe the physical dimensions of Olympia oyster spat? Can you explain why a covering of less than 1 millimeter could substantially impair the settlement of Olympia oyster spat on hard substrate?

Ostrea lurida larvae settle from swimming to "spat" glued to hard substrate at between 290 and 320 microns (0.29 – 0.32mm). Anything on the surface of the substrate which is substantially close to that size or larger is an impediment to finding (actually touching) and attaching to the substrate. A reasonable upper limit for substrate fouling is likely below 50 microns (0.05mm) and more likely below 20 microns (0.02mm) for minimal impact on larval spatfall success. Oyster growers have historically attempted to place shell at the last possible time before spatfall (the day before it is predicted to occur) to minimize the impact of sedimentation and fouling on their shell substrate.

Sincerely,

Alan Trimble, Ph.D.

References cited above:
Collins, J. W. 1892. Report on the fisheries of the Pacific Coast of the United States, Report of the Commissioner for 1888, United States Commission of Fish and Fisheries. Washington DC: Government
Printing Office. pp. 3–209.

Townsend, C. H. 1896. The transplanting of eastern oyster to Willapa Bay, Washington with notes on the native oyster industry. Report of the US Commissioner of Fisheries for 1895:193–202.

Exhibit 22

Confirmed Presence of Olympia oysters (*Ostrea lurida*) within Haynes Inlet, Coos Bay (29-30 June 2011)

<u>Observations and Photographs</u>:

Dr. Steve Rumrill, Research Program Coordinator
South Slough National Estuarine Research Reserve
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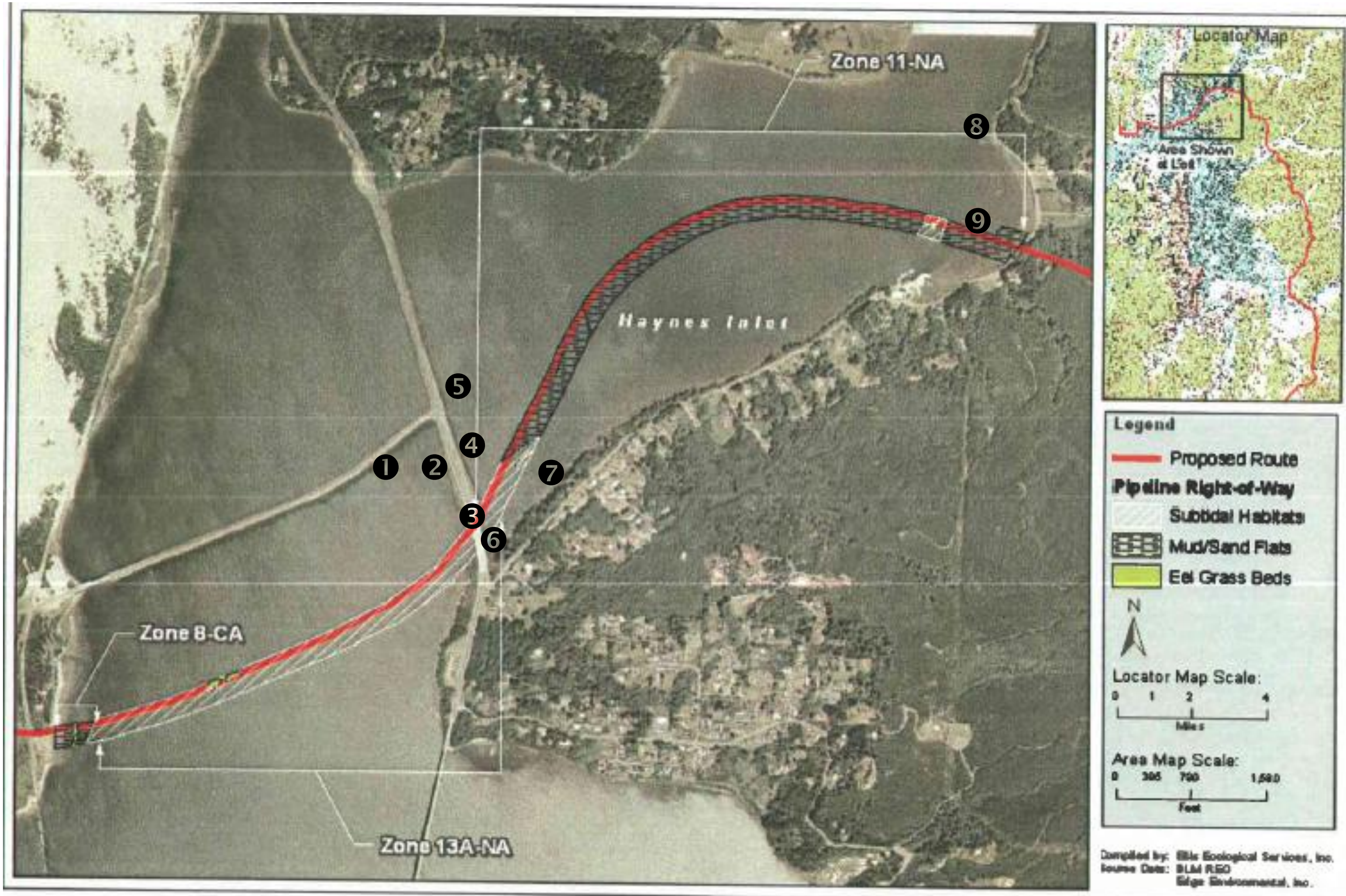
Charleston, OR 97420

Dr. Laura Peterio-Garcia, Post-doctoral Investigator
University of Oregon – Oregon Institute of Marine Biology
63466 Boat Basin Road
Charleston, OR 97420

Joanne Choi, Oregon Sea Grant Summer Scholar
University of Oregon – Oregon Institute of Marine Biology
63466 Boat Basin Road
Charleston, OR 97420

Location of 9 sites searched for Olympia oysters (Haynes Inlet, Coos Bay, OR; 29-30 June 2011)



Confirmed location of Olympia oyster populations in Haynes Inlet, Coos Bay, OR

Shoreline searches: June 29-30, 2011 (Low-tide 6:20 - 7:00 AM) / -0.9 ft)

OBSERVATIONS:

1. **North Inlet causeway / patchy populations of adults and juveniles**
2. **Haynes Inlet causeway west side / abundant adults and juveniles**
3. **Haynes Inlet bridge north side / abundant adults and juveniles**
4. **Haynes Inlet causeway east side / abundant adults and juveniles**
5. **Haynes Inlet causeway northeast side / abundant adults and juveniles**
6. **Haynes Inlet bridge south side / patchy populations of adults and juveniles**
7. **Haynes Inlet south shore / patchy populations of adults and juveniles**
8. **Haynes Inlet rocky point / patchy populations of adults and juveniles**
9. **Haynes Inlet mudflat / no Olympia oysters**

Site 2. Olympia oysters attached to rock on the west side of Haynes Inlet causeway, Coos Bay, OR (June 30, 2011).

White quadrat = 25cm x 25cm = $625cm^2$ = $0.0625m^2$; Olympia oyster density = 24 oysters/$0.0625m^2$

Site 3. Olympia oysters attached to rock underneath Haynes Inlet bridge (north), Coos Bay, OR (June 29, 2011).

Steel quadrat = 25cm x 25cm = $625cm^2$ = $0.0625m^2$;
Olympia oyster density = 28 oysters/$0.0625m^2$

Sites 4 and 5. Olympia oysters attached to rock along the northeast side of Haynes Inlet causeway, Coos Bay, OR (June 29, 2011).

Sites 6 and 7. Haynes Inlet bridge (south): Olympia oyster populations present as patches of adults and juveniles on rock and mud. (June 29, 2011).

Site 8. Haynes Inlet rocky point: Olympia oyster populations present as patches of adults and juveniles on rock and mud. (June 29, 2011).

Site 9. No Olympia oysters observed within the intertidal mudflat habitat of Haynes Inlet, Coos Bay, OR (June 29, 2011).

Exhibit 23

Journal of Shellfish Research, Vol. 28, No. 1, 51–58, 2009.

HISTORY OF OLYMPIA OYSTERS (*OSTREA LURIDA* CARPENTER 1864) IN OREGON ESTUARIES, AND A DESCRIPTION OF RECOVERING POPULATIONS IN COOS BAY

SCOTT GROTH[1] AND STEVE RUMRILL[2]
[1]*Shellfish Biologist, Oregon Department of Fish and Wildlife, 63538 Boat Basin Drive, P.O. Box 5003, Charleston, Oregon 97420;* [2]*Research Coordinator, South Slough National Estuarine Research Reserve, 61907 Seven Devils Road, P.O. Box 5417, Charleston, Oregon 97420*

ABSTRACT Historical evidence indicates that Olympia oysters (*Ostrea lurida*)† are indigenous to at least three of Oregon's estuaries. Populations of *O. lurida* occur in Yaquina Bay, Netarts Bay, and Coos Bay, although only the population in Yaquina Bay seems likely to have been continuous since prewestern settlement. The historical occurrence of Olympia (native) oysters in Yaquina and Netarts Bays is confirmed by numerous records of fishery landings. In contrast, historic populations in Coos Bay are inferred by the presence of large shell deposits buried in sediments throughout the polyhaline (salinity >18–30) region of the estuary. Other Oregon estuaries (such as Tillamook, Alsea, and Umpqua/Winchester Bay) may have had ambient environmental conditions suitable to support self-sustaining populations of *O. lurida*, but none of these estuaries are currently inhabited by natural populations, nor do they exhibit clear historical records of occupation in the past. We conducted searches of background information on many estuaries to summarize knowledge about the status of *O. lurida* populations in Oregon. The information presented here is based on a literature search, analysis of internal agency documents, and personal contacts with individuals most familiar with specific estuaries. As a case study, the Oregon Department of Fish & Wildlife (ODFW) repeated intertidal field surveys previously conducted in 1997 in an effort to document changes in *O. lurida* populations within Coos Bay. Field surveys conducted in 2006 followed methods that were similar to the 1997 intertidal surveys. Using previously published results as a baseline, we found that populations of native oysters exhibited spatial expansion throughout the mesohaline and polyhaline regions of the estuary, and that the intertidal oysters occurred at increased densities, over a wider range of sizes, and over a broader range of habitats. Further recovery of *O. lurida* populations in other regions of Coos Bay is most likely limited by the availability of suitable substratum for attachment and growth of the juvenile oysters.

KEY WORDS: Olympia oyster, Native oyster, Yaquina Bay, Coos Bay, Netarts Bay, Oregon, *Ostrea conchaphila*, *Ostrea lurida*, oyster populations

INTRODUCTION

Olympia oysters (*Ostrea lurida*) were once abundant and ecologically important components of estuarine communities throughout the Pacific Northwest biogeographic region. Living beds of oysters occurred within the lower intertidal and subtidal regions of the estuaries where they most likely provided several key ecosystem services including: (a) maintenance of a hardened substratum that served as benthic habitat for many species; (b) biofiltration of phytoplankton and sediment particles from the water column; (c) pelagic-benthic coupling resulting in the secondary production of molluscan tissue and other organic materials; and (d) increased biotic diversity and foraging areas for invertebrates, fish, and shorebirds. In addition, the dense beds of Olympia oysters also provided local indigenous people with an important source of food, and larger-scale harvests of *O. lurida* constituted an economically valuable commercial fishery in Washington, California, and parts of Oregon (Gordon et al. 2001, Baker 1995). Regional popularity of the native oysters as a targeted fishery species led to massive removal of shells from the benthic substratum and over-harvests in the late 1800s, and these practices contributed to a region-wide collapse in many Pacific coast estuaries during the late 19th and early 20th centuries.

Upon the arrival of European settlers to coastal Oregon (1850s), populations of Olympia oysters were only found in Yaquina Bay and Netarts Bay (Marriage 1954, Baker 1995). Extensive shell deposits were observed in Coos Bay, however, and provide clear evidence that large populations of *O. lurida* occurred in the past. No living oysters were found in Coos Bay at the time of European settlement (Dall 1897). Based on water quality parameters and proximity to larval supply, other bays such as Tillamook, Alsea, Siletz, Siuslaw, Umpqua, Coquille, and others may have, over the course of geologic history, been suitable for *O. lurida* populations. However, conclusive evidence of the historical presence of *O. lurida* in these other estuaries is lacking. The overall purpose of this project was to document the historical and recent occurrence of *O. lurida* in Oregon estuaries, and to describe the spatial extent and recovery of Olympia oyster populations within Coos Bay.

HISTORICAL AND RECENT OCCURRENCE OF OLYMPIA OYSTERS IN OREGON ESTUARIES

Estuaries with Confirmed Populations of Olympia Oysters

Netarts Bay

Netarts Bay is a small (930 ha), marine-dominated, bar-built estuary located along the northern shoreline of Oregon (Fig. 1). The mouth of the estuary has not been stabilized by jetties, and the shallow tidal basin contains extensive sand flats, mudflats, and eelgrass beds as well as primary and secondary tidal channels. The watershed drainage basin for Netarts Bay is

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†The taxonomy of the Olympia oyster has been in dispute since Harry (1985) proposed synonymy of *Ostrea lurida* Carpenter 1864 and *Ostrea conchaphila* Carpenter 1857. Polson et al. (2009) provide molecular evidence that the Olympia oyster refers to the nominal species, *Ostrea lurida* Carpenter 1864. In view of their genetic data, and for consistency, the original taxon, *Ostrea lurida*, is used throughout this volume to refer to the Olympia oyster, which is distributed from approximately Baja California (Mexico) to southeast Alaska.

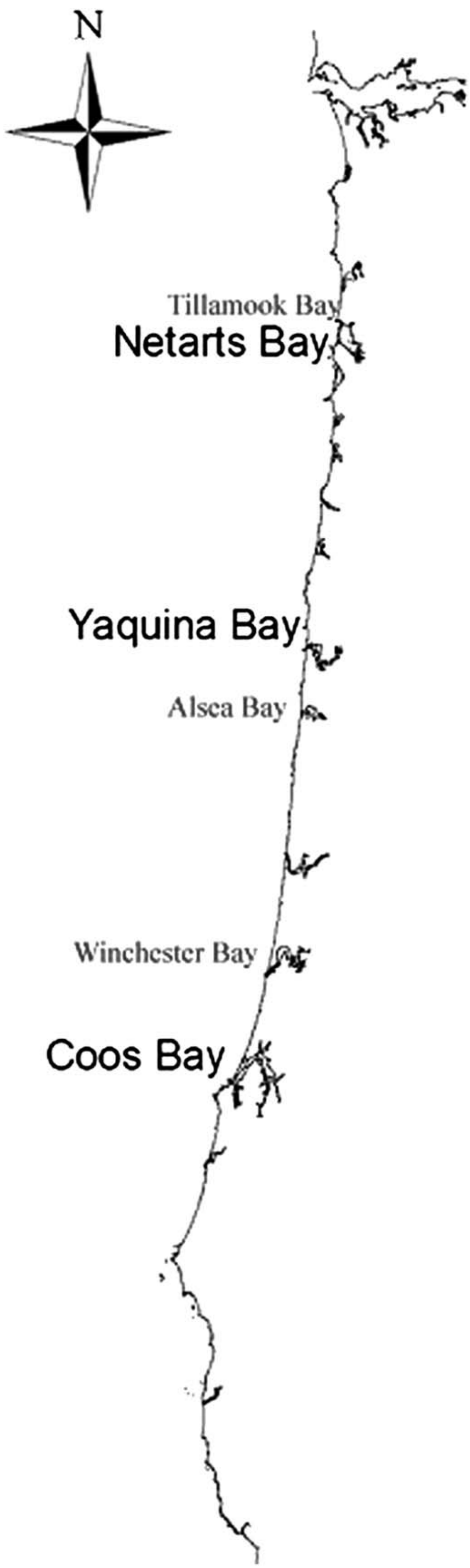

Figure 1. Map of Oregon estuaries indicating the location of confirmed populations of *O. lurida* in Netarts Bay, Yaquina Bay, and Coos Bay. The map also indicates the location of other estuaries (Tillamook Bay, Alsea Bay, Winchester Bay) that may be suitable for populations of Olympia oysters.

approximately 3,626 ha, and input of freshwater occurs through numerous small creeks.

Netarts Bay historically supported a commercial fishery for *O. lurida* beginning in the 1860s, but overall landings and duration of the fishery were always substantially lower than that of Yaquina Bay. Commercial harvest of Olympia oysters took place in the upper region of Netarts Bay where water quality parameters are most favorable (Stout 1976, Bonacker et al. 1979). In the 1930s native oysters were believed to exist in low numbers in Netarts Bay, and the remaining populations may have been affected by localized introduction in 1957 of *Ocenebra japonica* (Dunker 1860), a nonindigenous gastropod predator, (Stout 1976) concurrent with the introduction of Pacific oysters (*Crassostrea gigas*) from Japan. Olympia oysters were found to be "present in very small numbers upbay" in the mid-century (Marriage 1954), and the oysters were considered to be "locally extinct" by 1979, although many areas of the upper bay where oysters would be expected to survive were not surveyed (Kraeg 1979). Qualitative surveys of Netarts Bay conducted by the Oregon Department of Fish and Wildlife in 1992 did not discover any living oysters (J. Johnson, pers. comm.). An attempt was made by ODFW to re-establish the oysters in Netarts Bay over the period from 1993–1998. The reintroduction effort included establishment of approximately 9 million spat set on 150 sacks of nonindigenous Pacific oyster (*C. gigas*) cultch (ODFW, unpublished records). This effort likely re-established ephemeral populations of *O. lurida* that were detected in 2004 during surveys carried out by The Nature Conservancy (TNC). A field experiment was undertaken within Netarts Bay in 2005 to 2006 to investigate the ecological effect of cultch (i.e., *O. lurida* juveniles on nonliving *C. gigas* shell) on native oyster survival, growth, and eelgrass abundance (Archer 2008). Currently, TNC is continuing their efforts to restore populations of Olympia oysters in Netarts Bay (D. Vander Schaaf, pers comm.).

Yaquina Bay

Yaquina Bay is a moderately-sized (1,700 ha), drowned river-mouth estuary located along the central Oregon coast (Fig. 1). The mouth of the bay is protected by rock jetties and rip-rap, and the estuarine tidal basin contains a primary navigational channel, extensive sand flats and mudflats, subsidiary sloughs, and an elongated riverine region. The watershed drainage basin for Yaquina Bay is about 65,526 ha, and the Yaquina River provides the primary source of freshwater inputs.

Environmental conditions within Yaquina Bay have been suitable over long time periods to allow for persistent populations of *O. lurida*. The most productive commercial harvests of native oysters were limited to a three-mile stretch of polyhaline (salinity >18–30) and mesohaline (salinity >5–18) waters (Fasten 1931). Oyster stocks within this confined region of the estuary were considerable in the past, and success of the oyster harvest contributed to colonization of the Newport area by European settlers (Dimick 1939). Harvests of Olympia oysters began to decrease in the 1890s, and significant commercial operations ended in the 1940s. Populations of *O. lurida* were not supplemented in Yaquina Bay throughout the years of the commercial fishery. The eventual decline of Olympia oysters in Yaquina Bay is attributed primarily to over fishing, although other factors such as pollution and habitat loss were also factors

(Dimick et al. 1941). Various habitat enhancement efforts have taken place in Yaquina Bay from the early years of the fishery to the present. Like many habitat enhancement projects related to *O. lurida*, they focused on the addition of cultch as a means to replace habitat loss associated with harvest and removal of shell rubble.

The presence of *O. lurida* in Yaquina Bay is well documented in historical accounts to the present, indicating adequate larval supplies and the persistence of self-sustaining populations (Dimick et al. 1941, Baker 1995). Occurrence of natural populations of *O. lurida* has recently been confirmed by a coast-wide survey to document peak densities of Olympia oysters in the intertidal zone (M. Polson, pers. comm.). Efforts to enhance populations of *O. lurida* in Yaquina Bay have been undertaken by the United States Army Corps of Engineers (mid 1990s) and by the Confederated Tribe of Siletz (2005–2006, S. Van De Wetering, pers. comm.).

Coos Bay

Coos Bay is a large (5,383 ha), drowned river-mouth estuary located along the shoreline of south-central Oregon (Fig. 1). The mouth of the bay is protected by a rocky headland, rock jetties, and rip-rap. The estuarine tidal basin contains a primary navigational channel, extensive sand flats and mudflats, several subsidiary inlets and sloughs, and an elongated riverine region. The watershed drainage basin for Coos Bay is about 157,470 ha, and the Coos and Millicoma Rivers provide the primary source of freshwater inputs.

The shoreline and bottom of Coos Bay contain massive shell deposits of *O. lurida*. However, no live *O. lurida* were observed at the time of European settlement (1850s). Absence of living oysters has been attributed to a local extinction event (Baker 1995, Baker et al. 2000); the Olympia oysters were most likely decimated by the excessive inputs of sediments that resulted from a "big fire" in 1846 (Dimick et al. 1941), and/or because of sedimentation associated with a subduction zone earthquake and tsunami in 1700 (Nelson et al. 1996). Contemporary re-establishment of Olympia oysters in Coos Bay has been described by Baker (1995) and Baker et al. (2000).

A few living individuals of *O. lurida* were found in 1986 in Haynes Inlet (northern region of Coos Bay) near commercial aquaculture plats (*Crassostrea gigas*). Small individuals of *O. lurida* were commonly observed on the bottom of Isthmus Slough (southern region of upper Coos Bay) in 1988 (Carlton 1989, Baker 1995). By 1997, self-sustaining populations of *O. lurida* had also become established within the East Arm of Coos Bay (Baker et al. 2000). Because that time, the populations of *O. lurida* in Coos Bay have expanded in spatial distribution and abundance. To date, these populations have reached intertidal densities of >60/m^2 (documented by quantitative surveys along transect lines), although higher localized densities have been observed during qualitative surveys (S. Groth, pers. obs.).

No deliberate attempts to further establish or enhance populations of *O. lurida* have occurred in Coos Bay subsequent to their recent return. Anecdotal evidence exists for unsuccessful introductions of *O. lurida* in the early 1900s (Baker et al. 2000) and mid 1960s. These attempts have not been quantified or fully substantiated. A new project supported by the NOAA Community-Based Restoration Program will investigate factors that contribute to recovery of Olympia oysters in the South Slough estuary (S. Rumrill, pers. obs.). The project will evaluate the survivorship, growth, and ecological interactions for an experimental population of *O. lurida* in the polyhaline region of the South Slough tidal channel.

Estuaries with Potential for Populations of Olympia Oysters

We are confident that populations of *O. lurida* occurred historically within Netarts Bay, Yaquina Bay, and Coos Bay (Baker 1995). Given the tendency of *O. lurida* populations to undergo localized extinction followed by re-establishment, it is clear that further evaluation is needed to provide diagnostic evidence of oyster presence or absence for other Oregon estuaries. Many other Oregon estuaries were examined for possible existence of historic populations of *O. lurida*, based on a review of their characterization and suitability for aquaculture of *C. gigas* (Osis & Demory 1976). Contradictory information was discovered for some estuaries. In particular, it is possible that Olympia oysters were historically harvested from Tillamook Bay. The close proximity of Tillamook Bay to Netarts Bay may be responsible for documented exportation of Olympia oysters during the period of intensive commercial harvest of *O. lurida* in Oregon. It is known that oysters were harvested from Netarts Bay, and then transported and shipped through Tillamook Bay, thereby providing a logical avenue for their documented records of export through Tillamook Bay (Stout 1976). No evidence of the natural presence of *O. lurida* populations was found for any estuaries other than Yaquina, Netarts, and Coos Bays (Baker 1995, this study).

SPATIAL EXTENT AND RECOVERY OF OLYMPIA OYSTERS IN COOS BAY

Description of Study Sites in Coos Bay

The Coos estuary (Coos Bay) is the sixth largest estuary along the Pacific coast of the contiguous United States (Proctor et al. 1980). As the largest estuary located completely within Oregon state lines, the Coos estuary is an important coastal industrial center and shipping port with direct commercial ties to San Francisco, the Columbia River, Puget Sound, and other major port facilities throughout the Pacific rim (Fig. 1). The Coos estuary is classified by the Oregon Department of Land Conservation and Development as a Deep Draft Development Estuary (Cortright et al. 1987; Jennings, et al. 2003) and its entrance is stabilized and protected by a pair of 1 km rock jetties. The navigational channel within the Coos estuary is routinely dredged to maintain adequate depths for commercial shipping, and the shoreline contains special zoning units for: (a) urban and industrial development, (b) conservation of natural resources, and (c) natural management of significant fish and wildlife habitats. Like many other Pacific northwest estuarine systems, the Coos estuary is a drowned river-mouth that was inundated by tidal waters during the most recent transgression of sea level (beginning *ca.* 20,000 y ago; Thompson et al. 1993; Rumrill 2006).

Pony Point

The Pony Point study site (43°25′26.16″N/124°14′20.74″W) is located in the polyhaline region of the estuary near the lower bay range extent of Olympia oysters in Coos Bay (Fig.2, Fig. 3). The upper intertidal substratum is characterized by large basalt rip-rap that secures adjacent fill deposited to form the runway

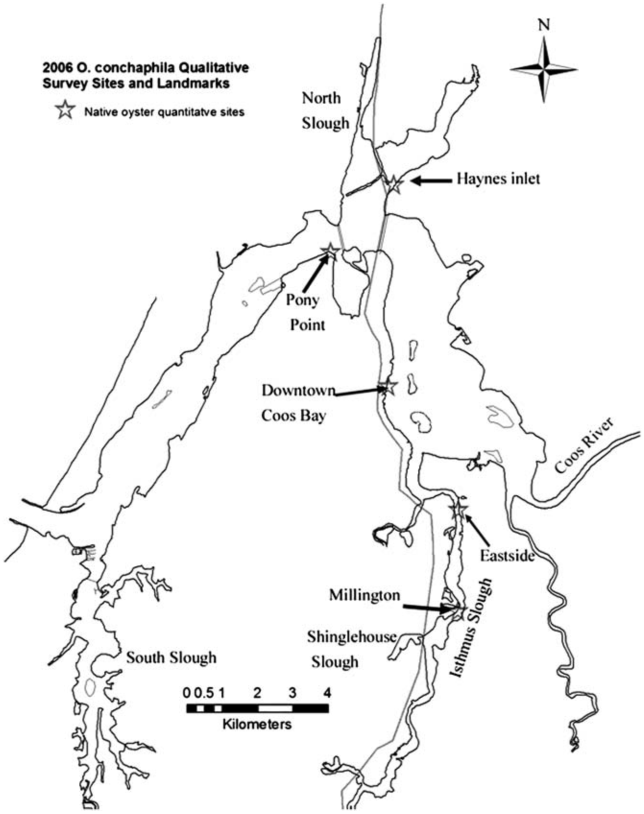

Figure 2. Coos Bay estuary, OR. Map indicates the location of local landmarks and five study sites examined in 2006 during quantitative surveys of *O. lurida* populations.

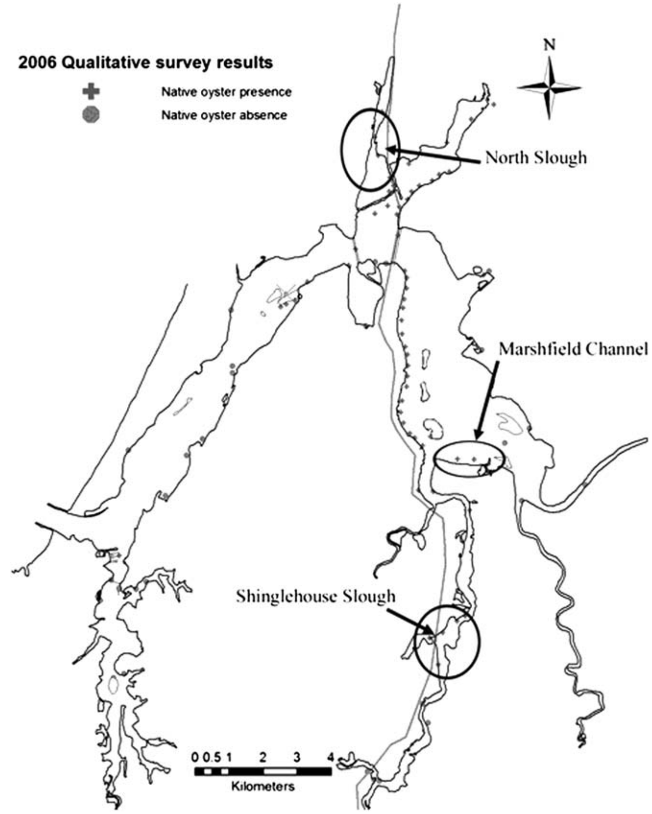

Figure 3. Coos Bay estuary, OR. Map indicates the distribution of *O. lurida* noted during qualitative surveys conducted throughout the bay in 2006. Circles indicate locations where substantial changes in distribution were observed in North Slough, Marshfield Channel, and Shinglehouse Slough.

for the local airport. Dense eelgrass beds (*Zostera marina*) occur in muddy-sand in the lower intertidal area north of the airport. Rocky rip-rap is the primary substrate used by *O. lurida* at this location and a diverse community of invertebrates co-occurs, including arthropods (*Cancer magister, C. productus*, *Carcinus maenas*, *Hemigrapsus oregonensis*, *Neotrypaea californiensis*, and *Pachygrapsus crasspes*), bivalves (*Tresus capax, Clinocardium nuttallii*, *C. gigas*, *Mya arenaira*, *Macoma* sp., *Mytilus* sp.), and gastropods (*Euspira lewisii*, *Nucella* sp.).

Haynes Inlet

The Haynes Inlet study site (43°26′38.79″N/124°12′48.85″W) is located in the polyhaline region of the estuary within a subestuary at the northern bend of Coos Bay (Fig. 2, Fig. 3). The intertidal substratum is characterized by sandstone and rip-rap along the shoreline adjacent to tide flats used for commercial oyster production. Hard surfaces (shell rubble, gravel, rip-rap and rock) that are the preferred substratum for settlement of *O. lurida* in Coos Bay are not readily available in Haynes Inlet. Macro-invertebrates common to this area include arthropods (*C. magister, C. productus*, *C. maenas*, *H. oregonensis*, and *N. californiensis)*, bivalves (*C. nuttallii*, *C. gigas*, *M. arenaira*, *Macoma* sp., *Mytilus* sp.), and gastropods (*Nucella* sp.).

Downtown Coos Bay

The Coos Bay study site (43°23′30.17″N/124°13′2.42″W) is located in the mesohaline/polyhaline region of the estuary near the City of Coos Bay (Fig. 2,Fig. 3). The intertidal zone is characterized by steeply sloped rip-rap banks adjacent to a deep (>30′ deep) dredged navigational channel. The preferred substratum for settlement of *O. lurida* at this site is primarily rip-rap, and the narrow lower intertidal area below the rip-rap is extremely soft mud and likely not suitable to support Olympia oysters. Invertebrates common to this area include arthropods (*C. magister, C. maenas*, *H. oregonensis*, and *N. californiensis)*; bivalves (*C. gigas*, *M. arenaira*, *Macoma* sp., *Mytilus* sp.); and gastropods (*Nucella* sp.).

Eastside

The Eastside study site (43°21′38.98″N/124°11′33.28″W) is located in the mesohaline/polyhaline region of the estuary near the municipality of Eastside (Fig. 2, Fig. 3). The narrow intertidal zone is characterized by a shallow gradient slope between the banks and deep channel where the substratum is a mixture of gravel, rock, and mud. The preferred substratum for settlement of *O. lurida* at this site is primarily gravel discarded from an adjacent quarry storage area. Invertebrates common to this area include arthropods (*C. magister, C. maenas*, *H. oregonensis*, and *N. californiensis)*; bivalves (*C. gigas*, *M. arenaira*, *Macoma* sp., *Mytilus* sp.); and gastropods (*Nucella* sp.).

Millington

The Millington study site (43°19′56.69″N/124°11′31.59″W) is located in Isthmus Slough (mesohaline region of the estuary) near the municipality of Millington (Fig. 2, Fig. 3). This site, and nearby Shinglehouse Slough, establish the upper bay range limit for Olympia oysters in Coos Bay. The narrow intertidal zone is characterized by soft sediments and woody debris that transitions quickly to the deep navigational channel. The preferred substratum for settlement of *O. lurida* at this site is primarily wood bark and other wood materials discarded from local lumber operations. Invertebrates common to this area include arthropods (*C. magister, C. maenas*, *H. oregonensis*, and *N. californiensis)*; bivalves (*C. gigas*, *M. arenaira*, *Macoma* sp., *Mytilus* sp.); and gastropods (*Nucella* sp.).

Survey Methods

We used three survey methods to document changes in the distribution, abundance, and size of *O. lurida* in Coos Bay.

Qualitative Surveys

The goal of this sampling effort was to revisit previous study sites to determine any changes in the distributional range of *O. lurida* populations in Coos Bay. Study sites were chosen strategically throughout Coos Bay based on previously described oyster habitat and areas that offered potentially suitable habitats. During each qualitative survey, the intertidal zone was thoroughly examined at times when the low tides were below 0′ Mean Lower Low Water (MLLW). In addition to the study sites described above, we also included 20 sites examined in previous surveys to establish the baseline distribution of oysters in Coos Bay (Baker et al. 2000).

Quantitative Surveys

The goal of this sampling effort was to re-examine the abundance of *O. lurida* at different locations throughout Coos Bay. Quantitative surveys of oyster densities were conducted in the intertidal zone following previous methods (Baker et al. 2000) at the five study sites described above (Pony Point, Haynes Inlet, Downtown Coos Bay, Eastside, and Millington; Figure 2). At each site a 10-m transect line was laid out along the intertidal zone, parallel to shoreline, and six 0.25-m^2 quadrats were placed at random intervals along the line. All adult oysters (shell length $\geq$ 20 mm) that occurred within the quadrats were counted and measured. Juvenile oysters (<20 mm) were omitted from the quantitative surveys because of the lack of comparability based on time of year and because of time constraints required to complete the surveys within a single low tide event. Notably, juvenile oysters, (<20 mm) were a significant component (~97% of total) of the oyster population surveyed in 1997 and were excluded from 2006 surveys because of time constraints.

Index Survey

The goal of this sampling effort was to establish a repeatable index of oyster density in an area of high abundance for future monitoring. The oyster index area was established at the Eastside (Isthmus Slough) study site where populations of *O. lurida* occur consistently on the gravel substrata (Fig. 2). A 50-m section of the eastern shoreline of Isthmus Slough was examined and identified as suitable oyster habitat. Randomly chosen transects (0.5-m width) were run perpendicular to the 50 m line beginning at the highest oyster found and ending at the water line. All field surveys were performed at tides lower than -1.0 MLLW, and all oysters ($\geq$20 mm) within transects were counted. The Downtown Coos Bay study site (Fig. 2) was initially explored as a potential index site, but this area proved unsuitable because of the extremely high and patchy densities of oysters, primarily caused by the highly variable availability of rock as a suitable substrata.

Changes in Oyster Distribution, Abundance, and Size

Distribution in Coos Bay

The spatial distribution of *O. lurida* within Coos Bay in 2006 was generally similar to the distribution described earlier by Baker (1987) and by Baker et al. (2000), with a few notable changes. In 1986 and 1997, the lower bay distribution of *O. lurida* ended near the North Bend airport (near the Pony Point study site; Fig. 2) and the upper bay range limit was found in Isthmus slough near Millington (Fig. 2). In 2006, the lower bay range extended to rip-rap at the end of the airport runway and the upper bay range had increased slightly to include Shinglehouse Slough and a short distance further up Isthmus Slough (Fig. 2).

Notable Areas of Population Change

Haynes Inlet and North Slough

Two subestuaries are located in the northern portion of Coos Bay, roughly where the bay is separated into the western and eastern arms. The re-established population of *O. lurida* was first discovered in Haynes Inlet (Baker et al. 2000). The oysters are evenly distributed and occur at densities that are similar to those found in the quantitative surveys. High densities of *O. lurida* are limited to locations where substrate is suitable. Hard substrate (i.e., sandstone, shell, bark, basalt, and gravel) is readily available throughout this area and lends to the even distribution. Adult *O. lurida* were absent in North Slough during the surveys conducted in 1997, but they were present in the qualitative surveys conducted in 2006 when their range extended 2.8 km upstream.

Marshfield Channel

In the area east of the entrance of Isthmus Slough oysters are currently found commonly attached to decaying bark, the primary available substrate of the area. Fossil shells of *O. lurida* are dense in the fill material and banks of this area, but live oysters were absent here in 1997. Optimal settlement substrate is lacking throughout this area.

Shinglehouse Slough

In 2006, a dense intertidal population of Olympia oysters was found within Shinglehouse Slough in an area noted in 1997 as ''marginal/incidental.'' This area is the site where a highway bridge was replaced in 1988 and substantial amounts of gravel were added below the bridge to help stabilize the sediments. The gravel provides a suitable substratum for *O. lurida* and the oysters were attached directly to the small rocks embedded in the soft mud.

South Slough

The South Slough tidal inlet forms the primary subestuary of lower Coos Bay. Several large adult *O. lurida* were observed attached to floating docks located throughout the Charleston

Boat Basin during the qualitative surveys conducted in 2006. In a result similar to the 1997 surveys, these adults were the only living *O. lurida* found in the lower bay area. Although other areas in South Slough are potentially suitable for *O. lurida* (i.e., Collver Point, Joe Ney Slough, Long Island Point), oysters were absent. South Slough National Estuarine Research Reserve is currently undertaking a project to evaluate the viability of habitats further upstream in areas that are potentially suitable for settlement and recovery of oyster populations on benthic substrata.

Changes in Oyster Abundance

Quantitative surveys of oyster abundance in Coos Bay conducted in 2006 revealed much higher densities of *O. lurida* than those found previously (Table 1). In general, large oysters (≥20 mm) had become much more abundant within the mid region of their range (Eastside, Coos Bay), and they also increased in abundance at the upper region (Millington and Haynes Inlet) extensions of the bay (Fig. 2).

The most notable areas of population change occurred in Millington and at the Eastside/Downtown Coos Bay study site (Fig. 2).

Millington

During the 1997 surveys this area was noted for the absence of living oysters. In 2006, we observed that a small but apparently viable population had become established on the woody debris embedded in the soft mud. Very little substratum that is suitable for settlement of *O. lurida* occurs at this site, and further recovery of the oyster populations appears to be limited by the availability of hard surfaces.

Eastside/Downtown Coos Bay

Dense populations of *O. lurida* were observed in 2006 throughout the intertidal areas of lower Isthmus Slough and the downtown shoreline of Coos Bay wherever suitable substrate was available. Oyster densities of 46.7 per m^2 and 61.3 per m^2 were observed at the Eastside and Downtown Coos Bay locations, respectively. These high densities of oysters are typical of the adjoining areas and are greater than the densities observed in 1997 (Table 1, Baker et al. 2000).

Changes in oyster sizes

Populations of adult oysters observed in our 2006 quantitative surveys included a broader range of smaller size classes in comparison with the sizes of oysters measured in 1997 (Fig. 4). In 2006, the average shell length for adult oysters (≥20 mm) was 32.8 (S.D. 7.4) mm compared with 38.1 (S.D. 4.5) mm in 1997. Despite the small number of adult shells measured in 1997 ($n = 17$) compared with the larger number measured in 2006 ($n = 177$), a single-factor ANOVA of the size frequencies of oyster shell lengths (20 mm bins) revealed that the difference between the populations was highly significant ($F = 8.3755$; $P = 0.0042$). Pearson's coefficient of skewness also differed substantially between the populations measured in 1997 (0.0775) when the modal shell length was 44.0 mm, and the population measured in 2006 (–0.0662) when the modal shell length was 33.0 mm. Negative skew in favor of smaller size classes in 2006 indicates that the populations of *O. lurida* probably experienced substantial and repeated episodes of recruitment during the preceding years.

Index Survey

The oyster index survey site established near Eastside (Fig. 2) yielded an average *O. lurida* density of 56.4 oysters per m^2. This high density of adult oysters is comparable to the high densities of *O. lurida* observed nearby at the Eastside study site and at the Coos Bay study site (Table 1). Our initial measurements of high and consistently occurring oyster densities at this site establish the baseline for future measurements of *O. lurida* populations within the mesohaline region of the estuary.

DISCUSSION

Beds of *O. lurida* were historically abundant in the Coos estuary and South Slough (Oregon) where they were used extensively as a food source by the indigenous people. Several shell middens that contain native oysters occur along the shoreline of the South Slough (Moss & Erlandson 1995) and they have radiocarbon ages of about 400 ± 60 y before present. Olympia oyster shells are commonly included in the dredged materials removed from the estuarine channels. Beds of *O. lurida* probably became locally extinct in Coos Bay and South Slough prior to written history caused by basin-wide changes in

TABLE 1.

Comparison of the densities of *O. lurida* at various study sites in Coos Bay between intertidal surveys conducted in 1996–97 and 2006.

	1996–1997	2006
	Large oysters (≥20 mm)	Large oysters (≥20 mm)
Study Site	Density (#/m^2)	Density (#/m^2)
Millington	0	2.7
Eastside	0.7	46.7
Downtown Coos Bay	6.7	61.3
Haynes Inlet	0.7	4.7
Pony Point	5.3	3.3

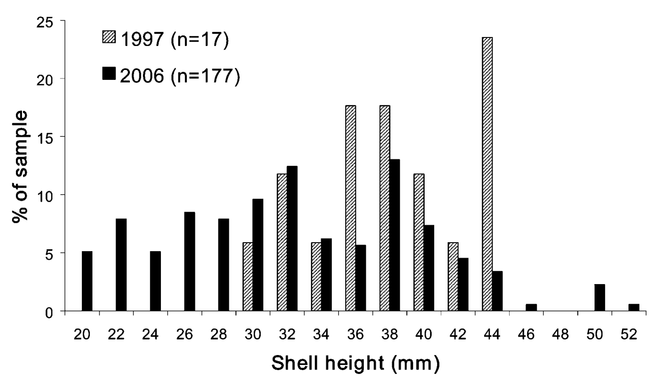

Figure 4. Comparison of the size distribution of adult *O. lurida* from surveys conducted in 1997 and 2006. Oyster sizes for the 1997 surveys are adapted from Baker et al. (2000). Note: Shell height is synonymous with shell length.

the inputs and distribution of fine sediments associated with fire and/or a tsunami (Nelson et al. 1996, Rumrill 2006). Over the first century after colonization of the shoreline of the Coos estuary by euro-western settlers (*ca*. 1850–1950), aquatic and estuarine habitats within portions of Coos Bay were chronically degraded by growing urbanization and the cumulative effects of sedimentation, log storage, bark decay, dredging, deposition of dredge spoils, diking, filling, domestic and industrial pollution, commercial mariculture, and by the colonization of estuarine habitats by nonindigenous aquatic species. Despite these alterations and degradation of the shoreline, and reduction of the entire wet surface area of the Coos estuary by 26% (Borde et al. 2003), water column and benthic habitat conditions have improved considerably over the past 30 years within particular regions of the tidal basin; conditions are now conducive to the recovery of Olympia oysters. In 1988, after several years of inadvertent inoculations *via* commercial shellfish culture activities, discontinuous populations of Olympia oysters became re-established at low intertidal and subtidal elevations within the polyhaline (salinity 22–28 ppt) region of the Coos estuary (Baker et al. 2000). Baker hypothesized that changes in *O. lurida* range were dependent on changes to salinity intrusion, primarily attributed to deepening of the navigational channel. Additional channel deepening occurred roughly simultaneous with the previous surveys and may be responsible for the increased spatial distribution of *O. lurida* observed in 2006. It is anticipated that further changes to the navigational channel will result in alterations in salinity intrusion and thus may dictate future changes in the distribution and range of *O. lurida* populations.

Although isolated populations of Olympia oysters have become marginally established a within the Coos estuary, widespread recovery of *O. lurida* has not occurred because of several potentially limiting factors. These factors include: (a) suboptimal biotic and physical conditions that may hamper feeding, survivorship, growth, and reproduction; (b) inadequate production and larval retention; (c) decreased availability of adequate shell substratum for settlement; (d) poor survival of postsettled juveniles; and (e) predation, competition, and ecological interactions with other established Olympia and nonnative species. It is anticipated that once these hurdles are understood and perhaps overcome, it may be possible to initiate recovery of Olympia oyster beds in Coos Bay and South Slough in a manner that will allow the oyster populations to become self-sustaining. Re-establishment of self-sustaining populations of *O. lurida* is desirable because, in addition to the recovery of the oysters, the growing physical structure of the oyster beds will serve to restore some of the lost ecological functions to the estuarine tidal basin, and the living oyster beds may reach a point in the future where they can provide substantial benefits for diverse communities of invertebrates, fish, shorebirds, and humans.

CONCLUSION

Populations of *O. lurida* currently exhibit spatial expansion and increased abundance in parts of Coos Bay, and also provide evidence of recruitment by juveniles into the established populations of adults. Olympia oysters seem to have become a viable species and it is possible that they may continue to expand their distribution and fulfill their former role in the estuarine ecosystem at some time in the future. However, our field observations indicate that the availability of suitable substratum is likely a key limiting factor that hinders further recovery in Coos Bay. The potential of oyster populations to recover in Netarts and Yaquina Bay is currently being explored *via* enhancement projects. These projects include ecological assessment work that will provide guidance for the future of Olympia oysters in Oregon's historically productive bays and estuaries.

ACKNOWLEDGMENTS

The authors thank Nick Wilsman, Bruce Miller, Jean McCrae, Sylvia Yamada, and Kate Groth for assistance in moving this project forward, and for their encouraging words. Dean Headlee and Jill Smith provided excellent help in the field. The authors also thank the federal and state agencies for their continued steps to encourage and support research related to the restoration and recovery of Olympia oysters whose economic value is less apparent than its value to the ecosystems of the Pacific Northwest.

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Exhibit 24

October 8, 2011

Andrew Stamp
Hearings Officer
c/o Coos County Planning Department
225 N. Adams Street
Coquille, Oregon 97423

At the request of Mark Chernaik, expert for Citizens Against LNG, I was asked to answer the following questions relating to the surveying of Olympia oysters in Haynes Inlet.

Q1. Could you please describe your qualifications for answering the following questions? How many years have you studied the biology of Olympia oysters? What peer-reviewed scientific publications about the biology of Olympia oysters have you authored?

I have been working on aspects of the biology of the Olympia oyster, *Ostrea lurida*, since 2002, when I was a postdoctoral scholar at UCLA, working on developing methods to track larval oysters through their dispersal stage in collaboration with scientists from Bodega Marine Labs. Since then I have studied multiple aspects of the ecology and evolution of this species, including completing surveys of adult density and abundance. For example, my lab group has been monitoring oyster spatfall settlement and adult density at 6 sites in Newport Bay, CA since 2006.

I am currently working with collaborator Doug Eernisse (CSU Fullerton) to develop a rapid and inexpensive barcode method (without sequencing) to identify *O. lurida* and non-native *Crassostrea gigas*. I have also recently (summer 2010) initiated a study in Newport Bay, CA that explores the effects of various oyster restoration techniques on the recruitment, growth and survival of *O. lurida*, as well as on epifaunal and infaunal community diversity. Last, I have teamed with Dr. Jennifer Burnaford (CSU Fullerton) and Dr. Sarah Gilman (Claremont Colleges) to quantify the density of both native and non-native oysters in several estuaries within southern California, and to begin to develop thermal profiles for these species on artificial versus natural substrata.

I have published 4 papers on *Ostrea lurida*, dealing with oyster settlement, population demographics, evolutionary relationships, and methods for tracking oyster larvae:

Polson, M., W. E. Hewson, D. J. Eernisse, P. K. Baker, and D. C. Zacherl. 2009. You say *conchaphila*, I say *lurida*: Molecular evidence for restricting the Olympia oyster to temperate western North America. Journal of Shellfish Research **28**:11-21.

Polson, M. and D. C. Zacherl. 2009. Geographic distribution and intertidal population status for the Olympia oyster, *Ostrea lurida* Carpenter 1864, from Alaska to Baja California. Journal of Shellfish Research **28**:69-77.

Seale, E. and D. C. Zacherl. 2009. Seasonal settlement of Olympia oyster larvae, *Ostrea lurida* Carpenter 1864, and its relationship to seawater temperature in two southern California estuaries. Journal of Shellfish Research **28**:113-120.

Zacherl, D. C., S. G. Morgan, S. E. Swearer, and R. R. Warner. 2009. A shell of its former self: Can *Ostrea lurida* Carpenter 1864 larval shells reveal information about a recruit's birth location? Journal of Shellfish Research **28**:23-32.

Q2. What documents have you examined about the potential impacts of the proposed pipeline on Olympia oysters in Haynes Inlet in Coos Bay?

I have reviewed two documents provided by Dr. Chernaik:
Pacific Connector Gas Pipeline: Olympia Oyster Survey, authored by Bob Ellis/Ellis Ecological Services,Inc., dated September 13, 2011
Report on the Potential Impacts of the Pacific Connector Gas Pipeline on the Olympia oyster (*Ostrea lurida*) and the "resource productivity" of Haynes Inlet, authored by Mark Chernaik, Ph.D, dated September 2011

Q3. Can you explain how Olympia oysters (*O. lurida*) can have a 'cryptic' appearance within the intertidal zone? Can you explain how the ability of finding *O. lurida* in the intertidal zone depends on the amount of training a surveyor has received? Considering the survey methods described in the pipeline company's expert report, what fraction of oysters might have been overlooked employing this method if the surveyors were untrained? What comments are relevant to understand the survey results as presented by Ellis Ecological Services?

Oysters are notoriously morphologically plastic, difficult to identify, and in the case of many species of the genus *Ostrea*, cryptic in appearance. *Ostrea lurida,* in particular, because of its small size, sometimes heavily fouled shell, its muddy habitat, and the fact that it prefers to dwell on the undersides of hard substrates, can be extremely difficult to locate and survey. As case in point, when I began my survey work in southern California, I contacted several scientists who regularly work in the mudflats and estuary environments and asked about the presence/absence of this oyster species. I was told, universally, that the oyster was not present in southern California estuaries. In fact, my survey work has demonstrated quite clearly that it is common; it had simply gone unnoticed for decades. In my lab group, new surveyors undergo significant training before they are allowed to participate in survey work. They first work on species identification with voucher specimens in the lab, and then are paired with "expert" surveyors first as data collectors, then as "practice" surveyors, and finally, after several trips into the field, as full-fledged surveyors. When my inexperienced students are paired with expert surveyors, they typically miss more than half of the oysters in a given area. Once they develop their "search image" they become much more proficient. It is not clear how much training, if any, the surveyors at Ellis Ecological Services had prior to their survey work.

The Olympia oyster survey results provided by Ellis Ecological Services were vague. They did not report density (# individuals per unit area) anywhere, and, despite the fact that they note they generally followed the methods outlined in our paper (Polson and Zacherl, 2009), they did not present their data in a way that allows one to calculate total abundance in the target area. They provide a number of oysters encountered, 79, but neglect to report the percentage of area they surveyed out of the total area designated by the project. Typically, surveys are designed to sub-sample an area, and we rely upon measures of density so that we can extrapolate total abundance from that number. Using our survey techniques (Polson and Zacherl, 2009), Ellis Ecological Services should have been able to estimate (and report) density per 50 meters of mudflat surveyed. They also should have reported the total % of area surveyed out of total project area. Last, they did not even report density in the area where the oysters were most concentrated, and where they noted in their methods that they did record density.

In sum, their results are based upon surveys performed by surveyors whose qualifications and training are not provided, and their results do not allow us to evaluate how many oysters will be impacted, nor the total area of oyster habitat that will be destroyed. In that vacuum of information, I cannot fathom how one would negotiate mitigation or weigh the value of the project against impacts sustained.

Sincerely,

Danielle Zacherl, Ph.D.
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Fullerton, CA 92834-6850

(657) 278-7510 (cell)

dzacherl@fullerton.edu

Exhibit 25

BEFORE THE LAND USE BOARD OF APPEALS

OF THE STATE OF OREGON

11/27/17 PM 2:07 LUBA

OREGON SHORES CONSERVATION COALITION,
Petitioner,

and

JOHN CLARKE, DEB EVANS, RON SCHAAF,
ROGUE CLIMATE, HANNAH SOHL,
STACEY McLAUGHLIN, JODY McCAFFREE, and THE
CONFEDERATED TRIBES OF COOS, LOWER UMPQUA
and SIUSLAW INDIANS,
Intervenors-Petitioners,

vs.

COOS COUNTY,
Respondent,

and

JORDAN COVE ENERGY PROJECT L.P.,
Intervenor-Respondent.

LUBA No. 2016-095

FINAL OPINION
AND ORDER

Appeal from Coos County.

Courtney Johnson, Portland, filed the petition for review and argued on behalf of petitioner. With her on the brief was Crag Law Center.

Kathleen P. Eymann, Bandon, filed a petition for review and argued on behalf of intervenor-petitioner John Clarke.

Tonia L. Moro, Medford, filed a petition for review and argued on behalf of intervenors-petitioners Deb Evans, Ron Schaaf, Rogue Climate and Hannah Sohl.

Jody McCaffree, North Bend, filed a petition for review and argued on her own behalf.

Stacy McLaughlin, Myrtle Creek, represented herself.

Denise Turner Walsh, Carlsbad, California, filed a petition for review on behalf of intervenor-petitioner Confederated Tribes of Coos Lower Umpqua and Siuslaw Indians. Richard K. Eichstaedt argued on behalf of the Confederated Tribes.

Keith A. Leitz, Coos County Legal Counsel, Coquille, filed a response brief and argued on behalf of respondent.

Seth J. King, Portland, filed response briefs and argued on behalf of intervenor-respondent. With him on the brief was Perkins Coie LLP.

BASSHAM, Board Member; RYAN, Board Chair; HOLSTUN Board Member, participated in the decision.

REMANDED 11/27/2017

You are entitled to judicial review of this Order. Judicial review is governed by the provisions of ORS 197.850.

Opinion by Bassham.

NATURE OF THE DECISION

Petitioner appeals a county board of commissioners' decision approving a conditional use permit for a liquified natural gas (LNG) export terminal at Jordan Cove in Coos County, near the city of Coos Bay.

INTRODUCTION

Petitioner Oregon Shores and several intervenors-petitioners filed petitions for review. With minor exceptions, the five petitions for review filed do not present overlapping challenges. Therefore, we provide here only a general summary of the facts and legal context. Specific facts and legal standards relevant to particular challenges are set out under the pertinent assignments of error.

In 2015, intervenor-respondent Jordan Cove Energy Project L.P. (JCEP) applied to the county to construct an LNG export terminal at Jordan Cove, located on the North Spit at Coos Bay, located in Coos County.[1] The proposed facility would receive approximately 1.04 billion cubic feet per day of natural

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[1] JCEP had previously obtained county approvals for an LNG import terminal. *See SOPIP, Inc. v. Coos County*, 57 Or LUBA 44, *aff'd* 223 Or App 495, 196 P3d 123 (2008), and *SOPIP, Inc. v. Coos County*, 57 Or LUBA 301 (2008). The county also approved a separate application for a 49.72-mile section of a natural gas pipeline to serve the LNG import terminal. *Citizens Against LNG v. Coos County*, 63 Or LUBA 162 (2011). Various components and iterations of the project have over the years generated a number of permits and decisions from several bodies, including proceedings before the Federal Energy Regulatory Commission (FERC).

gas via pipeline, liquify the gas to produce approximately 6.8 million metric tons of LNG, and load the LNG on tanker ships for export to international or domestic markets in the non-contiguous United States.

The LNG facility consists of a number of components, including (1) the LNG export terminal, (2) a marine slip and access channel, (3) a barge berth, (4) a gas processing center, and (5) a fire station and emergency training center, along with associated roads and utilities. The project would also require significant dredging, dredge disposal, shoreline stabilization, and wetland impact mitigation.

The terminal, gas processing facility, and fire station and emergency training center will be located on upland areas zoned for industrial uses. Much of the port facilities (slip, barge berth, tugboat dock, etc.) will be located in coastal shoreland areas, which are generally zoned to allow for water-dependent uses. The marine slip and access channel will require dredging in Jordan Cove, designated a natural estuary, and Henderson Marsh, a Statewide Planning Goal 5 (Natural Resources, Scenic and Historic Areas, and Open Spaces) inventoried wetland.

The county hearings officer held a hearing on December 18, 2015, and held the record open thereafter for additional testimony and rebuttal. On May 2, 2016, the hearings officer issued a decision with recommendations to approve the applications. On August 16, 2016, the county board of commissioners held a public meeting to deliberate on the recommendations, and voted to adopt the hearings officer's findings as the county's decision, with minor modifications. The county's final decision was issued on August 30, 2016. This appeal followed.

FIRST ASSIGNMENT OF ERROR (OREGON SHORES)

The Coos Bay Estuary Management Plan (CBEMP) governs the use of the Coos Bay estuary and adjacent shorelands, implementing Statewide Planning Goal 16 (Estuarine Resources). The CBEMP designates a number of estuarine resources in the Jordan Cove area. Some are designated as "Development" zones, others as "Natural" zones in which development, including dredging and filling, is limited or prohibited.

Under the first assignment of error, petitioner Oregon Shores Conservation Coalition (Oregon Shores) cites to testimony that development of the gas processing facility will involve placement of fill in the 7-NA (Natural Aquatic) zoning district, a zone that comprises much of Jordan Cove, in which placing fill is prohibited. According to Oregon Shores, the county adopted no findings addressing the proposal to place fill in the 7-NA zone to support the gas processing facility.

Intervenor-respondent JCEP (JCEP) responds that the application did not propose placing fill anywhere in the 7-NA zone. JCEP also notes that the county rejected testimony that the application proposes to place fill in the 7-NA zone. Record 197 (findings discussing an opponents' letter "arguing, incorrectly, that the applicant's map on page 407 shows that the applicant intends to place fill in the 7-NA aquatic zone."). As far as we can tell, JCEP is correct that the application did not propose, and the decision does not approve, the placement of fill in the 7-NA zone.

The first assignment of error (Oregon Shores) is denied.

SECOND ASSIGNMENT OF ERROR (OREGON SHORES)
THIRD ASSIGNMENT OF ERROR (ROGUE INTERVENORS)[2]

The application proposes dredging within areas zoned 5-DA and 6-DA (Development Aquatic Management Units), to construct an access channel from the navigation channel to the marine slip. Such dredging is subject to CBEMP Policy 5(I),[3] which implements Goal 16, Implementation Requirement

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[2] We follow the parties in referring to intervenors-petitioners Deb Evans, Ron Schaaf, Rogue Climate, and Hannah Sohl as "Rogue Intervenors."

[3] CBEMP Policy 5(I) (Estuarine Fill and Removal) provides, in relevant part:

> "Local government shall support dredge and/or fill only if such activities are allowed in the respective management unit, and:
>
> "a. The activity is required for navigation or other water-dependent use that requires an estuarine location or, in the case of fill for non-water-dependent uses, is needed for a public use and would satisfy a public need that outweighs harm to navigation, fishing, and recreation, as per ORS 541.625(4) and an exception has been taken in this Plan to allow such fill.
>
> "b. A need (i.e., a substantial public benefit) is demonstrated and the use or alteration does not unreasonably interfere with public trust rights.
>
> "c. No feasible alternative upland locations exist; and

2 (Goal 16 IR2).[4] Under CBEMP Policy 5(I), dredging is allowed in the estuary only if, in relevant part, (1) it is "required for navigation or other water-dependent use that requires an estuarine location," and (2) a "need (i.e., a substantial public benefit) is demonstrated and the use or alteration does not unreasonably interfere with public trust rights."

In two sub-assignments under the second assignment of error, Oregon Shores challenges the county's findings that JCEP has demonstrated that dredging required for the marine slip and access channel will (1) provide a substantial public benefit, and (2) not unreasonably interfere with public trust rights. In their third assignment of error, intervenors-petitioners Rogue Intervenors advance additional arguments under both the "substantial public benefit" and "interference with public trust rights" standards.

"d. Adverse impacts are minimized."

[4] Goal 16, Implementation Requirement 2 provides, as relevant:

"Dredging and/or filling shall be allowed only:

"a. If required for navigation or other water-dependent uses that require an estuarine location or if specifically allowed by the applicable management unit requirements of this goal; and,

"b. If a need (i.e., a substantial public benefit) is demonstrated and the use or alteration does not unreasonably interfere with public trust rights; and

"c. If no feasible alternative upland locations exist; and,

"d. If adverse impacts are minimized."

A. Need/Substantial Public Benefit

Under CBEMP Policy 5(I)(a), the county found that the proposed dredging is required for a "water-dependent use that requires an estuarine location[,]" the water-dependent use being components of the LNG terminal. The Statewide Planning Goals define "water-dependent" in relevant part as "[a] use or activity which can be carried out only on, in, or adjacent to water areas because the use requires access to the water body for water-borne transportation, recreation, energy production, or source of water." *See* full quote at n 26, below. Oregon Shores does not challenge the county's finding that the LNG terminal is a "water-dependent" use for purposes of CBEMP Policy 5(I)(a) or Goal 16.[5]

With respect to CBEMP Policy 5(I)(b), Oregon Shores argues that the county misconstrued the need/substantial public benefit standard in three ways.[6] First, Oregon Shores argues that the county erred in interpreting CBEMP Policy 5(I)(b) to require evaluation only of the public benefits of the

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[5] However, as discussed below, intervenors-petitioners Rogue Intervenors challenges the conclusion that an LNG *export* terminal qualifies as a "water-dependent use" for purposes of Goal 16 and CBEMP Policy 5(I)(a).

[6] Because CBEMP Policy 5 implements Goal 16, on review the county's interpretations of the policy are not entitled to deference under ORS 197.829(1) or *Siporen v City of Medford*, 349 Or 247, 259, 243 P3d 776 (2010).

dredging activity itself, divorced from the public benefits of the land-based use that the dredging serves.[7]

We agree with Oregon Shores. If the "substantial public benefit" analysis is limited to evaluation of the public benefits of the dredge or fill activity itself, then the standard would never be met, as it is difficult to conceive of any public benefit from dredging or filling that is distinct from the use that dredging or filling serves. While the text of CBEMP Policy 5(I)(b) and Goal 16 IR2 is not entirely clear on this point, the context indicates that the four standards do not apply only to the proposed dredging or fill. We note that Goal 16 IR2(c) requires a finding that "no feasible alternative upland locations exist," which clearly contemplates evaluation of the proposed land use, not proposed dredging, since dredging does not generally take place on upland locations. We conclude that, contrary to the county's finding, CBEMP Policy 5(I)(b) requires the county to evaluate the substantiality of the public benefits provided by the use that the proposed dredging serves, in this case the LNG

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[7] The county's findings state on this point:

> "The Board concludes that the term 'need (substantial public benefit)' used in Goal 16 and CBEMP Policy #5 refers to a public benefit *for the dredging activity*, and does not require the applicant to prove that there is a public need or benefit for the underlying proposed land use (*i.e.*, a marine slip and ship terminal, or more generally, an LNG export facility.)." Record 86 (emphasis in original).

terminal, or at least those components of the terminal that are properly viewed as water-dependent uses.

Next, Oregon Shores argues that the county erred in interpreting CBEMP Policy 5(I)(b) to require evaluation only of the public benefits, and not to require any consideration of detriments or adverse impacts.[8] The county's interpretation of Policy 5(I)(b) is based on the observation that the adjoining Policy, CBEMP Policy 5(I)(a), expressly requires that the proponent of a non-water-dependent use demonstrate that there is a need for the use that "outweighs harm to navigation, fishing and recreation[.]" *See* n 3. As the findings note, this expressly required balancing test implements a statute. The county inferred that because CBEMP Policy 5(I)(b) does not expressly require a similar balancing test, the drafters of CBEMP Policy 5(I)(b) did not intend the county to engage in a similar balancing of benefits and detriments.

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[8] The county's findings state, in relevant part:

> "[T]he Board specifically rejects the argument that the [']public need/benefit' standard requires the County to balance need/benefit with (and weigh against) public detriments. In the previous sentence of Policy 5, the drafters required that an applicant for a non-water-dependent use to demonstrate that dredging and fill 'is needed for a public use and would satisfy a public need that outweighs harm to navigation, fishing and recreation.' That specific language did not come out of Goal 16, but rather is taken from ORS 196.825(4). Had the drafters of the CBEMP intended to impose a similar balancing test requirement on to the 'public need/benefit' standard, they could [] easily have done so (as they expressly did in the prior sentence), but they chose not to do so." Record 88.

As Oregon Shores argues, the question is not what the drafters of CBEMP Policy 5 intended, but what the drafters of Goal 16 IR2 intended, which CBEMP Policy 5(I)(b) implements almost verbatim. The text of Goal 16 IR2(b) does not expressly require balancing or weighing of benefits against detriments, but requires only a demonstration of a "substantial public benefit." That could be understood to represent a "net" public benefit, after consideration of both benefits and detriments. However, the fact that another implementation requirement, Goal 16 IR2(d), requires that "adverse impacts are minimized" suggests that potential adverse consequences of the proposed use are evaluated under a different standard. Given the absence of an express or a fairly implied requirement to balance or weigh benefits against adverse consequences under Goal 16 IR2(b), and the fact that adverse consequences are expressly addressed under a different standard, we decline to read Goal 16 IR(2)(b) to include an implicit requirement to balance or weigh public benefits of the proposed use against adverse consequences.

Finally, Oregon Shores challenges the county's view that the "need/substantial public benefit" standard is satisfied if the dredging activity is needed to construct a permitted or conditional use allowed on the nearby coastal shorelands or upland areas.[9] Oregon Shores argues that this

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[9] The county's findings state, in relevant part:

> "The Board believes that the 'need/substantial benefit' standard is met if the applicant demonstrates that the dredging or fill activity

interpretation conflates CBEMP Policy 5(I)(a) with 5(I)(b), and Goal 16 IR2(a) with IR2(b). According to Oregon Shores, the fact a water-dependent use is allowed on coastal shorelands under the county's zoning code does not automatically demonstrate that there is a "substantial public benefit" for purposes of CBEMP Policy 5(I)(b) and Goal 16 IR2(b).

We agree with Oregon Shores. CBEMP Policy 5(I)(a) and Goal 16 IR2(a) in relevant part require that the proposed dredging serve a water-dependent use allowed under the county's code. The county's view that the "need/substantial public benefit" standard in CBEMP Policy 5(I)(b) and Goal 16 IR2(b) is met simply by the fact that the proposed dredging serves a use allowed under the county's code, conflates CBEMP Policy 5(I)(a) and (b) and gives no independent effect to the latter. Even if the proposed dredging serves a water-dependent use allowed under the county's code, the county can allow

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is needed to enable [construction of] a permitted or condition[al] use allowed in the neighboring coastal shoreland zone and related upland zones. In other words, Coos County has, via its enactment of the CBEMP (aka: Zoning Ordinance), set forth the panoply of uses that the County believes would serve a need and/or a substantial public benefit in each particular zone (*i.e.,* it has established a list of uses that are deemed to be appropriate in each zone in question.). If the applicant is proposing one of those favored uses, and there is a need to conduct fill or dredging activity in order to facilitate that favored use, then there is, *ipso facto*, a substantial benefit to allowing the applicant to conduct that fill/removal so that it can construct and operate the use." Record 88 (emphasis in original).

the dredging only if it also finds that the use provides a substantial public benefit.

B. Interference with Public Trust Rights

CBEMP Policy 5(I)(b) and Goal 16 IR2(b) also require that the proposed dredging does not unreasonably interfere with public trust rights. The public trust doctrine protects public access to and use of navigable waters and submerged lands, for navigation, fishing and commercial uses. *See, e.g.*, *Weise v. Smith*, 3 Or 445, 450 (1869) (stating that navigable waters are "public highways" that each person has an "undoubted right to use * * * for all legitimate purposes of trade and transportation.").

1. Navigable Water

Oregon Shores first argues that the county erred by limiting the scope of public trust assets to submerged lands, and failing to include the waters overlaying those lands. JCEP responds that, while the findings cite to a circuit court case stating that the public trust doctrine protects only submerged lands, the findings in fact evaluate impacts on navigation and fishing and other uses of the navigable waters overlaying submerged lands. As discussed below, JCEP is correct that the county in fact evaluated impacts on navigation, fishing and other uses of navigable water, and did not limits its analysis to impacts on submerged lands.

2. Security Zone

Oregon Shores next challenges the county's findings regarding the impact of security zones around LNG tankers on commercial and recreational boat movements in the estuary. The application proposes that approximately 100 LNG tankers will traverse the Coos Bay Estuary to and from the LNG terminal per year. For each passage, the Coast Guard will impose a security zone extending 500 yards from the tanker in all directions, in which all other vessel movements are restricted. Oregon Shores argues that, because portions of the estuary are less than 1,000 yards wide, each tanker passage will completely halt navigation, fishing and commercial use of those portions of the estuary until the LNG tanker passes. Oregon Shores contends that the county's conclusion that the proposed security zone provisions will not unreasonably interfere with public trust rights relies on an inference from testimony in the record that is not supported by substantial evidence.

The record includes a statement from the Coast Guard that it will "allow vessels to transit the Safety/Security zone based on a case-by-case assessment conducted on scene." Record 3033. JCEP's consultant, Amergent Techs, interpreted this statement to mean that the Coast Guard would allow some boats to transit the security zone with minimal delay. Record 1817. In its findings, the county understood Amergent's testimony to be that all "known" boats would be allowed to transit the security zone without delay, presumably meaning only unknown boats will be delayed. Based on that understanding, the county concluded that tanker passage would not unreasonably interfere with navigation or public trust access to the estuary.[10]

Nothing in the record cited to us explains the distinction between a "known" and "unknown" boat. That problem aside, as Oregon Shores argues, the county's understanding that all "known" boats would be able to transit the security zone with minimal delay is not supported by the Amergent Techs memo, much less by the Coast Guard statements in the record. Neither the Amergent Techs memo nor the Coast Guard statements suggest that the Coast Guard's case-by-case evaluation would rely on a distinction between "known" and "unknown" boats, and allow the former passage through the security zone

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[10] The county's findings state, in relevant part:

> "The testimony from Amergent Techs provides clarifications regarding the limited impacts caused by LNG vessel passage and docking in Coos Bay. Importantly, the memo clarifies that the Safety/Security zones are not 'exclusion zones.' Rather, they are regulated navigation areas. Essentially, that means that the Coast Guard will control traffic near the LNG ships but will still allow boat pilots [to] transit the zone on a case-by-case basis. The Board's understanding of this explanation is that the Coast Guard will let known vessels pass but can forcibly exclude vessels or delay [vessels] that it does not recognize. As a practical matter, local commercial fishermen operating known vessels should experience no significant delays as they will receive permission from the COTP [Captain of the Port] to proceed. Less frequent users of the bay, such as recreational boaters, may experience some delay as the COTP makes efforts to identify them and conduct a threat assessment. Given that clarification, the Board believes that there will be no unreasonable interference with public trust rights. * * *" Record 100-01.

without delay, although that may well be the case. The county's findings rely on its understanding of the Amergent Techs testimony as the primary basis for its conclusion that the transit of approximately 100 LNG tankers per year through the narrow estuary will not unreasonably interfere with navigation or public trust access to the estuary. JCEP argues that there is other evidence in the record that could support that conclusion, noting testimony that delay caused to recreational or fishing vessels by an LNG vessel would last only 20-30 minutes, and that the LNG transit times would be announced in advance, so local vessels could make plans to avoid the narrow portions of the estuary at those times. Record 3764. While that evidence could lend support to a finding that LNG tanker transit will not unreasonably interfere with public trust rights, the findings do not cite that evidence, and JCEP does not argue that that evidence is sufficient, in itself, to "clearly support[]" the county's decision on this point, in the absence of adequate findings. ORS 197.835(11)(b).[11] We

[11] ORS 197.835(11)(b) provides:

> "Whenever the findings are defective because of failure to recite adequate facts or legal conclusions or failure to adequately identify the standards or their relation to the facts, but the parties identify relevant evidence in the record which clearly supports the decision or a part of the decision, the board shall affirm the decision or the part of the decision supported by the record and remand the remainder to the local government, with direction indicating appropriate remedial action."

agree with Oregon Shores that remand is necessary for the county to adopt more adequate findings, supported by substantial evidence, on this point.

3. Adverse Impacts of Climate Change

Rogue Intervenors argue in their third assignment of error that the county erred in failing to consider the adverse impacts of climate change created by LNG shipped via the LNG terminal, in evaluating whether the proposed dredging serves a use that provides "substantial public benefits" and does not unreasonably interfere with public trust rights. Rogue Intervenors contend that in evaluating both standards the county must consider the impact of greenhouse gas emissions on ocean acidification, sea level rise and other climatic changes.

We disagree with Rogue Intervenors. As discussed above, the "substantial public benefits" standard does not include an implicit requirement to balance the public benefits of the proposed LNG terminal against detriments or adverse impacts of that use, much less consider the adverse effects of greenhouse gases on climate that could be attributed to the eventual consumption of the natural gas that is shipped to markets around the world via the LNG facility. Nor have Rogue Intervenors established that the public trust doctrine requires evaluation of the contributions of greenhouse gases attributable to consumption of natural gas shipped via the terminal.

The second assignment of error (Oregon Shores) is sustained, in part.

The third assignment of error (Rogue Intervenors) is denied.

THIRD ASSIGNMENT OF ERROR (OREGON SHORES)

As noted above, CBEMP Policy 5(I)(d) allows dredging in development aquatic management units (5-DA and 6-DA) only if "[a]dverse impacts are minimized." CBEMP Policy 5(II) provides that "[i]dentification and minimization of adverse impacts as required in [Policy 5(I)(d)] shall follow the procedure set forth in Policy 4." CBEMP Policy 4(I)(d) provides in relevant part that dredging and fill in development aquatic units must be supported by findings demonstrating "the public's need and gain which would warrant any modification or loss to the estuarine system, based upon a clear presentation of the impacts of the proposed alteration, as implemented in Policy #4a."[12] CBEMP Policy 4(II) sets out standards for an impact assessment.[13] CBEMP

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[12] CBEMP Policy 4(I)(d) provides, in part"

> "Where the impact assessment requirement (of Goal #16 Implementation Requirements #1) has not been satisfied in this Plan for certain uses or activities [as identified in Policy #4] then such uses or activities shall not be permitted until findings demonstrate the public's need and gain which would warrant any modification or loss to the estuarine ecosystem, based upon a clear presentation of the impacts of the proposed alteration, as implemented in Policy #4a."

[13] CBEMP Policy 4(II) provides, in relevant part:

> "An impact assessment need not be lengthy or complex, but it should give reviewers an overview of the impacts to be expected. It may include information on:
>
> "a. the type and extent of alterations expected;

Policy 4a includes additional requirements and procedures for the impact assessment.

Oregon Shores argues that the county failed to adopt any findings addressing CBEMP Policy 4 or 4a, or provide a "clear presentation of the impacts of the proposed alteration[.]" Oregon Shores notes that the record includes an analysis of the impacts of proposed dredging, prepared by David Evans & Associates (DEA), at Record 1900-03. However, Oregon Shores argues that the county did not adopt the DEA analysis as part of its findings, and further that the DEA analysis did not follow the procedure set out in CBEMP Policy 4a.

JCEP concedes that the county did not adopt findings directly addressing CBEMP Policy 4 or 4a, but argues that the record includes evidence that "clearly supports" a finding of compliance with those policies, and therefore the decision may be affirmed on this point notwithstanding inadequate findings, pursuant to ORS 197.835(11)(b). *See* n 11. JCEP argues that the record includes ample evidence that the "public's need and gain" would

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"b. the type of resource(s) affected;

"c. the expected extent of impacts of the proposed alteration on water quality and other physical characteristics of the estuary, living resources, recreation and aesthetic use, navigation, and other existing and potential uses of the estuary; and

"d. the methods which could be employed to avoid or minimize adverse impacts."

warrant any modification or loss to the estuarine system, in the forms of economic gains from the proposed terminal. CBEMP Policy 4(I)(d). JCEP contends that the DEA analysis at Record 1900-03 provides the "clear presentation of the impacts" of the proposed dredging that CBEMP Policy 4 requires, and LUBA should rely on the DEA analysis to conclude that CBEMP Policy 4 is met.

The "clearly supports" standard of review at ORS 197.835(11)(b) allows LUBA to overlook nonexistent or inadequate findings only if compliance with the applicable approval standard is "obvious" or "inevitable." *Marcott Holdings v. City of Tigard*, 30 Or LUBA 101 (1995). CBEMP Policy 4 requires the county to exercise considerable subjective judgment, including identifying "the public's need and gain," and determining whether that need or gain warrants modification or loss to the estuarine system, and to ensure that impacts of the proposed alteration are minimized or mitigated. ORS 197.835(11)(b) does not authorize LUBA to affirm decisions based on LUBA's evaluation of evidence under standards such as CBEMP Policy 4, which require the exercise of significant subjective judgment. Accordingly, we agree with Oregon Shores that remand is necessary for the county to adopt findings addressing compliance with CBEMP Policy 4 and 4a.

The third assignment of error (Oregon Shores) is sustained.

FOURTH ASSIGNMENT OF ERROR (OREGON SHORES)

Proposed development in coastal shorelands, in the 6-WD (Water-Dependent Development Shorelands) and 7-D (Development Shorelands) zones, is subject to compliance with CBEMP Policy 30, which requires in relevant part that the county justify development in these areas "only upon the establishment of findings that shall include at least * * * [m]ethods for protecting the surrounding area from any adverse effects of the development[.]" CBEMP Policy 30(I)(c).[14] This language implements Statewide Planning Goal 18 (Beaches and Dunes), Implementation Requirement 1(c) (Goal 18 IR1(c)).

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[14] CBEMP Policy 30(I) provides:

> "Coos County shall permit development within areas designated as 'Beach and Dune Areas with Limited Development Suitability' on the Coos Bay Estuary Special Considerations Map only upon the establishment of findings that shall include at least:
>
> "a. The type of use proposed and the adverse effects it might have on the site and adjacent areas;
>
> "b. Temporary and permanent stabilization programs and the planned maintenance of new and existing vegetation;
>
> "c. Methods for protecting the surrounding area from any adverse effects of the development; and
>
> "d. Hazards to life, public and private property, and the natural environment which may be caused by the proposed use; and

JCEP's consultant prepared a site investigation report addressing CBEMP Policy 30(I), which identified "erosion and migration of disturbed dune sands from the site" as an adverse effect of development for purposes of CBEMP Policy 30(I)(c). To identify "methods for protecting" the surrounding beach and dune areas from those adverse impacts, the report relied on "State DEQ and FERC permits that require mitigation of erosion, re-vegetation, and monitoring of permanent stabilization measures." Record 9801.

Oregon Shores argues that the report fails to identify methods for "protecting" surrounding beaches and dunes from the identified adverse impacts. According to Oregon Shores, the term "protect[]" as used in CBEMP Policy 30(I)(c) and Goal 18 IR1(c) has the same meaning as the term "protect" as defined in the statewide planning goals, *i.e.,* "[s]ave or shield from loss, destruction, or injury for future intended use." Oregon Shores notes that LUBA has interpreted the term "protect" as used in the context of Goal 16 to require measures that will reduce the adverse impacts of development to a *de minimis* or insignificant level. *Columbia Riverkeeper v. Clatsop County*, 61 Or LUBA 96, 111, *aff'd* 238 Or App 439, 464-65, 243 P3d 82 (2010). Oregon

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> "e. Whether drawdown of groundwater would lead to loss of stabilizing vegetation, loss of water quality, or intrusion of saltwater into water supplies.
>
> "Implementation shall occur through an administrative conditional use process which shall include submission of a site investigation report by the developer that addresses the five considerations above."

Shores contends that mitigation and monitoring do nothing to reduce impacts to a *de minimis* level.

JCEP responds that the report describes more than mitigation and monitoring, but also prescribes re-vegetation and stabilization measures to reduce erosion and migration of disturbed sand. Record 9800-01. Oregon Shores does not present any argument regarding why the proposed re-vegetation and stabilization of soils are insufficient to ensure compliance with CBEMP Policy 30(I)(c). Absent a more developed argument, we agree with JCEP that Oregon Shores fails to explain why re-vegetation and stabilization measures are insufficient to satisfy CBEMP Policy 30(I)(c).

Oregon Shores also argues that the county erred in dismissing concerns raised by Oregon Shores and the State of Oregon regarding potential subsidence from dewatering activities during construction of the tank/slip facilities within the 6-WD zone. Record 7751, 8178. The county concluded that subsidence or site stability due to dewatering is not an issue that is within the scope of the only provision of the policy that explicitly addresses impacts on groundwater, CBEMP Policy 30(I)(e). *See* n 14; record 135. Oregon Shores argues, however, that subsidence due to dewatering is a potential issue under CBEMP Policy 30(I)(c), because it could constitute an "adverse effect[] of the development" on the surrounding area within the meaning of subsection (c).

JCEP responds that the county adopted an alternative finding that the proposed groundwater dewatering is "within historic levels that did not lead to the loss of stabilizing vegetation," and that Oregon Shores failed to challenge that alternative finding. Record 135. However, the quoted finding addresses "loss of stabilizing vegetation," which is an issue addressed under CBEMP Policy 30(I)(e). *See* n 14. Oregon Shores' argument is based on the language of CBEMP Policy 30(I)(c). If there are findings concluding that subsidence from proposed dewatering is not a potential issue under CBEMP Policy 30(I)(c), JCEP does not cite them. We conclude that remand is necessary to address whether subsidence is a potential issue under CBEMP Policy 30(I)(c) and, if so, adopt findings resolving that issue.

Finally, Oregon Shores argues that the finding of compliance with CBEMP Policy 30(I)(c) relies on the applicant obtaining FERC permits, but notes that FERC has denied JCEP the permits for the proposed LNG terminal. This issue is raised under the sixth assignment of error, and we address it there.

The fourth assignment of error is sustained in part.

FIFTH ASSIGNMENT OF ERROR (OREGON SHORES)

The county approved placing fill in the 7-D (Development Shorelands) zone, which is subject to "special conditions" at Coos County Land Development Ordinance (LDO) 3.2.286. Special Condition 5 states that "[t]he wetland in the southeast portion of this district can be filled for a development project contingent upon satisfaction of the prescribed mitigation described in

Shoreland District #5." The county's finding of compliance with Special Condition 5 states:

> "The Board finds that the application proposes fill in the southeast portion of this district for a development project and will mitigate in accordance with all prescribed mitigation. Therefore, the Board finds that the proposed fill is consistent with Special Condition 5." Record 70.

Oregon Shores argues that the foregoing finding is inadequate and not supported by substantial evidence, because the county failed to identify the proposed mitigation, or explain how the proposed mitigation satisfies the "prescribed mitigation described in Shoreland District #5."

JCEP does not dispute that the above-quoted finding is inadequate, but argues that no party raised any issue under Special Condition 5 during the proceedings below, and thus no party can challenge on appeal whether the county's finding of compliance with Special Condition 5 is adequate, pursuant to ORS 197.763(1).

Oregon Shores replies that a participant submitted testimony below that at one point quotes Special Condition 5 and at another point raises objections to proposed mitigation at the West Jordan Cove Mitigation Site, which is apparently where the application proposed to conduct mitigation. Record 5984. While that testimony does not advance any specific issues under Special Condition 5, it is sufficient to allow Oregon Shores to challenge the adequacy of the county's findings addressing Special Condition 5. *Lucier v. City of Medford*, 26 Or LUBA 213, 216 (1993).

On the merits, we agree with Oregon Shores that the county's only finding of compliance with Special Condition 5 is conclusory and inadequate. The findings do not identify the proposed mitigation for fill in the wetland in the southeast portion of the 7-D district, or relate it in any way to "the prescribed mitigation described in Shoreland District #5." Remand is necessary for the county to adopt more adequate findings on this point.

The fifth assignment of error (Oregon Shores) is sustained.

SIXTH ASSIGNMENT OF ERROR (OREGON SHORES)

Oregon Shores argues that the county found compliance with CBEMP Policies 5, 8 and 30 based in part on the condition that JCEP obtain and comply with state and federal permits, including FERC permits.[15] However, Oregon Shores cites testimony that on March 11, 2016, during the proceedings before the hearings officer, FERC denied JCEP's application for a permit for the proposed LNG terminal. Because the required FERC permits have been denied, Oregon Shores argues, the county erred in relying on FERC permits to demonstrate compliance with applicable approval criteria. *See Bouman v. Jackson County*, 23 Or LUBA 626, 647 (1992) (where a local government

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[15] Oregon Shores advances a similar challenge to the county's findings of compliance with CBEMP Policy 17. However, in response to intervenor's waiver challenge Oregon Shores concedes that no issues were raised below under CBEMP Policy 17. Intervenor also argues that no issues were raised below under CBEMP Policy 30, but in its reply brief Oregon Shores cites to locations in the record where issues of compliance with Policy 30 were raised.

relies on the applicant obtaining state agency permits, the record must include substantial evidence that the applicant is not precluded as a matter of law from obtaining the state agency permits).

JCEP responds that at the time of the county's decision JCEP's request for FERC to reconsider its denial was still pending, and thus the record at that time included substantial evidence that JCEP was not precluded as a matter of law from obtaining the required FERC permits. JCEP acknowledges that FERC later denied its request for reconsideration, but argues the decision denying reconsideration post-dates the county's decision and thus is not in the evidentiary record (although LUBA has taken official notice of the decision denying reconsideration). JCEP also notes that LUBA has taken official notice of the fact that JCEP has initiated a pre-filing with FERC, which is a necessary step to filing a new application for a FERC permit. Thus, JCEP argues that even if LUBA looks beyond the evidentiary record there is no reason to conclude that JCEP is precluded, as a matter of law, from obtaining FERC permits for the LNG terminal.

The county's findings observe that "[i]f it stands" FERC's March 11, 2016 permit denial decision "may very well kill the entire project, at least for the time being." Record 83. The findings note, however, that the primary basis for denial (lack of LNG contracts) could potentially be remedied, and further noted that JCEP had appealed the March 11, 2016 denial. *Id.* However, the findings do not appear to address whether or not the March 11, 2016 denial means that JCEP is precluded, as a matter of law, from obtaining FERC permits for the LNG terminal. As noted, with respect to several policies the findings expressly rely on JCEP obtaining FERC permits in order to satisfy applicable county criteria. In our view, given that the required FERC permit had, in fact, been denied during the proceeding before the county, the county erred in adopting findings of compliance with local approval standards that are unconditionally predicated on the applicant obtaining a FERC permit, without first addressing whether the denial means that JCEP is precluded, as a matter of law, from obtaining the FERC permit. Remand is necessary for the county to consider that question, and on remand the county may consider the FERC decisions or applications that post-date the county's decision in this appeal.

The sixth assignment of error (Oregon Shores) is sustained.

SEVENTH ASSIGNMENT OF ERROR (OREGON SHORES)

JCEP proposes to construct the Southwest Oregon Regional Safety Center (SORSC) on a parcel zoned for industrial and water-dependent uses.[16] The SORSC is a large "multiorganizational office complex" on eight acres that includes a fire station as one component. Record 143-44. A fire station is a permitted use in the industrial zone. Record 143. The proposed fire station would have a daily staff of four persons. Record 9826. The SORSC also

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[16] Apparently, the SORSC facility is intended to meet the requirements of a 2014 Memorandum of Understanding entered into between intervenor and the State of Oregon.

includes a number of other components, including (1) offices for the Coos County sheriff, Coast Guard, and Port of Coos Bay, (2) a security center, (3) a personal safety access point (apparently a type of emergency call center), and (4) a training center for the sheriff and Southwestern Oregon Community College. Record 144. These uses would have a daily staff of approximately 12 persons. The training center includes classrooms to train up to 100 persons. Record 9826. All the latter components of the SORSC are not allowed uses in the industrial zone. However, the county approved them as "accessory uses" to the fire station.

According to the county's decision, LDO 2.1.200 defines "accessory uses" as uses that (1) are subordinate to and serve a principal use; (2) subordinate in area or purpose to that principal use; (3) contribute to the comfort, convenience, or necessity of occupants of the principal use; and (4) are located on the same unit of land as the principal use. Record 144.[17] The

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[17] The version of the LDO 2.1.200 definition of "accessory use" available on the county's website is different than the version paraphrased in the decision, perhaps reflecting an inaccurate paraphrase, or more recent amendments. The website version states:

> "ACCESSORY USE: A use, building or structure that is (1) customarily incidental and subordinate to the principal use, main building or structure, and (2) subordinate in extent, area and purpose to the principal use. A use that constitutes, in effect, conversion to a use not permitted in the district is not an accessory use."

county rejected arguments that the various SORSC components are not "subordinate" to the fire station:

> "The SORSC serves, and is subordinate in purpose to, the Fire Station because the SORSC is a training center for firefighters who will work at the Fire Station. The SORSC contributes to the comfort and convenience of the firemen who utilize the Fire Station because the SORSC offers training to current and future firefighters. * * *
>
> "* * * * *
>
> "* * * Although the SORSC will house government offices for the Coos County Sheriff, the Coast Guard, and the Port, these 'offices' are permitted in conjunction with a permitted or conditionally permitted use. [LDO] 4.4.200(26). In this regard, this is no different than a fast food restaurant that has a manager's office—the office is not a separate land use from a restaurant but is rather an inherent part of the restaurant. In this case, the offices will occur in conjunction with the Fire Station, which is a permitted use under [LDO 4.4.200(20). * * *" Record 144.

Oregon Shores argues that the county's finding that the SORSC is "subordinate" to the fire station misconstrues the applicable law and is not supported by substantial evidence. According to Oregon Shores, no reasonable person could conclude that the various government office and educational components that make up the bulk of the SORSC, including a regional training facility for up to 100 persons, are "subordinate" to a local fire station staffed by four firefighters.

JCEP responds that the county's interpretation of the code term "accessory use" is not inconsistent with the express language of that term, as defined, and must be affirmed under the deferential standard of review that

LUBA must apply to a governing body's code interpretations, under ORS 197.829(1) and *Siporen*, 349 Or at 259.[18] JCEP argues that the county viewed the SORSC office components to be an enhancement to the fire station, finding that "offices for public safety and security entities * * * will have a role in responding to fire and other natural events as service providers." Record 144. With respect to the training center, JCEP does not dispute that it will function as a training center for fire fighters and other emergency responders from around the region, not limited to training staff at the fire station, but argues that

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[18] ORS 197.829 provides:

> "1. [LUBA] shall affirm a local government's interpretation of its comprehensive plan and land use regulations, unless the board determines that the local government's interpretation:
>
> "(a) Is inconsistent with the express language of the comprehensive plan or land use regulation;
>
> "(b) Is inconsistent with the purpose for the comprehensive plan or land use regulation;
>
> "(c) Is inconsistent with the underlying policy that provides the basis for the comprehensive plan or land use regulation; or
>
> "(d) Is contrary to a state statute, land use goal or rule that the comprehensive plan provision or land use regulation implements.
>
> "2. If a local government fails to interpret a provision of its comprehensive plan or land use regulations, or if such interpretation is inadequate for review, [LUBA] may make its own determination of whether the local government decision is correct."

the LDC definition of "Accessory Uses" does not require that an accessory use serve *only* the principal use.

The county's "interpretation" is conclusory, and largely inadequate for review. The findings do not attempt to explain the meaning of "subordinate" and the other key terms in the LDO 2.1.200 definition of "accessory use," and the rationales offered for the county's conclusion are strained at best. The findings analogize the proposed government offices (sheriff, port, coast guard) to the offices for a primary business use, providing the example of an office for a restaurant. The flaw in that analogy is that the proposed government offices are not "offices" for the fire station. It may be true that staff in the government offices will occasionally provide support for the fire station, during an emergency, for example. But that is not the *function* of those government offices; any support the offices might provide to the fire station in an emergency would be, at best, ancillary to the offices' main function. Even if, as JCEP argues, the LDO 2.1.200 definition of "accessory use" does not limit an accessory use to serving *only* the primary use, it is difficult to understand how a use can be viewed as "accessory" to the primary use when any support or service it provides to the primary use is ancillary, and the purported "accessory" use has a main function that has nothing to do with the primary use.

Similarly, with respect to the regional training center, the fact that the four firefighters staffing the fire station may take classes at the 100-seat training center does little to demonstrate that the training center is "subordinate" to the fire station, under any conceivable interpretation of that term. LDO 2.1.200 requires that the accessory use be "subordinate in area or purpose to that principal use[.]" However, the findings do not discuss whether any of the SORSC components are subordinate in "area" or "purpose" to the fire station. The findings do not describe how much area is occupied by the fire station, versus the area occupied by other SORSC components, or discuss the purpose of those components, and to what extent those components "serve" the fire station, as opposed to serving other purposes.[19]

Because the findings are conclusory and do not address key language and considerations in the code definition of "accessory use," it is hard to say whether the county's conclusion that the SORSC components are accessory to the fire station embodies an interpretation of LDO 2.1.200 that is inadequate for review, or an interpretation that is simply implausible, *i.e.,* inconsistent with the express language, purpose and policy underlying LDO 2.1.200. To the extent the county's decision interprets LDO 2.1.200 to the effect that a use is "subordinate" to a primary use as long as it provides some support to the primary use, regardless of how minimal and tangential that support is compared

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[19] As far as we can tell, the findings do not discuss the proposed security center, or the personal safety access point (which we understand to be a type of emergency call center). It is possible that these uses are allowed in the industrial zone under the category of "emergency services," a permitted use that includes the proposed fire station. LDO 4.4.210(4). However, without findings about the nature of these uses, it is hard to tell.

to the putative accessory use's purpose and function, we reject the interpretation as implausible.

We do not intend to foreclose the possibility that the board of commissioners can adopt an interpretation of LDO 2.1.200 that is sustainable under the deferential standard of review we apply under ORS 197.829(1)(a), supporting a conclusion that some or all of the SORSC components are "accessory" to the fire station, as defined at LDO 2.1.200. However, the present decision includes no such interpretation. Further, any sustainable interpretation of LDO 2.1.200 must give effect to all of its applicable terms. The findings do not include an interpretation, at least one adequate for review, explaining why the proposed SORSC components are subordinate to and serve a principal use, and subordinate in area or purpose to that principal use. Or, in the words of the version of LDO 2.1.200 on the county's website, whether the SORSC uses are "customarily incidental and subordinate to the principal use," and "subordinate in extent, area and purpose to the principal use." *See* n 17. Because it may be possible on remand for the county to adopt a more sustainable interpretation under which at least some components of the SORSC can be viewed as subordinate to the fire station use, we conclude that it is appropriate to remand this issue to the county for further proceedings.

The seventh assignment of error (Oregon Shores) is sustained.

FIRST ASSIGNMENT OF ERROR (McCAFFREE)

Intervenor-petitioner Jody McCaffree (McCaffree) argues that (1) the county commission chair, Sweet, was biased in favor of the proposed LNG terminal and (2) the county commissioners failed to declare *ex parte* communications.

A. Bias

McCaffree alleges that Chair Sweet was biased in favor of the proposed LNG terminal. According to McCaffree, on April 22, 2016, Chair Sweet sent a letter, on county letterhead, to FERC expressing support for the Jordan Cove LNG terminal and Pacific Connector Pipeline Project applications then pending before FERC. Supplemental Record 527. In addition, McCaffree quotes Chair Sweet as making public statements in support of the Jordan Cove project. *Id.* at 529-30. McCaffree contends that the letter and statements demonstrate that Chair Sweet was incapable of deciding the land use application pending before the county with the requisite impartiality.

In order to succeed in a bias claim, the petitioner must first establish that the evidence of bias offered by petitioner relates to the "matter" before the tribunal. *Columbia Riverkeeper v. Clatsop County*, 267 Or App 578, 608-10, 341 P3d 790 (2014). The "matter" is "precisely and narrowly defined," as the individual land use decision that the county board of commissioners considered and decided in the local proceeding. *Id.* at 608.

Second, in order to disqualify a decision-maker from participating, a party must meet the "high bar for disqualification," demonstrating that "actual bias" has occurred, not simply an "appearance of bias." *Columbia Riverkeeper*, 267 Or App at 610; *cf. Friends of Jacksonville v. City of Jacksonville*, 42 Or LUBA 137 (2002) (finding actual disqualifying bias occurred when a city council member stated during his election campaign that he could not be objective in reviewing a pending application were he to be elected).

Finally, to demonstrate actual bias, the petitioner must establish that "the decision maker has so prejudged the particular matter as to be incapable of determining its merits on the basis of the evidence and arguments presented." *Columbia Riverkeeper*, 267 Or App at 602. To demonstrate actual bias, petitioner must identify "explicit statements, pledges, or commitments that the elected local official has prejudged the specific matter before the tribunal." *Id.* at 609-10.

We disagree with McCaffree that Chair Sweet's April 11, 2016 letter, or his public statements, demonstrate that Chair Sweet was incapable of determining the merits of the land use application based on the evidence and arguments presented. As the Court of Appeals recently explained in *Columbia Riverkeeper*, 267 Or App at 599:

> "A judge is expected to be detached, independent and nonpolitical. A county commissioner, on the other hand, is expected to be intensely involved in the affairs of the community. He is elected because of his political predisposition, not despite it, and he is expected to act with awareness of the needs of all elements of the

> county, including all government agencies charged with doing the business of the people.
>
> "* * * * *
>
> "The goal of [the *Fasano v. Washington County Commission*, 264 Or 574, 588, 507 P2d 23 (1973) impartiality requirements] is that land-use decisions should be made fairly. * * * *Fasano* cannot be applied so literally that the decision-making system is aborted because an official charged with the public duty of adjudication fears that his motivation might possibly be suspect." (Internal citations and quotation marks omitted).

As far as McCaffree has established, Chair Sweet's statements of support of the LNG terminal represent no more than the general appreciation of the benefits of local economic development that is common among local government elected officials. Those statements fall far short of demonstrating that Chair Sweet was not able to make a decision on the land use application based on the evidence and arguments of the parties.

B. *Ex Parte* Communications

McCaffree also argues that the commission erred by failing to disclose the contents of Chair Sweet's April 11, 2016 letter to FERC during the proceedings below, and by failing to disclose that Chair Sweet attended a luncheon in 2014 at which JCEP's representative offered a presentation about the proposed LNG terminal. Another commissioner, Main, also attended the luncheon, and disclosed that he had attended the luncheon and heard the presentation, which he characterized as general in nature.

ORS 215.422(3) provides:

> "No decision or action of a planning commission or county governing body shall be invalid due to ex parte contact or bias resulting from ex parte contact with a member of the decision-making body, if the member of the decision-making body receiving the contact:
>
> "(a) Places on the record the substance of any written or oral ex parte communications concerning the decision or action; and
>
> "(b) Has a public announcement of the content of the communication and of the parties' right to rebut the substance of the communication made at the first hearing following the communication where action will be considered or taken on the subject to which the communication related."

In response, JCEP argues, and we agree, that the letter from Chair Sweet to FERC does not qualify as *ex parte* contact for two reasons. First, the letter from Chair Sweet to FERC is not "*ex parte* contact" because it does not "concern[] the decision or action" made by the county commission as required by ORS 215.422(3)(a), but rather it concerns a separate decision or action by FERC. Second, the letter from Chair Sweet does not qualify as an "*ex parte* contact" because the letter was *from* Chair Sweet *to* FERC. As the text of ORS 215.422(3) indicates, the statute only governs required disclosures when the decision-maker "receiv[es] the contact." As a result, no disclosure of the April 11, 2016 letter was required pursuant to the statute.

With respect to Chair Sweet's attendance at a 2014 luncheon presentation by JCEP on the LNG project, intervenor does not dispute that Sweet failed to disclose the content of the presentation, which the other attending commissioner, Main, treated as an *ex parte* communication. It may be that the presentation does not qualify as an *ex parte* communication, or if so that Main's disclosure was sufficient for both commissioners. However, because the county's decision must be remanded for other reasons, it is appropriate to remand also to allow Chair Sweet to disclose the substance of any *ex parte* communications that occurred at the presentation.

The first assignment of error (McCaffree) is sustained, in part.

SECOND ASSIGNMENT OF ERROR (McCAFFREE)

In her second assignment of error, McCaffree argues that in the proceedings below, the county hearings officer misapplied applicable law and prejudiced McCaffree's rights due to bias against unrepresented parties. Citing to various statements by the hearings officer, McCaffree argues that the statements demonstrate a bias in favor of testimony coming from attorneys for the project applicant, over testimony from unrepresented project opponents. According to McCaffree, the hearings officer's bias against unrepresented opponents violated Statewide Planning Goal 1 (Citizen Involvement).

JCEP responds that McCaffree failed to preserve the issue by objecting before the local decision-maker. Even if the issue is preserved, JCEP argues that McCaffree has failed to demonstrate that the hearings officer was biased, or that any bias prejudiced McCaffree's procedural rights. Further, JCEP argues that McCaffree has failed to establish that any error committed by the hearings officer tainted the county commission's consideration and final decision. Finally, JCEP argues that Goal 1 is not directly applicable to the proposed permit applications.

It is not clear to us that a decision-maker's bias is properly viewed as a *procedural* error, even if evidence of the alleged bias stems from comments made by the decision-maker during a hearing. McCaffree does not identify any *procedure* that the hearings officer failed to follow. In any case, as we understand, some of the unrepresented parties below objected to the hearings officer's apparent preference for argument from represented parties.[20] To the extent preservation principles require lodging an objection to the alleged bias of the hearings officer against unrepresented parties, an objection was made.

On the merits, we have no trouble agreeing with McCaffree that the hearings officer's comments regarding the testimony were unnecessary and unfortunate. Nonetheless, we do not believe that those comments are sufficient to demonstrate that the hearings officer was biased in the sense that the hearings officer was unable to make a decision based on the arguments and evidence presented. Moreover, even if we concluded that the hearings officer was biased, JCEP is correct that the hearings officer was not the final county decision-maker. McCaffree offers no argument as to why the hearings officer's alleged bias tainted the proceedings before, or the decision of, the board of

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[20] After the hearings officer expressed a preference for hearing testimony from represented parties, one participant stated: "I'm not going to waste my time [testifying before the hearings officer]. I am not an attorney and you ain't going to listen to me anyway[.]" McCaffree Petition for Review 18.

commissioners, the final decision-maker. Accordingly, McCaffree's arguments under this assignment of error do not provide a basis for reversal or remand.

The second assignment of error (McCaffree) is denied.

THIRD ASSIGNMENT OF ERROR (McCAFFREE)

In her third assignment of error, McCaffree argues that the findings adopted by the county commissioners demonstrate bias in favor of the application, because the findings generally cite and rely on evidence submitted by proponents, and ignore or erroneously discredit opposing evidence.

As an example, McCaffree argues that the county chose to rely on a report from one of JCEP's experts (Sullivan) regarding sedimentation from dredging, notwithstanding that Sullivan is a landscape architect and not an engineer, while rejecting the opponent's expert testimony (Ravens) from a licensed engineer. The Ravens testimony had been submitted in an earlier proceeding related to the LNG pipeline, but the county chose not to rely upon it in that proceeding. McCaffree submitted the Ravens testimony again in this present proceeding on the LNG terminal. According to McCaffree, the county's rejection of the Ravens testimony and reliance on a report filed by a landscape architect indicates that county decision-makers were biased in favor of the applicant.

JCEP responds that the Sullivan report was prepared by multiple authors including an environmental specialist, and a biologist. Record 1907-08. Further, JCEP argues that, while the county chided McCaffree for mischaracterizing the testimony of the opponents' engineer regarding sedimentation, the county in fact accepted and considered that testimony, and did not reject it.[21] JCEP argues that simply because the commissioners did not find the Ravens testimony persuasive does not mean that the commissioners were biased or that the Ravens testimony does not constitute substantial evidence.

Although couched as an argument regarding "bias," McCaffree's arguments can be more accurately described as a substantial evidence challenge. JCEP argues, and we agree, that McCaffree's arguments regarding how the county weighed the evidence regarding sedimentation does not demonstrate that the county was "biased" in favor of the application or, more accurately, that the county's findings regarding sedimentation are not supported by substantial evidence.

The third assignment of error (McCaffree) is denied.

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[21] The county's findings state, in relevant part:

> "On page 23 of her letter dated January 12, 2016, Ms. McCaffree cites to previously submitted testimony from Dr. Tom Ravens, and states that '[o]ur sedimentation expert actually proved [Pacific Connector] to be wrong on this issue * * *.' <u>This statement is demonstrably false</u>. In fact, the hearings officer [in a different decision] previously rejected Dr. Ravens' analysis. *See* Hearings Officer Recommendation HBCU 10-01 (Remand) at pp. 40-57, which is incorporated herein by reference." Record 107 (emphasis added).

ASSIGNMENT OF ERROR (THE TRIBES)

Intervenor-petitioner The Confederated Tribes of the Coos, Lower Umpqua & Siuslaw Indians (the Tribes) advance four sub-assignments of error, each essentially arguing that the county failed to properly apply CBEMP Policy 18, Protection of Historical, Cultural and Archaeological Sites.

CBEMP Policy 18 provides in relevant part that a development proposal involving a cultural, archeological or historical site shall include a site plan application showing all areas proposed for excavation, clearing, and construction, and submit that site plan to the Tribes for a 30-day review period.[22] The county must then conduct a review of the site plan and approve

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[22] CBEMP Policy 18 provides, in relevant part:

> "Local government shall provide protection to historical, cultural and archaeological sites and shall continue to refrain from widespread dissemination of site specific information about identified archaeological sites.
>
> "I. This strategy shall be implemented by requiring review of all development proposals involving a cultural, archaeological, or historical site to determine whether the project as proposed would protect the cultural, archaeological, and historical values of the site.
>
> "II. The development proposal, when submitted, shall include a Site Plan Application, showing, at a minimum, all areas proposed for excavation, clearing, and construction. Within three (3) working days of receipt of the development proposal, the local government shall notify [the Tribes] in writing, together with a copy of the Site Plan Application. [The Tribes] shall have the right to submit a written

or deny based in part on whether the Tribes and the applicant have agreed on "appropriate measures" to protect cultural, archeological or historical resources.[23]

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statement to the local government within thirty (30) days of receipt of such notification, stating whether the project as proposed would protect the cultural, historical, and archaeological values of the site or, if not, whether the project could be modified by appropriate measures to protect those values. [giving examples of appropriate measures]."

[23] CBEMP Policy 18 continues:

"III. Upon receipt of the statement by [the Tribes], or upon expiration of [the Tribes'] thirty day response period, the local government shall conduct an administrative review of the Site Plan Application and shall:

"a. Approve the development proposal if no adverse impacts have been identified, as long as consistent with other portions of this plan, or

"b. Approve the development proposal subject to appropriate measures agreed upon by the landowner and [the Tribes], as well as any additional measures deemed necessary by the local government to protect the cultural, historical, and archaeological values of the site. If the property owner and [the Tribes] cannot agree on the appropriate measures, then the governing body shall hold a quasi-judicial hearing to resolve the dispute. The hearing shall be a public hearing at which the governing body shall determine by preponderance of evidence whether the development project may be allowed to proceed, subject to any modifications deemed necessary by the governing body to protect the cultural, historical, and archaeological values of the site."

Initially, the county failed to provide notice and a 30-day comment period to the Tribes as required by CBEMP Policy 18(II). On December 18, 2015, the Tribes submitted an initial set of testimony that included information on archeological sites in the area, and noting that the Tribes had earlier designated the entirety of Jordan Cove as a site of archeological significance. The Tribes also took the position that the project would not protect the cultural and archeological values of the site, and objected that the applicant had not provided the site plan as required by CBEMP Policy18(II), which limited the Tribes' ability to provide focused objections. The county corrected its notice error and gave the Tribe 30 days to submit additional testimony, and the Tribes submitted a second set of testimony on January 12, 2016. However, the county did not initiate the administrative review process set out in CBEMP Policy 18(III), but instead apparently chose to consider the Tribes' testimony within the ongoing conditional use permit proceeding.

As noted, the county hearings officer held the only public hearing on December 18, 2015, and issued his recommendations on May 4, 2016. In his findings, later adopted by the commissioners, the hearings officer expressed skepticism about the Tribes' claim that the entirety of Jordan Cove has been designated as an archeological site, and criticized the Tribes for failing to provide site-specific objections and for failing to take a clear position on whether the proposal would protect the cultural, historical, and archaeological values of the site. With respect to the site plan required by CBEMP Policy

18(II), the hearings officer speculated that a plot plan found in the application was intended to be that site plan. Ultimately, however, the hearings officer made no findings of compliance with CBEMP Policy 18, but instead accepted JCEP's request to impose a condition of conditional use permit approval, deferring entirely consideration of CBEMP Policy 18 to a subsequent proceeding.[24] Accordingly, the county imposed Condition E.1., which provides, in its entirety:

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[24] Intervenor requested the following condition of approval:

> "Upon receipt of the statement from the Tribe(s) under CBEMP Policy 18.II, the County shall take one of the following actions: (1) if no adverse impacts to cultural, historical or archeological resources on the site have been identified, the County shall find that the Applications are consistent with CBEMP Policy 18; (2) if the Tribe(s) and the applicant reach agreement regarding the measures needed to protect the identified resources, the County shall find that the Applications are consistent with CBEMP Policy 18, subject to any additional measures the County believes are necessary to protect those resources; or (3) if the County finds that there will be adverse impacts to identified CBEMP Policy 18 resources on the site and the applicant and the Tribe(s) have not reached agreement regarding protection of such resources, then the Board of County Commissioners shall hold a quasi-judicial hearing to resolve the dispute. The hearing shall be a public hearing at which the governing body shall determine by [a] preponderance of the evidence whether the development project may be allowed to proceed, subject to any modifications deemed necessary by the governing body to protect the cultural, historical, and archeological values of the site. For purposes of this condition, the public hearing shall be subject to the provisions of [LDO 5.7.300] with the Board of Commissioners serving as the

> "The Board shall hold a quasi-judicial hearing to determine compliance with CBEMP Policy 18. The hearing shall be a public hearing at which the governing body shall determine by preponderance of the evidence whether the development project may be allowed to proceed, subject to any modifications deemed necessary by the governing body to protect the cultural, historical, and archaeological values of the site. For purposes of this condition, the public hearing shall be subject to the provisions of section 5.7.300 of the CCZLDO with the Board of Commissioners serving as the Hearings Body. The Board's decision in that matter shall constitute the Board's decision regarding the Applications' consistency with CBEMP Policy 18." Record 216.

A. Subassignments of Error A, C, and D

In these subassignments of error, the Tribes allege the county erred by deferring its CBEMP Policy 18 project review obligations by: (1) refusing to recognize and consider the Tribe's testimony regarding identified archaeological sites and districts within the project area and significant adverse impacts from the project; (2) approving the LNG Terminal without requiring the applicant to submit the site plan required by CBEMP Policy 18(II); and (3) deferring CBEMP Policy 18 determinations for an undetermined amount of time.

Hearings Body. The Board's decision in that matter shall constitute the Board's decision regarding the Applications' consistency with CBEMP Policy 18." Record 126.

1. **Deferral**

Because subassignments of error A, C, and D rest upon the petitioners' challenge to the county's decision to defer its CBEMP Policy 18 obligations, we begin with that issue.

The Tribes contend that, as a matter of law, the county cannot defer the procedures and determination of compliance with CBEMP Policy 18. To the extent deferral of compliance with CBEMP Policy 18 is permissible in some cases, the Tribes argue that it is not permissible in the present case.

In response, JCEP cites *Rhyne v. Multnomah County*, 23 Or LUBA 442, 447-48 (1992), for the proposition that local governments are permitted to defer a determination of compliance with a permit approval standard until a second stage in the approval process, as long as the second stage approval process provides the same notice and hearing as the initial stage:

> "Where the evidence presented during the first stage approval proceedings raises questions concerning whether a particular approval criterion is satisfied, a local government essentially has three options potentially available. First, it may find that although the evidence is conflicting, the evidence nevertheless is sufficient to support a finding that the standard is satisfied or that feasible solutions to identified problems exist, and impose conditions if necessary. Second, if the local government determines there is insufficient evidence to determine the feasibility of compliance with the standard, it could on that basis deny the application. Third, if the local government determines that there is insufficient evidence to determine the feasibility of compliance with the standard, instead of finding the standard is not met, it may defer a determination concerning compliance with the standard to the second stage. In selecting this third option, the local government is not finding all applicable approval standards are complied with,

> or that it is feasible to do so, as part of the first stage approval (as it does under the first option described above). Therefore, the local government must assure that the second stage approval process to which the decision is making is deferred provides the statutorily required notice and hearing, even though the local code may not require such notice and hearing for second stage decisions in other circumstances. *Holland v. Lane County*, 16 Or LUBA 583, 596-97 (1998)." *Id.* (Footnotes omitted).

There are several problems with JCEP's reliance on *Rhyne*. First, *Rhyne* contemplates a multi-stage approval process, where consideration of criteria that apply at the first stage can be safely deferred to the second stage, if the requisite determinations and assurances are made, because no development is possible until the final, second stage approval is obtained. However, the permit applications in the present case do not involve a multi-stage approval process. The county has, in effect, created an *ad hoc* multi-stage conditional use permit approval process, where compliance with most standards are finally determined in the first stage, leaving only compliance with one standard (CBEMP Policy 18) to be resolved at a second stage solely devoted to that purpose. That *ad hoc* approach might be permissible in some cases, with respect to some kinds of approval standards, but it requires basic assurances that Condition E.1 lacks.

Notably, nothing in Condition E.1 requires that the second stage approval be obtained prior to development, or indeed provides any assurances that there will be a second stage approval process at all. Condition E.1 is silent regarding the timing and initiation of the second stage. JCEP's request suggested that the second stage process would be initiated only when the

Tribes submitted the statement described in CBEMP Policy 18(II). *See* n 23 ("Upon receipt of the statement from the Tribe(s) * * *."). But that is not consistent with CBEMP Policy 18, which contemplates that the CBEMP Policy 18 process is initiated by the applicant filing the development application with the required site plan. The Tribes took the position that JCEP has not yet submitted the required site plan to the county, and that its efforts to provide a response to the application were hampered by the lack of the site plan. In his findings, the hearings officer identified a "plot plan" that he believed was intended to represent the site plan required by CBEMP Policy 18(II), but that issue was never resolved. Absent an adequate condition of approval that specifies how and when the CBEMP Policy 18 review process will be initiated, there is no assurance that it will ever be initiated and completed prior to development.

In addition, as a predicate to the deferral option, *Rhyne* requires that the local government determine that there is insufficient evidence to determine compliance or the feasibility of compliance with the applicable standard. *See also Gould v. Deschutes County*, 227 Or App 601, 611-12, 206 P3d 1106 (2009) (to defer a finding of compliance with first stage approval criteria to a second stage approval process, the county must find that eventual compliance with the applicable approval standards is "feasible" in the sense that the county can rule out denial as the outcome required by the hearing record). The county made none of the determinations required by either *Rhyne* or *Gould*, but simply stated that intervenor's request to defer consideration of Policy 18 "seemed reasonable." Record 126.

More fundamentally, we question whether CBEMP Policy 18 is the kind of approval standard that can be deferred. CBEMP Policy 18 is more than an approval standard, it also invokes a particular process. That process is explicitly linked to the initial development application. *See* ns 22 and 23 (requiring the county to notify the Tribes within three days of receiving the application, and providing 30 days for the Tribes to respond). CBEMP Policy 18 clearly contemplates that resolution of issues raised by the Tribes, which may change the scope, scale and footprint of the development proposal considerably, or even cause it to be denied outright, will be completed before the development is approved.

Moreover, it is important to note that CBEMP Policy 18 requires coordination with and the resolution of disputes raised by a *sovereign* government. Under CBEMP Policy 18, the Tribes are not merely another participant in the proceedings. The Tribes are entitled under CBEMP Policy 18 to special notification and consideration of issues raised, as well as the power to compel the applicant into negotiations to resolve those issues, and to compel county resolution of unsuccessfully negotiated issues. That power is considerably vitiated if the applicant can first obtain county approval of the proposed development, and only then sit down with the Tribes to negotiate changes to the approved development. Given the inertia of an existing conditional use permit approval, the county is less likely in a deferred CBEMP Policy 18 proceeding to force the applicant to accept changes to a development proposal that the county has already considered and approved. It is even less likely in such a deferred proceeding that the county would take seriously arguments that the application cannot comply with CBEMP Policy 18 and must be (retroactively) denied.

The county's findings include no interpretation of CBEMP Policy 18 explaining why it believes compliance with the policy can be deferred to a second stage proceeding, other than deferral "seemed reasonable." Record 126. It is not clear to us if the question of whether compliance with CBEMP Policy 18 can be deferred to a second stage proceeding is a matter of local or state law. Even if it is purely a matter of local law, in the absence of an adequate local interpretation, for the reasons set out above we conclude under ORS 197.829(2) that the county erred in deferring compliance with CBEMP Policy 18 to a second stage proceeding.

B. Subassignment of Error B

In this subassignment of error, the Tribes argue the county erred to the extent it rejected the Tribes' claim that the entirety of Jordan Cove is a cultural and archeological site for purposes of CBEMP Policy 18. That claim is based in part on the fact that in 2015 the Tribes designated Jordan Cove as a "significant" archaeological site under ORS 358.905(1)(b)(B).[25]

JCEP responds that the skepticism expressed in the hearings officer's findings that the entirety of Jordan Cove is a cultural or archeological site for purposes of CBEMP Policy 18 was merely nonbinding *dicta*, which would have no preclusive effect on any future proceeding to consider compliance with CBEMP Policy 18. We agree with JCEP that the challenged findings are *dicta*, given that the county completely deferred consideration of compliance with the policy to a second stage proceeding. As explained above, that deferral was erroneous, and remand is necessary for the county to conduct the proceedings required by CBEMP Policy 18, before approving the conditional use permit application. On remand, questions regarding the location and scope of archeological sites affected by the development remain issues to be resolved.

The first assignment of error (The Tribes) is sustained, in part.

FIRST ASSIGNMENT OF ERROR (ROGUE INTERVENORS)

As noted, the application proposes development in areas designated as coastal shorelands under Statewide Planning Goal 17. OAR chapter 660, division 037 implements Goal 17 and the state policy to generally limit development of coastal shorelands to uses that are "water-dependent." The

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[25] ORS 358.905(1)(b)(B) provides that a "Site of archaeological significance" means "Any archaeological site that has been determined significant in writing by an Indian tribe."

Goals define "water-dependent" to mean "[a] use or activity which can be carried out only on, in, or adjacent to water areas because the use requires access to the water body for water-borne transportation, recreation, energy production, or source of water." Statewide Planning Goals, Definitions 8.

OAR 660-037-0040(6) provides additional definitions for purposes of the rule, which the county has implemented verbatim in LDO 2.1.200. In relevant part, OAR 660-037-0040(6)(C) defines "water-borne transportation" to mean uses of water access that fit into one of three subcategories, uses which are themselves transportation, uses which "require the receipt of shipment of goods by water," or uses which are themselves not water-borne transportation, but that are "necessary to support water-borne transportation," with the example provided of "terminal and transfer facilities."[26]

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[26] OAR 660-037-0040(6) provides, in relevant part:

"Water-Dependent Use.

"(a) The definition of 'water-dependent' contained in the Statewide Planning Goals (OAR chapter 660, division 015) applies. In addition, the following definitions apply:

"(A) 'Access' means physical contact with or use of the water.

"(B) 'Requires' means the use either by its intrinsic nature (e.g., fishing, navigation, boat moorage) or at the current level of technology cannot exist without water access.

The county concluded that the components of the LNG facility located on coastal shorelands are "water-dependent uses" as defined at LDO 2.1.200

> "(C) 'Water-borne transportation' means uses of water access:
>
> > "(i) Which are themselves transportation (e.g., navigation);
> >
> > "(ii) *Which require the receipt of shipment of goods by water*; or
> >
> > "(iii) Which are necessary to support water-borne transportation (e.g. moorage fueling, servicing of watercraft, ships, boats, etc.[, and] *terminal and transfer facilities*).
>
> "* * * * *
>
> "(b) Typical examples of water dependent uses include the following:
>
> > "(A) Industrial — e.g., manufacturing to include boat building and repair; water-borne transportation, *terminals, and support*; energy production which needs quantities of water to produce energy directly; water intake structures for facilities needing quantities of water for cooling, processing, or other integral functions.
>
> "* * * * *
>
> "(c) For purposes of this division, examples of uses that are not 'water dependent uses' include restaurants, hotels, motels, bed and breakfasts, residences, parking lots not associated with water-dependent uses, and boardwalks." (Emphasis added.)

and OAR 660-037-0040(6), because the facility involves "water-borne transportation" and is also a "terminal and support." Record 44.

On appeal, Rogue Intervenors argue that the county erred in concluding that the facility constitutes "water-borne transportation," to the extent it relied upon OAR 660-037-0040(6)(a)(C)(ii), for uses of water access "[w]hich require the receipt of shipment of goods by water[.]" Rogue Intervenors argue that "water-borne transportation" under subcategory (ii) is limited to uses related to the *import* of goods, and therefore does not include a facility dedicated to exporting LNG.

JCEP responds that Rogue Intervenors do not challenge the county's alternative conclusion that the facility is a "terminal," and therefore an express example of a water-dependent industrial use. JCEP is correct. OAR 660-037-0040(6)(a)(C)(ii) is one of three separate subcategories of uses of water access that concern "water-borne transportation." The third, OAR 660-037-0040(6)(a)(C)(iii), expressly includes "terminals and transfer facilities." *See also* OAR 660-037-0040(6)(b) (citing "terminals" as a typical example of an industrial water-dependent use). Even if the OAR 660-037-0040(6)(a)(C)(ii) subcategory is limited to import facilities, as Rogue Intervenors argue, there can be no possible dispute that a facility that loads goods onto cargo ships is a "terminal" for purposes of OAR 660-037-0040(6)(a)(C)(iii) and thus properly viewed as "water-borne transportation" for purposes of the definition of "water-dependent use."

The first assignment of error (Rogue Intervenors) is denied.

SECOND ASSIGNMENT OF ERROR (ROGUE INTERVENORS)

The proposed LNG facility includes a 20-acre gas-processing facility, located on an industrially zoned portion of the site. The gas-processing facility first refines natural gas arriving by pipeline to remove water and carbon dioxide.[27] The refined gas is then sent through a multi-stage liquefaction process to cool and liquefy the gas. Record 18. The resulting product, LNG, is stored at a temperature of -260 degrees in large storage tanks and eventually transferred to LNG tankers via a cryogenic line. When the LNG reaches its ultimate destination, it is unloaded and converted back into gaseous form.

The industrial zone allows the processing of mineral resources as an allowed use. LDO 2.1.200 defines "Mineral Resources—Processing" as "[t]he act of refining, perfecting, or converting a natural mineral into a useful

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[27] The county's decision describes the refinement process:

> "* * * Once natural gas is transferred to the Applicant through the metering station, the gas would go through a processing plant. The processing facility would consist of two feed gas pre-treatment trains, each containing two systems in the series: a CO2 removal process which utilizes a primary amine to absorb CO2, followed by a dehydration system which uses two solid absorbents to remove water and mercury from the feed gas. The gas processing units would remove substances that would freeze during the liquefaction process, namely CO2 and water. Mercury would also be removed to prevent corrosion to downstream equipment. Trace amounts of hydrogen sulfide (H2S) would be removed as well. * * *" Record 22.

product." In this assignment of error, Rogue Intervenors argue that the county misconstrued LDO 2.1.200 in concluding that the gas-processing facility processes a mineral resource. According to Rogue Intervenors, the gas-processing facility does not convert natural gas into a "useful product," but instead takes natural gas that is of household quality, and converts it for transportation purposes only into LNG, which is not itself a "useful product." Rogue Intervenors argue that, as a matter of law, transforming a useful product into a non-useful product for transportation does not fit within the definition of "Mineral Resources—Processing" at LDO 2.1.200.

The county board of commissioners rejected that argument below:

> "* * * In its gaseous form, natural gas on the mainland of the U.S. is not a useful product for consumers living in Hawaii, for example, because there is no way to get it to that market in an unrefined form. The natural gas is refined and then converted into a liquid form so that it may be transported and used as a 'useful product' throughout the Pacific Rim." Record 141.

The county concluded that "[i]f a mineral needs to be further processed or 'perfected' to make transportation economically viable, then it follows that further processing is required to make the mineral a 'useful product' for the intended market." *Id.*

JCEP argues, and we agree, that the commissioners' interpretation of LDO 2.1.200—that processing a natural mineral into a form that allows it to be transported to markets renders that natural mineral a "useful product" for that purpose—is consistent with the express language of LDO 2.1.200's definition and accordingly must be affirmed. That the natural gas arriving at the gas-processing facility is of "household quality" and is already one form of useful product does not mean that it cannot be further processed into a different, but still useful, product, even if the usefulness of that product is to allow transportation to markets where the product will be processed further to return it to a gaseous and more useful form.

The second assignment of error (Rogue Intervenors) is denied.

FOURTH ASSIGNMENT OF ERROR (ROGUE INTERVENORS)

Rogue Intervenors argue that the county erred in failing to impose a condition making the conditional use permit approval effective only when and if JCEP obtains all required state and federal approvals for the proposed LNG terminal, including FERC approval. In addition, Rogue Intervenors note that the gas processing facility will require a new electrical power plant, for which JCEP has not yet filed applications. Rogue Intervenors argue that the county should have made its permit decision effective only when and if the county approves the application for the new power plant.

The county's decision requires JCEP to obtain all required state and federal permits (which are required in any event by state and federal law), but does not delay the effective date of the conditional use permit approval until all required permits and approvals are obtained. JCEP responds, and we agree, that Rogue Intervenors have not identified any law that requires the county to impose a condition delaying the effectiveness of its permit approval until all other permits and approvals have been obtained. Absent a more developed argument, Rogue Intervenors' fourth assignment of error provides no basis for reversal or remand.

The fourth assignment of error (Rogue Intervenors) is denied.

FIRST ASSIGNMENT OF ERROR (CLARKE)

The proposed gas processing facility includes two "amine contactor" towers, or thermal oxidizers, that will vent heated gas into the atmosphere. The facility is located across the estuary from the Southwest Oregon Regional Airport. A portion of the LNG terminal site is within the approach surface of Runway 13, but as proposed the gas processing facility is not within the approach surface or the associated flight path.

In three sub-assignments of error, intervenor-petitioner John Clarke (Clarke) challenges the county's findings regarding compliance with LDO 4.11.445(4), which provides:

> "Industrial Emissions. No new industrial, mining or similar use * * * shall, as part of its regular operation, cause emissions of * * * steam that could obscure visibility within airport approach surfaces, except upon demonstration, supported by substantial evidence, that mitigation measures imposed as approval conditions will reduce the potential for safety risk or incompatibility with airport operations to an insignificant level. The review authority shall impose such conditions as necessary to ensure that the use does not obscure visibility."

JCEP submitted a "thermal plume" study to demonstrate compliance with LDO 4.11.445(4). The study evaluated the plumes generated by the gas processing facility, as well as the electrical power plant that is not part of this application. According to the study, the thermal oxidizers will generate only four percent of the heat plumes from both sources, and the plumes from all sources will meet applicable aviation standards. Clarke objected during the proceedings below that the thermal oxidizers will produce steam, which will obscure visibility within the airport approach surface, stating that "[b]asic physics tell you that heated air released into cool, damp air will produce steam." Record 7158. JCEP responded with a letter from Himes, a registered engineer with 46 years of experience including 10 years designing LNG facilities, who testified in relevant part that "[t]here are no visible or steam plumes from the facility." Record 3757. The county found that Himes' testimony constitutes substantial evidence and is more credible than any evidence to the contrary. Record 172.

Clarke argues that (1) Himes' statement that the thermal oxidizers will not produce visible steam plumes is not substantial evidence, given the "common knowledge" that heated air released into a cool atmosphere will produce steam; (2) although the gas processing facility is proposed to be located outside of Runway 13's surface approach area, the applicant did not seek, and the county did not approve, site plan approval, and it is possible that the gas processing facility could be moved to a location within the surface approach area; and (3) the county failed to adopt any "mitigation measures" to ensure that steam plumes will not obscure visibility within the airport surface approach area.

JCEP responds, and we agree, that Clarke's arguments do not provide a basis for reversal or remand. Himes' expert testimony is substantial evidence that the thermal oxidizers will not produce visible plumes of steam, and that testimony is not undermined by Clarke's statement, based on "common knowledge," that heated air released into cool air produces steam. In any case, LDO 4.11.445(4) is concerned only with obscured visibility within the surface approach area. Clarke's speculation that the gas processing facility could be moved from its proposed and approved location into the surface approach area is just that—speculation. JCEP proposed a specific location for the gas processing facility, and justified that facility's compliance with LDO 4.11.445(4) based in part on that proposed location, outside the surface approach area. Clarke does not explain how the gas processing facility could be relocated from that approved location west to a site within the surface approach area without modifying the conditional use permit or otherwise triggering evaluation under LDO 4.11.445(4)

The first assignment of error (Clarke) is denied.

The county's decision is remanded.

Exhibit 26

Jody McCaffree
Individual / Executive Director
Citizens For Renewables /
Citizens Against LNG
PO Box 1113
North Bend, OR 97459

December 26, 2018

City of North Bend
Planning Commission
835 California St.
North Bend, OR 97459

RE: **Appeal of Planning Director's Decision and Issuance of LUCS on the Jordan Cove/Pacific Connector Project.**

Please accept the following documentation for appeal. An appeal form has been hand delivered in person to your offices today along with the required fee. This documentation is being sent electronically to you due to my not being able to deliver it in person at this time. This appeal is being filed within 10 days of being sent copies (and therefore notification) of two Land Use Compatibility Statements (LUCS) that have been issued on the Jordan Cove/Pacific Connector project by the North Bend Planning Director (LUCS 17-18 and LUCS 18-18). On December 14, 2018, the North Bend Planning Director sent myself and several other individuals notification that applications had been submitted by the Jordan Cove Energy Project (JCEP) and Pacific Connector Gas Pipeline, L.P. and we would need to file public records requests in order to obtain copies of the documents. Since July 19, 2013, I have requested to be notified of documents that are before North Bend with respect to the Jordan Cove/Pacific Connector project. A public records request for copies of these 'application' documents cost me $24.25 and revealed at the close of business on Friday December 21, 2018 that two LUCS had already been issued by the North Bend Planning Director on December 13, 2018, prior to any land use applications being filed. The LUCS 17-18 and LUCS 18-18 were apparently based on:

1) A Preliminary Project Review Request filed on 4-18-2018 by Seth King attorney representing Pacific Connector Gas Pipeline, LP ("PCGP")
2) A Request for Preliminary Project Review Meeting dated October 17, 2018 by Seth King attorney representing Pacific Connector Gas Pipeline, LP ("PCGP")
3) A Zoning Compliance Determination Application dated May 8, 2018 with a received date of May 3, 2018, along with an e-mail from attorney Steven L Pfeiffer (Perkins Coie) dated May 2, 2018.

No notification of the following documents were ever sent or revealed prior to my receiving them at the close of business on December 21, 2018. Due to the City of North Bend offices being closed for the Christmas holiday, I am filing this appeal on the first official North Bend business day after I actually received and found out about the above referenced documents.

Both LUCS 17-18 and LUCS 18-18 that have been issued state that the "*activity or use is allowed outright according to North Bend Zoning Ordinance – Section 18.44.010(1)"* and also state that the Project requires *Administrative Estuarine Permit authorization* and *Floodplain Development Permit authorization* and *applicable Engineering Permits* *before compatibility can be determined*.

Appeal Issues

LUCS 17-18 and 18-18 have been issued prematurely and in error due to:

1) Estuarine Permits, Floodplain Development Permits, as well as applicable Engineering Permits have not been completed yet or issued. There is no way to determine compatibility of the project prior to these permit processes

2) Not enough information has been provided by the applicant in order for the Planning Director to be making an informed decision on the project. No complete applications have been filed yet, at least none that we are aware of. The Planning Director is making decisions based on assumptions about the project that are not correct or accurate.

3) The Planning Director has made a decision about the project without a proper public process that determined that the Pacific Connector Gas Pipeline LP was a "utility facility and operation" when it clearly is not and would therefore not be an allowed outright use. The North Bend code does not define what a "*Utility Facility and Operation*" is exactly but the Pacific Connector is NOT a Utility due to the fact it does not offer any services to the general public. It is a private gas transmission line, not a gas distribution line. The entire volume of gas proposed to be transmitted through the line would be exclusively used for export for the benefit of a private, foreign, Canadian corporation whose proposed LNG export terminal is not even located within the city limits of North Bend.[1] The project serves no compatible use or purpose to North Bend businesses or residents.

From Google:

What does Utility mean in business?
Related Terms. 1. ***Business****: Large firm that owns and/or operates facilities used for generation and transmission or distribution of electricity, gas, or water to general public*

The proposed Pacific Connector 36-inch high pressure gas transmission line that would have a hazard radius of between 800 and 1,000 feet.[2] The construction of the proposed pipeline would require a 95-foot construction easement along with a 50-foot permanent easement.[3] This would negatively impact other businesses that are already in operation

[1] Public Section 3 FERC Application of Jordan Cove Energy Project L.P. under CP17-495: https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20170921-5142
[2] A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines - Topical Report https://pstrust.org/docs/C-FerCircle.pdf
[3] Public Section 7 FERC Application of Pacific Connector Gas Pipeline, LP under CP17-494:

under the bridge and/or future potential businesses that may want to locate there. The proposed project would create a potential health and safety hazard to nearby residents along with the North Bend City Park systems that are located adjacent to the proposed project and activity. The proposed project is not in compliance with North Bend City Code 15.16.070 and 15.16.080 and fails to protect the National Historic Registered McCullough Bridge as required. The proposed project has not proven compliance with North Bend City Code 15.04.020 Structural Specialty Code and Fire and Life Safety Code. The proposed project has not provided evidence that it would protect Threatened and Endangered Species, Archeological and Cultural resources as required.[4]

For these reasons stated above I am appealing LUCS 17-18 and LUCS 18-18 due to the proposed project not being in compliance with the North Bend Zoning and Land Development Ordinance and City codes and therefore not an outright allowed use. More information will be provided at the De Novo hearing before the Planning Commission.

North Bend Municipal Codes for Appeal Reference:[5]

North Bend 18.44.010 (1) states:

18.44.010 Uses permitted outright.

In an M-H zone, the following uses and their accessory uses are permitted outright:

(1) A use permitted outright in an M-L zone.

(2) Manufacturing, repairing, compounding, fabricating, processing, packing or storage. (Ord. 1952 § 1(4), 2006)

Chapter 18.40

LIGHT INDUSTRIAL ZONE M-L

Sections:

18.40.010 Uses permitted outright.
18.40.020 Conditional uses permitted.
18.40.030 Limitations on use.
18.40.040 Signs.
18.40.050 Yards.
18.40.060 Height of buildings.

18.40.010 Uses permitted outright.

In an M-L zone, subject to the limitations provided herein, uses permitted outright include wholesale supply, utility operations and facilities, warehousing, compounding, packaging, processing, repairing, fabricating, marshalling, shipping, light manufacturing, and servicing of materials, equipment, supplies and other personal property, and other compatible uses having similar impacts on traffic and surrounding or adjoining properties. (Ord. 1952 § 1(4), 2006)

18.40.020 Conditional uses permitted.

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https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20170921-5139

[4] Mitigation and Conservation Plan - North Point Workforce Housing Site – SHN Consulting Engineers & Geologist Inc - Feb2014

[5] http://www.northbendoregon.us/cityrecorder/page/municipal-codes

In an M-L zone, the following uses and their accessory uses are permitted when authorized in accordance with the requirements of Chapter 18.60 NBCC:
(1) Governmental structure or use.
(2) A use permitted outright in the C-G zone.
(3) Improvement of an existing dwelling requiring a building permit.
(4) Areas for the accommodation of recreational vehicles and/or trailers, commonly known as RV parks or travel parks. (Ord. 1952 § 1(4), 2006)

18.40.030 Limitations on use.
In an M-L zone, the following conditions and limitations shall apply:
(1) Any use which creates a nuisance because of noise, smoke, odor, dust or gas is prohibited.
(2) Materials shall be stored and grounds shall be maintained in a manner which will not attract or aid the propagation of insects or rodents or otherwise create a health hazard.
(3) All service, processing and storage on property abutting or facing a residential zone shall be wholly within an enclosed building or screened from view from the residential zone by a permanently maintained, sight-obscuring fence at least six feet high.
(4) Points of access from a public street to properties in an M-L zone shall be so located as to minimize traffic congestion and avoid directing traffic onto residential streets.
(5) Building entrances or other openings adjacent to or across the street from a residential zone shall be prohibited if they cause glare, excessive noise or otherwise adversely affect residential uses. (Ord. 1952 § 1(4), 2006)

North Bend: 15.16.070 The designated landmarks register.

(1) Properties listed on the National Register of Historic Places, including all properties within National Register Historic District boundaries, are eligible for automatic listing on the designated landmarks register. As historic resources of statewide significance, all such properties are subject to the regulations in NBCC 15.16.080 regardless of their listing on the designated landmarks register, pursuant to OAR 660-023-200. However, only properties listed on the designated landmarks register shall be eligible for public incentives and code consideration pursuant to this chapter

North Bend: 15.16.080 Alterations, relocations, and demolitions.

(1) No exterior, interior, landscape, or archaeological element of a designated landmark which is specified as significant in its designation shall be altered, removed, or demolished without a permit issued pursuant to this chapter.
(2) No major exterior alteration, relocation, or demolition of a historic resource of statewide significance shall be allowed without a permit issued pursuant to this chapter.

NB Buildings and Construction Code 15.04.020:[6]

15.04.020 *Structural specialty code and fire and life safety code – Adopted*. *There is hereby adopted by reference and made a part of this chapter the administrative provisions contained in Chapters 1, 2 and 3 of the "State of Oregon Structural Specialty Code and Fire and Life Safety Code," which shall be used in the administration and enforcement of the provisions of this chapter. (Ord. 1623 § 1, 1980; Ord. 1554 § 1, 1978; Ord. 1511 § 1, 1975)*

[6] http://northbendoregon.us/adds/2014/09/Northbend151.pdf

North Bend 15.16.100 Appeals.

(1) Decisions of the commission are appealable to the city council. Decisions of the city council are appealable to the land use board of appeals.

(2) Procedures for appeals to the city council shall be the same as those for appeals of planning commission decisions. (Ord. 1892 § 10, 2002)

North Bend 18.70.160 Appeals.

Appeals from decisions of the planning director or planning commission to the city council shall be taken under the following procedures:

(1) Notice of appeal must be filed with the city recorder within 10 calendar days of the date that the decision is filed with the city recorder ***and mailed or delivered to the parties****; and if no appeal is taken within that time, then the decision of the planning director or planning commission shall be final and conclusive.*

(2) The notice of appeal shall raise all issues relied on with sufficient specificity as to afford the city council and other parties an adequate opportunity to respond to and resolve each issue.

(3) Notice of the hearing before the city council on appeal shall be provided by mail to all parties who appeared in the proceeding before the hearings officer or planning commission and all property owners referred to in NBCC 18.60.040 at least 20 days before the date of the hearing. The notice shall contain the descriptions of all issues raised by the appellant in the notice of appeal, the other applicable information from the notice provided for in NBCC 18.60.040, and the date, time and location of the hearing;

* * * *

North Bend 18.92.020 Appeal.

Appeals from discretionary land use decisions of the hearings officer or planning director go to the planning commission and appeals from the planning commission go to the city council. The city council may designate a hearings officer to conduct the hearing; in that case, city council shall review the record and the hearings officer's recommendation to make their decision. Appeal hearings shall be conducted as de novo hearings and shall be taken under the following procedures:

(1) Notice of appeal must be filed with the city planning department, along with the appropriate fee, within 10 calendar days of the date that the decision is reduced to writing ***and mailed to the parties of record****, and if no appeal is taken within that time, then the decision of the hearings officer, 18.92.030 North Bend City Code (Revised 5/17) 18-52 planning director or planning commission shall be final and conclusive.*

(2) The notice of appeal shall establish the appellant's party status and raise all appeal issues relied on with sufficient specificity as to afford the planning commission or city council and other parties an adequate opportunity to respond to and resolve each issue. An issue which may be the basis for an appeal shall be raised during the applicable public comment period for the decision. Such issues shall be raised and accompanied by statements or evidence sufficient to afford the planning commission or city council an opportunity to respond to each issue.

* * * *

Sincerely,

Jody McCaffree

Jody McCaffree

Exhibit 27

Industrial Energy Consumers of America (IECA)

The Energy Voice of Industrial Energy Consumers

EXCESSIVE LIQUIFIED NATURAL GAS (LNG) EXPORTS TO NFTA COUNTRIES ARE NOT IN THE PUBLIC INTEREST AND INCREASE NATURAL GAS AND ELECTRICITY PRICES TO CONSUMERS

JANUARY 30, 2019

OUTLINE

1. All DOE LNG export studies say exports increase natural gas prices.

2. The DOE has already approved volumes for export that are not in the public interest and plan to approve volumes equal to 52.8 billion cubic feet per day (Bcf/d). A volume equal to 71 percent of U.S. 2017 demand. The DOE has decided to let foreign countries determine the level of exports rather than limit export volumes that provide domestic consumers a safety net.

3. The DOE has never defined public interest under the NGA. All DOE studies confirm that LNG exports create winners and losers. The winners are the producers and exporters of natural gas. The losers are consumers and the economy.

4. DOE's approval of LNG exports for 20 to 30 years is a firm legal commitment to foreign countries LNG buyers. Where is the commitment to protect U.S. consumers?

5. The international LNG market is not a free market. It is for this reason that it is sound public policy to place limits on export volumes to levels that assure LNG exports will not increase domestic prices or impact reliability.

6. DOE has not addressed vital short- and long-term risks to consumers and the economy that are core issues in considering whether an LNG export application is consistent with the public interest.

    a. Failure to consider pipeline and storage capacity risks for existing and future constraints (and at peak demand), and their cost and reliability impacts.

    b. Failure to consider resulting higher marginal prices for natural gas and electricity consumers.

    c. Failure to address cumulative demand versus availability of natural gas resources.

    d. Failure to consider the uncertain nature of technically recoverable natural gas resources.

e. Failure to consider future political decisions such as limit to acreage available for drilling, regulations on water or hydraulic fracturing that could increase costs that must be recovered in higher prices of natural gas, thereby increasing consumer risk.

f. Failure to consider that the majority of producers of natural gas do not have a positive cash flow business, which means prices have to go up.

g. Failure to consider that gas producing companies are consistently overestimating well production, which leads to higher natural gas resources estimates than are available for the future.

h. Failure to consider that foreign consumers of U.S. LNG exports are receiving the benefits of using our infrastructure that is paid for by U.S. consumers, without paying for it. Their use of this infrastructure increases our costs.

7. The United States Trade and Development Agency (USTDA) is using federal tax dollars (or taxpayer money) to fund and promote LNG exports to importing countries.

COMMENTS

1. All DOE LNG export studies say exports increase natural gas prices.

The DOE released a study entitled, "Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Exports"[1] which illustrates that LNG exports would substantially increase U.S. natural prices. On page 54 of the study it states that "for all the reference supply scenarios in the more likely range, natural gas prices could be from $5.00 to $6.50 per MMBtu in 2040. These mid-range scenarios have a combined probability of 47%." This is the highest probability the study gave any scenario. Since the Henry Hub price has most often been at roughly $3.00 MMBtu, the study confirms that natural gas prices could more than double causing domestic natural gas prices to rise to a level which would harm natural gas-dependent manufacturers and every homeowner. Consumers do not have an alternative. This is clearly not in the public interest.

The DOE released an earlier study in 2015 entitled, "The Macroeconomic Impact of Increasing LNG Exports"[2] and it provides the same conclusions, but also explains that the price of goods will rise and that the manufacturing sector will be damaged, along with competitiveness and the trade balance. On page 24 it states, "Henry Hub prices are higher than they would otherwise be as U.S. LNG exports increase because producers increasingly exploit reserves with higher extraction costs. Higher natural gas prices will erode consumers' purchasing power both directly and indirectly as the impact of higher domestic natural gas prices filters through the supply chains of other sectors causing the prices of other goods and services to rise. This will negatively

[1] "Macroeconomic Outcomes of Market Determined Levels of U.S. LNG Export," U.S. Department of Energy (DOE), June 7, 2018, https://www.energy.gov/sites/prod/files/2018/06/f52/Macroeconomic%20LNG%20Export%20Study%202018.pdf.

[2] "The Macroeconomic Impact of Increasing LNG Exports," U.S. Department of Energy, October 29, 2015, https://www.energy.gov/fe/downloads/lng-export-studies

impact consumption with the energy intensive sectors being most affected. Changes in relative natural gas prices across countries will impact U.S. competitiveness. If energy prices in the United States rise relative to energy prices in the rest of the world, this raises production costs for U.S. firms relative to international competitors. This erosion in U.S. competitiveness will weigh on the U.S. trade balance. The tradable energy intensive sectors such as chemicals and steel will generally be most exposed to shifts in industrial competitiveness."

LNG exports also increase price volatility. In a recent Forbes article it states, "Truth be told, however, while U.S. gas prices have been their most volatile in around a decade over the past 10 weeks, more and more LNG exports to meet growing needs abroad would mean more ups and downs in domestic prices. We know that as the most bullish domestic demand factor, U.S. LNG exports will put a floor under our own market. LNG exports will increasingly become a baseload demand market and are not going to be easy to simply shut off if our own prices rise."[3]

In May 2018, the Commodity Futures Trading Commission (CFTC) released a report entitled, "Liquefied Natural Gas Developments and Market Impacts."[4] The report states, "Given the magnitude of U.S. exports, there is also the potential that domestic natural gas markets could become subject to global supply-demand dynamics with the potential for increased volatility." The report concludes that, "U.S. LNG export growth may put upward pressure on domestic (U.S.) natural gas prices and expose a heretofore relatively isolated North American market to global market dynamics."

2. **The DOE has already approved volumes for export that are not in the public interest and plan to approve volumes equal to 52.8 billion cubic feet per day (Bcf/d). A volume equal to 71 percent of U.S. 2017 demand. The DOE has decided to let foreign countries determine the level of exports rather than limit export volumes that provide domestic consumers a safety net.**

The DOE has already approved LNG export volumes equal to 30 percent of 2017 U.S. demand for shipment to NFTA countries, and volumes equal to 75 percent of 2017 U.S. demand to FTA countries, for periods of 20 to 30 years. NFTA countries are the largest global LNG consumers. Importantly, the DOE will consider the approval of 13 other applications to export in 2019.

Why markets should not be used to justify levels of specific LNG export applications volumes of LNG exports is illustrated with U.S. crude oil and gasoline prices. In the first half of 2018, because the U.S. crude oil price was connected to the global market, U.S. gasoline prices rose to the highest levels in over four years. Global demand from other countries dictated demand and price versus the U.S. supply and demand. The net result is that the U.S. consumer was NOT benefiting from our vast crude oil resources. This can and will happen to natural gas if our low natural gas prices are connected to the high price of global LNG markets. Today's low prices of

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[3] "U.S. Liquefied Natural Gas Hits Record Highs Again," Forbes, January 6, 2019, https://www.forbes.com/sites/judeclemente/2019/01/06/u-s-liquefied-natural-gas-hits-record-highs-again/#39f174a8141e

[4] "Liquefied Natural Gas Developments and Markets," U.S. Commodity Futures Trading Commission, https://www.cftc.gov/sites/default/files/2018-05/CFTC_LNG0518_3.pdf

natural gas are attributable to the fact that prices are determined by domestic supply and demand, not the global market.

This threat is not merely hypothetical, it happened in Australia. The Australian example shows that using markets to determine levels of LNG exports is not in the public interest. They are at least ten years ahead of the U.S. in exporting LNG. Australia has vast natural gas resources. Historically, the consumer prices have been around $3.00 MMBtu. Now, because of LNG exports, the Australian consumer pays the Asian LNG netback price. This means that the Australian consumer pays the high Asian LNG price, less transportation and liquefaction costs, which has resulted in Australian domestic consumer prices at $8, $9 and $10 MMBtu.

The Australian Competition and Consumer Commission started publication of LNG netback prices in order to boost price transparency.[5] The Australian consumer netback prices have increased from 7.27 Gj in 2017 to 10.69 Gj YTD 2018, a 47 percent increase. In approving LNG export terminals, the Australian government let markets determine the volume of exports, which has now directly caused disastrous impacts to consumers and the manufacturing sector as jobs continue to decrease.

3. **The DOE has never defined public interest under the NGA. All DOE studies confirm that LNG exports create winners and losers. The winners are the producers and exporters of natural gas. The losers are consumers and the economy.**

Congress raised the concern of exporting to NFTA countries in the NGA and delegated the responsibility of addressing LNG export applications to the DOE. Pursuant to section 3 of the NGA 15 U.S.C. 717b exports of natural gas, including LNG, must be authorized by the DOE. Under NGA section 3(a) 15 U.S.C. 717b(a) applications that seek authority to export natural gas to NFTA countries are presumed to be in the public interest unless, after opportunity for hearing, the DOE finds that the authorization would not be consistent with the public interest.

The problem is that DOE has never defined public interest according to the Government Accountability Office report of September 2014.[6] Despite the request of the Industrial Energy Consumers of America (IECA)[7], a trade association that represents manufacturing companies in Washington, DC, the DOE has refused to do so. Instead, the DOE has conducted studies that conclude that exports create net economic benefits for the U.S and have approved every application to export.

On June 21, 2018 it states in the Federal Register, "In granting each application, DOE concluded that exports of U.S. LNG will generate net economic benefits to the broader U.S. economy and will provide energy security and environmental benefits to the global community (including emerging economies presently reliant upon more carbon intensive fuels).[8]" As consumers, we

[5] Australian Competition and Consumer Commission, October 2018,, https://www.lngworldnews.com/australian-watchdog-starts-lng-netback-price-publication/?utm_source=emark&utm_medium=email&utm_campaign=daily-update-lng-world-news-2018-10-05&uid=55872
[6] "Federal Approval Process for Liquefied Natural Gas Exports," U.S. Government Accountability Office (GAO), September 2014
[7] Industrial Energy Consumers of America homepage, www.ieca-us.org
[8] Federal Register/Vol. 83 No. 120/Thursday, June 21, 2018, page 28843

completely reject this definition. Instead, we support a Supreme Court definition of public interest. We believe that Congress had intended the public interest to be about the welfare of consumers (people) of natural gas.

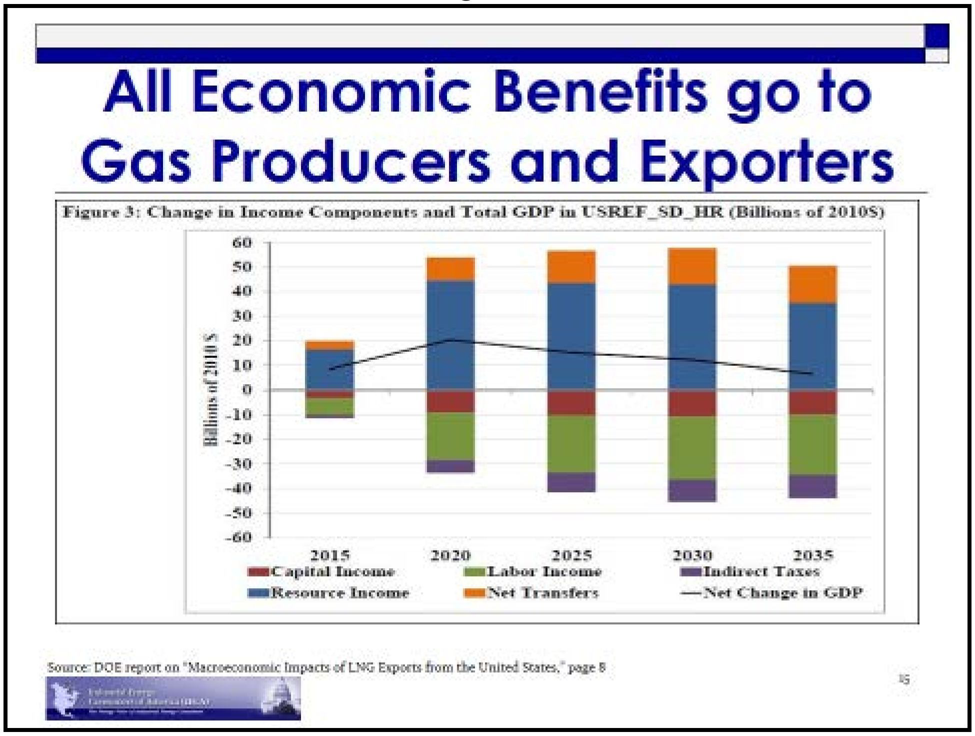
The U.S. Supreme Court has stated that "in order to give content and meaning to the words 'public interest' as used in the Federal Power and Natural Gas Acts, it is necessary to look to the purposes for which the Acts were adopted. In the case of the Power and Gas Acts it is clear that the principal purpose of those Acts was to encourage the orderly development of plentiful supplies of electricity and natural gas at reasonable prices."[9] Furthermore, the Supreme Court also stated that the "primary aim" of the NGA is "to protect consumers against exploitation at the hands of natural gas companies."[10]

To this point, in 2012, the DOE released a report entitled "Macroeconomic Impacts of LNG Exports from the United States."[11]. The report illustrates how natural gas companies exploit U.S. consumers by exporting LNG. Figure 1 below is from page 8 of the report. You will note that the only entities that benefit from LNG exports are a small sliver of the U.S. economy, namely producers and exporters of natural gas, while everyone else, while 323 million citizens are negatively impacted.

Page 7 of the report states that, "Expansion of LNG exports has two major effects on income: it raises energy costs and, in the process, depresses both real wages and the return on capital in all other industries." Please also note that for volumes of 12 Bcf/d of LNG exports, it only contributes $20 billion to the economy in 2020 and decreases each year thereafter, while the negative impacts to consumers increases through 2030 before it levels off.

[9] NAACP v. Fed. Power Comm'n, 425 U.S. 662, 669-70 (1976).
[10] FPC v. Hope Gas Co., 320 U. S. 591, 610 (1944).
[11] "Macroeconomic Impacts of LNG Exports from the United States," U.S. Department of Energy, December 3, 2012, https://www.energy.gov/sites/prod/files/2013/04/f0/nera_lng_report.pdf.

Figure 1



The vast majority of LNG is consumed by countries that do not have a free trade agreement with the U.S. It is inconsistent with the public interest to export LNG to NFTA countries.

Most U.S. shipped LNG is purchased by countries with which the U.S. does not have an FTA. From February 2016 to September 2018, 50.1 percent of U.S. LNG was shipped to NFTA countries.[12] These are countries that discriminate against U.S. manufacturing and farm products. Yet, we are shipping them a non-renewable vital resource for which every American consumer does not have an alternative. And, the DOE LNG export studies make clear that exporting LNG lowers the price of natural gas, especially to Asian countries. Page 8 of the 2015 DOE LNG report it states, "In every case, greater LNG exports raise domestic prices and lower prices internationally. The majority of the price movement (in absolute terms) occurs in Asia." Page 8 of this study also states that LNG exports creates declines in manufacturing and especially in energy-intensive industries, such as: chemicals, plastics, steel, aluminum, paper, refining, glass, cement, and food processing.

4. **DOE's approval of LNG exports for 20 to 30 years is a firm legal commitment to foreign countries LNG buyers. Where is the commitment to protect U.S. consumers?**

The Federal Register states, "As a preliminary matter, DOE/FE wishes to allay concerns about the security of existing (or future) non-FTA export authorizations. In this policy statement, DOE/FE affirms its commitment to all export authorizations issued under the NGA, including long-term authorizations approving the export of LNG to non-FTA countries. As indicated above, DOE/FE

[12] "LNG Reports," U.S. Department of Energy, https://www.energy.gov/fe/listings/lng-reports.

currently has issued 29 final non-FTA export authorizations, based on a thorough consideration of the public interest under section 3(a) of the NGA."[13]

> "However, DOE does not foresee a scenario where it would rescind one or more non-FTA authorizations. The United States government takes very seriously the investment-backed expectations of private parties subject to its regulatory jurisdiction. In particular, DOE understands the far-ranging economic investments and natural gas supply commitments associated with these authorizations over their full term—affecting both U.S. and global interests. DOE emphasizes that it remains committed to the durability and stability of the export authorizations it has granted under the NGA, as well as to supporting the approved export of U.S. natural gas around the world.[14]"

5. The international LNG market is not a free market. It is for this reason that it is sound public policy to place limits on export volumes to levels that assure LNG exports will not increase domestic prices or impact reliability.

Government limitations to LNG exports is in the public interest because natural gas is a non-renewable resource, U.S. consumers do not have an alternative, and the LNG market is not a free market. The LNG market buyers are countries – not companies or consumers (homeowners, farmers, businesses). The entities buying LNG are government backed state-owned enterprises (SOEs) and utilities who have automatic cost pass-through. Because they are countries, their responsibility is to ensure that sufficient supplies are purchased to keep the lights on at home and factories running. What this means is that, if necessary, they will pay any price, no matter how high, to supply their country's needs. In the future times when there are limits to supply capacity, this could pit countries against the U.S. consumer. Many countries who buy LNG also subsidize their manufacturing sector by not passing through the real costs of the purchased LNG, and regulate the price.

In December 2018, LNG World News report stated, "The major LNG buyers – CNOOC, CPC, JERA, KOGAS, PetroChina, Sinopec and Tokyo Gas – together account for more than 50 percent of the global LNG market."[15] Four out of six are Chinese SOEs.

> CNOOC (China National Offshore Oil Corporation, or CNOOC Group, is a major national oil company in China. It is the third-largest national oil company in the People's Republic of China, after CNPC and China Petrochemical Corporation.)
>
> CPC (China Petrochemical Corporation or Sinopec Group is the world's largest oil refining, gas and petrochemical conglomerate, administered by SASAC for the State Council of the People's Republic of China.)

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[13] FPC v. Hope Gas Co., 320 U. S. 591, 610 (1944).
[14] Federal Register/Vol. 83 No. 120/Thursday, June 21, 2018, page 28843
[15] "WoodMac: uncontracted demand by world's seven largest LNG buyers to quadruple," LNG World News, December 13, 2018, https://www.lngworldnews.com/woodmac-uncontracted-demand-by-worlds-seven-largest-lng-buyers-to-quadruple/?utm_source=emark&utm_medium=email&utm_campaign=daily-update-lng-world-news-2018-12-14&uid=55872

JERA (JERA Co., Inc.; Parent organizations: Tokyo Electric Power Company, Chubu Electric Power)

KOGAS (Korea Gas Corporation is a South Korean public natural gas company that was established by the Korean government in 1983. KOGAS has grown into the largest LNG-importing company in the world and operates four LNG regasification terminals and natural gas pipelines in South Korea.

PetroChina (PetroChina Company Limited is a Chinese oil and gas company and is the listed arm of state-owned China National Petroleum Corporation. It is China's second biggest oil producer.

Sinopec (China Petroleum & Chemical Corporation, or Sinopec, is a Chinese oil and gas enterprise based in Beijing, China.

Tokyo Gas (Tokyo Gas Co., Ltd., founded in 1885, is the primary provider of natural gas to the main cities of Tokyo, Kanagawa, Saitama, Chiba, Ibaraki, Tochigi, Gunma, Yamanashi, and Nagano. As of 2012, Tokyo Gas is the largest natural gas utility in Japan.)

6. **DOE has not addressed vital short- and long-term risks to consumers and the economy that are core issues in considering whether an LNG export application is consistent with the public interest.**

   a. **Failure to consider pipeline and storage capacity risks for existing and future constraints (and at peak demand), and their cost and reliability impacts.**

The DOE, nor the Federal Energy Regulatory Commission (FERC), has completed a study to consider existing and future limitations in natural gas pipeline and storage infrastructure capacity and maximum deliverability capacity needed to supply the U.S. market at peak demand and export LNG. Peak demand occurs in winter and summer months. All of the DOE LNG export studies used to justify approval of LNG applications to export assume that pipeline and storage capacity will be adequate, despite the fact that constraints already exist and the ability to build-out new pipeline capacity is threatened by multiple legal and public opposition headwinds.

The question of whether there is adequate pipeline capacity at peak demand is extremely important because the majority of LNG export buying countries are located in the Northern Hemisphere. This means that they have winter when we do. Their highest demand for buying U.S. LNG is when U.S. consumers have peak demand. The largest LNG importing countries are China, South Korea, Japan, and the EU.

LNG exports reduce the availability of pipeline capacity to domestic consumers. As more and more LNG export terminals are operational, the pipeline capacity used to feed these terminals are no longer available to U.S. consumer. And, there is evidence that LNG export terminals that need bank financing to construct the export terminal are required to have firm natural gas pipeline capacity available at all times to load the LNG export ships. If this is true, it means that these companies are not releasing their firm pipeline capacity to the market when they do not need it, thereby reducing the availability of pipeline capacity to U.S. consumers.

There are recent past winters where, for example, natural gas-fired power generation units and manufacturing companies have been unable to get the gas they need to operate due to pipeline capacity limitations. For power generators, this creates a reliability issue for electric consumers. For manufacturing, cutting back or shutting down can cost tens of millions of dollars per day per facility. LNG exports can compound these events.

b. Failure to consider resulting higher marginal prices for natural gas and electricity consumers.

The DOE LNG export studies used to justify approval of LNG export applications never considered its impact on the marginal price of natural gas and electricity. This is important any time of the year, but especially at peak summer and winter demand periods. The net effect of not doing so results in lower forecasted prices under macroeconomic LNG export scenarios.

c. Failure to address cumulative demand versus availability of natural gas resources.

In March 2018, IECA released a report which compares the U.S. Energy Information Administration's (EIA) AEO 2018 cumulative demand through 2050 to EIA's estimates of technically recoverable natural gas resources in the lower 48. Doing so illustrates that this demand would consume 69 percent of all resources. And, EIA has LNG exports peaking at only 14.5 Bcf/d. A very conservative forecast. While over time resources have been increasing, forecasted demand is outstripping new resources growth. IECA did the same analysis using EIA AEO 2017 demand. That analysis concluded that 57 percent of all resources would be consumed. We anticipate that AEO 2019 will show substantially higher and faster consumption of available resources.

d. Failure to consider the uncertain nature of technically recoverable natural gas resources.

It is also important to keep in mind that *technically available* resources do not mean that they are *economical* to produce. To this point, the natural gas industry's Potential Gas Committee's most recent report of July 2017[16] states that 58 percent of all natural gas resources are classified as either possible (new fields) or speculative (frontier fields), which adds more uncertainty that these resources may not produce low-cost natural gas. All DOE LNG export reports assume that this natural gas is economical to produce when no one really knows because no one has ever drilled a well in these new fields or frontier fields.

e. Failure to consider future political decisions such as limit to acreage available for drilling, regulations on water or hydraulic fracturing that could increase costs that must be recovered in higher prices of natural gas, thereby increasing consumer risk.

We have Presidential elections every four years that can change everything. As we have seen with some past Administrations, there were regulatory actions to limit access to federal lands for drilling and regulations to control drilling processes that increase the cost of production. A

[16] "Potential Supply of Natural Gas in the United States," Potential Gas Committee, December 31, 2016, http://pttc.mines.edu/PGC_Press_Conference_2017_07-19-2017_Final.pdf

new Administration could inflict all of these and more thereby increasing natural gas costs and prices. States have and will continue to take action to limit drilling. The DOE report used to justify LNG export applications do not consider these risks to consumers.

f. Failure to consider that the majority of producers of natural gas do not have a positive cash flow business which means prices have to go up.

In September 2018, the New York Times released a story entitled, "The Next Financial Crisis Lurks Underground." It states that the fracking industry is on shaky financial ground and have not proved they can make money. The 60 biggest exploration and production firms are not generating enough cash from their operations to cover their operating and capital expenses. In aggregate, from mid-2012 to mid-2017, they had negative free cash flow of $9 billion per quarter."[17] This is not sustainable long-term. Wall Street is concerned about the indebtedness of producers. Investors demand certain ROE's to continue to invest or lend money for drilling more wells. The fact that interest rates are also increasing puts further pressure on costs. Combined, this means that the price of natural gas must rise. DOE LNG studies do not address this fundamental issue.

g. Failure to consider that gas producing companies are consistently overestimating well production, which leads to higher natural gas resources estimates than are available for the future.

In January 2019, the Wall Street Journal released a story entitled, "Fracking's Secret Problem—Oil Wells Aren't Producing as Much as Forecast."[18] The story is equally telling because it provides hard facts that data analysis reveals thousands of locations are yielding less than their owners projected to investors, illusory picture of prospects. And, well production rates are used to forecast resource estimates used by the EIA and all others.

Thousands of shale wells drilled in the last five years are pumping less oil and gas than their owners forecast to investors, raising questions about the strength and profitability of the fracking boom that turned the U.S. into an oil superpower.

The Wall Street Journal compared the well-productivity estimates that top shale-oil companies gave investors to projections from third parties about how much oil and gas the wells are now on track to pump over their lives, based on public data of how they have performed to date.

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[17] The Next Financial Crisis Lurks Underground, New York Times, September 1, 2018 https://www.nytimes.com/2018/09/01/opinion/the-next-financial-crisis-lurks-underground.html

[18] "Fracking's Secret Problem—Oil Wells Aren't Producing as Much as Forecast," Wall Street Journal, January 2, 2019, https://www.wsj.com/articles/frackings-secret-problemoil-wells-arent-producing-as-much-as-forecast-11546450162?emailToken=a83066aebe513ddd3dbf2884e46f03a2E51ZQs+dQXSXmYA/3dmjTGk92FGXvXm7YSvOKXP+yQkyys4Bhn0BJxZ8FcuVVg7cHl/sdfXzOdkDxa15Bqz5JNUhgx2GNxFLBsdMnCWf2IPz1zknNveMW3XGN8lad2VngvgXbxw79Pc8iAaMMoHQTQ%3D%3D&reflink=article_email_share

"Two-thirds of projections made by the fracking companies between 2014 and 2017 in America's four hottest drilling regions appear to have been overly optimistic, according to the analysis of some 16,000 wells operated by 29 of the biggest producers in oil basins in Texas and North Dakota.

"Collectively, the companies that made projections are on track to pump nearly 10% less oil and gas than they forecast for those areas, according to the analysis of data from Rystad Energy AS, an energy consulting firm. That is the equivalent of almost one billion barrels of oil and gas over 30 years, worth more than $30 billion at current prices. Some companies are off track by more than 50% in certain regions.

"There are a number of practices that are almost inevitably going to lead to overestimates."

h. Failure to consider that foreign consumers of U.S. LNG exports are receiving the benefits of using our infrastructure that is paid for by U.S. consumers, without paying for it. Their use of this infrastructure increases our costs.

LNG exports use of U.S. infrastructure increasing the costs to all U.S. consumers. DOE has failed to consider these costs nor is this in the public interest.

7. The United States Trade and Development Agency (USTDA) is using federal tax dollars (or taxpayer money) to fund and promote LNG exports to importing countries.

We urge your support to stop the use of federal tax dollars to promote the export/import of U.S. LNG by the USTDA. This is corporate welfare and certainly not in the public interest. According to a news story entitled, "When it Comes to Natural Gas, US 'Open for Business"[19] the USTDA has funded 13 projects in 20-plus countries.

According to the story, USTDA has received more than 40 gas-related proposals this year, including a floating gas processing unit on China's east coast facility. Other spending included help to supply LNG to Morocco, Spain and Portugal, a gas-fired power plant in Egypt, and gas terminals in Honduras and Romania. If it is in the interest of those countries to import LNG, they should be willing and able to fund their own efforts.

In November of 2017, the USTDA, oil and natural gas industries, LNG export industries, and the U.S. Chamber of Commerce launched the "U.S. Infrastructure Exports Initiative."[20] We mention this only to reinforce the extremely high level of momentum behind the push to export unlimited volumes of LNG globally for which U.S. consumers are unaware and unprotected.

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[19] When I Comes to Natural Gas, US 'Open for Business', December 12, 2018, Associated Press, https://www.usnews.com/news/best-states/texas/articles/2018-12-12/when-it-comes-to-natural-gas-us-open-for-business

[20] "USTDA and U.S. Industry Launch U.S. Gas Infrastructure Exports Initiative," USTDA, November 17, 2017, https://ustda.gov/print/1501; "U.S. Gas Infrastructure Exports Initiative," https://www.ustda.gov/program/us-gas-infrastructure-exports-initiative; "General Funding Request Guidelines," https://www.ustda.gov/sites/default/files/Gas%20Proposal%20Guidelines.pdf

For all of the above reasons, we urge you to urgently act to protect the interest of the public and our economy. It is the shale gas revolution that has created the manufacturing renaissance. And, we are about to ship away our economic advantage to other countries.

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The Industrial Energy Consumers of America is a nonpartisan association of leading manufacturing companies with $1.0 trillion in annual sales, over 3,700 facilities nationwide, and with more than 1.7 million employees worldwide. It is an organization created to promote the interests of manufacturing companies through advocacy and collaboration for which the availability, use and cost of energy, power or feedstock play a significant role in their ability to compete in domestic and world markets. IECA membership represents a diverse set of industries including: chemicals, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, building products, automotive, brewing, independent oil refining, and cement.

Exhibit 28

https://theworldlink.com/news/local/deq-hits-clausen-oysters-with-fine/article_9fb57e0c-b070-11df-8cc0-001cc4c03286.html

DEQ hits Clausen Oysters with $25,000 fine

By Gail Elber, Staff Writer Aug 25, 2010

The Oregon Department of Environmental Quality has levied $24,992 in penalties on Clausen Oysters in North Bend for wastewater violations.

According to DEQ, the business operated from 2005 to 2009 without a wastewater discharge permit, incurring penalties of $16,349.

It then violated its newly obtained permit this year by failing to monitor wastewater and report monitoring results to DEQ, incurring penalties of $5,643.

It also discharged water to the bay without screening it, incurring a $3,000 penalty.

'Out of the blue'

Lilli Clausen, who with her husband Max has owned the company on Haynes Inlet since 1994, said that the letter from DEQ came "out of the blue."

She said that for 2003 and 2005, she paid for the permit and has the canceled checks.

For other years, she said, she never got a bill.

Her microbiological testing has been done, but the reports weren't filed due to a miscommunication, she said.

And the required screening system has long been a bone of contention between her and the DEQ.

"We're going to appeal," she said.

Spotty permits

Clausen Oysters, owned by Max and Lilli Clausen, has operated a processing facility at 66234 North Bay Road since 1994. Originally, it had a permit to discharge process wastewater - generated from washing oysters and equipment - to Haynes Inlet.

Wastewater from the company's sinks and toilets isn't at issue. It's treated in a septic tank and dispersed in a drainfield across the road from the bay.

In November 2005, the environmental agency canceled the facility's process wastewater permit because the Clausens had not renewed it.

For four years, the Clausens operated the facility without a permit, finally obtaining one in January 2010.

Reports required

But after obtaining the new permit, the Clausens didn't follow its requirements, the environmental agency said.

They didn't have equipment in place to screen solids out of their wastewater, as their permit required.

They also didn't submit monthly discharge monitoring reports with production information, microbiological test results, and amounts of waste solids produced.

Clausen said that she paid for permits in 2003 and 2005, and never saw a bill after 2005.

"I'm quite concerned about our credit, so if I had seen a bill, I would have paid it."

She said she paid for 2009 when she applied for a permit in November 2009, which she received in January 2010.

"If I had known then that I owed anything, I could have paid it then and there."

Screens a problem

Clausen has struggled with the agency's requirement to screen her process wastewater.

Regulations require a fine screen that clogs constantly, Clausen said, which caused problems in her operation.

"It is most impractical and very unnecessary," she said.

Clausen maintains that no oyster meat enters the wash water - just mud it washes off the oysters.

"The mud comes out of the bay; it goes back in the bay."

Recently they got a screen that works, she said.

But Steve Nichols of the Department of Environmental Quality's Coos Bay office, who inspects seafood processing facilities, said he hasn't seen it in action yet.

As for the missing discharge water quality reports, Clausen isn't yet sure what happened.

She said that she pays to have the North Bend wastewater treatment plant do the testing.

She thought it would send in the reports, but apparently they weren't being sent to the right place, she said.

The Clausens have until Sept. 10 to file an appeal.

Reporter Gail Elber can be reached at 541-269-1222, ext. 234; or at gelber@theworldlink.com.

Exhibit 29

Limitations of the Haynes Inlet sediment transport study

by

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Nov. 13, 2011

Limitations of the Haynes Inlet sediment transport study presented in Exhibit 4:

Chapters 10 and 11 of Exhibit 4 (entitled Jordan Cove Energy Project and Pacific Connector Gas Pipeline - Volume 2) present sediment transport calculations which purport to show that sediment transport impacts of the proposed dredging project in Haynes Inlet would have minimal impacts. However, close scrutiny of Exhibit 4 shows that there are serious deficiencies in the methodology employed in the sediment transport modeling. Consequently, the finding that there would only be limited impacts is lacking a solid foundation. The most serious flaws are outlined below:

1. Use of un-validated sediment transport model to establish background conditions

According to the Department of Environmental Quality, an "impacted" area is one that suffers a dredging-related turbidity level that is 10% or greater than background. Establishing background conditions is therefore a critical part of the process of defining impacted areas. The authors of the sediment transport study indicated that little data on ambient suspended sediment concentrations was available. The limited data available near the dredging site was collected in summer time whereas the dredging would occur in the fall and winter. As a consequence, the authors decided to use a model to establish background conditions. However, the model used was not validated with measurements from the study site.

Use of an un-validated sediment transport model to establish background conditions leads one to question the reliability of the project's findings. Using turbidity calculations generated by an un-validated model to establish background conditions is not reliable since sediment transport models are notoriously inaccurate especially when they have not been calibrated with data. Figure 1 (below) compares measured and modeled sediment transport (including bedload and

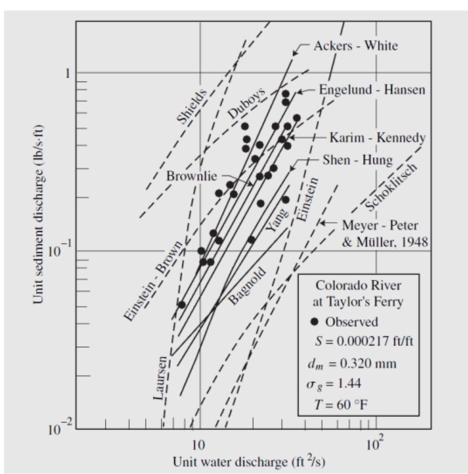

Figure 1. Plot comparing measured and calculated sediment discharge in the Colorado River as a function of water flow rate. The dashed and solid lines are calculated with various sediment transport models and the dots are measurements. The figure is from Erosion and Sedimentation, 2nd Edition, by Prof. Julien, Univ. of Colorado.

suspended sediment transport). It demonstrates the unreliable nature of sediment transport equations and models. If the authors of the Haynes Inlet sediment transport study are intent on using a model to establish ambient conditions, they should use the available data to validate their model. Model validation is a key part of peer-reviewed science and engineering work.

Use of an un-validated sediment transport model could result in an over-estimate of the background turbidity or suspended sediment concentration. This, in turn, would lead to an underestimate of the area impacted by the dredging project. For example, suppose the model calculated the background suspended sediment concentration to be 500 mg/liter (500 milligrams/liter), whereas the actual background concentration was 100 mg/liter. Based on the modeled result, the dredging-derived suspension could be as high as 50 mg/liter (10% of background) before the area was designated as impacted. However, based on the actual background condition, areas seeing dredging-derived suspension greater than 10 mg/liter should be defined as impacted. Using the actual background would clearly lead to an increase in the area that was designated as being "impacted". We can estimate the increase by extrapolating from Figure 10-5 of Exhibit 4 (reproduced below). Use of the true threshold (10 mg/liter or 2% on the y axis of Figure 10-5) would cause the linear extent of the impacted area to increase from about 350 ft to about 600 ft (for a 4 ft/s current).

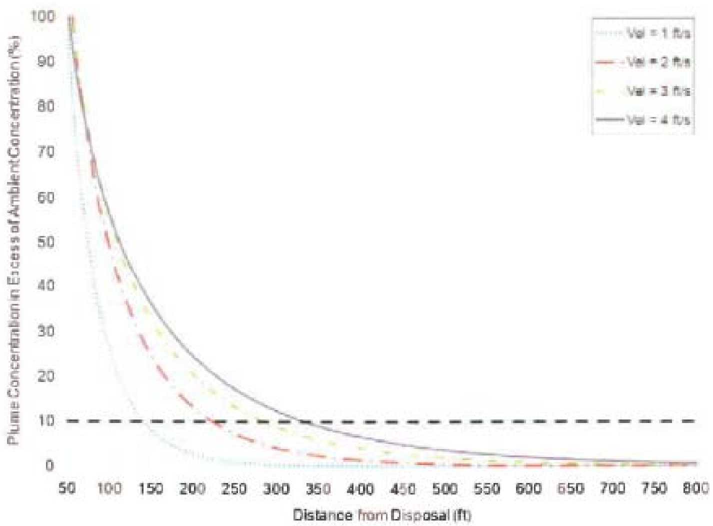

Figure 10-5. Suspended sediment concentration in excess of ambient concentration from numerical modeling results of trench stockpile placement activities in Haynes Inlet

Figure 2. Reproduction of Figure 10-5 of Exhibit 4.

2. Assumption of spatially uniform sediment size despite data indicating significant heterogeneity.

The authors of the Haynes Inlet sediment transport study conduct their modeling of background conditions and their modeling of dredging-related releases of sediment assuming that the sediment grain size is uniform throughout the study area (grain size is assumed to be 0.27 mm). However, the sediment characterization study conducted by GeoEngineers (August 2010) indicates that the sediments are significantly finer than this in large portions of the study area. GeoEngineers examined composite samples from three sections of the proposed pipeline route (DWWU-1, DWWU-2, DWWU-3, Figure 3). They found that, in section DWWU-1, the majority of the sediments were in the silt/clay size range with an overall median grain size of 0.04 to 0.05 mm (Figure 4, below).

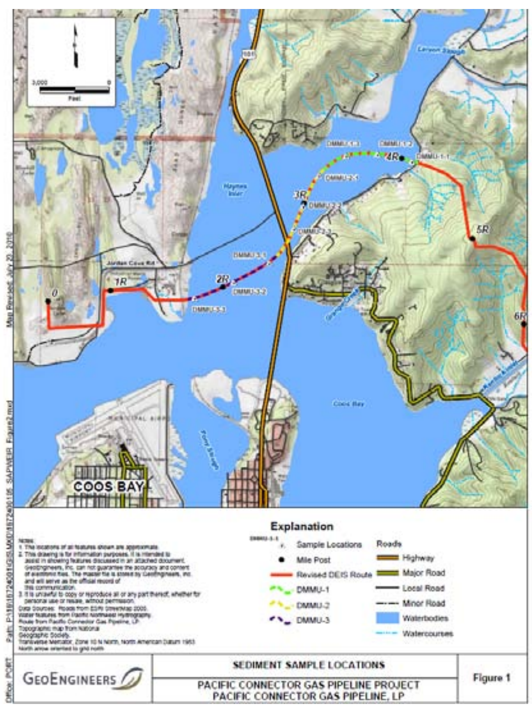

Figure 3. Map of sections of the pipeline (DWWU-1, DWWU-2, DWWU-3) from Figure 1 of the sediment characterization study of GeoEngineers.

TABLE B-1

GRAIN SIZE ANALYSIS

PACIFIC CONNECTOR GAS PIPELINE PROJECT

HAYNES INLET, OREGON

Sample Identification	Sample Depth (ft)	Percent (%)		
		Gravel	Sand	Silt/Clay
In-Place Sediment Samples				
DMMU-1-Composite	0-9	1.2	48.4	50.4
DMMU-2-Composite	0-9	0.0	67.0	33.0
DMMU-3-Composite	0-9	0.7	86.2	13.1

W:\Boise\Projects\16\16724001\05\Finals\Sediment Characterization\[16724-001-05Tables.xlsx]B-1

Figure 4. Grain size data in the various sections of the pipeline from Table B-1 of the GeoEngineers Sediment Characterization Study.

The implications of assuming a uniform grain size when in fact the grain size is spatially variable are two-fold. First, the calculation of the background turbidity distribution at the study site would be inaccurate if the wrong grain size is assumed (even if the model itself was accurate). This is because sediment transport calculations are very sensitive to grain size. To illustrate this point, the average suspended sediment concentration was estimated for three different grain sizes (0.27, 0.10, and 0.05 mm) for a particular hydraulic condition (velocity = 3.3 ft/sec, depth = 10 ft, T = 50 F), similar to that assumed in Exhibit 4. The results are summarized in Table 1 below. Sediments of grain size 0.27 and 0.10 mm were considered to be non-cohesive. Suspended sediment concentrations were estimated based on the Einstein method (Julien 2010). In this approach, a near-bottom reference concentration is estimated based on a bedload transport calculation, and the Rouse Equation is used to determine the vertical distribution of suspended sediment. For the 0.05 mm sediment, a different calculation technique was used since the sediment would likely be cohesive. With cohesive sediment, resistance to motion is controlled by inter-particle forces instead of gravitational forces. The technique of Lavelle et al. (1984) of estimating a near-bottom reference concentration based on the sediment erosion rate and fall velocity was employed. Sediment erosion rate was estimated based on a linear erosion rate model in which erosion rate constant of 0.0032 kg m^{-2} s^{-1} Pa^{-1} was assumed (following Ravens and Gschwend 1999).

Grain size (mm)	Critical shear stress	Sediment fall velocity	Average suspended sediment concentration
[mm]	[Pa]	[mm/s]	[mg/liter]
0.27	0.2	30	10
0.10	0.1	9	3000
0.05	0.1	2	200

Table 1. Estimated suspended sediment concentrations for different grain sizes assuming an average velocity of 3.3 ft/sec and a depth of 10 ft.

The second implication of assuming the wrong grain size is that the modeling of the dredging-derived turbidity would be inaccurate. The time a given dredging-derived turbidity plume is suspended can be estimated based on the ratio of depth over the fall velocity. The fall velocity for 0.27 mm and 0.05 mm sediments is about 30 mm/s and 2 mm/s, respectively. Consequently, the finer sediment would be suspended for about 15 times as long and would be dispersed over 15 times the distance.

References:

Julien, P. Y. 2010. Erosion and Sedimentation, 2nd edition, Cambridge University Press.

Lavelle, J. W., Mofjeld, H. O., and Baker, E. T. (1984). ‘‘An in situ erosion rate for a fine-grained marine sediment.’’ *J. Geophys. Res.*, 89(C4): 6543–6552.

Ravens, T. M. and P.M. Gschwend. 1999. “Flume Measurements of Sediment Erodibility in Boston Harbor.” *J. of Hydraulic Engineering*. 125(10): 998-1005.

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Oct. 14, 2011

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At the request of Mark Chernaik, expert for Citizens Against LNG, I was asked to answer the following questions relating to the modeling of sedimentation impacts of pipeline construction in Haynes Inlet.

Q1. Could you describe your qualifications for answering the following questions? How many years have you studied hydrodynamic modeling of sedimentation that results from dredging activities? What peer-reviewed scientific publications on hydrodynamic modeling of sedimentation have you authored?

I have been modeling hydrodynamics and sediment transport in estuarine environments for 18 years. Some of the work that I have done tangentially addressed sediment transport impacts of dredging. My peer-review scientific publications that address hydrodynamics and sediment transport in coastal environments include:

Ravens, T., Jones B. M., Zhang, J., Arp, C. D., and J. A. Schmutz. Process-Based Coastal Erosion Modeling for Drew Point (North Slope, Alaska). *J. of Waterway, Port, Coastal, and Ocean Engineering* (in press).

Ravens, T. M., Thomas, R. C., Roberts, K. A., and P. H. Santschi. 2009. Causes of Salt Marsh Erosion in Galveston Bay, Texas. *J. of Coastal Research*, 25(2): 265-272.

Ravens, T. M. and M. Sindelar. 2008. Flume Test Section Length and Sediment Erodibility. *J. of Hydraulic Engineering*, 134(10): 1503-1506.

Rogers, A. and T. M. Ravens. 2008. Measurement of longshore sediment transport rates in the surf zone on Galveston Island, Texas. *J. of Coastal Research, 24(2): 62-73.*

Ravens, T. M. and R. C. Thomas. 2008. Ship wave-induced sedimentation of a tidal creek in Galveston Bay. *J. of Waterway, Port, Coastal, and Ocean Engineering.* 134(1): 21-29.

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Ravens, T. M., and K. I. Sitanggang. 2007. Numerical modeling and analysis of shoreline change on Galveston Island. *J. of Coastal Research*, 23(3): 699-710.

Ravens, T. M. 2007. Comparison of two techniques to measure sediment erodibility in the Fox River, Wisconsin. *J. of Hydraulic Engineering*, 133(1): 111-115.

Ravens, T. M., and R. A. Jepsen. 2006. CFD analysis of flow in a straight flume for sediment erodibility testing. *J. of Waterway, Port, Coastal, and Ocean Engineering*, 132(6): 457-461.

Ravens, T. M., and P. M. Gschwend. 1999. Flume measurements of sediment erodibility in Boston Harbor. *J. Hydraulic Engineering* 125(10): 998-1005.

Ravens, T. M., Madsen, O. S., Signell, R. P., Adams, E. E., and P. M. Gschwend. 1998. Hydrodynamic forcing and sediment quality in Boston Harbor. *Journal of Waterway, Port, Coastal, and Ocean Engineering.* 124(1): 40-42.

I would also point out that I am a regular reviewer of peer-reviewed Journals that address hydrodynamics and sediment transport including ASCE's Journal of Hydraulic Engineering, ASCE's Journal of Waterway, Port, Coastal and Ocean Engineering, Limnology and Oceanography, etc.

I earned my Ph.D. in Civil and Environmental Engineering from MIT. I have been tenured and promoted at both Texas A&M University and the University of Alaska.

Q2. What documents have you examined about the hydrodynamic modeling of sedimentation related to dredging in Haynes Inlet in Coos Bay?

1. Haynes Inlet – Trenched Sediment Transport and Sedimentation, dated 2011-09-21

2. Letter from Vladimir Shepsis, dated 2011-10-10

3. Report of Mark Chernaik, dated 2011-10-10 (see last section)

Q3. Could you please describe what "source terms" are in hydrodynamic modeling of sedimentation? Why would the disclosure of these source terms be indispensable for evaluating the validity of predictions from hydrodynamic models of dredging impacts?

Dredging and trenching operations are notorious for generating unwanted suspended sediment concentrations and deposition. For example, the recent dredging of PCB-contaminated sediments from the Hudson River has released a huge amount of sediments and contaminants. The EPA estimates that 440 kg of PCB's (largely born by sediments) was released (see the

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Executive Summary of the EPA Phase 1 Evaluation Report, March 12 2010). Sediment transport modeling of dredging operations should generally include a sediment production term that accounts for the introduction of suspended sediment into the water column. Data such as that cited in the report by Mark Chernaik (Exhibit 7) – showing the mass rate of sediment introduction due to clam shell dredging – should be used to assess the sediment transport impacts of dredging operations. However, a close reading of the statement provided by Vladimir Shepsis indicates that such an accounting of the particle generation of the dredging operation was not undertaken.

Vladimir Shepsis states:

My analysis is limited to the question of whether flow velocities resulting from pipeline construction will cause an increase in suspended sediment concentration and deposition of sediments in Haynes Inlet.

Thus, his analysis does not address the fate and transport of particles generated by the dredging project. His modeling only calculates the changed velocities that would result following dredged material placement and the increase in suspended sediment transport due to the changed velocity and – presumably - the changed bottom morphology. Again, there is no explicit accounting of suspended particles generated by the dredging and placement operation.

Although his statements are ambiguous[a], Vladimir Shepsis implies that more particles are generated **following** placement of dredged materials than during the dredging and placement process. If this is true, it is not common knowledge among sediment transport specialists. He should provide data or references to back up this assertion.

In addition to the issues raised above, it is important to point out that the statement provided by Vladimir Shepsis does not provide sufficient information to enable a full review of his sediment transport assessment. The statement provides little or no data on the character of the sediments. For sediment transport specialists, data on particle grain size distribution and fall velocity are critical. Also, it is critical to know whether the sediments are cohesive (fine) or non-cohesive (sand/gravel). If the particles are cohesive, then it is important to know the erodibility of the sediments. All of this basic information is missing.

The statement of Vladimir Shepsis does indicate that there would in fact be some elevated suspended sediment concentrations associated with the trenching. Further, he states that those suspensions would disperse and effectively disappear. This is not credible. Small concentration of particles can lead to significant deposition over time.

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[a] The ambiguous statement by Vladimir Shepsis is provided below:

Results from our analysis on this project and many other projects indicate that turbidity during placement of dredged material on an open bottom of a water body … is significantly higher than that during the digging of the same material.

Taking this statement at face value, it would appear prudent to assess the turbidity generated "*during the placement of dredged material*". However, elsewhere in his statement (see quote at the beginning of this section), he implies that turbidity generated during dredging and placement is minor compared to that which is generated following placement.

Q4. Do any of the documents you examined about the hydrodynamic modeling of sedimentation related to dredging in in Haynes Inlet in Coos Bay reveal the source terms?

As stated above, a close reading of the statements indicate that there was no accounting of the generation of particles due to the dredging/trenching operation.

Thom M. Raven

Tom Ravens, Ph.D.
Professor, Dept. of Civil Engineering
University of Alaska, Anchorage
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Exhibit 30

U.S. Department of Homeland Security
United States Coast Guard

Commanding Officer
United States Coast Guard
Sector Portland

6767 N. Basin Avenue
Portland, OR 97217
Phone: (503) 240-9307
Fax: (503) 240-9586

16611
July 1, 2008

Lauren O'Donnell
Director of Gas – Environmental & Engineering, PJ-11
Federal Energy Regulatory Commission
888 First Street, N.E., Room 62-45
Washington, DC 20426

WATERWAY SUITABILITY REPORT FOR THE JORDAN COVE ENERGY PROJECT

Dear Ms. O'Donnell:

This Waterway Suitability Report (WSR) fulfills the Coast Guard's commitment under the Interagency Agreement among the Federal Energy Regulatory Commission (FERC), the Research and Special Programs Administration (RSPA), and the Coast Guard for the Safety and Security Review of the Waterfront Import/Export Liquefied Natural Gas Facilities that was signed in February 2004. Under this agreement, our agencies work together to ensure that both land and maritime safety and security risks are addressed in a coordinated and comprehensive manner. In particular, the Coast Guard serves as a subject matter expert on maritime safety and security issues.

On June 11, 2008, the Coast Guard completed a review of the Waterway Suitability Assessment (WSA) for the Jordan Cove Energy Project (JCEP) that was submitted in September of 2007. This review was conducted following the guidance provided in Navigation and Vessel Inspection Circular (NVIC) 05-05 of June 14, 2005. The review focused on the navigation safety and maritime security risks posed by LNG marine traffic, and the measures needed to responsibly manage these risks. During the review, the Coast Guard consulted a variety of stakeholders including state and local emergency responders, marine pilots, towing industry representatives, members of the Ports and Waterways Safety Committee and the Area Maritime Security Committee.

Based upon this review, I have determined that Coos Bay is not currently suitable, but could be made suitable for the type and frequency of LNG marine traffic associated with this proposed project. Additional measures are necessary to responsibly manage the maritime safety and security risks. The specific measures, and the resources needed to implement them, where applicable, are described below and in a separate supplementary report which is being provided to you under the terms and conditions established for handling Sensitive Security Information (SSI). This supplemental report includes a copy of the Jordan Cove Waterway Suitability Assessment. This determination is preliminary as the NEPA analysis has not yet been completed.

The following is a list of specific risk mitigation measures that must be put into place to responsibly manage the safety and security risks of this project. Details of each measure, including adequate support infrastructure, will need further development in consultation with the Coast Guard and state and local agencies through the creation of an Emergency Response Plan as well as a Transit Management Plan that clearly spell out the roles, responsibilities, and specific procedures for the LNG vessel and all agencies responsible for security and safety during the operation.

Navigational Measures:

<u>LNG Tanker Size Limitations:</u> Based on the Ship Simulation Study conducted by Moffatt & Nichol on March 17-20, 2008, the maximum size LNG tanker permitted to transit through the Port of Coos Bay is a spherical containment LNG carrier with the physical dimensions of a 148,000 m^3 class vessel. The ship dimensions used in the study reflect a length overall of 950 feet, beam of 150 feet and a loaded draft of 40 feet. The channel must demonstrate sufficient adequacy to receive LNG carriers for any single dimension listed. Consequently, prior to approving the transit of an LNG ship larger than 148,000 m^3, or any increase in the physical dimensions cited, additional simulator studies must be conducted in order to assure the sufficiency of the channel.

- <u>Safety/Security Zone:</u> A moving safety/security zone shall be established around the LNG vessel extending 500-yards around the vessel but ending at the shoreline. No vessel may enter the safety/security zone without first obtaining permission from the Coast Guard Captain of the Port (COTP). The expectation is that the COTP's Representative will work with the Pilots and patrol assets to control traffic, and will allow vessels to transit the Safety/Security zone based on a case-by-case assessment conducted on scene. Escort resources will be used to contact and control vessel movements such that the LNG Carrier is protected.

  While the vessel is moored at the facility there shall be a 150 yard security zone around the vessel, to include the entire terminal slip. In addition, while there is no LNG vessel moored, the security zone shall cover the entire terminal slip and extend 25-yards into the waterway.

  Resource Gap: Resources required to enforce the safety/security zone are discussed under Security Measures in the supplemental report.

- <u>Vessel Traffic Management:</u> Due to a narrow shipping channel, navigational hazards, and the proximity to populated areas, LNG vessels will be required to meet the following additional traffic management measures:
  - A Transit Management Plan must be developed in coordination with the Coos Bay Pilot Association, Escort Tug Operators, Security Assets and the Coast Guard prior to the first transit.
  - This plan must be submitted to the COTP no less than 6 months to initial vessel arrival, and followed by an annual review to ensure that it reflects the most current conditions and procedures.
  - For at least the first six months, all transits will be daylight only, unless approved in advance by the COTP.
  - The LNG Vessel must board Pilots at least 5 miles outside the sea buoy.
    - Overtaking or crossing the LNG tanker within the security zone is prohibited for the entire transit from the Coos Bay Sea Buoy to mooring the vessel at the LNG terminal.
  - Vessel transits and bar crossings will be coordinated so as to minimize conflicts with other deep draft vessels, recreational boaters, seasonal fisheries, and other Marine Events.
  - 24 hours prior to arrival, the Coast Guard, FBI, Coos Bay Pilot Association, Escort Tug Masters, and other Escort assets will meet to coordinate inbound and outbound transit details.

Resource Gaps: The Vessel Transit Management Plan must be approved by the COTP at least 60 days prior to the first vessel arrival.

- Vessel Traffic Information System /Vessel Traffic System: The Port of Coos Bay does not have the capacity to receive Automatic Identification System (AIS) signals. AIS receiving capability must be established and must have the capacity to be used by appropriate agencies, port authorities and ship husbandry companies. Additionally, the Port does not have any means for continuous monitoring the navigable waterway. In order to ensure vessel safety and security, a robust camera system capable of monitoring the entire transit route must be established. Due to weather concerns, these cameras must be equipped with the means to adequately monitor vessel traffic in wind, rain and fog conditions.

  Resource Gaps: AIS receiver and camera systems including necessary hardware, software, staffing and training. Camera system must have complete coverage of the entire transit route, capable of detecting vessel traffic in wind, rain, fog, and dark conditions. Equipment and access to data feed of video imagery must be provided to state and local emergency operations centers impacted by the project.

- Tug Escort and Docking Assist: Due to the confined channel and high wind conditions, each LNG Carrier must be escorted by two tractor tugs, which will join the vessel as soon as safe to do so. The primary tug will be tethered at the direction of the pilot. A third tractor tug is required to assist with turning and mooring. Based on the Ship Simulation Study conducted by Moffatt & Nichol on March 17-20, 2008, vessels are limited to transiting during periods of high tide and 25 knot winds or less. While unloading, all three tugs will remain on standby to assist with emergency departure procedures.

  All three tractor tugs must be at least 80 Ton Astern Bollard Pull or larger and equipped with Class 1 Fire Fighting equipment.

  Resource Gaps: Three 80 Bollard Ton Tractor Tugs with Class 1 Fire Fighting capability.

- Navigational Aids:
  - Based on the Ship Simulation Study conducted by Moffatt & Nichol on March 17-20, 2008, four aids to navigation must be added and eight aids to navigation relocated on the waterway (pg. 12-17).
  - Physical Oceanographic Real-Time System (PORTS) must be contracted with NOAA to provide real time river level, current and weather data.

- LNG Carrier familiarization training for Pilots and Tug Operators: Prior to the arrival of the first vessel, simulator training must be provided for pilots and tug operators identified as having responsibility for LNG traffic.

Safety Measures:

Emergency Response Planning: Regional emergency response planning is limited in the region. Emergency response planning resources will need to be augmented to adequately develop emergency response procedures and protocols as well as continuously update those plans as conditions change.

Resource Gap: To be determined in conjunction with local and regional response agencies through the Emergency Response Planning process.

- Vessel and Facility Inspections: LNG tankers and facilities are subject to (at a minimum) annual Coast Guard inspections to ensure compliance with federal and international safety, security and pollution regulations. In addition, LNG vessels and facilities are typically required to undergo a pre-arrival inspection, and transfer monitor.

  Resource Gap: Additional Coast Guard Facility and Vessel Inspectors.

- Shore-Side Fire-Fighting: Firefighting capability is limited in the area surrounding the proposed LNG terminal. Shore side firefighting resources and training will need to be augmented in order to provide basic protection services to the facility as well as the surrounding communities along the transit route.

  Resource Gap: To be determined in conjunction with local and regional response agencies through the Emergency Response Planning process.

- In-Transit Fire-Fighting: Firefighting capability is limited along the entire transit route for proposed LNG vessels.

  Resource Gap: A plan must be developed for managing underway firefighting, including provisions for command and control of tactical fire fighting decisions as well as financial arrangements for provision of mutual aid and identification of suitable locations for conducting fire fighting operations along the transit route. To be determined in conjunction with local and regional response agencies through the Emergency Response Planning process.

  Public Notification System and Procedures: Adequate means to notify the public along the transit route, including ongoing public education campaigns, emergency notification systems, and adequate drills and training are required. Education programs must be tailored to meet the various needs of all waterway users, including commercial and recreational boaters, local businesses, local residents, and tourists.

  Resource Gap: A comprehensive notification system, including the deployment of associate equipment and training, must be developed. To be determined in conjunction with local and regional response agencies through the Emergency Response Planning process.

- Gas Detection Capability: No gas detection capability exists at the Port of Coos Bay, along the transit route and at the site of the proposed facility. Emergency response personnel require appropriate gas detection equipment, maintenance, and training. Additionally, the use of fixed detection equipment will ensure accurate and expedited gas detection in the event of a large scale LNG release. The installation of these detectors at strategic points along the waterway must be developed.

Resource Gap: Gas Detectors, appropriate training, and maintenance infrastructure. To be determined in conjunction with local and regional response agencies through the Emergency Response Planning process.

Security Measures:

- Security Boardings, Waterway Monitoring, and Vessel Escorts: Extensive security measures will be required to provide adequate protection for LNG vessels in transit to and while moored at the facility. The details of these measures are SSI, and are outlined in a separate supplementary report.

- Facility Security Measures: LNG facilities are subject to the security regulations outlined in 33 CFR 105, and are required to submit a Facility Security Plan (FSP) for Coast Guard approval, and undergo (at a minimum) an annual Coast Guard security inspection. The facility shall also develop a plan to provide for appropriate security measures from the start of construction through implementation of the Coast Guard approved FSP.

- Sandia Study: The WSA proposes the potential to receive vessels with up to 217,000 m^3 cargo capacity. The Sandia Report is based on consequences of LNG breaches, spills and hazards associated with LNG vessels having a cargo capacity no greater than 148,000 m^3 and spill volumes of 12,500 m^3. There remains some question as to the size of hazard zones for accidental and intentional discharges and the potential increased risk to public safety from LNG spills on water for larger vessels. Based on these existing uncertainties, Jordan Cove must either complete a site-specific analysis for the largest sized LNG vessel or limit arrivals to vessels with a cargo capacity no greater than 148,000 m^3 until additional analysis addressing vessels with higher cargo capacities is completed. However, this requirement is contingent on the requirement for US Coast Guard approval to receive LNG tankers larger than 148,000 m^3.

In the absence of the measures described in this letter and the resources necessary to implement them or changes in Coast Guard policy upon which the resource decisions are based, Coos Bay would be considered unsuitable for the LNG marine traffic associated with the Jordan Cove LNG Terminal. The applicant shall be required to submit an annual update to the Waterway Suitability Assessment to the Coast Guard which shall be revalidated by the COTP and AMSC. For further information, please contact Mr. Russ Berg of Coast Guard Sector Portland at (503) 240-9374.

Sincerely,

F. G. Myer
Captain, U.S. Coast Guard
Captain of the Port
Federal Maritime Security Coordinator

Copy: Thirteenth Coast Guard District (dp)
Coast Guard Pacific Area (Pp)
Commandant, Coast Guard Headquarter (CG-52), (CG-522), (CG-544)
Maintenance and Logistics Command Pacific (Sm)

Exhibit 31

COOS BAY HARBOR SAFETY PLAN

Coos Bay Harbor
Safety Committee

February 2018

TABLE OF CONTENT

1. Executive Summary

1.1 Introduction

The Coos Bay Harbor Safety Committee (CBHSC) is a volunteer committee comprised of industry stakeholders; local, state and federal agencies; and waterway user groups to help improve local coordination and leadership within the harbor. The committee was created under the recommendation of the Interagency Committee for the Maritime Transportation System (ICMTS) and the MTS National Advisory Council (MRSNAC) which were created following a report to Congress from the Maritime Transportation System (MTS) Task Force in September of 1999.

The purpose of the CBHSC is to recommend actions to improve the safety, security, mobility and environmental protection of Coos Bay and its waterways through:

- Effective communication and coordination between stakeholders
- Alignment with local, state and federal laws and regulations
- Identification and mitigation of hazards to navigational safety
- Collaboration with governmental agencies to improve and promote maritime and environmental safety within the committee's area of responsibility.

The Coos Bay Harbor Safety Committee (CBHSC) is an open forum comprised of public and private stakeholders in Oregon with vital interests in assuring safe navigation to protect the environment, property, and personnel on the waterways within the Coos Bay Region.

The CBHSC stakeholders accomplish the mission by adopting or developing appropriate standards and guidelines that address environmental and operational elements of maritime operations unique to the Coos Bay Region.

The CBHSC provides an inclusive, cooperative and equitable venue for addressing waterways issues to ensure the continuation and improvement of prudent management practices for our local waterways. Throughout the process, the CBHSC strives to ensure reliable and efficient marine transportation.

The CBHSC Charter is included in this plan under Appendix A.

1.2 The Harbor Safety Plan.

The plan has been adopted by Coos Bay in an effort to maintain and promote safety among all of the harbors users and create a platform for communication and collaboration. Guidance in setting up this Harbor Safety Committee and in developing this plan was taken from the US Coast Guard Navigation Circular (NVIC) 1-00; by attending other harbor safety committee meetings and from existing harbor safety plans from the states of Washington and California. The CBHSC's area of responsibility begins at the seaward approaches into Coos Bay and continues into the bay, and includes navigable tributaries within the bay.

1.2.1 Plan Implementation

The Coos Bay Harbor Safety Plan (CBHSP) is intended to complement existing regulations by advising the mariner of unique conditions and requirements that may be encountered in the region by providing standards of care and protocols developed by local experts. The CBHSP will be implemented through consensus agreement and cooperation from industry members, state and federal agencies, pilots and the Port of Coos Bay to follow the plan to the fullest extent possible barring any unforeseen circumstance that may warrant a change. The CBHSP is not intended to replace the good judgment of a ship's master in the safe operation of his/her vessel.

1.2.2 Plan Maintenance

The CBHS Committee will review the Harbor Safety Plan on an annual basis to ensure all information is up to date. Recommendations may be made to incorporate new information or additional standards of care at any regular meeting of the CBHS Committee. Plan updates are included in Appendix L and recommendations in Appendix I.

1.3 Harbor Safety Committee

The Committee General membership is responsible for providing recommendations, direction, and support within the committee's area of responsibility.

1.3.1 Chair:

The seven (7) member Board is made up of individuals representing the following waterway users.

1. Coos Bay Pilot Association
2. Stevedoring Company
3. Marine Terminal Operator, lower bay
4. Marine Terminal Operator, upper bay
5. International Oregon Port of Coos Bay
6. Fishing Representative
7. Public Representative

Officers are nominated and elected by a vote of a simple majority of a quorum of the Managing Board. Candidates for Officers are selected from the membership of the Managing Board.
Officer Positions include Chair, Vice Chair, and Secretary.

1.3.2 Members:

Members consist of individuals from companies, organizations, state and federal agencies as defined in the Charter.

Names and contact information can be obtained by emailing the Coos Bay Harbor Safety Committee at Coosbayharborsafety@gmail.com.

2 General Information

2.1 Geographical Boundaries

The Committees geographic region of responsibility (in blue boxes) begins at the seaward approach into Coos Bay, continues into the Bay and includes navigable tributaries within the Bay.

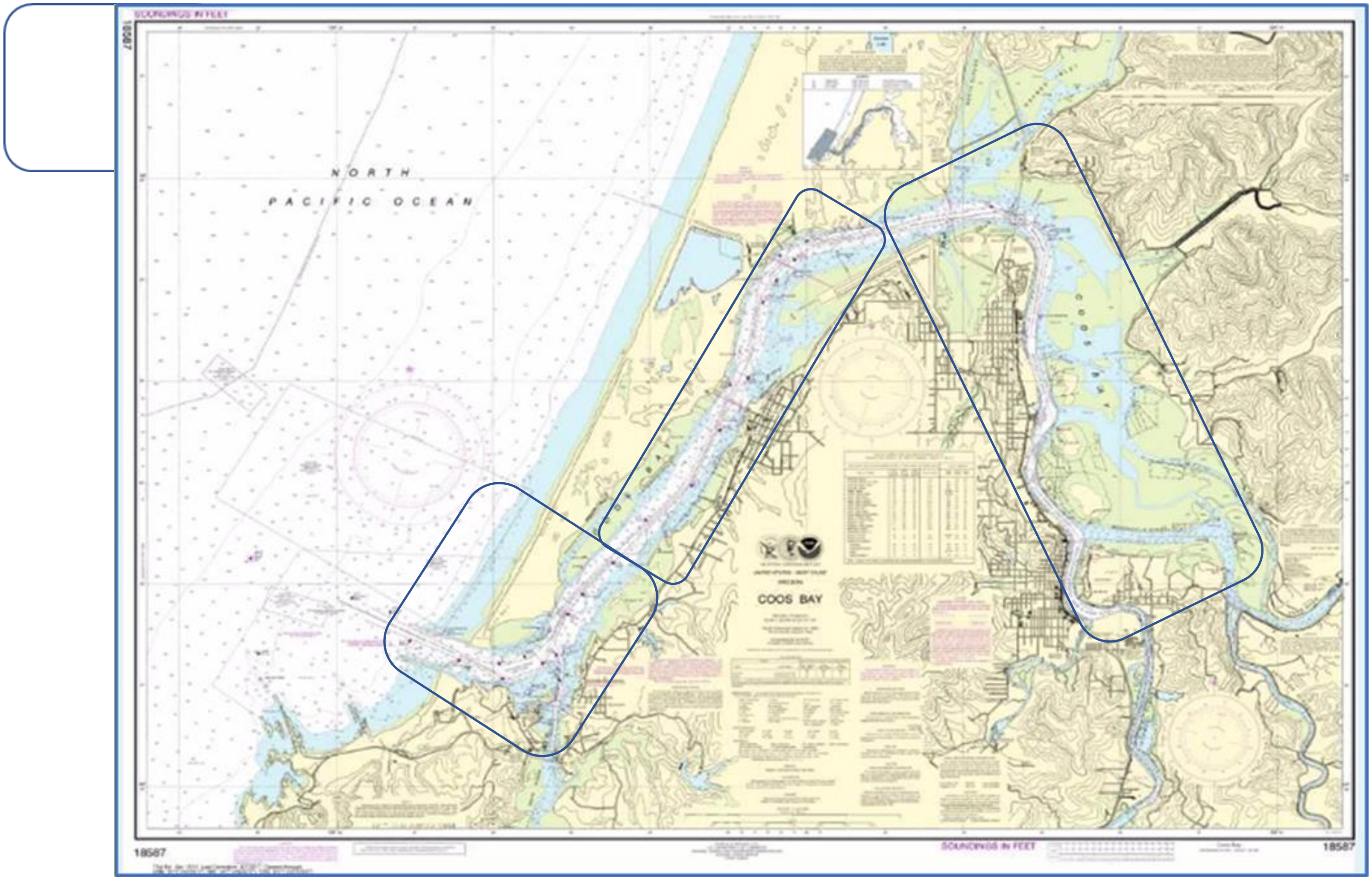


FIGURE 1 - NOAA CHART COOS BAY AND CBHSC AREA OF RESPONSIBILITY

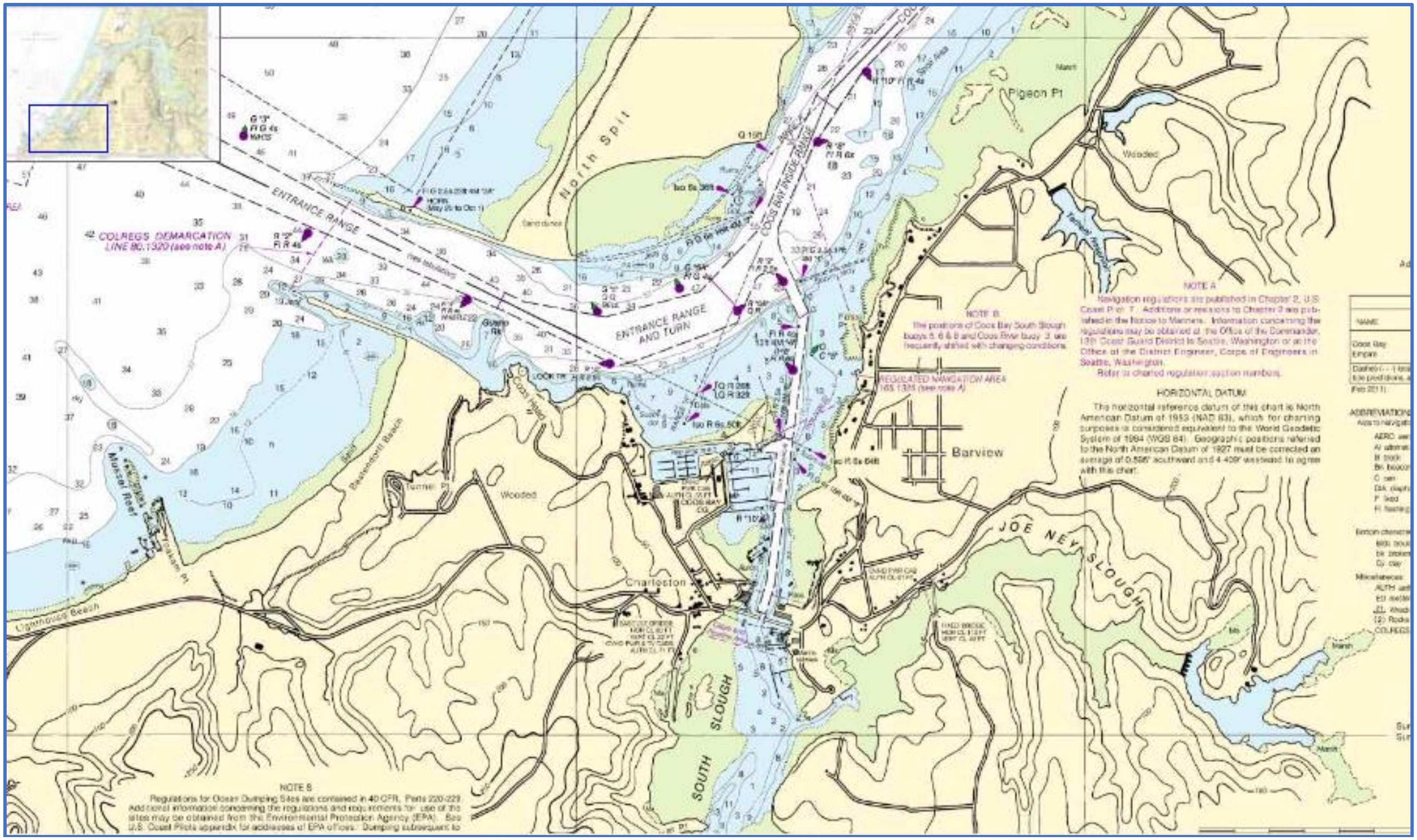


FIGURE 2 - SECTION OF CHART 18587 – ENTRANCE OF COOS BAY

This Section of Chart 18587 shows the Colreg Demarcation line and harbor entrance flanked by jetties with Charleston Channel and Boat Basin and South Slough to the south.

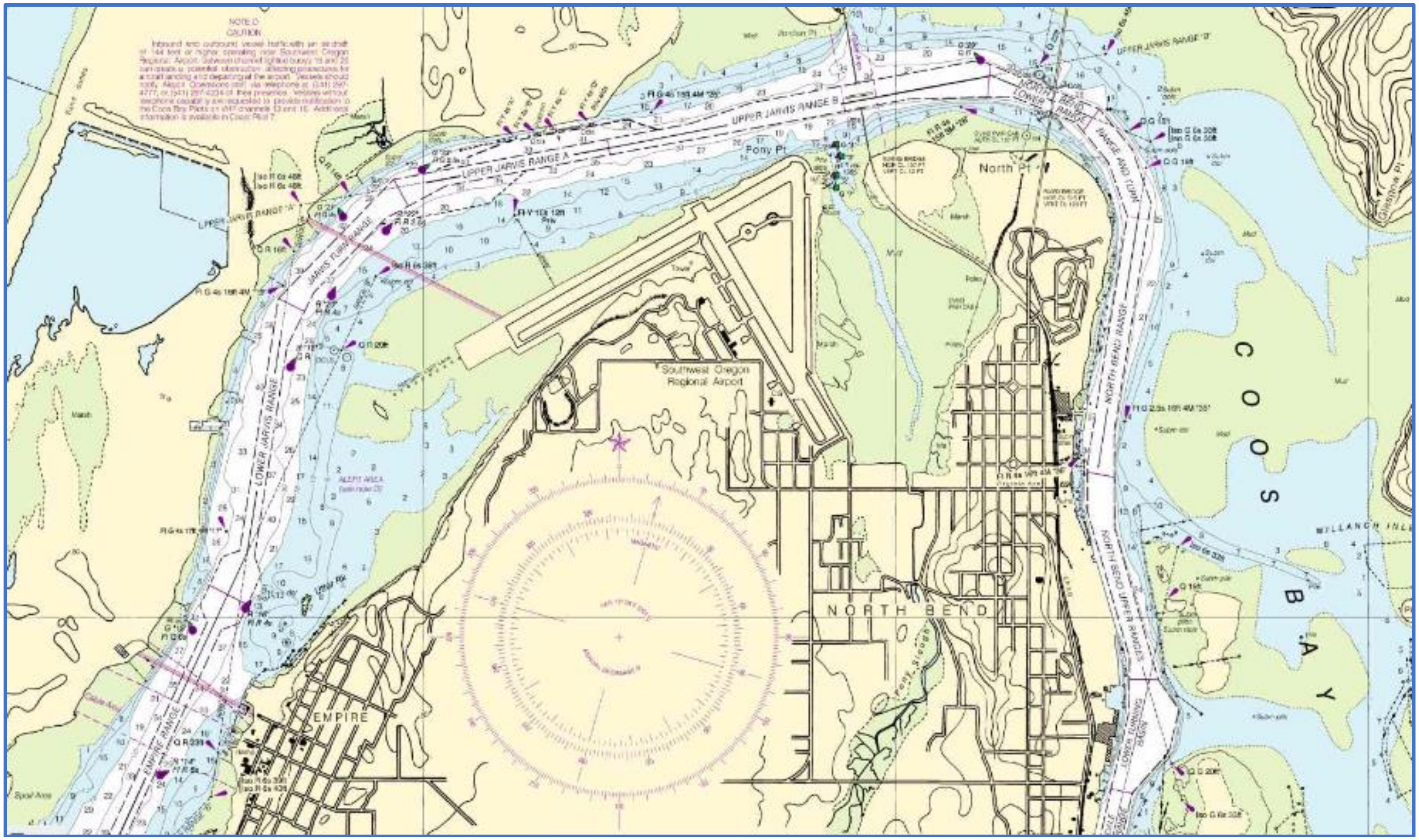


FIGURE 3 - SECTION OF CHART 18587- TOWNS OF EMPIRE AND NORTH BEND

Section of Chart 18587 showing the towns of Empire and North Bend and the airport in between.

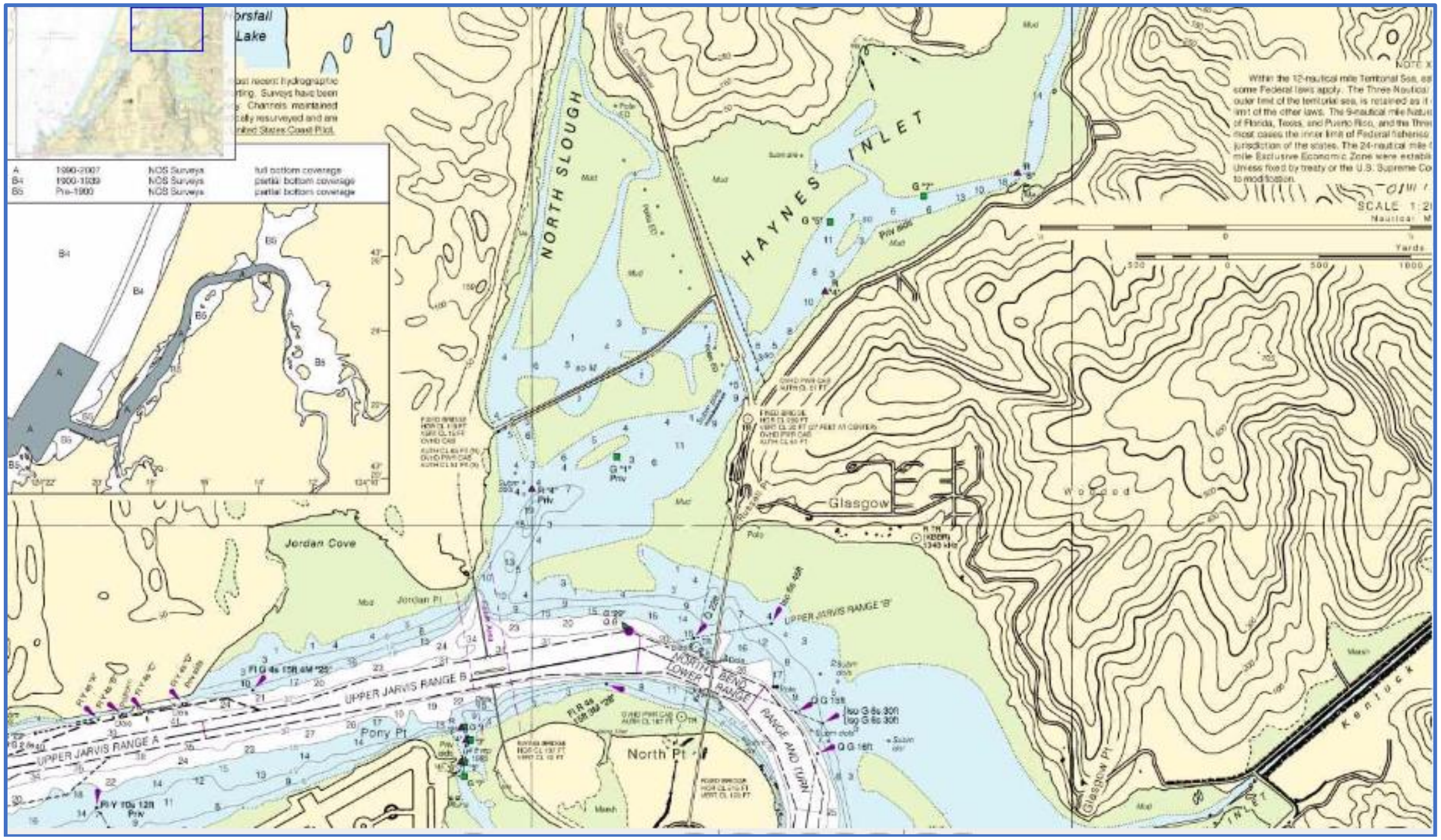


FIGURE 4 - SECTION OF CHART 18785 - JORDAN COVE TO HAYES INLET

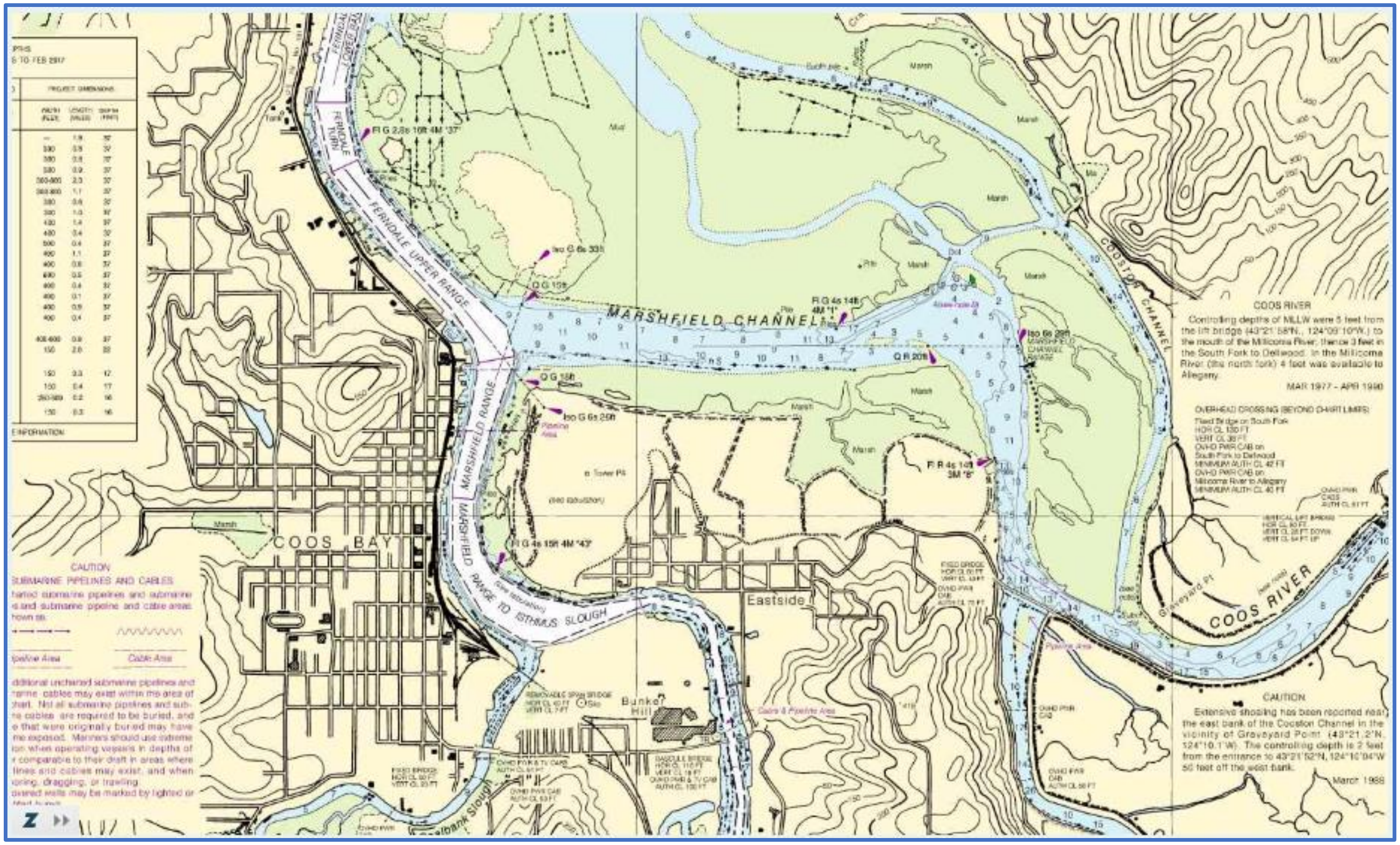


FIGURE 5 - SECTION OF CHART 18785 - TOWN OF COOS BAY, MARSHFIELD, COOSTON CHANNEL, ISTHMUS SLOUGH AND THE COOS RIVER

2.2 Economic and Historical Background

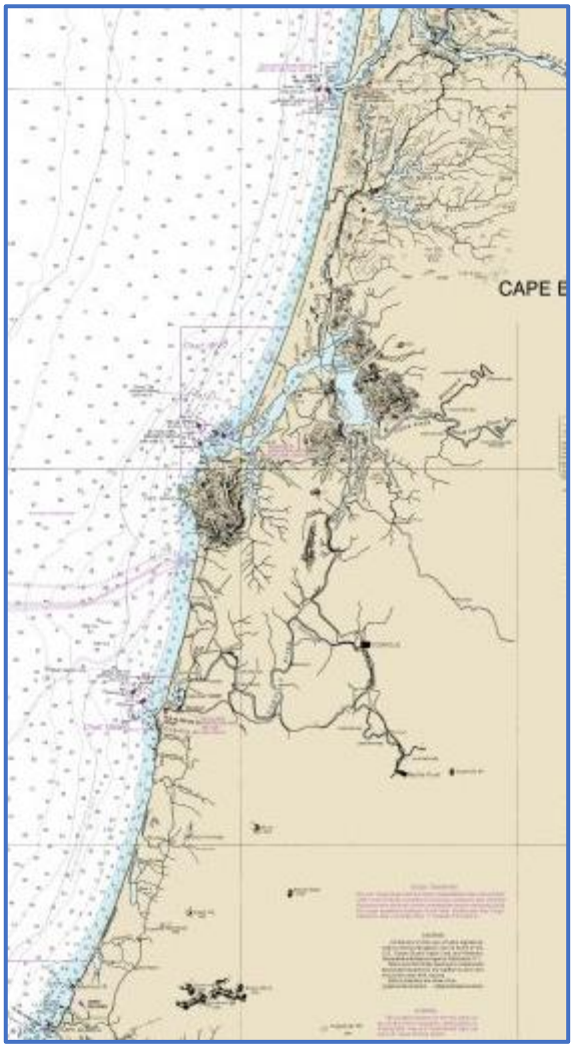


FIGURE 6 - SECTION OF CHART 18580 - OREGON COAST SHOWING COOS BAY

Coos Bay is the largest coastal harbor between San Francisco and Puget Sound, and Oregon’s second busiest maritime port. The federally authorized and maintained deep-draft navigation channel is under the management and oversight of the US Army, Corps of Engineers. Manufactured forest products and wood fiber exported from the port’s marine terminals continue to make it one of the leading wood products shipping centers of North America. The Port imports and exports logs and exports large quantities of wood chips which are used in making paper products and biomass fuels.

The port’s vision is to promote the optimal use of Coos Bay's deep-water port for the enhancement of the economy and quality of life in the region.

Historically, wood products, commercial fishing, and shipping have been the mainstays of the Bay area’s economy; more recently tourism has become an important segment. Though it has waned, the port is still one of the leading centers for the lumber and wood products industry. The area is also known for its 32 million pounds of seafood landed annually by crabbers (Dungeness crab), trollers and trawlers fish for chinook salmon, albacore tuna, and pink shrimp.

Oregon International Port of Coos Bay is designated a State Port; consequently, members of the Board of Commissioners are appointed by the Governor and confirmed by the Oregon Senate for 4-year terms. Commissioners must be residents of the Port District.

The Port Authority, the Oregon International Port of Coos Bay, is controlled by a Board of Port Commissioners and an Executive Director. Harbor regulations, under Oregon Revised Statute 777, are prescribed by the Port Commissioners and enforced by the Executive Director. The Port owns 700 acres of the property but they do not operate any of the maritime facilities with the exception of the Charleston Marina. The marina is located just inside the entrance to Coos Bay and is home to a fishing and recreational fleet of 400-500 boats.

3 Coos Bay

Thirty-three (33) miles north of Cape Blanco, Coos Bay is used as a harbor of refuge and can be entered at any time except in extreme weather. From the entrance, the bay extends northeast for 8 miles with widths of 0.3 to 1 mile, then bends southeast for about 4 miles to the mouth of Isthmus Slough. The dredged channel through the bay is bordered by marshland and intersected by several sloughs.

The entrance to Coos Bay is located at latitude 43° 22' North/Longitude 124 ° 22' West. The Coos Bay Sea Buoy is approximately 173 nautical miles/320 km south of the Columbia River, and 367 nautical miles/680 km north of the entrance to San Francisco Bay.

3.1 Prominent features

Coos Head is a good guide to the entrance. The sand dunes north toward Umpqua River are prominent. The entrance to the bay is protected by jetties. A light with a seasonal sound signal marks the north jetty. A lighted whistle buoy ((RW "K" MO (A) Whis)) is 1.8 miles west-north-west of the entrance. The channels are marked with lighted ranges, lights, buoys and day beacons. Although no longer lighted, Cape Arago Lighthouse is a prominent 44-foot white octagonal tower attached to a building on a rocky, partially wooded island close inshore, 2.5 miles north of the cape.

3.2 Routes

There is usually a current sweeping either north or south just off the jetties, and this current should be guarded against. The entrance ranges should be watched carefully until clear of all dangers. The south current is often encountered during the summer. With strong south winds during the winter, the current sometimes sets to the north.

Approaching from any direction in thick weather, great caution is essential. The currents are variable and uncertain. Velocities of 3 to 3.5 knots have been observed offshore between Blunts Reef and Swiftsure Bank, and greater velocities have been reported. The most favorable time for crossing the bar is on the last of the flood current, and occasionally it is passable only at this time.

3.3 Coos Bay Channel

Coos Bay's short 15-mile Federal navigation channel helps ensure that inbound and outbound cargoes move rapidly and efficiently through the harbor's marine terminals to domestic and international markets. Travel time from ocean to land is only 90 minutes.

3.3.1 Depths and Widths

A Federal Project provides for a 37-foot deep and nominal 300-foot-wide channel across the bar to the railroad swing bridge at Pony Point, and then is 400-foot-wide to the end of the navigation channel at a point 1.1 mile above the mouth of Isthmus Slough, and thence, 22 feet to Millington, 14.7 miles above the entrance to the bay. Turning basins at North Bend and Coos Bay have depths of 37 feet.

COOS BAY ,ISTHMUS SLOUGH AND CHARLESTON CHANNEL DEPTHS
TABULATED FROM SURVEYS BY THE CORPS OF ENGINEERS • SURVEYS TO NOV 2016

CONTROLLING DEPTHS FROM SEAWARD IN FEET AT MEAN LOWER LOW WATER (MLLW)					PROJECT DIMENSIONS		
NAME 01' CHANNEL	OUTSIDE QUARTER	HALF OF CHANNEL	OUTSIDE OUAATER	DATE OF SUAIIEY	WIDTH (FEET)	IENGTH (MILES)	DEI'Tt1 (FEET)
ENTRANCE RANGE	39	39	40	816	—	1.9	37
ENTRANCE RANGE AND TURN	38	44	33	11·16	300	0.8	37
COOS BAY INSIDE RANGE	38	38	38	11-16	300	0.8	37
COOS BAY RANGE	37	37	36	1116	300	0.9	37
EMPIRE RANGE	3D	37	30	10-16	300-800	2.3	37
LOWER JARVIS RANGE	S4	38	21	1016	300-800	1.1	37
JARVIS TURN RANGE	37	41	34	1 16	300	0.6	37
UPPER JARVIS RANGE A	37	37	3S	1 16	300	1.0	37
UPPER JARVIS RANGE B	3S	37	36	1 16	400	1.4	37
NORTH BEND LOWER RANGE	36	39	36	1 16	400	0.4	37
RANGE AND TURN	34	39	38	10·16	500	0.4	37
NORTH BEND RANGE	33	38	35	10-16	400	1.1	37
NORTH BEND UPPER RANGES	35	38	37	1 16	400	0.8	37
LOWER TURNING BASIN	37	38	38	10-16	B00	0.5	37
FERNDALE LOWER RANGE	32	38	34	9 16	400	0.4	37
FERNDALE TURN	20	33	35	9·16	400	0.1	37
FERNDALE UPP£A RANGE	8	27	24	916	400	0.9	37
MARSHRELD RANGE	28	25	17	9·18	400	0.4	37
MARSHRELD RANGE TO ISTHMUS SLOUGH	19	17	25	9 18	400-600	0.9	37
ISTHMUS SLOUGH	19	20	19	4-85	150	2.0	22
CHARLESTON CHANNEL							
ENTRANCE	18	19	18	10·18	150	0.3	17
ENTRANCE TO BASIN	18	18	16	10-16	150	0.4	17
BASIN	15	15	16	10-16	250.000	0.2	16
BASIN TO BRIDGE	16	18	16	10·16	150	0.3	16

NOTE· CONSULT THE CORPS OF ENGINEERS FOR CHAHGES SUBSEOUENT TO THE ABOVE INFORMATION

FIGURE 7 - CHANNEL DEPTHS, 2016 SURVEY

3.3.2 Tidal Range

Tidal Ranges

- Mean 5.6 feet/1.7 meters
- Diurnal 7.3 feet/2.2 meters
- Maximum 12 feet/3.7 meters
- Tidal ebb to 3 knots

3.3.3 Dredging Plans

The USACE maintains the 15.2-mile federal navigation channel and the Charleston channel to the Bascule bridge, South Slough. Dredging for the federal projects is completed based on annual appropriations and critical needs. The Oregon International Port of Coos Bay holds and maintains a Unified dredging permit for 18 public and private terminals and marinas within the bay. This permit authorizes these facilities to fund and conduct dredging operations within their authorized dredge prism. Dredging operations can be conducted under the Unified permit during the authorized In-Water Work Period (IWWP) from October 1st to February 15th. An IWWP Variance may be requested and approved on a case-by-case basis.

3.3.4 Coos Bay Channel Modification Project

The Port of Coos Bay is proposing to deepen and widen the Federal navigation channel through a project that will expand the existing channel from -37 feet depth and a nominal 300 feet width to -45 feet depth and nominal 450 feet width from the channel entrance to river mile 8.2.

3.4 Charleston Channel

The channel is maintained 150 feet wide and 20 feet deep and starts upstream of Buoy 6A and ends at the Bascule Bride. The channel is mostly used by recreational boaters and the commercial fishing fleet.

3.5 Anchorage

Anchorage for small craft is available almost anywhere in the bay outside the dredged channels. However, there are no dedicated anchorages outside of Coos Bay or within the harbor for larger commercial vessels. The bottom conditions outside the harbor are sandy with moderate holding power. Inside the harbor within the channel, the bottom is sandstone mixed with sand/silt. While anchoring in the channel by deep draft vessels can be accomplished under certain circumstances at the Pilot’s discretion, it is not frequently done.

Due to the rapid and severe onset of weather from the North Pacific Ocean, anchorage in the ocean outside of Coos Bay is reported not safe and is dangerous during the winter months. Like all unprotected areas along the Oregon coast, large swells and heavy winds characterize the area during the winter. These conditions can suddenly and unexpectedly besiege the unwary with catastrophic results. The prevailing direction of both swell and wind will drive disabled or improperly handled vessels onto the shore.

While desired, there are currently no designated anchorage areas off the coast or within the channel, primarily due to the grounding of the M/V New Carissa in 1999 off the coast of Coos Bay.

3.6 Layberths

There are no designated layberths, but vessels may request and coordinate the use of a private berth/docks with the facility in question.

3.7 Navigational Dangers

- Guano Rock, on the south side of the entrance channel and 280 yards northwest of Coos Head. It never uncovers even during extreme low tides.

- Submerged Jetties:
  - A submerged section of the north entrance jetty extends about 450 yards west of the visible jetty, and a submerged section of the south entrance jetty extends about 100 yards west of the visible jetty. Because of the submerged jetties, it is reported that there are breakers in these areas most of the time. Extreme care must be exercised at all times.
  - A submerged jetty extends 500 yards off the east shore of Coos Bay just inside the entrance, 0.8 miles northeast of Coos Head. In entering with a strong northwest wind, large vessels have difficulty in making the turn and may find themselves being set toward the submerged jetty.

- Coos Bay Rail Bridge: This is a swing bridge kept in the open position when no trains are crossing. Mariners should use extreme caution when passing through the bridge because of unpredictable changing winds, currents, and sea conditions reported in this area. The location of the Upper Jarvis ranges in relation to the bridge opening is offset 35 feet to the North, resulting in vessel passing closer to the center support of the bridge.

- Southwest Oregon Regional Airport: For safety reasons, the FAA limits the height of vessel transiting in front of the runway. Inbound and outbound vessel traffic near the Airport may affect procedures for aircraft landing and departing at the airport. Vessels with an air draft of 144 feet or greater present a potential obstruction to airspace that requires advisories be issued to aircraft by air traffic controllers, and in some cases, runway use may need to be restricted. See Special Navigational Conditions for more for more details.

- Crab Fishing Gear: Heavy concentrations of fishing gear may be expected off Coos Bay and along the coast between December 1 and August 15, from shore to about 30 fathoms. To reduce the destruction of fishing gear by vessels and to reduce the fouling of propellers and shafts by fishing gear, Washington Sea Grant, Washington State University Extension has coordinated an agreement between towboat operators and crab fishermen for the establishment of towboat lanes along the Pacific coast between San Francisco, California and Cape Flattery, Washington. Copies of the agreement showing fishing areas and towboat lanes may be obtained from Washington Sea Grant, Washington State University Extension, Box 88, South Bend, WA 98586; telephone 360–875–9331 and have been distributed to the towboat operators and the Dungeness crab fishery. This information can also be obtained on the Washington State University website:

https://wsg.washington.edu/wordpress/wp-content/uploads/Towlane-Chartlets-WA-OR-CA.pdf.

- However, despite the ongoing issue of crab gear being caught up in towboat propellers and towing gear, there are no designated tow boat lanes for the Coos Bay area during the crabbing season.

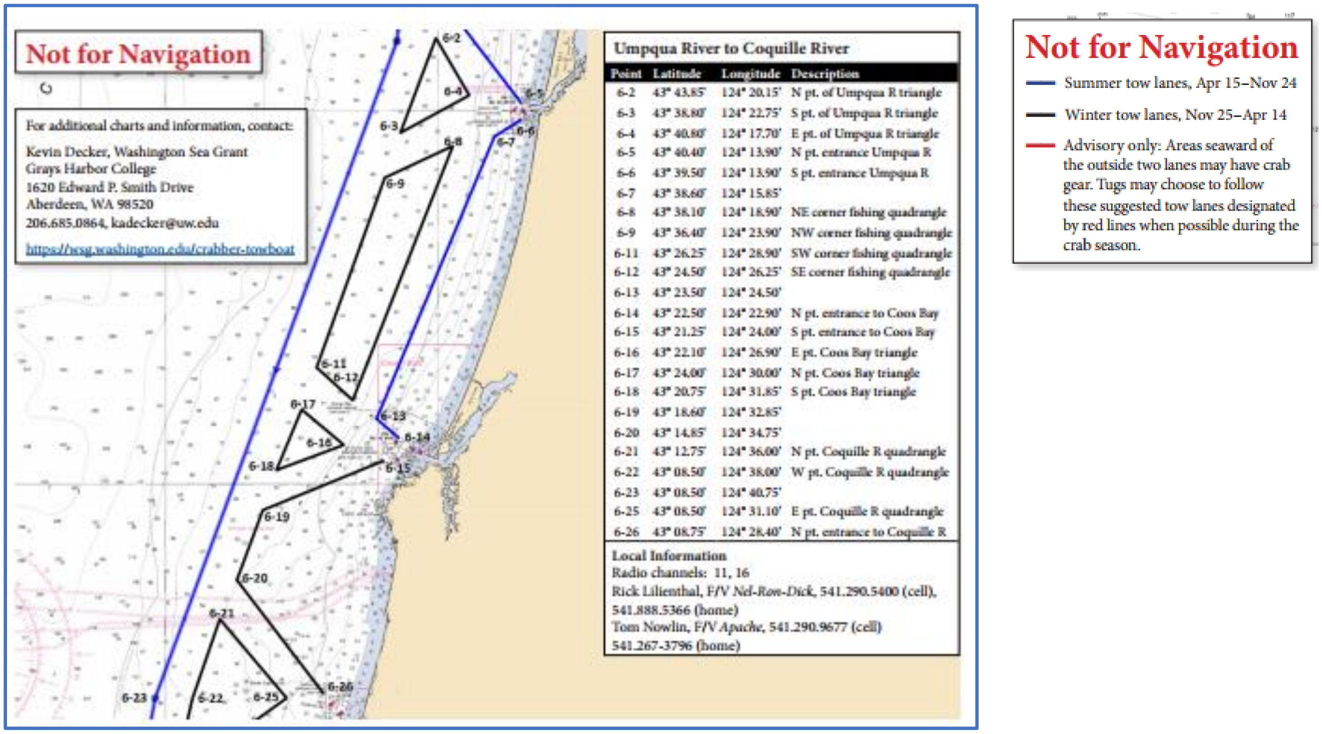


FIGURE 8 - COOS BAY TOW LANES

In June of 2017, The Oregon Dungeness Crab Commission has provided thumb drives containing the tow boat lanes along the coast in OR and WA and where the crab fisher traditionally drop their ports. These thumb drives were distributed by CBHSC to the tugboats companies (Amex, Foss, Dunlap, Brusco, Sause Brothers,). By educating both groups as to where the towing lanes and crabbing areas are, the CBHSC hopes to minimize the conflict between the two user groups.

3.8 Bridges

Coos Bay channel has three bridges running across it. Two are fixed and the other is a swing bridge for the railroad.

- The Coos Bay Link railroad bridge: This swing bridge is located 7.5 miles above the entrance, has a swing span with a vertical clearance of 12 feet in the closed position and a horizontal clearance of 197 feet in the open position. The bridgetender monitors VHF channel 18A and works on channel 13 when they are on the bridge for a train crossing. The rest of the time the bridge is unmanned and kept in the open position. For railroad status, information can be obtained from Coos Bay Rail Link at (541) 266-7245.

- The McCullough Memorial bridge is a fixed highway bridge, 8.7 miles above the entrance, has a clearance of 123 feet vertical clearance at the channel’s edge and 149 feet vertical clearance at the center of the span at Mean Lower Low Water (MLLW) tide and have a horizontal clearance of 515 feet.
- 100 yards west of the McCullough bridge is an overhead power cable bridge has a vertical clearance of 167 feet.

The Charleston Channel has one bridge:

- Bascule (Charleston) Bridge: Horizontal clearance is 80 feet and vertical clearance in the closed position is 22 feet (it is a lift cantilever bridge). There are overhead power cables on the south side of the bridge with a vertical clearance of 71 feet.

3.9 Pilotage

There is no Vessel Traffic System (VTS) covering the Coos Bay area or any other harbor along the Oregon Coast.

Pilotage is compulsory for all foreign vessels and all U.S. vessels under registry (except fishing and sail vessels). Pilotage is optional for U.S. vessels in the coastwise trade that have onboard a Pilot licensed by the Federal Government for these waters. Pilotage for Coos Bay, its tributaries, and Yaquina Bay is available from the Coos Bay Pilots Association. 686 N Front Street,
Coos Bay, OR 97420; Telephone (541) 267- 6555.

The pilot boats monitor VHF-FM channels 13 and 16 and use channels 12 and 18A as working frequency. The pilot boats, COOS BAY and NORTH BEND, are 76 and 72 feet respectively long tugs with black hulls, orange bands around the house, and white superstructure. The pilot boats use the standard pilot lights (red over white) at night. Vessels are handled 24-hours a day, with weather permitting. Arrangements for pilots are usually made by ships' agents or by telephone. A 24-hour notice of the time of arrival is requested. The pilots usually board vessels about 2 miles NW of Coos Bay Approach Lighted Whistle Buoy K. Vessels are requested to maintain a speed of about 6 to 7 knots and rig the ladder, without man-ropes, about 2.5 meters (8.2 feet) above the water.

The pilots were asked about emergency procedures in the event that a ship lost power or lost steering. In nearly all cases, the pilots would allow the ship to drift forward and easily set the side of the ship into the sand. In all cases, the pilots have a standby tug (the pilot boat) which is able to influence the movement of the ship. The pilot boat always moves just ahead of the ship or alongside depending upon the orders from the pilot. The Pilots would always avoid having the ship end up crossways in the channel with a bow on one side and the stern on another side of the channel.

3.10 Towage

There are seven tugs are available and are used for docking and mooring. There are no federal or state rules or guidelines establishing escort or ship assist requirements for vessels visiting Coos Bay, OR. Escort and ship assist tugs should meet classification society standards appropriate for escort and ship assist tugs.

Escort and ship assist tugs in Coos Bay which meet the requirements for large vessels operating in narrow channels shall have their bollard pull (ahead and astern) measured as provided below.

(1) Bollard pull measurements shall be verified by a member of the International Association of Classification Societies.

(2) Bollard pull measurements verified by a member of the International Association of Classification Societies in other ports of the State shall meet the requirements of this section, provided that evidence of the results of these measurements are on file with the Coos Bay Harbor Safety Committee.

(3) Companies providing escort and ship assist tugs shall provide the Coos Bay Harbor Safety Committee with the results of the bollard pull measurements verified pursuant to these provisions.

(4) Escort and ship assist tugs whose bollard pull has not been measured and verified or are not within the scope of the definition of "bona fide sister tug", shall not be used for the escort and/or ship assist of large vessels in Coos Bay.

An escort and/or ship assist tug determined by the Coos Bay Harbor Safety Committee to be a "bona fide sister tug" may be used with the same (ahead and astern) bollard pull as the certified sister tug.

The braking force shall be re-measured after any modifications and/or repairs to the main engines, hull, shaft-drive line, or steering, that could affect the bollard pull. The new measurements must be registered with the Coos Bay Harbor Safety Committee.

Notwithstanding any other provision of this plan:

(1) The vessel master remains responsible for the safe navigation and maneuvering of the vessel in all circumstances. The requirements outlined in this plan are in addition to, and not a limitation of, any other responsibilities created by custom, law, or regulation.

(2) Where an emergency exists, the vessel master may adjust the minimum escort and/or ship assist tug requirements. For purposes of this plan, an emergency is defined as any of, but is not limited to, the following:

- (A) the imminent and immediate danger to the vessel, its cargo or its crew;
- (B) the imminent and immediate danger to a marine terminal, ship assist or escort tug;
- (C) the imminent and immediate danger to a vessel in the proximity of the escorted vessel; or
- (D) any emergency declared by the United States Coast Guard, Captain of the Port which would necessitate a modification to the provisions set forth in this plan.

TABLE 1 - COOS BAY TOWING VESSELS

Vessel Name	Registered Owner	Type	Call Sign	Horsepower	Bollard Pull
Coos Bay	Coos Bay Pilots	Propeller	WY 6046	1,700	lbs
North Bend	Coos Bay Pilots	Propeller	WUR 9793	2,000	lbs
Oregon Escort	Coos Bay Pilots	Z Drive Tug	WDD 5907	6,700	lbs
Captain Louie	Knutson Towboat	Tug	WR 7513	1,750	lbs
Centennial	Knutson Towboat	Z Drive Tug	WCY 3200	3,000	lbs
Captain Harold	Knutson Towboat	Propeller	WDG4952	2,500	lbs
Casey H	Billeter Marine	Propeller	WDH 7360	2,700	lbs

Contact information for the towboat companies can be found in Appendix B of this plan.

3.11 United States Coast Guard

The US Coast Guard is present in the area providing its search and rescue, law enforcement and marine safety and pollution response services through the following units:

3.11.1 Operational Units:

U.S Coast Guard Sector North Bend: Sector North Bend is co-located with Air Station North Bend and is oversees all operations of Sector North Bend Units. They also support operational units by providing administrative, supply, medical, engineering and communication services.

Sector North Bend Units:

- Coast Guard Cutter Orcas – the 110-foot Island Class patrol boat has been stationed in Coos Bay, OR, since 1989.

- U. S. Coast Guard Aids To Navigation Team (ANT) Coos Bay was established in 1976 and is located near the mouth of Coos Bay in the fishing and tourist community of Charleston, Oregon. Their area of responsibility ranges over 240 miles of the Oregon coast and includes 5 lighthouses, 18 primary buoys, 43 secondary buoys and 156 other lights, day beacons and fog signals.

- Coos Bay Coast Guard Station: The Station located in the town of Charleston, is on the south side of Charleston Boat Basin, 0.7 miles southeast of Coos Head. and provide search and rescue operations from the Coos River to Cape Bianco. During the summer months, Station Coos Bay operates Search and Rescue Detachments Coquille River in Bandon, OR.

- North Bend Coast Guard Air Station is at the North Bend Municipal Airport.

- Coos Head Watch Tower is staffed during breaking bar season. The watchstander logs all vessels heading out who call into the tower and provides general lookout services.

Other Units are:

- Station Depoe Bay

- Station Yaquina Bay
- Station Umpqua River
- Station Siuslaw River
- Station Chetco River

3.11.2 Marine Safety Units

While the operational units are located within the Coos Bay area, the Captain of the Port is based out of Sector Columbia River, Astoria OR, providing vessel and facility inspections, pollution response and investigation services to Coos Bay.

3.12 Harbor Regulations

The port authority, Oregon International Port of Coos Bay, is controlled by a Board of Port Commissioners and an Executive Director. Harbor regulations are prescribed by the Port Commissioners and enforced by the Executive Director. The port manager's office is at 125 Central Avenue, Suite 300, Coos Bay, OR 97420.

3.13 Docks

Most of the deep-draft facilities in the Port of Coos Bay are in the cities of Coos Bay and North Bend. The following are the still **active and /or useable docks**:

3.13.1 Commercial Docks:

1. Cape Arago Dock/Sause Brothers (River Mile (RM) 5.4, utility/work dock
2. D.B. Western Inc. (RM 5.6, utility/work dock, vessel repair, and construction)
3. Southport Lumber Company/Southport Forest Products (RM 6.3, dead load barge slip)
4. Roseburg Coos Bay Shipping Terminal ("Roseburg") (RM 7.9, export woodchips)
5. Ocean Terminals Dock (RM 11, inbound and outbound logs)
6. K2 Export (RM 11.5, outbound logs)
7. Tyree Oil terminal (RM 12.5 oil dock for vessels – tug and fishing vessels)
8. Oregon Chip Terminal (RM 12.5, outbound woodchips)
9. Bayshore Dock/Sause Brothers (RM 12.7, tug and barge berths)
10. ORC Operations (RM 15, currently closed)
11. Georgia Pacific (RM 15, logs in / chips out)
12. Coastal Fibre (RM 17 chips out)

3.13.2 Government Docks:

- US Army Corps of Engineers (USACE) Coos Bay Moorage Dock and
- US Coast Guard (USCG) Orcas Dock (RM 13.2, USCG and USACE vessel berths)

Contact information these facilities are located in Appendix B of this plan.

3.14 Towns and Waterways

3.14.1 South Slough

Shoal and navigable only for small boats, extends 4 miles south from its junction with Coos Bay near the entrance. A Federal project provides for a 17-foot entrance channel extending south from the junction for about 0.6 miles to the Charleston Boat Basin, thence a 16-foot channel continues to a highway bascule bridge. The channel from the junction with Coos Bay to Charleston Boat Basin is subject to shoaling. Mariners are advised to seek local knowledge when transiting this area.

3.14.2 Charleston Boat Basin

Operated and maintained by the Port of Coos Bay, is 0.3 miles north of Charleston, across the slough from Barview. The basin is used by commercial and sports fishermen. About 500 berths with electricity, gasoline, diesel fuel, water, ice, a launching ramp, and marine supplies are available. A pump out station and wet and dry winter boat storage are available in the basin. A repair facility at the basin has a drydock that can handle vessels to 300 tons, 90 feet long, and 30 feet wide, and a marine railway that can handle craft 70 feet long, 22 feet wide, and 6 feet draft for hull and engine repairs. Electronic repairs can also be made at the basin. Four fish piers are in the basin, and three fish packing facilities are just south of the basin on South Slough. Coos Bay Coast Guard Station is on the south side of the basin.

A Coast Guard buoy storage area is in Coos Bay about 150 yards E of the channel and about 2.5 miles above the entrance jetties.

The highway bridge over South Slough, 1 mile south of the entrance, has a bascule span with a clearance of 22 feet. Power and television cables south of the bridge have a least clearance of 71 feet.

The west shore of Coos Bay as far as the bend is formed by a sandspit covered with dunes, partly wooded, and in some places as much as 90 feet high. On the E shore and above the bend are low rolling hills with houses and several prominent buildings.

3.14.3 Haynes Inlet and North Slough

Haynes Inlet and North Slough join the bay through a common entrance on the north side and are navigated by small boats. Haynes Inlet and North Slough channels are marked by private day beacons. A causeway with a fixed bridge over North Slough has a clearance of 15 feet. The causeway extends east and joins the State highway fixed bridge over Haynes Inlet, which has a clearance of 20 feet (27 feet at center).

3.14.4 North Bend

North Bend is 9.5 miles above the Coos Bay entrance and is a city that transitioned from sawmills and factories to its present tourism economy. A number of the docks where lumber is shipped are located in North Bend. The North Bend Fire Department has a small fireboat and launches from existing boat ramps. Coos Bay, 12 miles above the entrance, is the second city on the bay and is the distributing center for the area, which is primarily devoted to lumbering, fishing, and agriculture.

3.14.5 Empire District

The City of Coos Bay also includes the Empire district, which is 4 miles above the entrance. North Bend and Coos Bay form practically one continuous city extending along the shore from North Point to the mouth of Coalbank Slough.

Three sloughs empty into Coos Bay between the city of Coos Bay and Coos River.

- Coalbank Slough which is unused by boats.
- Isthmus Slough is used for logging operations to Millington. The highway bridge across the slough has a bascule span with a clearance of 18 feet. The overhead power and television cables just north of the bridge, and the overhead power cable 0.9 miles south of the bridge have clearances of 100 and 150 feet, respectively.
- Catching Slough is navigable for several miles by light-draft vessels. The fixed highway bridge across the mouth has a clearance of 40 feet. The power cable for about 1.7 miles above the bridge have a minimum clearance of 57 feet; other overhead cables upstream have clearances of 13 feet.

3.14.6 Coos River

The river empties through two channels into the bay at its head. The north unmarked channel follows the east side of the bay and empties abreast of North Bend. Marshfield Channel, marked by a lighted range, lights, and buoy, crosses the flats and empties abreast the city of Coos Bay. Coos River divides at a point 3.2 miles above Graveyard Point into South Fork and Millicoma River. A highway bridge across the river, 0.9 miles above Graveyard Point, has a lift span with clearances of 28 feet down and 54 feet up. The least clearance of the overhead power cables crossing Millicoma River is 40 feet. Allegany, 7.5 miles above the confluence, is the head of navigation on Millicoma River. Dellwood, 8.2 miles above the confluence, is the head of navigation on South Fork. A fixed highway bridge crossing South Fork 0.5 mile above the confluence has been removed; two concrete piers remain. A fixed highway bridge crossing South Fork 1.9 miles above the confluence has a clearance of 38 feet. Several overhead power and telegraph cables cross South Fork; least clearance is 42 feet

4 Coos Bay Harbor Conditions

Regional Harbor Conditions This section provides a description of existing and expected conditions of weather, tidal ranges, tidal currents and other factors which might impair or restrict visibility or impact vessel navigation.

4.1 Weather

4.1.1 Fog

The area is subject to fog conditions very similar to many west coast ports. Fog can be found anywhere within Coos Bay and its tributaries. Fog occurs mostly during summer and fall though is known to occur during other seasons too.

4.1.2 Storms

During the winter is when the port experiences heavy weather with increasing winds and storm conditions. Weather delays, driven by storms including gale and storm winds (winds in excess of 39 miles per hour), are infrequent in the area and account for only 3-10 days per year.

FIGURE 9 - HEAVY WEATHER AT THE COOS BAY BAR

4.1.3 Prevailing winds

Prevailing winds in the offshore sector are southerly winds, 15-30 knots, in the summer and most of the year but shifting to northerly winds in the winter. Prevailing NW winds and winter southerly storms.

- 25 knots winds and above affect big ship movements
- 20-25 knots winds affect commercial fishing and recreational boats
- Consistently heavier north winds during the summertime
- Winter winds from the south
- 35-knot winds typically associated with fronts
- 90-knot sheer winds once or twice a year
- Wind blows across channel out of North Slough
- Tugs and tows get set by winds onto aids to navigation

Deep draft ships are warned of anchoring offshore during winter while awaiting calmer winds to transit. The rapid and severe onset of weather may expose the vessel to the risk of dragging ashore.

Existing Mitigations:

- Pilots move ships in during the morning when it is calmer before winds pick up
- Have ample warning of approaching fronts

- The warning signs and lights at the entrance of the bay to alert operators to bar conditions
- Warning signs and lights at CG Station and boat ramps alert operators to bar conditions
- Telephone numbers available from which to obtain bar conditions
- Tune into AM radio channel 1610 as per the Bar warning sign
- Continuing education

NOAA provides weather forecast and actual weather conditions can be obtained online.

4.2 Tide and Currents

Since the tides at Coos Bay are semi-diurnal (occurring twice per day) there are two flood tides, two ebb tides, and four (4) slack tides (2 high slack and 2 low slack) in almost every 24 hour period. The times of high and low tides and the times of the tidal currents move nearly an hour forward every day.

At Coos Bay, the ebb tide is the condition which causes the most challenging conditions at the bar channel entrance. A strong ebb tide (often abetted by a strong river current) rushes out of the entrance channel. When it meets a strong onshore wind, sea, and swell, the waves can become very steep and then fall or break.

Tidal currents at the entrance are stated to travel in the direction 100° true during flood tides. This is generally an easterly direction into the harbor. During ebb tides (water moving out of the harbor) the direction of the current is 280° true. Predicted tidal currents vary from around one knot to almost 4 knots. Current observations in the entrance to Coos Bay indicated a velocity of about 2 knots. The greatest observed ebb velocity was a little over 3 knots. During long runouts, an ebb current of 5 knots has been reported at Guano Rock.

The tidal range between Mean Lower Low Water (MLLW) and mean higher high water (MHHW) is 7.5 feet near the open sea channel entrance at Charleston and 6.7 feet approximately in Empire. The lowest high tides are 4.2 to 5 feet above MLLW. Extreme low and high water are 3.0 feet below and 10.5 feet above MLLW, respectively. Based on measured tide data at Charleston, the tides are above +6 feet MLLW about 75% of the time and above +7 feet MLLW about 10% of the time.

In summary:

- Currents 3 knots and can be 5 knots at buoy #4 in jaws of jetty entrance
- Less than 3 knots in sloughs and creeks
- The tidal range of 7 feet on average
- Port area currents are tidal but during high river stages and heavy rains, the tide can be river driven
- There are cross-currents at:
  - The railroad bridge coming out of North Slough
  - Marshfield Channel junction coming down Coos River
  - Charleston coming out of South Slough

- Jarvis Turn

Existing Mitigations:

- Pilotage for required vessels
- Local knowledge of most port users
- Tide and current tables and predictions
- Tug companies have policies about what can be done on ebb and flood tides
- USACE tide gauges along the river can be used
- USCG announcements for the time of next tide change
- When the water is brown you know that somethin' ain't right
- NOAA provides river flow rate information

New ideas:
Information exchange can be improved between members of the port community through the Harbor Safety Committee. For example:

- The USACE could share tide gauge information with other users.
- The Sheriff's Department may share river height gauge information currently collected for flood prediction.
- The Sheriff's Department may include the Harbor Safety Committee membership to emergency notifications to expand information input.
- Tug companies could share policy information based on local knowledge

4.3 Other Weather Conditions

4.3.1 Crossing the Bar:

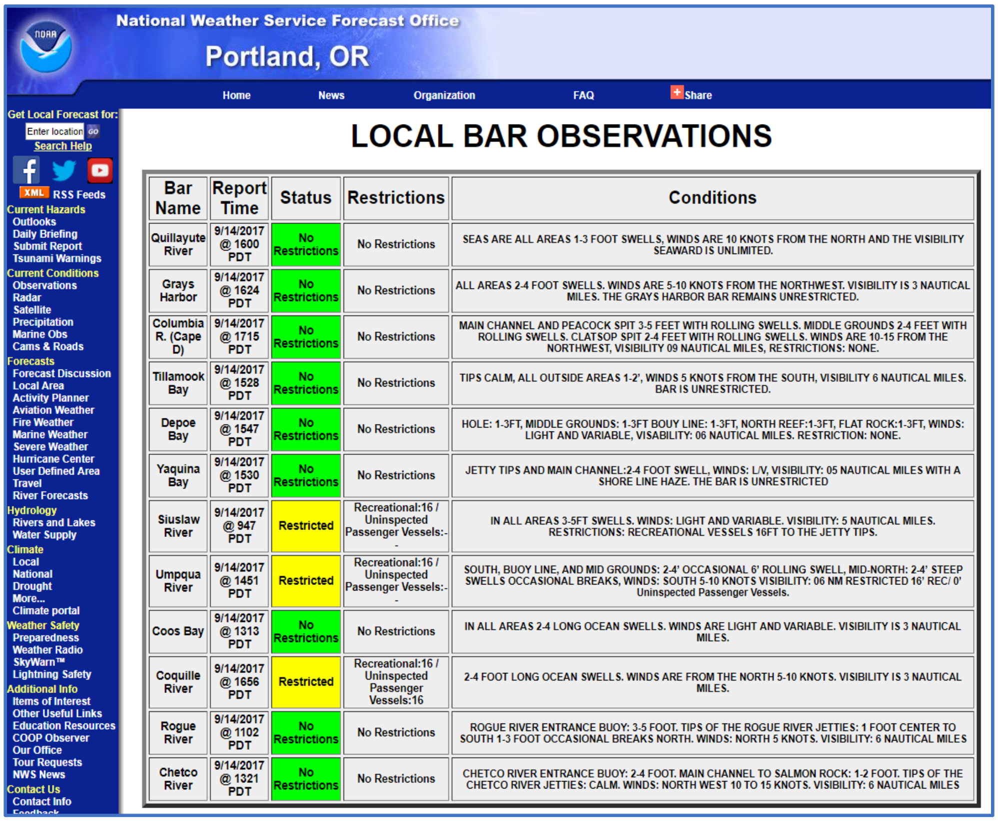
One of the main differences between Coos Bay and other harbors is the occasional occurrence of a "breaking bar" at the channel entrance. The "breaking bar" is a condition where the predominantly westerly seas and swells (often in storm conditions) meet an outgoing ebb tide which causes the waves to become quite steep, and to cascade onto the sea below. These breaking waves are very challenging to small craft and have led to several serious incidents over the years.

While this breaking bar can create spectacular conditions for small craft, the deep-water ship channel rarely experiences conditions closing the bar. The number of days per year when the bar channel is closed to shipping averages between 3 and 10 days per year.

The bar is the area where the deep waters of the Pacific Ocean meet with the shallower waters near the mouth of the river. Most accidents and deaths that occur on coastal bars are from capsizing. Coastal bars may be closed to recreational boats when conditions on the bar are hazardous. Failure to comply with the closure may result in voyage termination and civil and/or criminal penalties. The regulations are enforced by Coast Guard boarding teams. Improper loading and/or overloading are major causes of capsizing. Improper/overloaded boats have less stability and less freeboard, which can allow seas to break into the vessel, causing the boat to become even less stable. Boats are more likely to capsize when crossing the bar from the ocean because the seas are on the stern and the boater may have less control over the vessel. Boaters must make sure the bar is safe prior to crossing

There are four tides each day (two high and two low) in the Pacific Northwest. Tidal currents may gain tremendous velocity, particularly when the ebb current is augmented by river runoff. It is extremely dangerous to get caught on the bar during strong ebb current. Even on days that are relatively calm, fast-moving ebb can create bar conditions that are too rough for small craft.

Observed weather and bar conditions are updated every four hours or more frequently if there is a significant change in weather. Marine Information Broadcasts on Channel 16 VHF FM are conducted by the Coast Guard when hazardous bar conditions and restrictions are put in place or are lifted. Mariners are strongly encouraged to monitor channel 16 VHF/FM for all notices and weather updates. The AM radio broadcast is audible within a 6-mile radius from the Coast Guard Station in Charleston. It provides a continual



National Weather Service Forecast Office
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Outlooks
Daily Briefing
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Tsunami Warnings
Current Conditions
Observations
Radar
Satellite
Precipitation
Marine Obs
Cams & Roads
Forecasts
Forecast Discussion
Local Area
Activity Planner
Aviation Weather
Fire Weather
Marine Weather
Severe Weather
Hurricane Center
User Defined Area
Travel
River Forecasts
Hydrology
Rivers and Lakes
Water Supply
Climate
Local
National
Drought
More...
Climate portal
Weather Safety
Preparedness
Weather Radio
SkyWarn™
Lightning Safety
Additional Info
Items of Interest
Other Useful Links
Education Resources
COOP Observer
Our Office
Tour Requests
NWS News
Contact Us
Contact Info

LOCAL BAR OBSERVATIONS

Bar Name	Report Time	Status	Restrictions	Conditions
Quillayute River	9/14/2017 @ 1600 PDT	No Restrictions	No Restrictions	SEAS ARE ALL AREAS 1-3 FOOT SWELLS, WINDS ARE 10 KNOTS FROM THE NORTH AND THE VISIBILITY SEAWARD IS UNLIMITED.
Grays Harbor	9/14/2017 @ 1624 PDT	No Restrictions	No Restrictions	ALL AREAS 2-4 FOOT SWELLS. WINDS ARE 5-10 KNOTS FROM THE NORTHWEST. VISIBILITY IS 3 NAUTICAL MILES. THE GRAYS HARBOR BAR REMAINS UNRESTRICTED.
Columbia R. (Cape D)	9/14/2017 @ 1715 PDT	No Restrictions	No Restrictions	MAIN CHANNEL AND PEACOCK SPIT 3-5 FEET WITH ROLLING SWELLS. MIDDLE GROUNDS 2-4 FEET WITH ROLLING SWELLS. CLATSOP SPIT 2-4 FEET WITH ROLLING SWELLS. WINDS ARE 10-15 FROM THE NORTHWEST, VISIBILITY 09 NAUTICAL MILES, RESTRICTIONS: NONE.
Tillamook Bay	9/14/2017 @ 1528 PDT	No Restrictions	No Restrictions	TIPS CALM, ALL OUTSIDE AREAS 1-2', WINDS 5 KNOTS FROM THE SOUTH, VISIBILITY 6 NAUTICAL MILES. BAR IS UNRESTRICTED.
Depoe Bay	9/14/2017 @ 1547 PDT	No Restrictions	No Restrictions	HOLE: 1-3FT, MIDDLE GROUNDS: 1-3FT BOUY LINE: 1-3FT, NORTH REEF:1-3FT, FLAT ROCK:1-3FT, WINDS: LIGHT AND VARIABLE, VISABILITY: 06 NAUTICAL MILES. RESTRICTION: NONE.
Yaquina Bay	9/14/2017 @ 1530 PDT	No Restrictions	No Restrictions	JETTY TIPS AND MAIN CHANNEL:2-4 FOOT SWELL, WINDS: L/V, VISIBILITY: 05 NAUTICAL MILES WITH A SHORE LINE HAZE. THE BAR IS UNRESTRICTED
Siuslaw River	9/14/2017 @ 947 PDT	Restricted	Recreational:16 / Uninspected Passenger Vessels:--	IN ALL AREAS 3-5FT SWELLS. WINDS: LIGHT AND VARIABLE. VISIBILITY: 5 NAUTICAL MILES. RESTRICTIONS: RECREATIONAL VESSELS 16FT TO THE JETTY TIPS.
Umpqua River	9/14/2017 @ 1451 PDT	Restricted	Recreational:16 / Uninspected Passenger Vessels:--	SOUTH, BUOY LINE, AND MID GROUNDS: 2-4' OCCASIONAL 6' ROLLING SWELL, MID-NORTH: 2-4' STEEP SWELLS OCCASIONAL BREAKS, WINDS: SOUTH 5-10 KNOTS VISIBILITY: 06 NM RESTRICTED 16' REC/ 0' Uninspected Passenger Vessels.
Coos Bay	9/14/2017 @ 1313 PDT	No Restrictions	No Restrictions	IN ALL AREAS 2-4 LONG OCEAN SWELLS. WINDS ARE LIGHT AND VARIABLE. VISIBILITY IS 3 NAUTICAL MILES.
Coquille River	9/14/2017 @ 1656 PDT	Restricted	Recreational:16 / Uninspected Passenger Vessels:16	2-4 FOOT LONG OCEAN SWELLS. WINDS ARE FROM THE NORTH 5-10 KNOTS. VISIBILITY IS 3 NAUTICAL MILES.
Rogue River	9/14/2017 @ 1102 PDT	No Restrictions	No Restrictions	ROGUE RIVER ENTRANCE BUOY: 3-5 FOOT. TIPS OF THE ROGUE RIVER JETTIES: 1 FOOT CENTER TO SOUTH 1-3 FOOT OCCASIONAL BREAKS NORTH. WINDS: NORTH 5 KNOTS. VISIBILITY: 6 NAUTICAL MILES
Chetco River	9/14/2017 @ 1321 PDT	No Restrictions	No Restrictions	CHETCO RIVER ENTRANCE BUOY: 2-4 FOOT. MAIN CHANNEL TO SALMON ROCK: 1-2 FOOT. TIPS OF THE CHETCO RIVER JETTIES: CALM. WINDS: NORTH WEST 10 TO 15 KNOTS. VISIBILITY: 6 NAUTICAL MILES

FIGURE 10 - NATIONAL WEATHER SERVICE - LOCAL BAR OBSERVATIONS

broadcast on radio station 1610 AM containing bar conditions, bar restrictions, and local weather. As a public service Radio Station KBBR (1330 kHz) broadcasts bar conditions once each hour during the summer months. Current weather advisories are also posted at the Coast Guard Station in Charleston. You can also access current bar conditions and restriction on your smartphone or handheld device by going to, http://www.wrh.noaa.gov/pqr/marine/BarObs.php, as seen above.[1]

Existing Mitigations:

- Check the weather and tide conditions by:
  - Monitor Marine Information Broadcasts on Channel 16 VHF FM
  - Tune in to AM radio channel 1610 and Public Radio Station KBBR (130 kHz)

[1] The US Coast Guard published a handout which addresses the hazards of crossing the bar. The content of this handout, available at https://www.uscg.mil/d13/dpw/docs/Coos_Bay_Bar_Crossing_Handout.pdf

- Log into NOAA's website http://www.wrh.noaa.gov/pqr/marine/BarObs.php

- Check with other boaters or the Coast Guard to find out the condition of the bar.
- Always know the stage of the tide
- Cross the bar during slack water or on a flood tide, when the seas are normally calmest.

If you are caught on a rough bar running in:

- Make sure everybody aboard is wearing a personal flotation device.
- Keep the boat square before the seas.
- Keep the boat on the back of the swell. Ride the swell and stay clear of the following wave.
- Avoid sudden weight shifts from passengers, cargo or gear moving around in the boat. If possible, have passengers lie down as near the centerline of the boat as possible. Do not allow the waves to catch your boat on the side (beam). This condition is called broaching, and can easily result in capsizing.

4.4 Special Navigation Conditions

4.4.1 *North Jetty conditions*

In 2012, the Army Corps of Engineers completed a Major Maintenance Report (MMR) for the Coos Bay Jetties

Concerns (in order of greatest to least risk):

- North Jetty root and north spit sediment management (breach of North Spit)
- Structural stability of North Jetty head
- Structural stability of North Jetty trunk
- Structural stability of South Jetty root

MMR looked at 19 potential measures (individual project elements) used to create 9 alternatives (various combinations of measures). The 9 alternatives were evaluated against each other and the existing condition and the following were the preferred solutions:

Proposed mitigation:

- Buried revetment at log spiral bay (as seen by the dark blue line in Figure 12 below)
- Rebuild 400 linear feet of jetty root to +16' MLLW (light blue)
- Re-nourish log spiral bay
- Repair a low reach of north jetty root to +20' MLLW (pink)
- Repair targeted reaches of the north jetty trunk (green)
- Rubble-mound head at present location (pink)

FIGURE 11 - JETTY AND AREAS OF PROPOSED ALTERNATIVES

Engineering, Research and Design Center (ERDC) is currently conducting a physical model of the entrance to determine detailed jetty head design.

This project is currently in Detailed Design Report phase (DDR). After the DDR phase is completed, the Plans and Specifications phase (P&S) begins. After P&S phase is completed, rock procurement and construction phase begins. This is an evolving project.

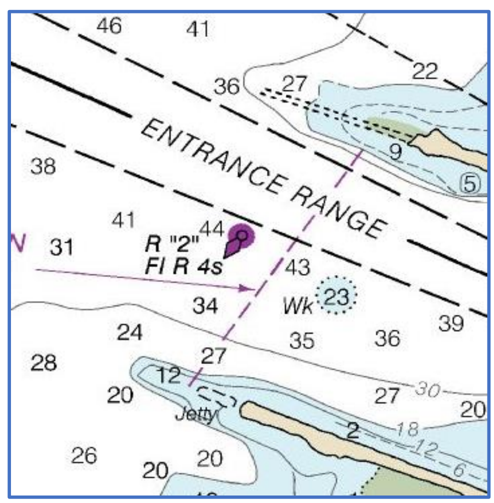


FIGURE 12 - CHART SHOWING SUBMERGED JETTIES

Existing mitigation:

- Pilots know to proceed clearly out of the channel before turning north or south.
- Charts indicate submerged sections of the jetty

4.4.2 *Upper Jarvis Range Location*:

As previously mentioned with regards to the Coos Bay Rail Bridge, mariners should use extreme caution when passing through the bridge because the location of the Upper Jarvis ranges in relation to the bridge opening is offset 35 feet to the North, resulting in vessel passing closer to the center support of the bridge and potentially alliding with it. The Upper Jarvis Range, while centered in the channel is not centered to the bridge opening.

Existing Mitigation:

- Mariners need to be aware of this offset.
- Chart 18587 clearly indicates the location of range in relation to the swing bridge in its open position.

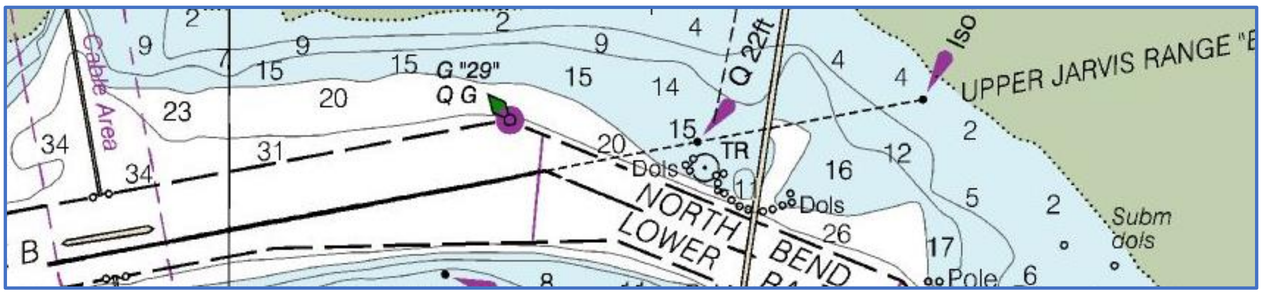


FIGURE 13 - CHART SHOWING UPPER JARVIS RANGE AND BRIDGE ALIGNMENT

4.4.3 *FAA Air Draft Restrictions*

NOAA recently added the following information in the Coast Pilot regarding vessels with a vertical clearance of 144ft and above.

Vessel Reporting Advisory

Operations in the Vicinity of Southwest Oregon Regional Airport

Inbound and outbound vessel traffic near Southwest Oregon Regional Airport may affect procedures for a1rcraft landing and departing at the airport. Vessels With an air draft of 144 feet or greater present a potential obstruction to airspace that require advisories be issued to aircraft by air traffic Controllers and in some case, runway use may need to be restricted. Notification by vessels exceeding 144 feet air draft (including raised cranes or other cargo gear), when operating in vicinity of the airport is essential to provide aircraft important notice of potential airspace obstruction during instrument approaches.

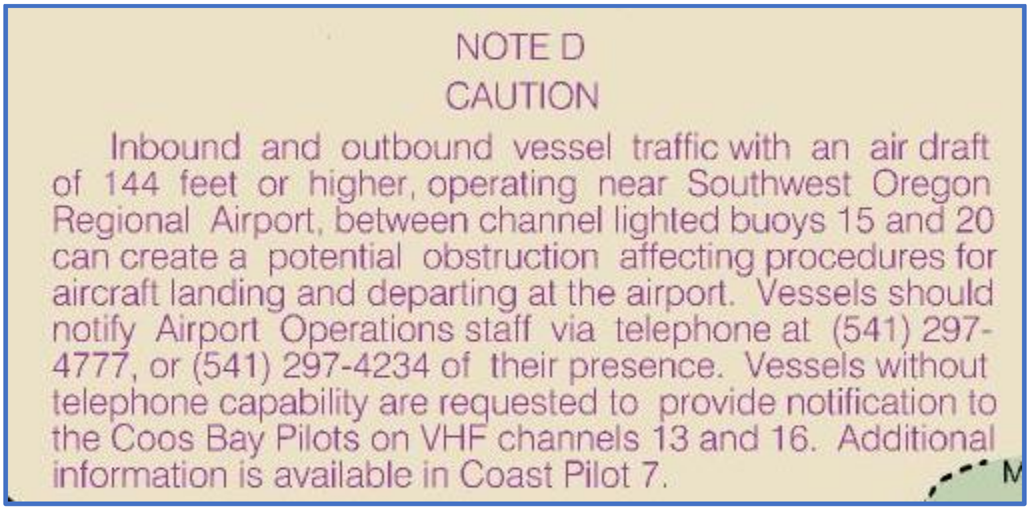
Vessels with an air draft height of 144 (44 meters) or greater are advised to report the following information:

- The vessel's name, a point of contact and a call-back method of communication to the ship.
- The vessel's maximum air draft height (including masts, cranes, antenna or other projections).
- If inbound from sea, report time of arrival at Coos Bay Channel Lighted Buoy 15 (with at least 10 minutes advance notice), and again when past Coos Bay Channel Lighted Buoy 20.
- If outbound to sea. report time of arrival at Coos Bay Channel Lighted Buoy 20 (with at least 10 minutes advance notice), and again when past Coos Bay Channel Lighted Buoy 15.

Notification can be made to the Airport Operations staff' via telephone at 541-297-4777 or 541-297-4234. Vessels without telephone capability are requested to provide notification to the Coos Bay Pilots on VHF-FM channels 13 and 16, to be relayed to the Airport operations personnel.

FIGURE 14 - FAA ADVISORY IN THE COAST PILOT

Upon notification, Airport traffic controllers will notify in and outbound aircraft, or restrict the runway until the vessel has passed. This information is also included in Chart 18587 as Note D Caution:



NOTE D

CAUTION

Inbound and outbound vessel traffic with an air draft of 144 feet or higher, operating near Southwest Oregon Regional Airport, between channel lighted buoys 15 and 20 can create a potential obstruction affecting procedures for aircraft landing and departing at the airport. Vessels should notify Airport Operations staff via telephone at (541) 297-4777, or (541) 297-4234 of their presence. Vessels without telephone capability are requested to provide notification to the Coos Bay Pilots on VHF channels 13 and 16. Additional information is available in Coast Pilot 7.

FIGURE 15 - FAA ADVISORY IN CHART 18587

NOTE: Pilots monitor VHF 13 and 16 only when on duty on vessels.

4.4.4 Upper Bay Shoaling.

The USACE has not dredged the navigation channel past RM 12.8 to 15.2 since 2010, due to lack of deep draft vessel traffic.

4.4.5 Transiting Rail Road bridge.

All vessels should ensure the Rail bridge is open, as it swings shut when trains are expected to pass over it. The train/bridge schedule is variable and not posted anywhere online or made publicly available. The bridge master can be reached via radio or telephone when they are on the bridge. Pilots onboard commercial vessels also ask the tugboats ahead of them, about the status of the bridge.

Swing bridges are required to have lights. Each swing span of every through swing bridge shall be lighted with three lanterns so that when viewed from an approaching vessel the swing span when closed will display three red lights on top of the span structure (see CFR 118.70 Lights in swing bridges).

Mariners should use extreme caution when passing through the bridge because of unpredictable changing winds, currents, and sea conditions reported in this area.

5 Conditions specific to Navigation Rule 9 - Narrow channel

This section is an assessment of current safety problems or conflicts with commercial, recreational, sailing and fishing vessels as it relates to a violation of Rule 9 (Narrow Channels Rule) of the Inland Navigational Rules Act (33 USC 2009). Each section of Rule 9 (*in italics*) has been broken down and issues for each assessed.

5.1 Keeping to starboard side outer limit of the channel

> *"(a) (i) A vessel proceeding along the course of a narrow channel or fairway shall keep as near to the outer limit of the channel or fairway which lies on her starboard side as is safe and practicable.*

There are currently no issues.

5.2 Down-bound right of way

Not applicable as the Coos River is not a Western river.

5.3 Impeding passage of vessels that only navigate in the channel

> *(b) A vessel of less than 20 meters in length or a sailing vessel shall not impede the passage of a vessel that can safely navigate only within a narrow channel or fairway.*

This has not been a major issue as most small vessels are aware to operate outside of the deep draft vessel channel when ships are approaching.

5.4 Fishing vessels impeding the passage of any other vessel

> *(c) A vessel engaged in fishing shall not impede the passage of any other vessel navigating within a narrow channel or fairway.*

5.4.1 Recreational fishing vessel

Recreational fishing vessels fish in the main channel and are known to tie up or anchor by the bridge pylons. This type of operation may create a navigational hazard for other waterway users by impeding or restricting their passage.

Recommendations:
Increase education of the waterway users to the potential hazards within the Coos Bay user community.

5.4.2 Derelict crab pots

Assessment

Some recreational fishing vessels never recover their crab pots that were either dropped in the channel or drift over into the channel. Vessels navigate over crab pots which results in their lines, and associated debris, getting caught in the propellers. This has caused multiple vessels to lose propulsion/steering and is a safety risk when vessels try to retrieve the entangled pots as they are not equipped to do so.

Recommendations
Increased education to the recreational crabbing community and commercial operators.
The Dungeness crab commission has derelict crab cop recovery program in place which involves financial incentive to fishermen to recover the pots.

5.4.3 Seasonal recreation fishermen

Assessment
The density of recreational fisherman, especially during fall salmon season, can pose hazards to navigation. The North Bend range is the most popular place for recreational salmon fishing in the Fall when there can be hundreds of small vessels in and out of the channel.

Recommendation
Increased education to the salmon fishing community regarding Rules of the Road and safe boating practices.

5.5 Crossing narrow channel

> *(d) A vessel must not cross a narrow channel or fairway if such crossing impedes the passage of a vessel which can safely navigate only within that channel or fairway. The latter vessel must use the signal prescribed in Rule 34(d) (§ 83.34(d)) if in doubt as to the intention of the crossing vessel.*

There are currently no issues.

5.6 Overtaking in a narrow channel

> *(e) (i) In a narrow channel or fairway when overtaking, the power-driven vessel intending to overtake another power-driven vessel shall indicate her intention by sounding the appropriate signal prescribed in Rule 34(c) (§ 83.34)(c)) and take steps to permit safe passing. The power-driven vessel being overtaken, if in agreement, shall sound the same signal and may, if specifically agreed to, take steps to permit safe passing. If in doubt she shall sound the danger signal prescribed in Rule 34(d) (§ 83.34)(d)). (ii) This Rule does not relieve the overtaking vessel of her obligation under Rule 13 (§ 83.13).*

There are currently no issues.

5.7 Vessel approaching a bend or area that obscures other vessels

(f) A vessel nearing a bend or an area of a narrow channel or fairway where other vessels may be obscured by an intervening obstruction shall navigate with particular alertness and caution and shall sound the appropriate signal prescribed in Rule 34(e) (§ 83.34(e)). (g) Any vessel shall, if the circumstances of the case admit, avoid anchoring in a narrow channel."

There are currently no issues.

6 Aids to Navigation

This section describes the fixed navigational hazards specific to the region and the aids to navigation systems in place to minimize the risk of contact with these hazards.

6.1 Types of Aids to Navigation

6.1.1 Rough Bar Advisory Sign

Coos Bay bar is a regulated navigation area and as such, the Coast Guard has established Coos Bay South Slough Regulated Navigation Warning Sign, a rough bar advisory sign, on the east end of the breakwater at Charleston Boat Basin in about 43°20'48"N., 124°19'18"W to promote safety for small-boat operators. The sign is diamond-shaped, painted white with an international orange border, and with the words “Rough Bar” in black letters. The sign is equipped with two quick flashing amber lights that will be activated when hazardous conditions exist and the bar is restricted to recreational and uninspected passenger vessels. Boaters are cautioned, however, that if the lights are not flashing, it is no guarantee that the sea conditions are favorable.

In accordance with 33 CFR 165.1325, the U.S. Coast Guard has the authority to restrict all recreational and uninspected passenger vessels from crossing the bar when hazardous conditions exist. Failing to comply with posted bar restrictions may result in a maximum civil penalty of $25,000.00

Additional warning signs are located at the boat ramps areas in Charleston and Empire. These signs are blue in color and have amber flashing lights that read: Warning When Flashing, Bar Restrictions in Effect, Tune to 1610 AM. When the amber lights are flashing on any of the warning signs hazardous conditions are present and a bar restriction is in place and mariners should tune in to listen to the restriction information.

6.1.2 Automatic Identification System (AIS)

AIS allows ports and ships installed with the system to automatically know where ships are located as viewed on the radar screen and share pertinent information about each vessel. While not currently used by the port of Coos Bay, AIS receiving capabilities could be installed and be used to the advantage of the agencies, the port, and ship husbandry companies. Since the port does not have Vessel Traffic Management System or use AIS; vessel transiting Coos Bay are responsible for their own safe passage.

6.1.3 Differential Global Positioning System (dGPS)

Differential Global Positioning System (dGPS) is an enhancement to Global Positioning System that provides improved location accuracy, from the 15-meter nominal GPS accuracy to about 10 cm in case of the best implementations.

The United States Coast Guard (USCG) runs its National dGPS (NGDS) on the longwave radio frequencies between 285 kHz and 325 kHz near major waterways and harbors. The USCG's

NGDPS is jointly administered with U.S. Department of Transportation's Federal Highway Administration. It consists of broadcast sites located throughout the inland and coastal portions of the United States. While available in the area, it is unreliable and not frequently used.

6.2 Evaluation of Navigational Hazards

Any channel modifications will require a new review of the Aids to Navigation (ATON) needs and any changes to the positioning of ATON by the USCG should be reviewed by CBHSC. The list of ATON under review by the USCG and CBHSC is included in Appendix C of this plan.

As previously mentioned, Coos Bay has several navigational hazards most of which are outside of the Federal navigational channel and as such are more likely to be a concern to small boats that can navigate outside of the channel. Deep draft vessels should still be aware of some of these hazards as they are located close to the channel; ex: submerged jetties and Guano Rock.

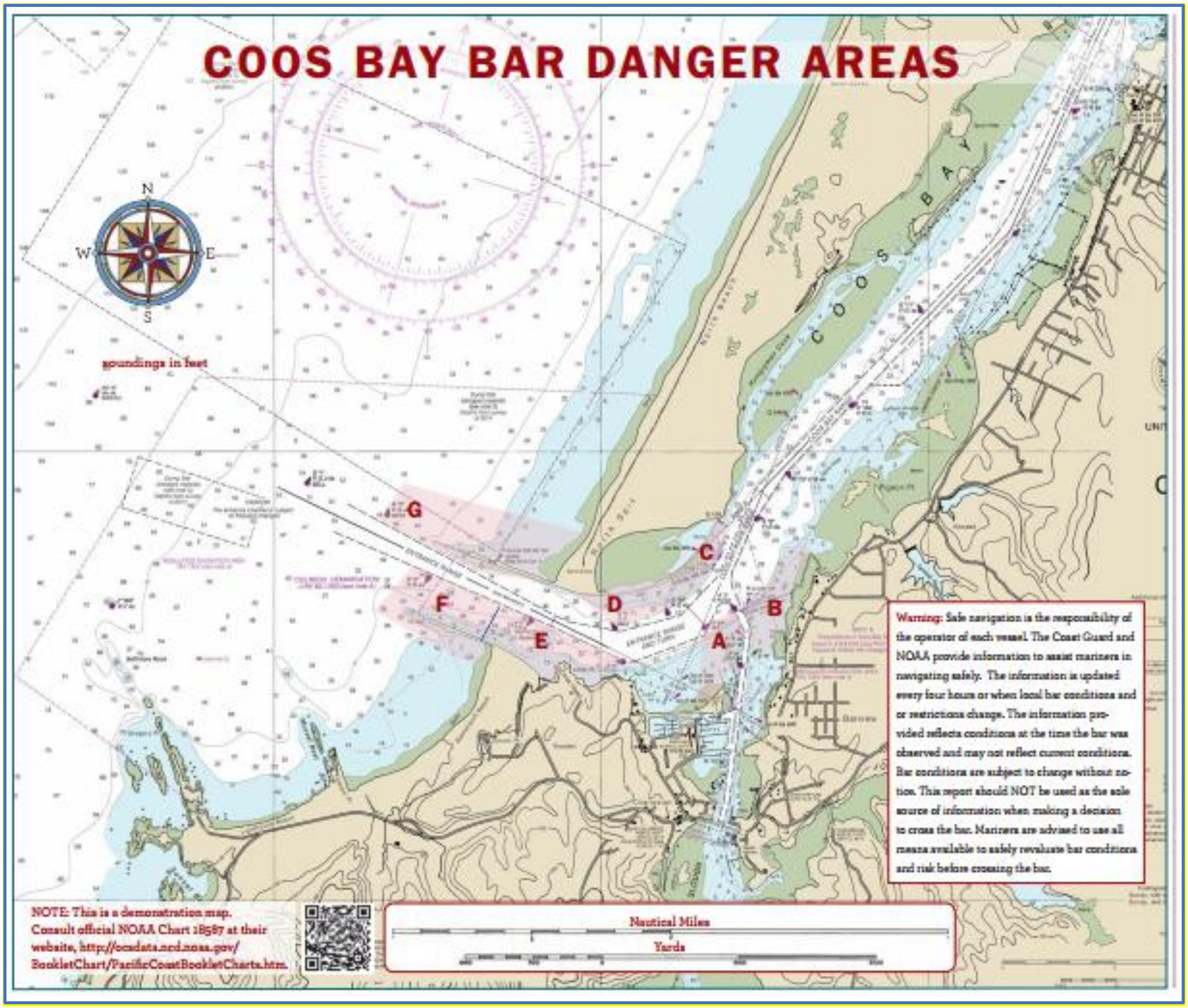


FIGURE 16 - COOS BAY BAR DANGER AREAS[2]

6.2.1 Navigational hazards affecting boats

A. South Slough Sand Spit. As you leave the Charleston Boat Basin, the South Slough Sand Spit extends north and parallel to the channel from South Slough Red Lighted Marker #8, approximately 450 yards north towards South Slough Red, Lighted Marker #4. South Slough Lighted Buoy 2 marks the north end of the sand spit. It is dangerous. DO NOT CROSS THIS AREA.

B. South Slough/Charleston Channel submerged jetty. From the entrance to the Charleston Channel from Green Lighted Marker #1, shoreward marks the end of the submerged jetty. This jetty is visible only at low water. When departing the Charleston Boat Basin, stay in the South Slough Charleston Channel to the left of Green Lighted Marker #1 at all times.

[2] https://www.uscg.mil/d13/dpw/docs/Coos_Bay_Bar_Crossing_Handout.pdf

C. Sandspit, North Beach. This area, commonly known as the cribs is located shoreward of buoy 7 and is dangerous due to its shallow depth and submerged jetties. Occasionally, on strong ebb tides, breakers will form in this area. This area should also be avoided because of the possibility of aground or striking submerged jetties and pilings. Inbound and outbound commercial tugs and deep draft vessels also pass close to channel boundaries and cannot stop for obstructions or small vessels in the channel.

D. The area north of Coos Bay Channel lighted buoy 5 and 5A. This area is shallow and can be very dangerous when there are any large swells on the bar or during ebb tide. Breakers are very common in this area, and without warning. While vessels transit this area on occasion, this area should be avoided. The main channel is the safest navigable water.

6.2.2 Navigational hazards affecting vessels

E. South Jetty, Guano Rock area. This is a very dangerous area because of shoals extending out from the south jetty to the entrance channel. Breakers are frequently experienced from Guano Rock Lighted Whistle Buoy 4 and sometimes breaks onto Coos Head extending out to sea. Exercise extreme care in this area at all times, especially on ebb tides. Submerged rock by the channel entrance only has about 10 feet of water above it at low tide. *Buoy R 4 marks the rock, but it has washed downstream from the rock and the US Coast Guard is not planning on changing it.*

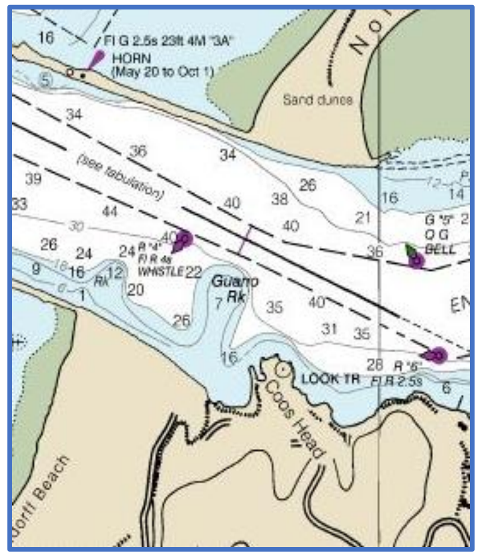


FIGURE 17 - GUANO ROCK BY COOS HEAD

F. South jetty submerged 100 yards. The outward end of the south jetty is submerged from the visible end of the jetty. NEVER CROSS THIS AREA. There are breakers in this area most of the time. When departing the bar southbound, be sure to pass seaward of Coos Bay south jetty Lighted Gong Buoy 2 before turning to the south.

G. North jetty submerged. The North Jetty extends approximately 300 yards to the West of the visible tip. The seaward end of the jetty is submerged from the visible tip towards Coos Bay North Jetty Lighted Whistle Buoy 3. NEVER CROSS THIS AREA. There are breakers in this area most of the time. When departing the bar northbound, be sure to pass seaward of Coos Bay North Jetty Lighted Whistle Buoy 3 before turning to the north."

6.3 Action Summary on Aids to Navigation

The list of ATON under review by the USCG and CBHSC is included in Appendix C of this plan.

7 Spill Response

7.1 Coos Bay Response Cooperative

The Coos Bay Response Cooperative, Inc. (CBRC) is a non-profit marine industry-owned association consisting of the terminal operators in the Coos Bay harbor. CBRC was formed in 1994 and acts as an initial responder. Additional contractors would be called out as necessary depending on the nature and duration of the response. Within 24 hours, the responsible party will bring additional contractors as necessary and reasonable.

The CBRC has developed this "Umbrella" Oil Spill Contingency Plan (Plan) to cover general commercial vessels calling at berths in Coos Bay. Oil Terminal Owner/Operators and Tank Vessels including Self Propelled Tankers and Tank Barges are covered by their respective Vessel/Facility Plans and may site the resources listed in the Plan if they are members of the CBRC and have executed appropriate Service Agreements. The geographic area covered by this Plan consists of Coos Bay from the Isthmus Slough Bridge at river mile 15 to the mouth (at river mile 0). Pollution response equipment accessible to CBRC is located at the following facilities/locations: Roseburg Coos Bay Shipping Terminal; Ocean Terminal; Carson Davis Oil, Tyree Oil, Market Avenue and SOMAR and includes, boom, boom boat, skimmers, skiffs, storage tanks, cab over truck and high-power jets.

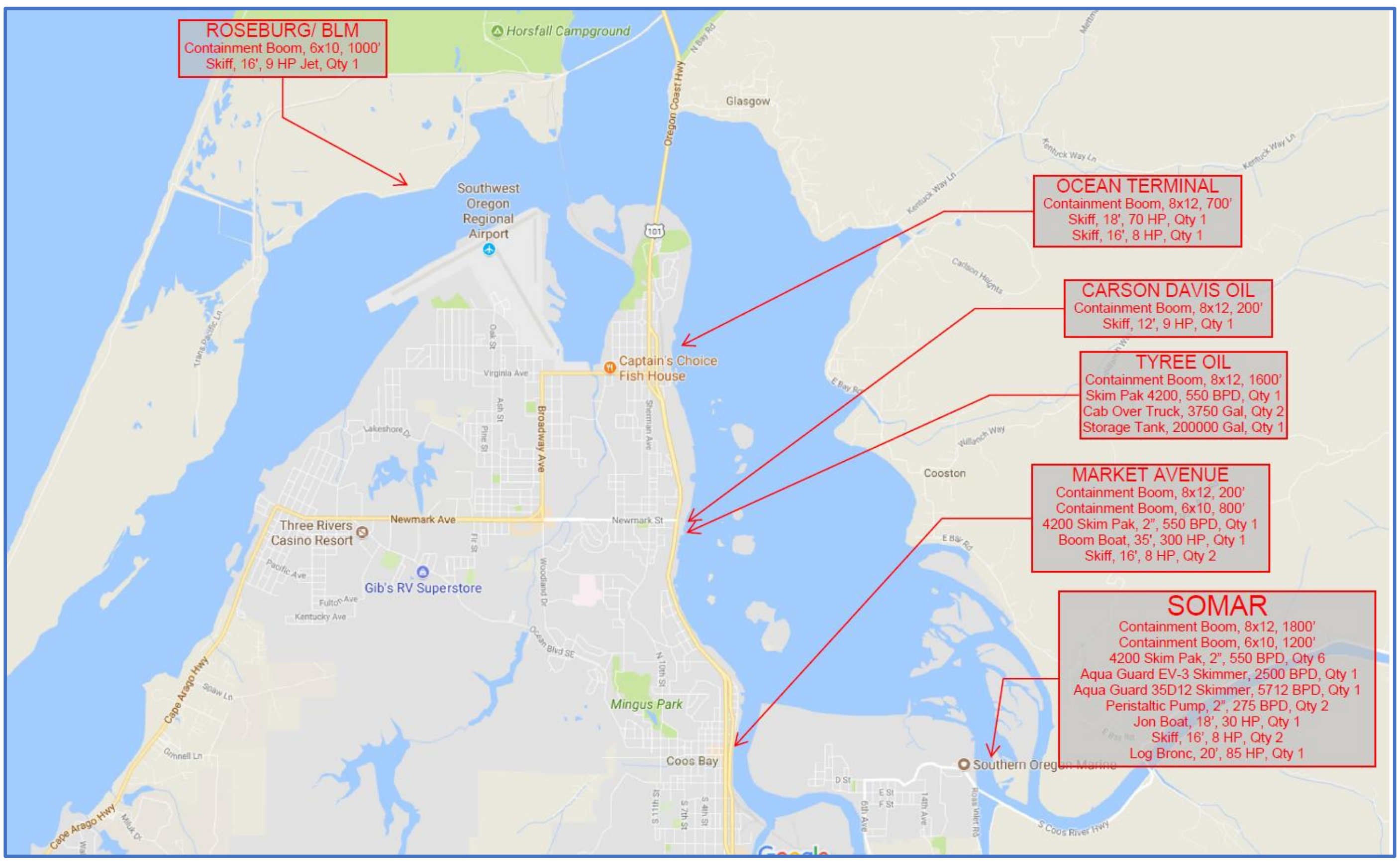


FIGURE 18 - CBRC OIL SPILL EQUIPMMENT LOCATION MAP

In response to a spill, responsible parties, Oil Spill Response Organizations as well as Federal, State and local agencies will implement an Incident Command Systems to effectively respond to the incident.

7.2 US Coast Guard

The US Coast Guard has spill response equipment located in a trailer at the Coos Bay Air Station and the Pacific Strike Team will be mobilized in response to a spill.

Response activities will follow the Coos Bay Geographic Response Plan.

8 Maritime Security Conditions

There are no current maritime security concerns and there has been no increase in Maritime Security Levels since the implementation of the Maritime Transportation Security Act, (MTSA), in 2002 and Codes of Federal Regulation (CFR) that govern ship and facility security (33 CFR 101, 103, 104 and 105).

The Act and CFR's require that facilities that receive foreign flagged vessels greater than 100 gross tons (GT), cruise ships or facilities that handle certain dangerous cargos develop and implement a security plan to help deter criminal and terrorist activities. Each Facility Security Plan (FSP) will be reviewed and approved by the Captain of the Port (COPT) and the facility audited on an annual basis.

FIGURE 19 – M/V FLORA PIONEER DEPARTING ROSEBURG COOS BAY TERMINAL

There are three maritime security levels (MARSEC), with level 1 being the lowest and 3 the highest. Facilities normally operate at MARSEC level is level 1, but this can be increased to higher levels by the Captain of the Port based on the credibility and specificity of security threats to the area, leading to the possibility of port closure when at MARSEC Level 3.

While this Harbor Safety Plan addresses safety concerns, there may be issues between safety and security, where depending on the situation, one will take a secondary position to the other. An example of this is an increase in MARSEC level where the implementation of additional security measures may affect existing safety procedures or concerns, such as closing access/exit doors to restrict and better control unauthorized access to the facility, pier or ship.

It is important to be aware of this relationship in developing any new safety procedures or recommendations.

9 Vessel Traffic and Cargos

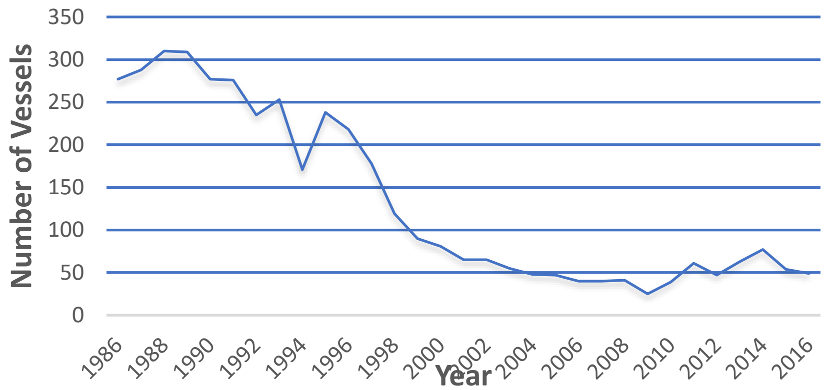
9.1 Commercial Vessels

Vessel cargo consists primarily of wood products and the number of large ships using the Coos Bay area has fallen off since the year 2000. During the past two years (2015-2016), a total of 100 ships have visited the Coos Bay Harbor complex. This equates to approximately one ship per week. While documented records were not available, tug and barge traffic has been approximately 200-400 per year.

Despite a continued drop in deep draft vessel calls since 1990, future projections indicate an increase in vessel arrivals into the port of Coos Bay.

Over the years, while the **number** of deep draft vessels typically calling on Coos Bay terminals has decreased, their size has increased from an average of 45,422 Metric Tonnes to an average of 52,894 Metric Tonnes with a projected near-term vessel size of 70,400 Metric Tonnes as seen in Appendix D.

TABLE 2 - VESSEL CALLS PER YEAR 1986-2016



This increase in vessel size creates its own set of safety concerns that the CBHSC should keep an eye on. Some of these concerns include:

- the suitability of the navigational channel (is the channel deep enough; are the turning basins large enough) and
- the maneuverability and responsiveness of these large vessels in a waterway with a projected increase in vessel traffic as well as
- the increase pollution potential of these larger vessels.

There are currently no issues that need attention from the CBHSC.

There are no vehicle or passenger ferries or cruise ships in or calling Coos Bay.

9.2 Commercial Fishing Vessels

The Coos Bay area was once a very large fishing area. Dungeness Crab, Chinook salmon are the primary commercial fisheries in Coos Bay with Albacore tuna and pink shrimp coming in second. The recent decline of the fisheries has diminished the fishing fleet, but the fleet still numbers some 85-100 vessels operating from the area. These vessels are both moored in the harbor as well as trailered to the marina for launching.

According to the US Coast Guard, in 2016, sixteen of the eighteen casualties involved commercial fishing vessels.

In addition to the commercial fishing fleet, there are five U.S. Coast Guard inspected passenger vessels which take customers out fishing during the season.

9.3 Recreational Boating

Recreational boaters are a safety concern in Coos Bay, as the operators do not always know the navigational rules of the road, keep a proper lookout or keep their boats in good operating conditions.

According to 2016 statistic collected and analyzed by the Oregon State Marine Board, the number one cause of fatal accidents this year was a 3-way tie of Force of Wave/Wake, Hazardous Waters and Operator Inexperience/Error with most of the accidents happening while crabbing/fishing and relaxing.

The US Coast Guard Auxiliary offers free vessel safety checks, boat safety training and reading material to help educate the recreational boating community regarding boating safety practices, rules of the road, Oregon boating laws and Coos Bay navigational hazards. Vessel Safety Checks are available by appointment in the Coos Bay, North Bend, Lakeside, Winchester Bay, Reedsport, and Bandon areas.

9.4 Vessel Traffic

This section provides a description of the procedures for routing vessel traffic, and any contingency or secondary routing plans which may be used during construction and dredging operations.

9.4.1 Vessel Traffic System

There is no Vessel Traffic System (VTS) in Coos Bay. The small amount of existing traffic is managed by the pilots. The larger vessels are generally handled a single ship at a time, which produces a one-way traffic pattern.

9.4.2 Notice of Arrivals

The National Vessel Movement Center (NVMC) was established to track notice of arrival information from ships entering U.S. ports. If a ship's voyage time is 96 hours or more, they must submit a Notice of Arrival (NOA) at least 96 hours before entering the U.S. port or place of destination. If a ship's voyage time is less than 96 hours, they must submit an NOA before departure, but at least 24 hours before entering the port or place of destination. This regulation applies to U.S. and foreign vessels bound for or departing from ports or places in the United States.

Notwithstanding the USCG requirement of 96 hours advance notice of arrival, the pilots request at least a 24-hour advance notice of arrival. This ensures they will be able to reach the pilot boarding station at the proper time, as well as advise the Master of the ship if there are potential delays in entering the harbor.

9.4.3 Vessel Routing

The risk of a grounding/collision generally increases the closer a vessel transits to shore. The higher risk areas were generally 25 nautical miles (nm) from land along the entire West Coast.

The West Coast of the United States has a voluntary agreement between the States, shipping companies, and the US Coast Guard. This agreement governs coastal traffic patterns. Using the Pacific States/BC Task Force Voluntary Routing Guide, tug and barges typically remain between 5-25 miles from the coast. Tank barges remaining at least 25 miles from the coast. Tank ships are obliged to stay greater than 50 miles from shore unless making port entry.

There is no specific or secondary routing for vessels transiting Coos Bay besides staying within the navigation channel as marked in NOAA Chart 18785 and following the Rules of the Road and the Law of Tonnage.

10 History of Accidents and Near Misses

This section reviews the history and types of all accidents and near-accidents which have occurred within the region during the past two years (2016-2017) and any corrective actions or programs taken to alleviate recurrences.

10.1 Statistics Year 2016

A total of 18 marine casualties were reported in 2016. Sixteen of the casualties involved commercial fishing vessels and included the following incidents: one (1) involved a grounding, one (1) involved a crewmember injury, three (3) involved vessel sinking and loss of life, described in the following section; three (3) involved loss of steering and eight (8) involved loss of propulsion. The other two marine casualties involved a crewmember injury onboard a bulk carrier and a reduction of propulsion onboard a tug.

10.2 Statistics Year 2017

A total of 6 marine casualties have been reported for 2017, as of July 7, 2017. Four of the casualties involved commercial fishing vessels and included three incidents of loss of propulsion and one incident with a loss of power. The other two casualties involved a loss of propulsion on an ATB (articulated tug and barge) and a crewmember injury onboard a bulk carrier.

10.3 Recent Accidents

Summary of recent accidents can be found in Appendix E.

10.4 Historical Accidents of Significance

10.4.1 Grounding of the M/V New Carissa

The M/V NEW CARISSA, a 639-foot bulk freight ship of Panamanian registry, was operated by TMM Co. Ltd., of Tokyo and owned by Green Atlas Shipping S.A. of Panama. On the night of 3 February 1999, there were 26 crewmen on board. The vessel carried no cargo, as it was inbound from Japan to pick up 37 thousand tons of wood chips at Coos Bay, Oregon. However, a strong ocean storm, with winds that reached 39 knots and seas up to 26 feet, was hitting the Central Oregon Coast that night. The Coos Bay pilot assigned to join the ship indicated that it would not enter the bay under those conditions and that he would join the ship the next day. During the storm, the ship dragged anchor and drifted towards shore. The crew tried to weigh anchor and move the ship, but during the early morning hours of 4 February, it went hard aground about 150 yards off a stretch of remote, undeveloped sandy beach three miles north of Coos Bay, Oregon.

The grounding of the M/V NEW CARISSA was unusual in that the ship became grounded twice, the response set a precedent by burning the ship's oil on board, and extraordinary means, including 69 rounds from a Navy destroyer and an MK-48 torpedo from a nuclear-powered submarine, were attempted to sink the ship in order to reduce the risk of a major oil spill.

The M/V NEW CARISSA casualty did not occur while entering or transiting Coos Bay. The vessel's master chose to wait out the storm at anchor instead of proceeding to sea and awaiting the pilot. Anchoring offshore has been restricted since this casualty.

10.5 Near Misses

According to the US Coast Guard, there have no records of near misses. This does not mean that they do not occur.

10.6 Loss of Propulsion/Steering

There is currently no guidance for vessels coming in and out that are having difficulty with steering/propulsion. Procedures will very much depend on how disabled the vessel is and its location in the Bay/ river.

Loss of Propulsion and Loss of Steering are reported to the US Coast Guard.

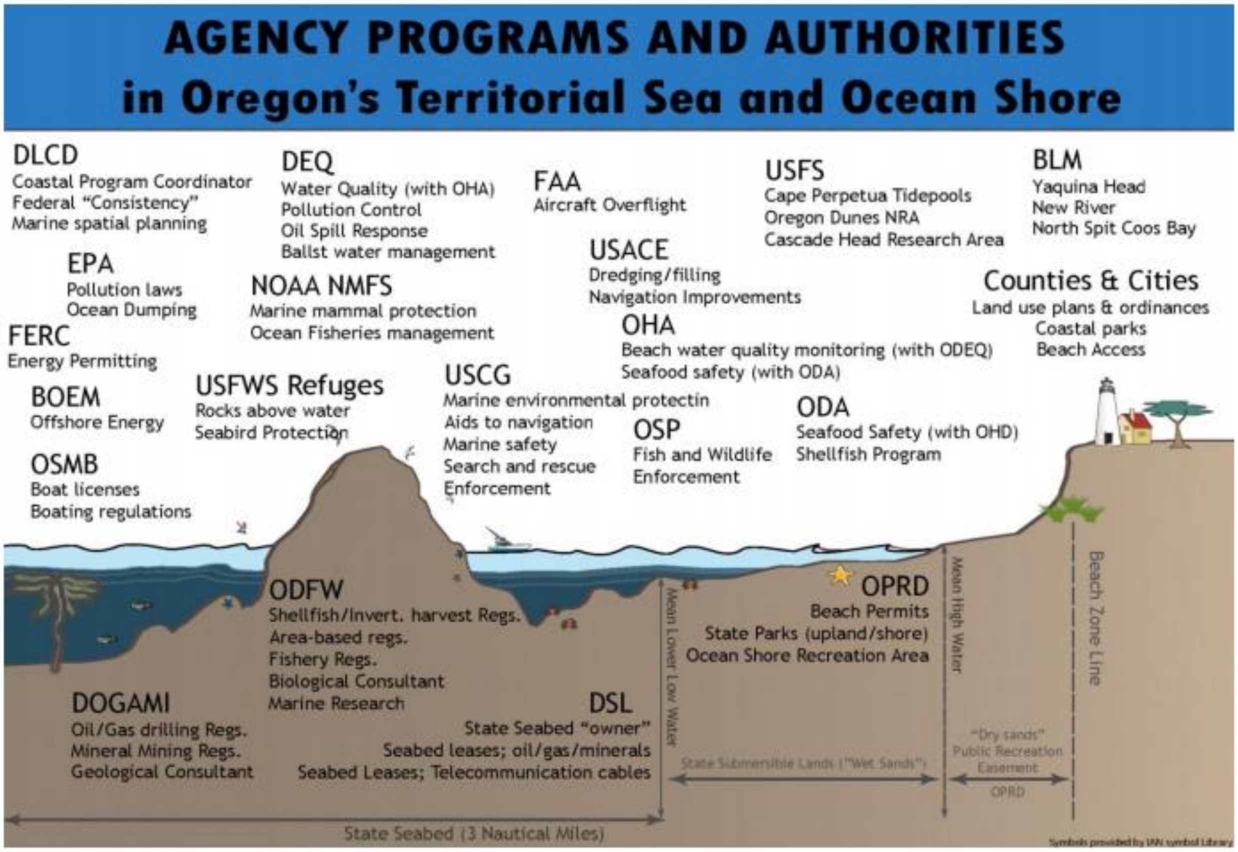
10.7 Corrective actions or programs

No corrective measures or programs have been taken or established by the CBHSC.

Boater education and information regarding weather and bar conditions continue to be distributed by the US Coast Guard, Coast Guard Auxiliary, Dungeness Crab Commission, NOAA and other agencies/entities.

11 Federal, State, And Local Agencies and Laws

As can be seen from the image below, many agencies have responsibility and authority over Oregon's territorial sea and ocean shore. However, of those listed only a few have jurisdictional authority and programs with direct impact on the maritime safety of the harbor.



Source: ODFW and Oregon Department of Land Conservation and Development (DLCD)

FIGURE 20 - JURISDICTIONAL AREAS OF OREGON AGENCY PROGRAMS AND AUTHORITIES

11.1 Federal Laws

The two Federal agencies with jurisdiction over the safety of Coos Bay Harbor are the US Coast Guard and the Army Corps of Engineers.

11.1.1 US Coast Guard (USCG)

The Captain of the Port has varying levels of jurisdiction extending to the outer limit (200 nautical miles) of the EEZ for foreign and domestic vessels.

The US Coast Guard has several lines of authority and program activities that relate to Oregon's territorial sea. The USCG (1) is the lead agency for oil-spill response and cleanup and is the on-scene coordinator for planning and response; (2) maintains search-and-rescue stations, including air stations at Warrenton (Astoria) and North Bend (Coos Bay); (3) has authority over buoys and markers to regulate vessel operations. The USCG has a program of routine Marine Environmental Patrols along the ocean shore to locate and ensure the safe removal of any hazardous materials or debris that may be washed ashore. The USCG is also responsible Harbor Security and Investigations of marine incidents and accidents.

- Regulations regarding vessel safety fall under Title 46 Code of Federal Regulations (CFR); Shipping
- Regulations regarding safe navigation and security fall under Title 33 CFR Navigation and Navigable Waters parts 1-199

11.1.2 Army Corps of Engineers (USACE)

The Corps is responsible for building and maintaining coastal navigational projects, including jetties, navigation channels, and navigational structures under the Rivers and Harbors Act (33 USC 401 - 709b and 2201 - 2329). Material dredged from coastal ports is frequently disposed in ocean waters at sites designated by the Environmental Protection Agency (EPA). Placement of dredged materials at these ocean sites is regulated under sections 102 and 103 of the Marine Protection, Research, and Sanctuaries Act (MPRSA) administered by the EPA or the Corps under section 404 of the Clean Water Act (CWA). The Corps also has permit authority over work performed by others in navigable waters under section 10 of the Rivers and Harbors Act, Section 404 of the CWA, and section 103 of the MPRSA.

- Regulations regarding navigation fall under Title 33 CFR Navigation and Navigable Waters parts 200-399

Other Federal Agencies with jurisdiction over the maritime interests are listed in Appendix F.

11.2 State

11.2.1 Department of State Lands

The Department of State Lands is responsible for management of publicly owned submerged and submersible land. The public has rights to use the beds and banks of navigable waterways for any legal activity, such as boating, fishing, and swimming. The following are typical uses of state-owned submerged and submersible lands:

- Houseboats
- Boat ramps
- Docks, floats, and wharfs
- Marinas and moorages
- Marine industrial facilities
- Bridges
- Utilities and pipeline crossings
- Sand and gravel operations
- Remedial cleanup
- Non-water dependent commercial uses (restaurants for example)

Any of the uses described above require an authorization from the Department of State Lands. Authorizations include leases, licenses, easements, registrations and short-term access agreements. The Department of State Lands also issues two types of permits and authorizations:

- Removal-fill permits for removal or fill activity in waterways and wetlands
- Proprietary waterway authorizations for use of state-owned waterways

11.2.2 Department of Environmental Quality

Oil Spill Contingency Planning Act (ORS 468B.300) requires an oil spill prevention and emergency response plan approved by the Department of Environmental Quality prior to the operation of onshore or offshore oil or gas facilities or operation of tanker, cargo, or passenger vessels in state waters of the Pacific Ocean, estuaries to the head of tide water, the Columbia River, and the Willamette River to Willamette Falls. This act includes legislative policy, provides the DEQ with authority to adopt standards for preparing contingency plans, and lists minimum requirements for such contingency plans. The act establishes an Oil Spill Prevention Fund, creates an Oregon coast safety committee, and establishes a wildlife rescue training program.

11.3 Local Laws

There are currently no local laws in effect that pertain to ports safety.

11.4 Existing and proposed Laws and Regulations

Review of existing and proposed federal, state and local laws, regulations or ordinances affecting the region to determine a need for any change;

11.4.1 Change to state pilotage laws

House Bill 2695 does not require local knowledge for tugboat operators. The Pilots are working with the US Coast Guard to make sure this is not the case and that some local knowledge is in place. Tugs sailing under registry from Canada to Coos Bay only are not required to take a state licensed Pilot.

12 Educational Needs

An assessment of the need for establishing or upgrading existing educational or public awareness programs for all waterway users.

12.1 Seasonal and Recreational Boaters

The Coast Guard reminds boaters to adhere and pay attention to bar restrictions while traveling rivers in the area. Deaths in bar-related accidents have been reported along the coast of Oregon each year. Failure to comply with rules and regulations could result in financial penalties, imprisonment, and forfeiture of the owner's vessel and equipment.

Boaters should check weather reports and ensure they have the proper safety and communication equipment before getting underway. To check local bar conditions, call the nearest Coast Guard station or tune the radio to 1610 AM. For up to date bar status or restrictions visit:

http://www.wrh.noaa.gov/pqr/marine/bars_mover.php[3]

While information is provided to the community, accidents still happen. The CBHSC recognizes the need for additional education and outreach programs to both the recreational and commercial boating community.

[3] United States Power Squadron, Coos Bay website http://www.usps.org/lc/coos/page3.html

13 Communications

13.1 Current ship-to-ship and ship communication

Radios:

- The USCG monitors channel 16
- The USCG provides notice to mariner, navigation safety update on channel 22A
- The pilot boats monitor VHF-FM channels 13 and 16 and use channels 12 and 18A as working frequency.
- Tugboats over 26’ in length are subject to the Bridge to Bridge Radio act and required to monitor Channel 16 (distress) and Channel 13 (communications). In Coos Bay, towboat operators primarily work 7A followed by 65. The Pilots work 18A.
- Coos County Sheriff boats use and monitor channel 16 when underway.

Cellular Phones:

- The use of cell phones/texting devices and phone applications aboard US Coast Guard boat force assets is not authorized without the permission of the coxswain. At no time will the operator of the boat use a cell phone or texting device.
- Cell phones are not used on the bridge by Pilots.

13.1.1 Current ship-to-shore communication systems used in the region

- Radios – VHF marine band
- Cellular Phones

13.2 Low propagation, or silent areas within the region

There are currently no low propagation or silent areas, however,

- Channel use is busy during fishing season and causes Pilot to change channels.

13.3 Strategy to address communication deficiencies.

There are currently no deficiencies that need to be addressed by the Harbor Safety Committee.

14 Bridge User Requirements

This section includes an assessment of current schedule for bridge openings, the adequacy of the ship to bridge communications and the physical limitations affecting vertical and horizontal clearances.

14.1 Rail Bridge

According to 33 CFR 117, the draw of the Port of Coos Bay railroad bridge, mile 7.5 at North Bend, shall be maintained in the fully open position, except for the crossing of trains or maintenance.

14.1.1 Schedule:

The trains do not follow a regular schedule due to the lack of demand. This is why there is no published schedule for when the Rail Bridge will be closed.

14.1.2 Communications

Bridge tenders only monitor the radio when they are on duty when a train is passing. At times, Pilots sometimes have difficulty reaching the bridgetenders on the radio and have to resort to using the landline, or the duty cell number.

Alternatively, if the Pilot cannot get hold of bridgetender, the Pilots will ask the tugs to verify the position of the bridge for them.

14.1.3 Clearances

As previously mentioned, vessels following the Upper Jarvis Range light will have to be aware of their proximity to the middle span of the open rail bridge.

15 Best Maritime Practices - TBC

15.1 Background

Best Marine Practices (BMPs) are not to be confused with regulations as they have no legal status. Instead, they provide guidance by the HSC to the maritime community on how a prudent mariner would proceed under specified circumstances. BMPs are clear and concise, as well as easily-accessed and understood by the mariner. It is hoped that such practical, hands-on safety measures will have broad appeal in the maritime community and reduce personnel, vessel and environmental casualties while facilitating the flow of maritime commerce.

Below are Best Maritime Practice "BMP" Guidelines[4]:

BMP should "NOT" be considered as follows:

1. A regulation, enforced by a regulatory agency
2. An underground regulation–it cannot be enforced by any regulatory agency

BMP should be considered as follows:

1. A common-sense measure or practice that would normally be employed by a prudent mariner
2. A useful tool that promotes safety and adds value and is not an exercise in generating paper
3. The result of "brainstorming at the grassroots level" by each HSC
4. An improved process or procedure that may originate as a recommendation from the HSC
5. "Best Maritime Practice" is an accepted and agreed upon method to conduct an operation or process that will enhance safety for vessels, personnel, dockside facilities and marine resources
6. A good example of a "Best Maritime Practice" would be the San Francisco and Los Angeles/Long Beach Harbor Safety Committees' recommended procedure with respect to bunker barge transfer operations while alongside containers vessels at terminals.
7. Include as a disclaimer that the "BMP" is not in conflict with nor do they replace existing regulations which are already in place

15.2 The BMP Process

1. Once a "BMP" is developed it should be communicated to members of the harbor community in one of or all of the following manners
    a. Incorporated into related procedure manuals or references made to the particular "BMP"
    b. Posted on the Port of Coos Bay web page for the public at large
    c. Distributed in the form of brochures
    d. Referenced in the "Coast Pilot" as appropriate
2. "BMP" should also be included in the Committee's Harbor Safety Plan

[4] The California Department of Fish and Game, Office of Spill Prevention and Response (OSPR) presented these guidelines to the California Harbor Safety Committees at their Summit on 11/3/2009

3. “BMP” should be reviewed or revisited annually to determine if they can be improved upon, or even discontinued as the case may be

15.2.1.1 Coos Bay Best Maritime Practices

BMP’s adopted by the CBHSC are included in Appendix G.

16 Monitoring & Plan Enforcement

This section includes suggested mechanisms that will ensure that the provisions of the plan are fully, uniformly and regularly enforced.

The Committee developed guidelines for vessels operating in this region to ensure safe, reliable, and environmentally sound marine transportation. Although the Committee cannot enforce these guidelines under state, federal, or local law, they institutionalize sound marine operating practices as Standards of Care that responsible vessel operators follow voluntarily. The Committee depends on its members, local, state, and federal agencies and the maritime community to monitor compliance with the Standards of Care.

Observed violations or deviations from this Plan should be referred to the Committee, Coast Guard, or State or local authorities for evaluation and possible enforcement under applicable federal and state law or regulation. If the Committee finds significant deviations, it will evaluate and may recommend more stringent enforcement, and, as appropriate, state, federal, or local rulemaking.

The following briefly summarizes Plan provisions requiring enforcement and the parties who directly monitor compliance. State and/or federal regulations cover some Plan sections discussed below, while others are guidelines.

1. Aids to Navigation: Federal regulations control all Aids to Navigation. Report any problems to the Coast Guard.

2. Anchorages: Federal regulations control anchorages. Pilots and Coast Guard normally monitor compliance with anchorage requirements. Violations are to be reported to the Coast Guard.

3. Harbor Depths, Channel Design, and Dredging: Federal law and regulations govern the harbor depths and dredging. Report any problems to the U.S. Army Corps of Engineers or port authorities.

4. Contingency Routing: Pilots and the Coast Guard monitor compliance, which the Coast Guard enforces. Violations are to be reported to the Coast Guard. Appendix H is a placeholder for the Coast Guard directive for emergency dispersal.

5. History of Accidents and Near Misses in the Harbor: This chapter's provisions are maintained by the Coast Guard and the Oregon Marine Board. Questions or concerns may be directed to them.

   Oregon:
   Oregon responsibilities of a boat operator at an accident scene: (ORS 830.475, 830.480, OAR 250-010-0110). Anyone involved in a boat accident must give name, address, other required information and aid to injured person(s), including transportation to a hospital if treatment appears necessary or is requested by injured person(s).

• Leaving a boat accident scene before performing operator's duties is a Class C felony punishable by five years in jail and/or a $100,000 fine.
• Boat operators involved in an accident resulting in death, injury or property damage exceeding $2000 must report the accident to the State Marine Board on a
Marine Board Accident Report Form:

–within 48 hours of an accident resulting in death or injury;
–within 10 days of an accident causing property/equipment damage only.

Occupants are responsible for making accident report when the operator is physically incapable of doing so.

In the case of immediate need of assistance, waterway boaters should call 911.

US Coast Guard:
Under the general marine casualty reporting provisions of 46 C.F.R. part 4, the owner, operator, or person in charge of a vessel must report marine casualties involving a grounding, allision (a moving vessel hitting a fixed object), or loss of propulsion that impacts the maneuverability of the vessel, impacts the vessel's seaworthiness, or fitness for service or route, loss of life, injury requiring professional medical treatment, property damage in excess of $35,000, or significant harm to the environment. 46 C.F.R. § 4.05-1.

The initial report must be made immediately by telephone to Sector Columbia River Investigations Department at 503-861-2242, followed by a written report (Form CG-2692), within five days of the marine casualty. This report must include any necessary alcohol or drug testing required by the regulations,

6. Communications: This Chapter mandates that highest quality communications standards are used in Coos Bay Harbor. Discipline programs reducing congestion, interference, unnecessary/ excessive use of high power settings, and frequency misuse. All radio users in the harbor area, as well as Committee members, can help the Coast Guard, the Oregon Department of Fish and Wildlife, and the Federal Communications Commission (FCC) monitor these standards. Violations are to be reported to the FCC and to the Harbor Safety Committee.

   Waterway users can file complaints with FCC using an online complaint form. You can also file a complaint by calling 1-888-CALL-FCC (1-888-225-5322) voice, 1-888-TELL-FCC (1-888-835-5322) TTY; faxing 1-866-418-0232, or writing to:

   Federal Communications Commission
   Consumer & Governmental Affairs Bureau
   Consumer Inquiries and Complaints Division
   445 12th St., SW
   Washington, DC 20554.

You can help FCC resolve your complaint more quickly by providing as much of the following information as possible:
(1) the date and time the material was aired;
(2) the call sign, channel, or frequency of the station;
(3) the city and state where the complaint occurs; and
(4) as many details as possible about the content of the broadcast to help the FCC determine whether the material was improper. It is also helpful to include your address, e-mail and phone numbers.

7. Bridges: Federal regulations govern bridge operations. Improper bridge management incidents are to be reported to the Coast Guard District 13 Bridge Management Section (800) 982-8813 or to Sector Columbia River, Waterway Management Division at 503-861-2242.

8. Small Craft: The main small vessel potential safety problem is a violation of the U.S. Inland Navigation Rules (1980), Rule 9: impeding the progress of large vessels within channels. Pilots and the Coast Guard monitor compliance with Rule 9. Recreational boat navigation violations are to be reported to the Coast Guard or any readily available local law enforcement authority including the Coos County Sheriffs.

9. Tug Escort/Ship Assist: There is currently no tug escort and/or ship assist regulatory requirements for Coos Bay harbor. The USCG and the Pilots have the authority to require escort and ship assist vessels on a case by case basis.

10. Pilotage: Pilots should remain in service on inbound vessels until they reach safe berth and on outbound vessels until 1mile past K buoy. The US Coast Guard and pilots monitor compliance. Report any deviations from the standard procedures or Standards of Care of this Plan made by pilots or other vessel operators to the Committee or Coast Guard.

11. Under-keel Clearance and Inclement Weather: Pilots to monitor for compliance. Violations are to be reported directly to the Coast Guard. Report violations regarding reduced visibility to USCG.

16.1 Enforcement Authorities

The Committee formally requests that its members, as well as all agencies with enforcement and monitoring authority within the scope of the Plan, monitor compliance with Plan guidelines and provisions. Furthermore, it is very important that members of the local maritime community, who regularly conduct business in the harbor area and have the strongest presence, assist in monitoring by acting as the eyes and ears of the Committee. Please report infractions of Plan guidelines, violations of state and federal regulations and any unsafe practices to the following bodies, as appropriate:

1. The Coast Guard - 24/7 Command Duty Officer: Violations of federal regulations or Plan guidelines, and unsafe practices

- (503) 861-2242

3. The Coos County Sheriff Marine Division: Violations of state laws, local ordinances;
   - (541) 396-7830
4. Oregon Department of Fish and Wildlife: NON- EMERGENCY notifications for violations of state regulations;
   - (503) 947-6000
5. Department of Environmental Quality: Violations of state law governing oil transfers at marine facilities;
   - (800) 452-4011

The Committee encourages the local maritime community and agencies that monitor regulatory compliance to notify the Committee of marine safety and environmental concerns by email at Coosbayharborsafety@gmail.com or attending the regular monthly meetings and make a report to the Committee.

Should the Committee find that Plan guidelines are not routinely followed, it will evaluate more-stringent approaches to enforcement, including, as appropriate, state, federal, and local rulemaking

17 CBHSC Recommendations and Accomplishments

17.1 Recommendations

The CBHSC has submitted recommendations to the community. These can be found in Appendix I of the plan.

17.2 Accomplishments

The CBHSC has accomplished the following:

- FAA review of the vessel transit height restriction and agreement that aircraft movements will be controlled to allow the safe passage of vessels with an air draft greater than 144 feet.
- Distribution of thumb drives to the towing and crabbing community with charts/plots showing the designated tow lanes and the crabbing areas to help both avoid operating each other's areas.

18 Implementation of CBHSC Action Items

Action items derived from Harbor Safety Committee meetings will be reviewed by the committee and assigned to an individual or to a subcommittee to execute within a given time frame.

Action Items and their status are tracked in the table found in Appendix J.

19 Applicable Regulations and Guidelines

USCG Ports and Waterways Safety Regulations, 33 CFR Subchapter P

- Part 160 Ports and Waterways General
- Part 162 Inland Waterways Navigation Rules
- Part 163 Towing of barges
- Part 164 Navigation Safety Rules
- Part 165 Regulated Navigation Areas
- Part 169 Ship Reporting Systems

USCG Pollution Regulations, 33 CFR Subchapter O

- Part 151 Vessels Carrying Oil, Chemicals, Garbage, and Ballast Water
- Part 153 Control of Pollution
- Part 154 Facilities Transferring Oil or Hazardous Material in Bulk
- Part 155 Oil/Hazardous Material Pollution Prevention Regulations for Vessels
    - Non-Tank Vessel Contingency Plan Regulations
    - Tank Vessel Contingency Plan Regulations
    - Salvage and Marine Firefighting
- Part 156 Oil/Hazardous Material Transfer Operations
- Part 158 Reception Facilities for Oil, Noxious Liquid Substances, and Garbage
- Part 159 Marine Sanitation Devices

USCG Maritime Security Regulations, 33 CRF Subchapter H

- Part 101 General
- Part 103 Area Maritime Security
- Part 104 Vessel Security
- Part 105 Facility Security

Guidelines for Under Keel Clearance in Coos Bays is on average 10% and is established by each vessel in consultation with the pilots.

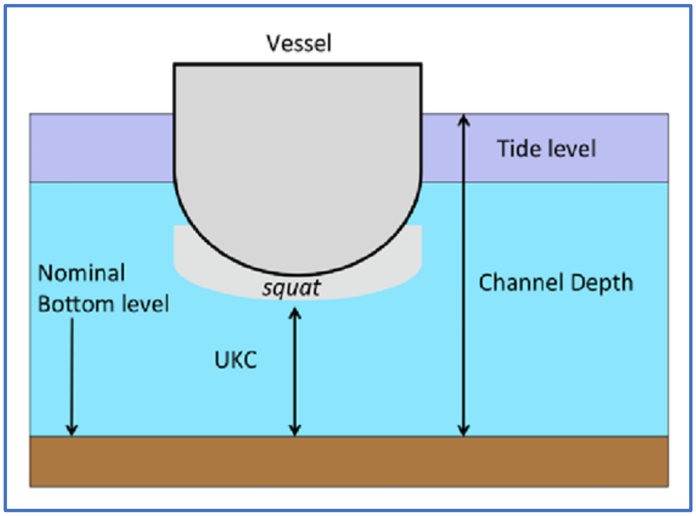


FIGURE 21 - UNDER KEEL CLEARANCE (UKC)

20 Funding

This section shall provide recommendations for funding projects that the committee intends to recommend or initiate; and consider the imposition of user fees, and assess existing billing mechanisms as potential funding sources.

There are currently no projects the committee would like to see funded nor are user fees or other mechanisms used to generate funding being considered at this stage.

21 Competitive Aspects

This section shall identify and discuss the potential economic impacts of implementing the provisions of the harbor safety plan and describe the significant differences in the restrictions that could vary from port to port within the region.

There are currently no identified economic impacts brought about by the implementation of the recommendations of the harbor safety plan, nor does the plan impose any additional restrictions that would render Coos Bay less favorable as compared to other ports in the area.

22 APPENDICES

Appendix A - Coos Bay Harbor Safety Committee Charter

Separate Document

Appendix B - Contact Information for Coos Bay

Separate Document

Appendix C – ATON review

Separate Document

Appendix D - Historical Vessel Statistics

Separate Document

Appendix E – Recent Accidents

Separate Document

Appendix F – Federal Agencies and Jurisdictions

Separate Document

Appendix G – Best Marine Practices

Separate Document

Appendix H – US Coast Guard Regulations, Directives, Advisories, NVICS

Separate Document

Appendix I– List of Recommendations presented to the Community

Separate Document

Appendix J– List of Action Items

Separate Document

Appendix K– U.S. Coast Guard Waterways Analysis and Management

Separate Document

Appendix L– Annual Plan updates and changes

Separate Document

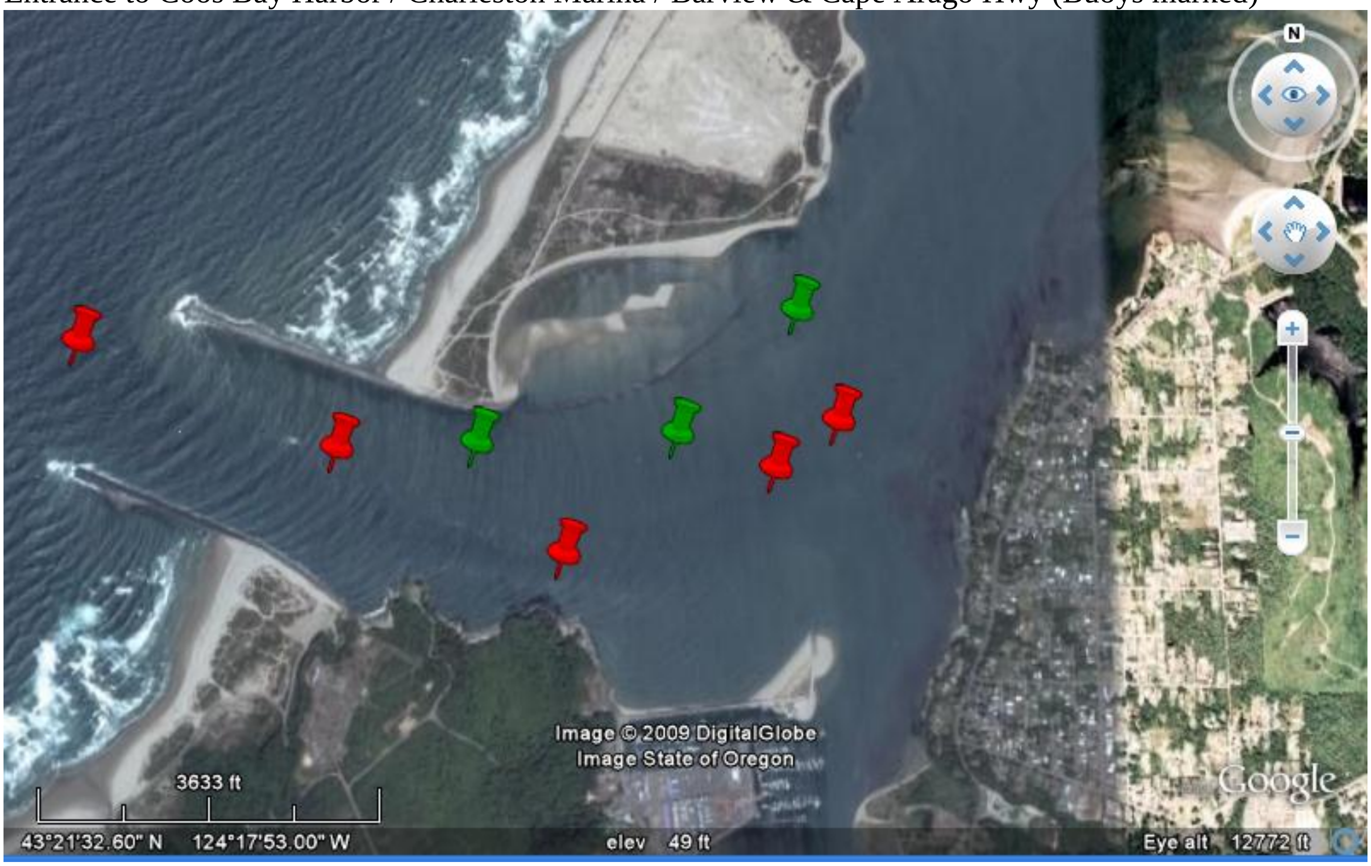
Exhibit 32

Coos Bay Channel Entrance

Distances and Buoy Markings.

Taken from Google Earth
(Buoys visually found and marked)

Entrance to Coos Bay Harbor / Charleston Marina / Barview & Cape Arago Hwy (Buoys marked)



Red Buoy to Shore .20 miles (1056 feet) (352 yards) (321.87 meters)
****

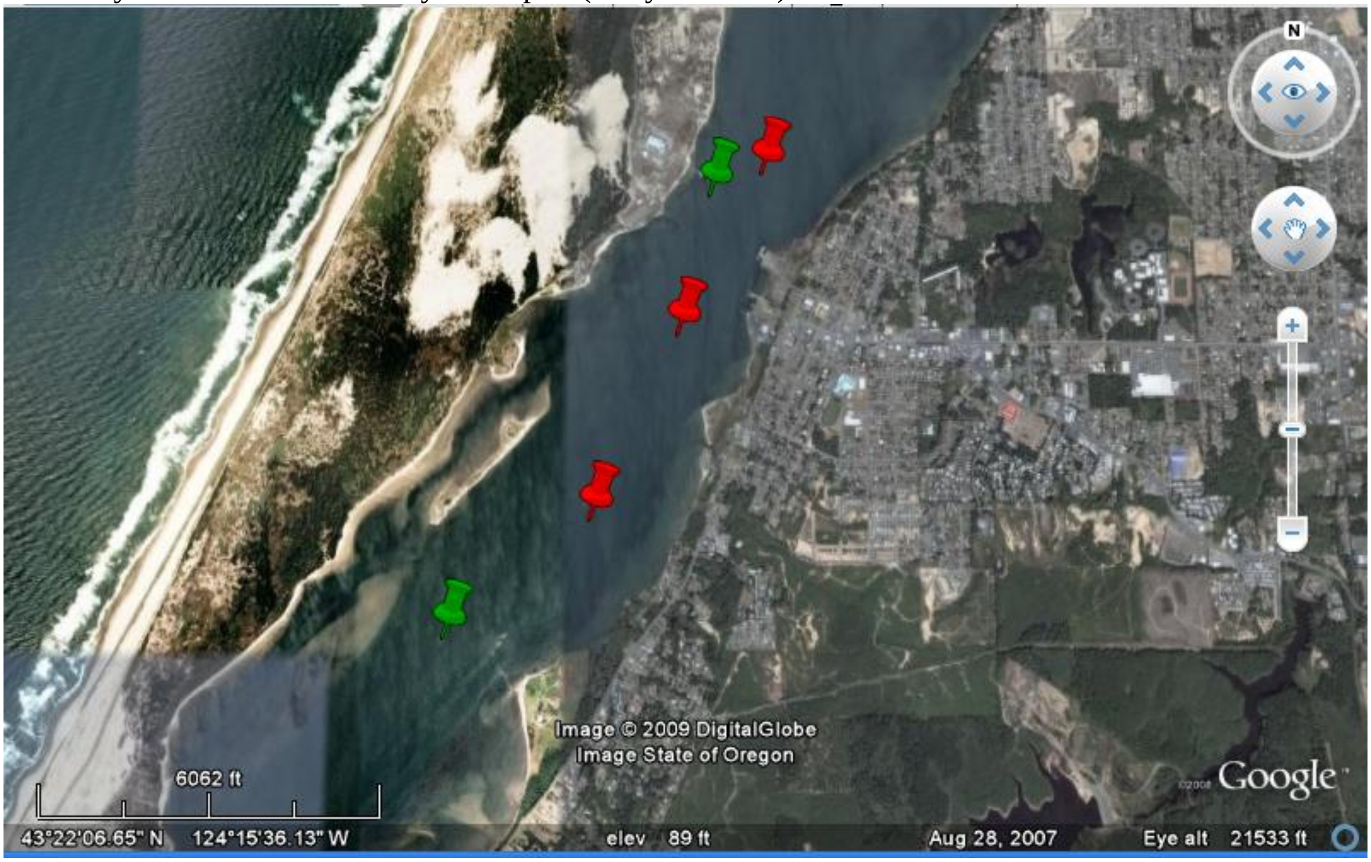
Red Buoy to shore .07 miles (369.6 feet) (123.2 yards) (112.65 meters)
****

Red Buoy to OIMB Auditorium .14 miles (739.2 feet) (246.4 yards) (225.31 meters)
****

Red Buoy to Coast Guard Housing Complex -.23 miles (1214.4 feet) (404.8 yards) (370.15 meters)
****

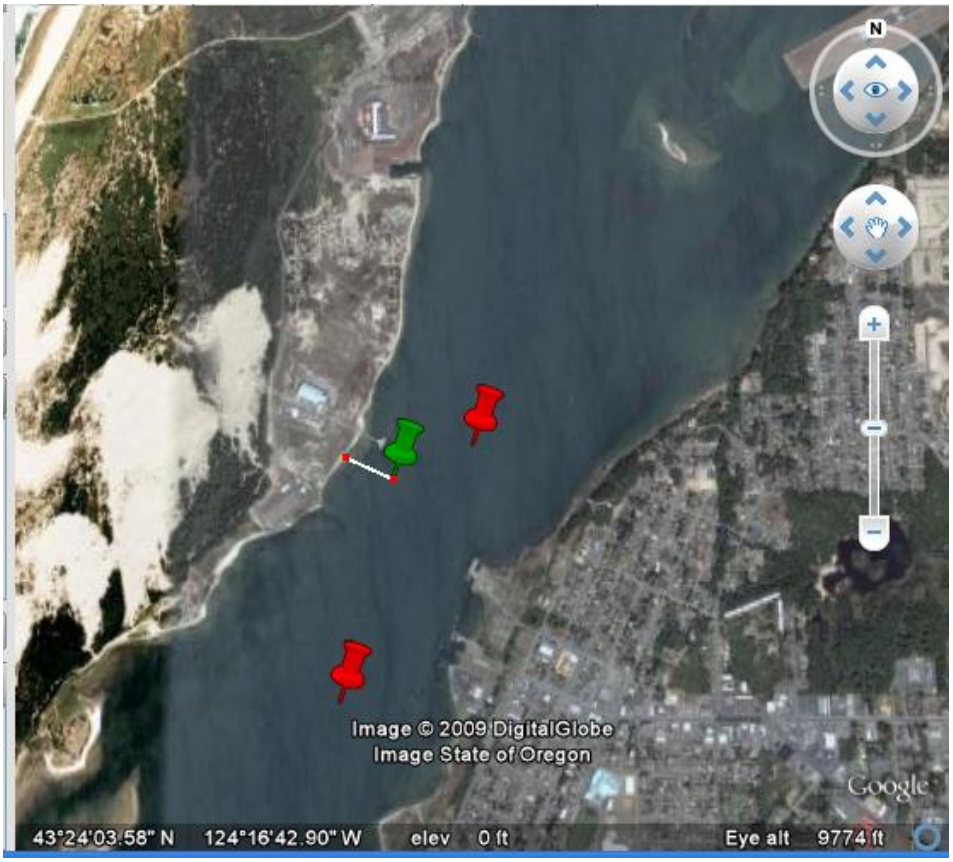
Red Buoy to House Along Cape Arago Hwy .34 miles (1795.2 feet) (598.4 yards) (547.18 meters)
****

Coos Bay Channel at Community of Empire (Buoys marked)

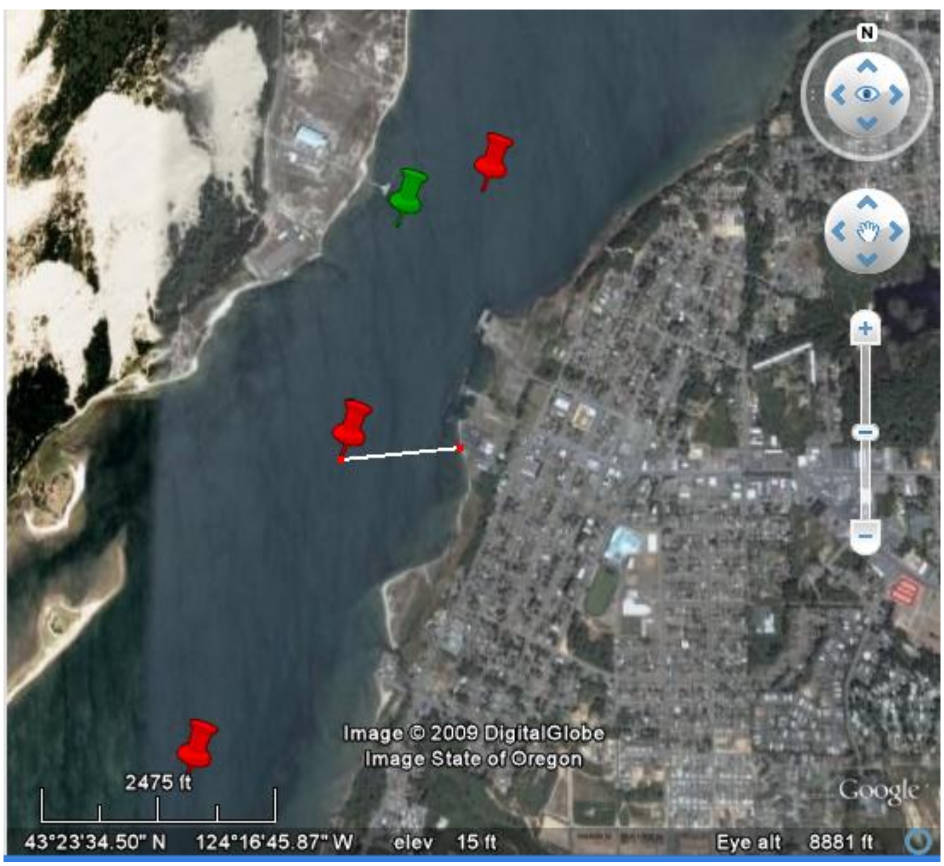


Red Buoy to Shoreline near DB Western .25 Miles (1320 feet) (440 yards) (402.34 meters)

****

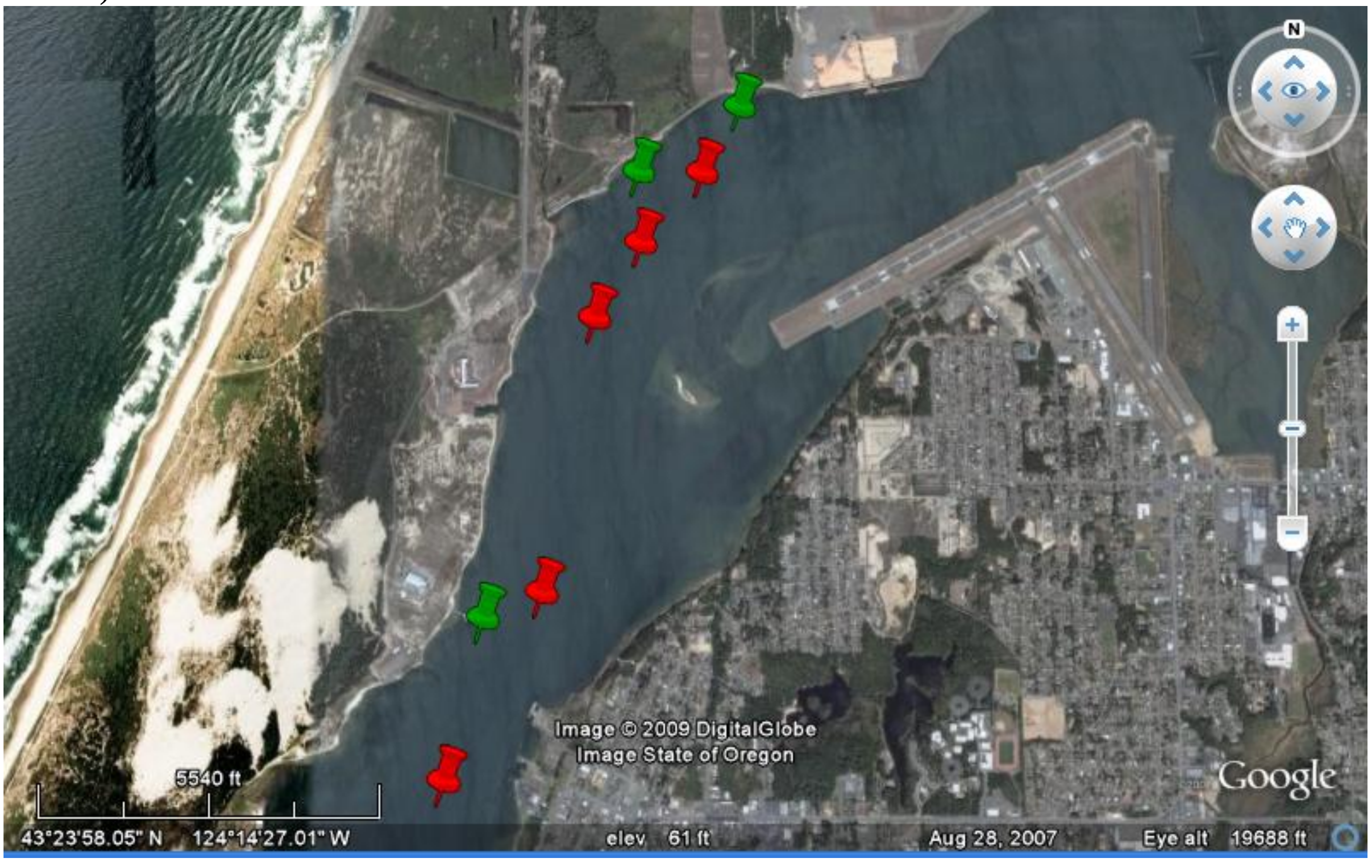


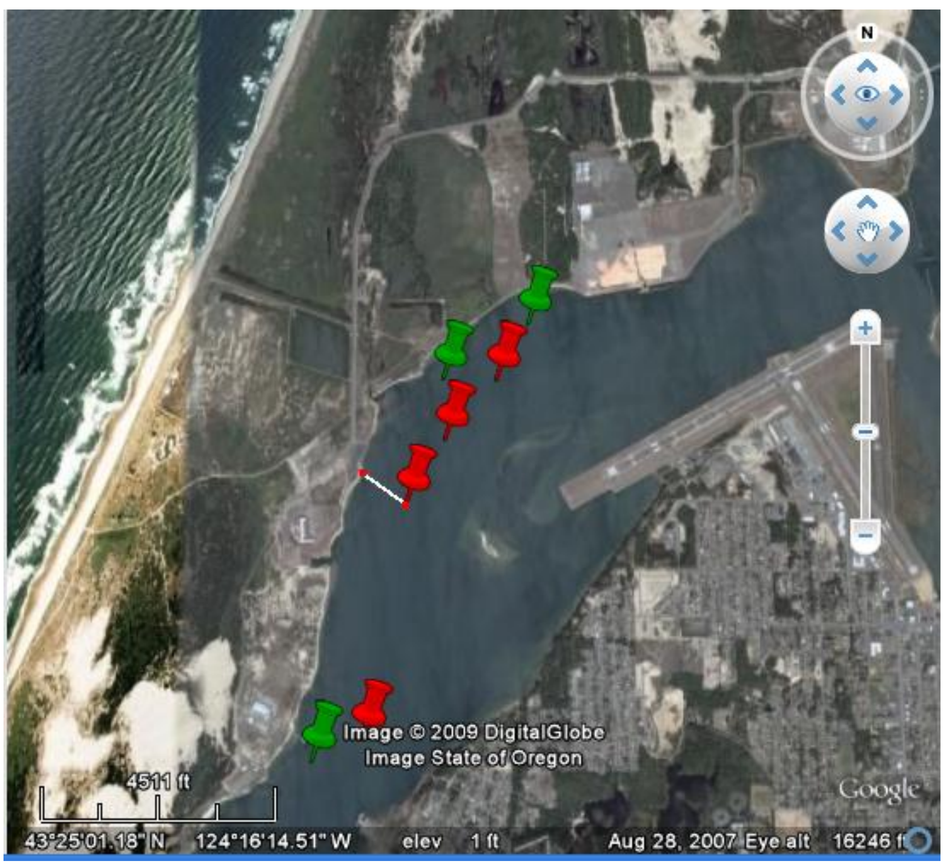
Green Buoy to Shoreline near DB Western .12 miles (633.60 feet) (211.2 yards) (193.12 meters)
****



Red Buoy to Empire Marina Parking Lot - .25 Miles (1320 feet) (440 yards) (402.34 meters)
****

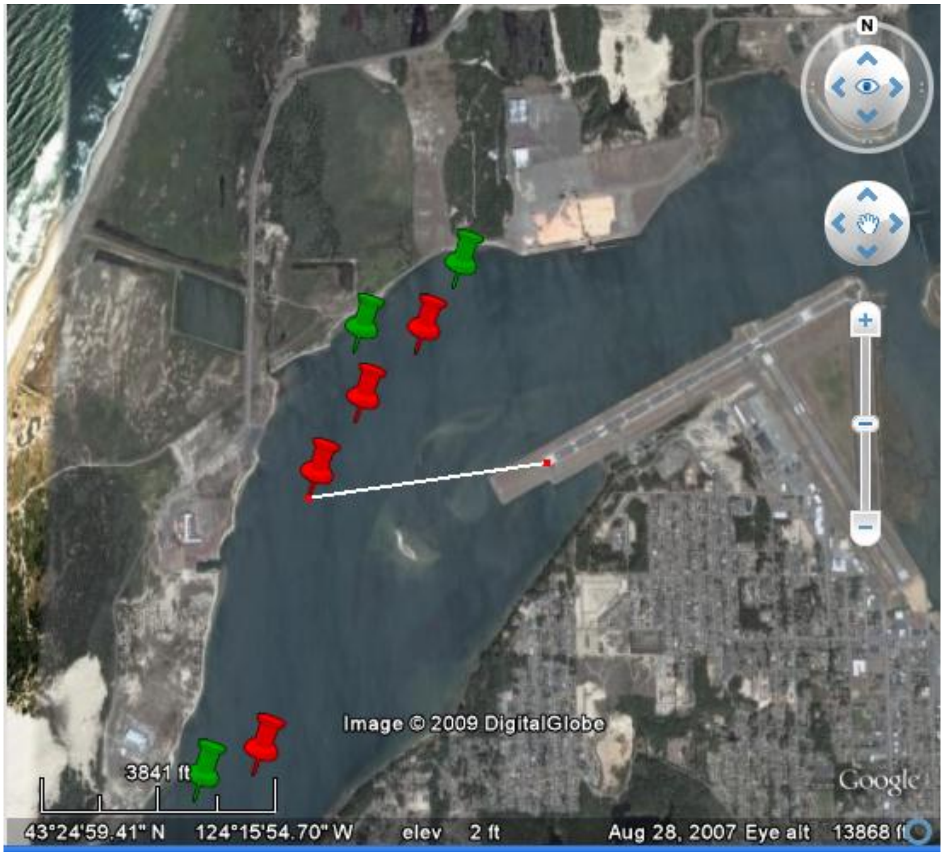
Coos Bay Channel – Jarvis Turn / Airport / City of North Bend / Industrial area on North Spit (Buoys marked)





Red Buoy to end of North Spit Boat Ramp .20 miles (1056 feet) (352 yards) (321.87 meters)

****



Red buoy to end of airport runway - .78 miles (4118.4 feet) (1372.8 yards) (1255.29 meters)
****

Exhibit 33

Federal Aviation Administration

« OE/AAA

Interim Cases for OR

Records 1 to 13 of 13 Page 1 of 1

Case Number	City	State	Latitude	Longitude	Site Elevation	Structure Height	Total Height
2017-ANM-5386-OE	North Bend	OR	43° 25' 48.88" N	124° 16' 00.87" W	23	219	242
2017-ANM-5387-OE	North Bend	OR	43° 25' 53.61" N	124° 16' 01.16" W	23	219	242
2017-ANM-5388-OE	North Bend	OR	43° 25' 59.24" N	124° 16' 00.87" W	42	131	173
2017-ANM-5389-OE	North Bend	OR	43° 26' 01.57" N	124° 16' 03.43" W	42	126	168
2017-ANM-5418-OE	North Bend	OR	43° 25' 40.52" N	124° 15' 57.06" W	10	199	209
2018-ANM-4-OE	North Bend	OR	43° 23' 49.37" N	124° 16' 56.55" W	12	199	211
2018-ANM-5-OE	North Bend	OR	43° 24' 07.84" N	124° 16' 41.25" W	12	199	211
2018-ANM-6-OE	North Bend	OR	43° 24' 32.44" N	124° 16' 38.26" W	12	199	211
2018-ANM-7-OE	North Bend	OR	43° 24' 55.79" N	124° 16' 29.14" W	12	199	211
2018-ANM-8-OE	North Bend	OR	43° 25' 07.71" N	124° 16' 17.62" W	12	199	211
2018-ANM-718-OE	North Bend	OR	43° 23' 36.85" N	124° 17' 04.51" W	12	199	211
2018-ANM-719-OE	North Bend	OR	43° 25' 20.59" N	124° 15' 48.27" W	12	199	211
2018-ANM-720-OE	North Bend	OR	43° 25' 13.85" N	124° 16' 09.31" W	12	199	211

Rows per Page: 20 ▼

Records 1 to 13 of 13 **Page: 1** Page 1 of 1

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
10101 Hillwood Parkway
Fort Worth, TX 76177

Aeronautical Study No.
2018-ANM-720-OE

Issued Date: 05/07/2018

Drew Jackson
Jordan Cove LNG
5615 Kirby Dr
Houston, TX 77005

**** NOTICE OF PRESUMED HAZARD ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	LNG Carrier Vessel - Stack, Transit Point 6
Location:	North Bend, OR
Latitude:	43-25-13.85N NAD 83
Longitude:	124-16-09.31W
Heights:	12 feet site elevation (SE) 199 feet above ground level (AGL) 211 feet above mean sea level (AMSL)

Initial findings of this study indicate that the structure as described exceeds obstruction standards and/or would have an adverse physical or electromagnetic interference effect upon navigable airspace or air navigation facilities. Pending resolution of the issues described below, the structure is presumed to be a hazard to air navigation.

If the structure were reduced in height so as not to exceed 155 feet above ground level (167 feet above mean sea level), it would not create a substantial adverse effect and a favorable determination could subsequently be issued.

Any height exceeding 155 feet above ground level (167 feet above mean sea level), will result in a substantial adverse effect and would warrant a Determination of Hazard to Air Navigation.

See Attachment for Additional information.

NOTE: PENDING RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE, THE STRUCTURE IS PRESUMED TO BE A HAZARD TO AIR NAVIGATION. THIS LETTER DOES NOT AUTHORIZE CONSTRUCTION OF THE STRUCTURE EVEN AT A REDUCED HEIGHT. ANY RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE MUST BE COMMUNICATED TO THE FAA SO THAT A FAVORABLE DETERMINATION CAN SUBSEQUENTLY BE ISSUED.

IF MORE THAN 60 DAYS FROM THE DATE OF THIS LETTER HAS ELAPSED WITHOUT ATTEMPTED RESOLUTION, IT WILL BE NECESSARY FOR YOU TO REACTIVATE THE STUDY BY FILING A NEW FAA FORM 7460-1, NOTICE OF PROPOSED CONSTRUCTION OR ALTERATION.

If we can be of further assistance, please contact our office at (206) 231-2990, or paul.holmquist@faa.gov. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2018-ANM-720-OE.

Signature Control No: 357210193-364494235 (NPH)

Paul Holmquist
Specialist

Attachment(s)
Additional Information

Additional information for ASN 2018-ANM-720-OE

ASN 2018-ANM-720-OE

Abbreviations

AGL - above ground level	AMSL - above mean sea level	RWY - runway
VFR - visual flight rules	IFR - instrument flight rules	NM - nautical mile
ASN- Aeronautical Study Number	CAT - category aircraft	
MDA - minimum descent altitude	DA - decision altitude	

Part 77 - Title 14 Code of Federal Regulations (CFR) Part 77, Safe, Efficient Use and Preservation of the Navigable Airspace

Our aeronautical study has disclosed that the proposed 199-foot AGL (211-foot AMSL) liquid natural gas carrier vessel (ship stack) shipping channel transit point location associated with the proposed Jordan Cove Liquid Natural Gas Terminal penetrates 14 CFR Part 77 protected airspace surfaces at Southwest Oregon Regional Airport (OTH) in North Bend, OR. The OTH airport elevation is 17 feet AMSL.

The proposed structure would exceed the following Part 77 surfaces:

Section 77.19(a): Horizontal Surface-a height exceeding a horizontal plane 150 feet above the established airport elevation. The proposed structure would exceed the OTH Horizontal Surface by 44 feet.

Additionally, the proposed structure would exceed the OTH VFR traffic pattern airspace in the Part 77 VFR Horizontal Surface feet as defined in FAA JO 7400.2L, 6-3-8, Evaluating Effect on VFR Operations.

This proposed structure would exceed the OTH VFR Traffic Pattern Horizontal Surface by 44 feet. The not-to-exceed height of 155 feet AGL (167 AMSL) will avoid penetrating the Horizontal Surface.

The OTH Airport Master Record, http://www.gcr1.com/5010web/airport.cfm?Site=OTH, states there are 36 single engine, eight (8) multi-engine, one (1) jet, and six (6) helicopter aircraft based there with 18,277 total operations for the 12 months ending 31 December 2013 (latest information). RWY 31 is designated Right Traffic.

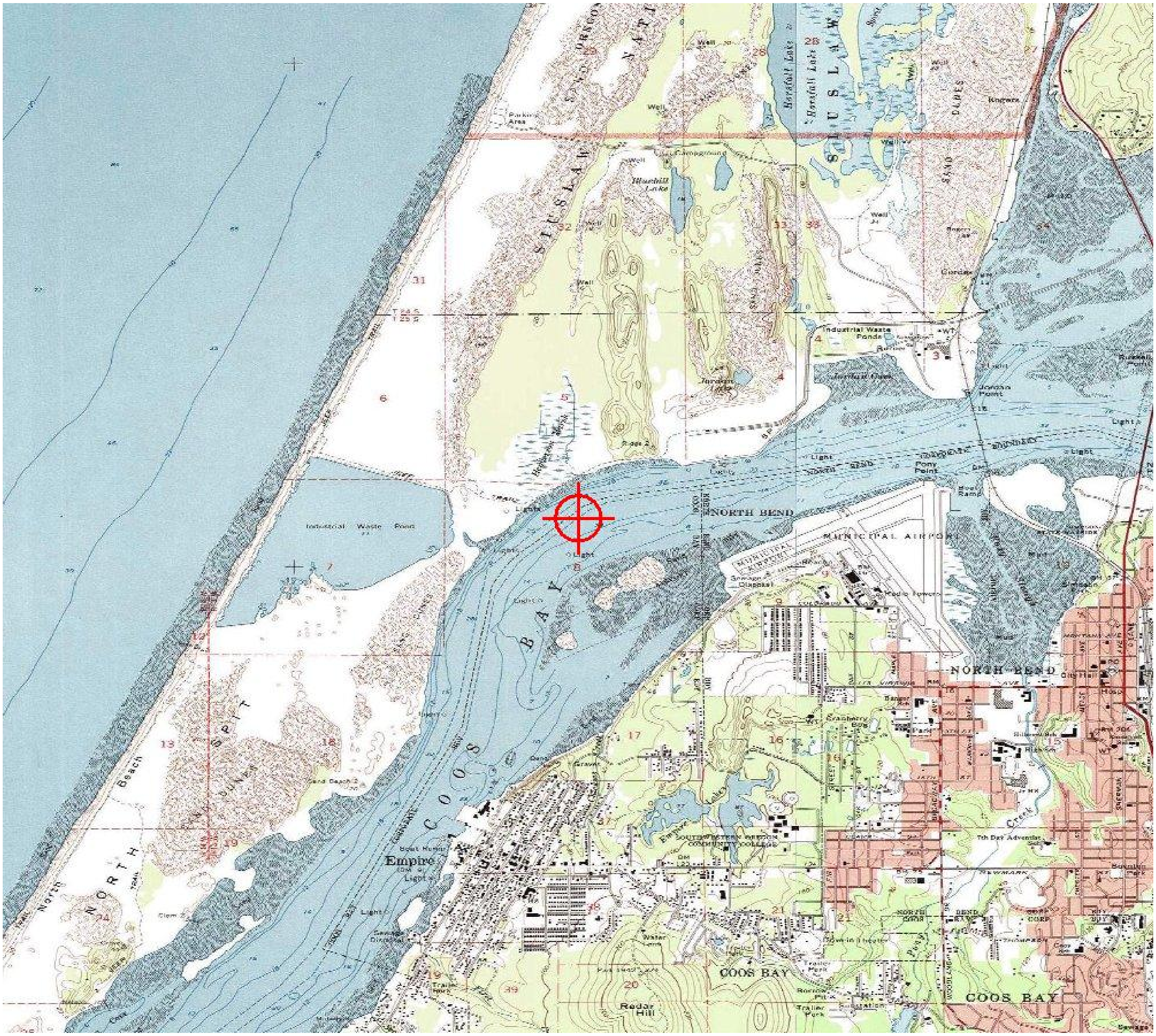
Your options and conditions for this proposal are as follows:

1. You must resolve the 44 foot VFR Traffic Pattern Airspace penetration by lowering the structure height, with all appurtenances, to a maximum height at 155 feet AGL (167 AMSL). If you agree to limit the structure height to 155 feet AGL (167 AMSL), the FAA can then withdraw this objection to the proposed structure as it would not exceed obstruction standards and a favorable determination could be subsequently issued.

2. You can terminate the proposal at this location.

Please email me within 60 days of the date of this letter at Paul.Holmquist@faa.gov with your intentions and any questions you might have regarding this aeronautical study.

Close Print


NORTH BEND
MUNICIPAL AIRPORT
COOS BAY
Empire
COOS BAY
NORTH SPIT
Industrial Waste Pond
Industrial Waste Ponds
SOUTHWESTERN OREGON COMMUNITY COLLEGE
Radar Hill

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
10101 Hillwood Parkway
Fort Worth, TX 76177

Aeronautical Study No.
2018-ANM-719-OE

Issued Date: 05/07/2018

Drew Jackson
Jordan Cove LNG
5615 Kirby Dr
Houston, TX 77005

**** NOTICE OF PRESUMED HAZARD ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	LNG Carrier Vessel - Stack, Transit East Point
Location:	North Bend, OR
Latitude:	43-25-20.59N NAD 83
Longitude:	124-15-48.27W
Heights:	12 feet site elevation (SE)
	199 feet above ground level (AGL)
	211 feet above mean sea level (AMSL)

Initial findings of this study indicate that the structure as described exceeds obstruction standards and/or would have an adverse physical or electromagnetic interference effect upon navigable airspace or air navigation facilities. Pending resolution of the issues described below, the structure is presumed to be a hazard to air navigation.

If the structure were reduced in height so as not to exceed 155 feet above ground level (167 feet above mean sea level), it would not create a substantial adverse effect and a favorable determination could subsequently be issued.

Any height exceeding 155 feet above ground level (167 feet above mean sea level), will result in a substantial adverse effect and would warrant a Determination of Hazard to Air Navigation.

See Attachment for Additional information.

NOTE: PENDING RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE, THE STRUCTURE IS PRESUMED TO BE A HAZARD TO AIR NAVIGATION. THIS LETTER DOES NOT AUTHORIZE CONSTRUCTION OF THE STRUCTURE EVEN AT A REDUCED HEIGHT. ANY RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE MUST BE COMMUNICATED TO THE FAA SO THAT A FAVORABLE DETERMINATION CAN SUBSEQUENTLY BE ISSUED.

IF MORE THAN 60 DAYS FROM THE DATE OF THIS LETTER HAS ELAPSED WITHOUT ATTEMPTED RESOLUTION, IT WILL BE NECESSARY FOR YOU TO REACTIVATE THE STUDY BY FILING A NEW FAA FORM 7460-1, NOTICE OF PROPOSED CONSTRUCTION OR ALTERATION.

If we can be of further assistance, please contact our office at (206) 231-2990, or paul.holmquist@faa.gov. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2018-ANM-719-OE.

Signature Control No: 357209466-364496207 (NPH)
Paul Holmquist
Specialist

Attachment(s)
Additional Information

ASN 2018-ANM-719-OE

Abbreviations

AGL - above ground level	AMSL - above mean sea level	RWY - runway
VFR - visual flight rules	IFR - instrument flight rules	NM - nautical mile
ASN- Aeronautical Study Number	CAT - category aircraft	
MDA - minimum descent altitude	DA - decision altitude	

Part 77 - Title 14 Code of Federal Regulations (CFR) Part 77, Safe, Efficient Use and Preservation of the Navigable Airspace

Our aeronautical study has disclosed that the proposed 199-foot AGL (211-foot AMSL) liquid natural gas carrier vessel (ship stack) shipping channel transit point location associated with the proposed Jordan Cove Liquid Natural Gas Terminal penetrates 14 CFR Part 77 protected airspace surfaces at Southwest Oregon Regional Airport (OTH) in North Bend, OR. The OTH airport elevation is 17 feet AMSL.

The proposed structure would exceed the following Part 77 surface:

Section 77.19(a): Horizontal Surface-a height exceeding a horizontal plane 150 feet above the established airport elevation. The proposed structure would exceed the OTH Horizontal Surface by 44 feet.

Additionally, the proposed structure would exceed the OTH VFR traffic pattern airspace in the Part 77 VFR Horizontal Surface feet as defined in FAA JO 7400.2L, 6-3-8, Evaluating Effect on VFR Operations.

This proposed structure would exceed the OTH VFR Traffic Pattern Horizontal Surface by 44 feet. The not-to-exceed height of 155 feet AGL (167 AMSL) will avoid penetrating the Horizontal Surface.

The OTH Airport Master Record, http://www.gcr1.com/5010web/airport.cfm?Site=OTH, states there are 36 single engine, eight (8) multi-engine, one (1) jet, and six (6) helicopter aircraft based there with 18,277 total operations for the 12 months ending 31 December 2013 (latest information). RWY 31 is designated Right Traffic.

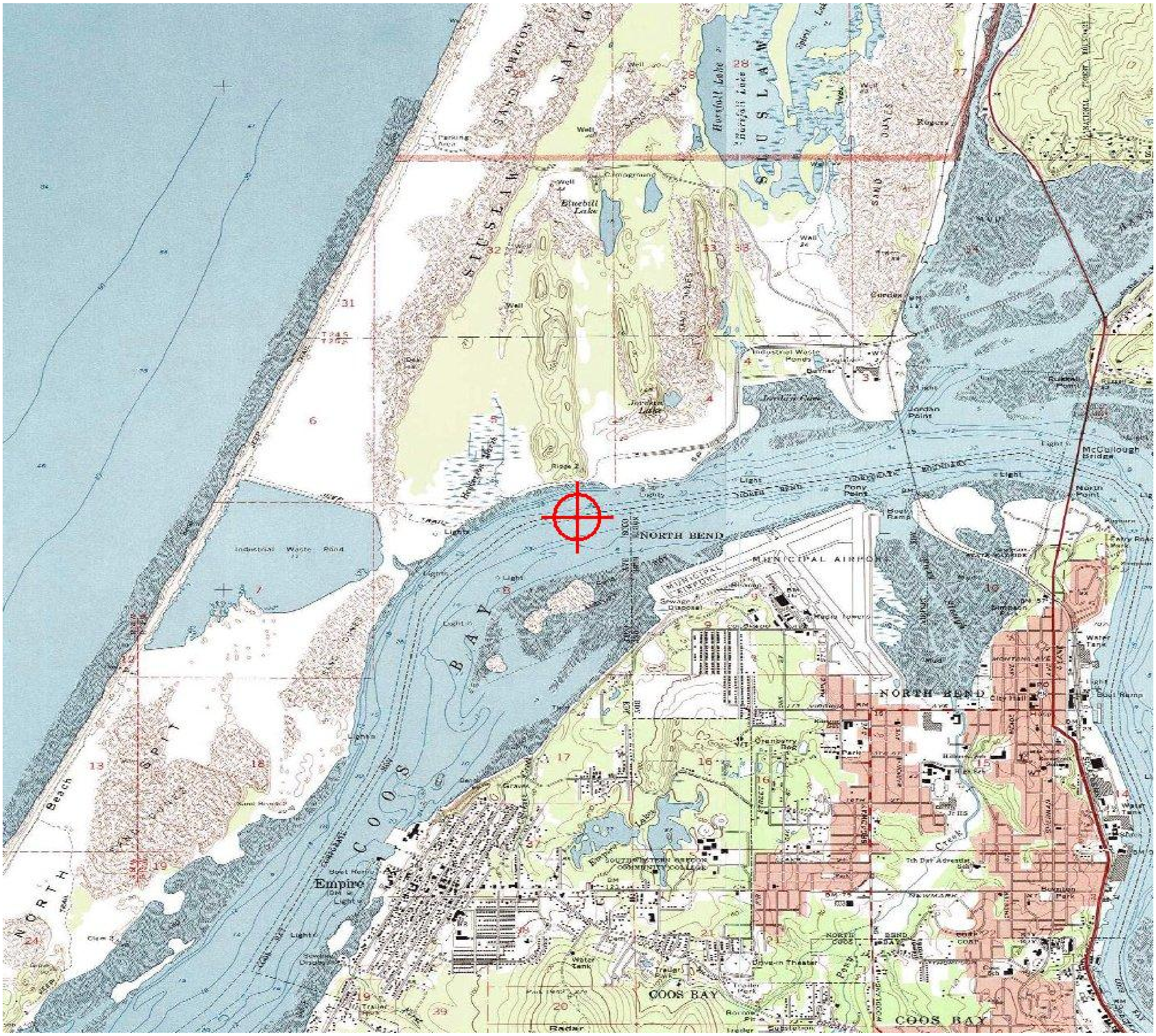
Your options and conditions for this proposal are as follows:

1. You must resolve the 44 foot VFR Traffic Pattern Airspace penetration by lowering the structure height, with all appurtenances, to a maximum height at 155 feet AGL (167 AMSL). If you agree to limit the structure height to 155 feet AGL (167 AMSL), the FAA can then withdraw this objection to the proposed structure as it would not exceed obstruction standards and a favorable determination could be subsequently issued. Further FAA study for any height greater than 155 AGL / 167 AMSL is not an option.

2. You can terminate the proposal at this location.

Please email me within 60 days of the date of this letter at Paul.Holmquist@faa.gov with your intentions and any questions you might have regarding this aeronautical study.

Close Print


Bluebill Lake
Horsfall Lake
Jordan Lake
Jordan Cove
Jordan Point
Industrial Waste Ponds
Industrial Waste Pond
Pony Point
North Point
McCullough Bridge
NORTH BEND
MUNICIPAL AIRPORT
COOS BAY
Empire
SOUTHWESTERN OREGON COMMUNITY COLLEGE
Drive-in Theater
City Hall
NORTH SPIT
North Beach

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
10101 Hillwood Parkway
Fort Worth, TX 76177

Aeronautical Study No.
2018-ANM-718-OE

Issued Date: 05/07/2018

Drew Jackson
Jordan Cove LNG
5615 Kirby Dr
Houston, TX 77005

**** NOTICE OF PRESUMED HAZARD ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	LNG Carrier Vessel - Stack, Transit West Point
Location:	North Bend, OR
Latitude:	43-23-36.85N NAD 83
Longitude:	124-17-04.51W
Heights:	12 feet site elevation (SE)
	199 feet above ground level (AGL)
	211 feet above mean sea level (AMSL)

Initial findings of this study indicate that the structure as described exceeds obstruction standards and/or would have an adverse physical or electromagnetic interference effect upon navigable airspace or air navigation facilities. Pending resolution of the issues described below, the structure is presumed to be a hazard to air navigation.

If the structure were reduced in height so as not to exceed 155 feet above ground level (167 feet above mean sea level), it would not create a substantial adverse effect and a favorable determination could subsequently be issued.

To pursue a favorable determination at the originally submitted height, further study would be necessary. Further study entails distribution to the public for comment, and may extend the study period up to 120 days. The outcome cannot be predicted prior to public circularization.

If you would like the FAA to conduct further study, you must make the request within 60 days from the date of issuance of this letter.

See Attachment for Additional information.

NOTE: PENDING RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE, THE STRUCTURE IS PRESUMED TO BE A HAZARD TO AIR NAVIGATION. THIS LETTER DOES NOT AUTHORIZE CONSTRUCTION OF THE STRUCTURE EVEN AT A REDUCED HEIGHT. ANY RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE MUST BE COMMUNICATED TO THE FAA SO THAT A FAVORABLE DETERMINATION CAN SUBSEQUENTLY BE ISSUED.

IF MORE THAN 60 DAYS FROM THE DATE OF THIS LETTER HAS ELAPSED WITHOUT ATTEMPTED RESOLUTION, IT WILL BE NECESSARY FOR YOU TO REACTIVATE THE STUDY BY FILING A NEW FAA FORM 7460-1, NOTICE OF PROPOSED CONSTRUCTION OR ALTERATION.

If we can be of further assistance, please contact our office at (206) 231-2990, or paul.holmquist@faa.gov. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2018-ANM-718-OE.

Signature Control No: 357209465-364496843 (NPH)

Paul Holmquist
Specialist

Attachment(s)
Additional Information

Additional information for ASN 2018-ANM-718-OE

ASN 2018-ANM-718-OE

Abbreviations
AGL - above ground level
AMSL - above mean sea level
RWY - runway
VFR - visual flight rules
IFR - instrument flight rules
NM - nautical mile
ASN- Aeronautical Study Number
CAT - category aircraft
MDA - minimum descent altitude
DA - decision altitude
Part 77 - Title 14 Code of Federal Regulations (CFR) Part 77, Safe, Efficient Use and Preservation of the Navigable Airspace

Our aeronautical study has disclosed that the proposed 199-foot AGL (211-foot AMSL) liquid natural gas carrier vessel (ship stack) shipping channel transit point location associated with the proposed Jordan Cove Liquid Natural Gas Terminal penetrates 14 CFR Part 77 protected airspace surfaces at Southwest Oregon Regional Airport (OTH) in North Bend, OR. The OTH airport elevation is 17 feet AMSL.

The proposed structure would exceed the following Part 77 surface:

Section 77.19(a): Horizontal Surface-a height exceeding a horizontal plane 150 feet above the established airport elevation. The proposed structure would exceed the OTH Horizontal Surface by 44 feet.

The OTH Airport Master Record, http://www.gcr1.com/5010web/airport.cfm?Site=OTH, states there are 36 single engine, eight (8) multi-engine, one (1) jet, and six (6) helicopter aircraft based there with 18,277 total operations for the 12 months ending 31 December 2013 (latest information). RWY 31 is designated Right Traffic.

Your options for this proposal are as follows:

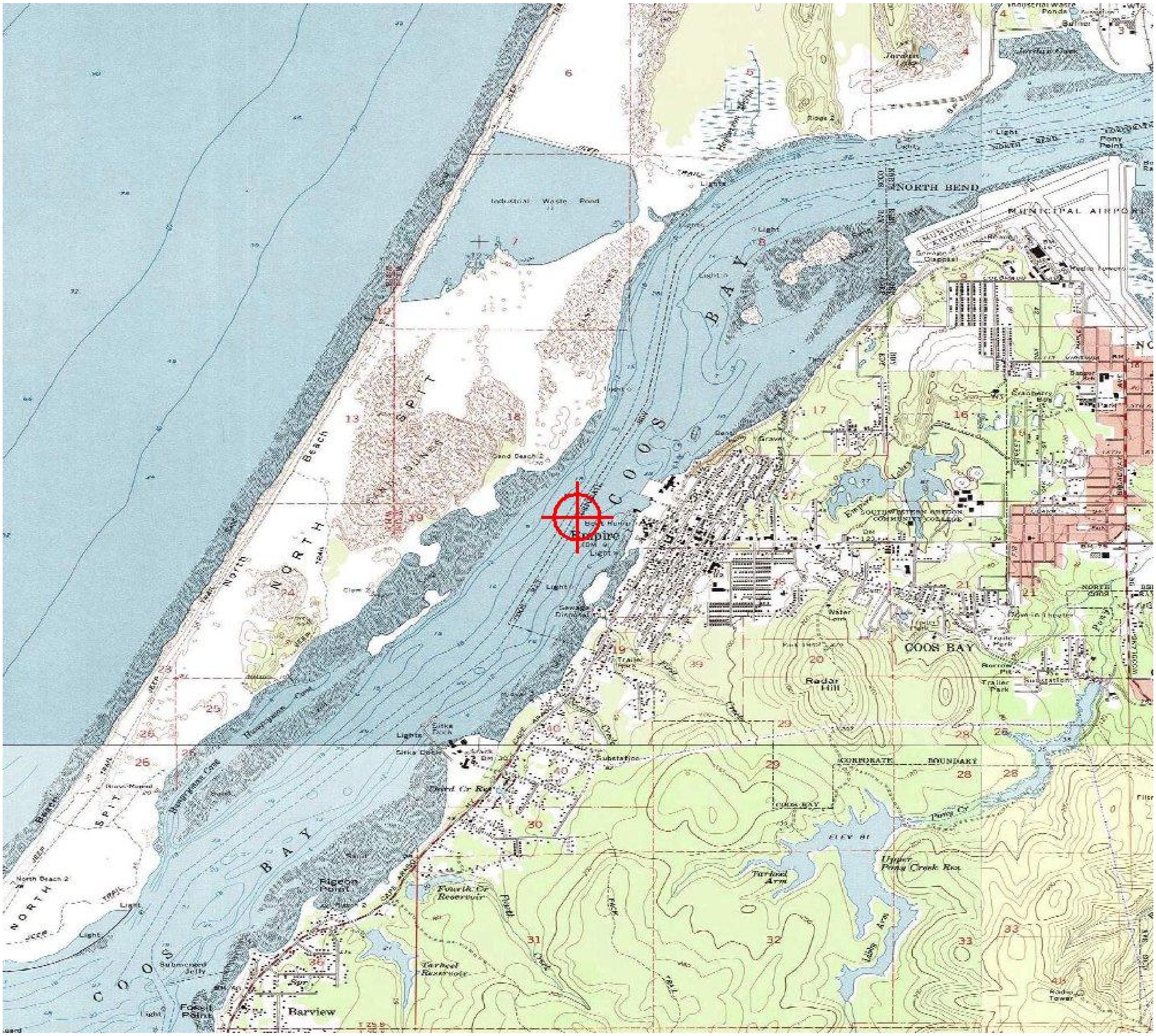
1. If you agree to limit the structure height to 155 feet AGL (167 AMSL), the FAA can then withdraw this objection to the proposed structure as it would not exceed obstruction standards and a favorable determination could be subsequently issued.

2. You can terminate the proposal at this location.

3. You can request further FAA study of the structure at the originally requested height. Further study will include a public notice circularization and 37-day comment period where the outcome cannot be predicted.

Please email me within 60 days of the date of this letter at Paul.Holmquist@faa.gov with your intentions and any questions you might have regarding this aeronautical study.

Close Print


Industrial Waste Pond
NORTH BEND
MUNICIPAL AIRPORT
COOS BAY
NORTH SPIT
North Beach
Empire
SOUTHWESTERN OREGON COMMUNITY COLLEGE
Radar Hill
CORPORATE BOUNDARY
Upper Pony Creek Res.
Pigeon Point
Fourth Cr Reservoir
Tarheel Reservoir
Barview
Fossil Point
Sitka Dock
Substation
Trailer Park
Radio Tower
Pony Point
Jordan Cove

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
10101 Hillwood Parkway
Fort Worth, TX 76177

Aeronautical Study No.
2018-ANM-8-OE

Issued Date: 05/07/2018

Drew Jackson
Jordan Cove LNG
5615 Kirby Dr
Houston, TX 77005

**** NOTICE OF PRESUMED HAZARD ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	LNG Carrier Vessel - Stack, Transit Point 5
Location:	North Bend, OR
Latitude:	43-25-07.71N NAD 83
Longitude:	124-16-17.62W
Heights:	12 feet site elevation (SE)
	199 feet above ground level (AGL)
	211 feet above mean sea level (AMSL)

Initial findings of this study indicate that the structure as described exceeds obstruction standards and/or would have an adverse physical or electromagnetic interference effect upon navigable airspace or air navigation facilities. Pending resolution of the issues described below, the structure is presumed to be a hazard to air navigation.

If the structure were reduced in height so as not to exceed 155 feet above ground level (167 feet above mean sea level), it would not create a substantial adverse effect and a favorable determination could subsequently be issued.

Any height exceeding 155 feet above ground level (167 feet above mean sea level), will result in a substantial adverse effect and would warrant a Determination of Hazard to Air Navigation.

See Attachment for Additional information.

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If we can be of further assistance, please contact our office at (206) 231-2990, or paul.holmquist@faa.gov. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2018-ANM-8-OE.

Signature Control No: 352163129-364497466 (NPH)
Paul Holmquist
Specialist

Attachment(s)
Additional Information

Additional information for ASN 2018-ANM-8-OE

ASN 2018-ANM-8-OE

Abbreviations

AGL - above ground level
AMSL - above mean sea level
RWY - runway
VFR - visual flight rules
IFR - instrument flight rules
NM - nautical mile
ASN- Aeronautical Study Number
CAT - category aircraft
MDA - minimum descent altitude
DA - decision altitude
Part 77 - Title 14 Code of Federal Regulations (CFR) Part 77, Safe, Efficient Use and Preservation of the Navigable Airspace

Our aeronautical study has disclosed that the proposed 199-foot AGL (211-foot AMSL) liquid natural gas carrier vessel (ship stack) shipping channel transit point location associated with the proposed Jordan Cove Liquid Natural Gas Terminal penetrates 14 CFR Part 77 protected airspace surfaces at Southwest Oregon Regional Airport (OTH) in North Bend, OR. The OTH airport elevation is 17 feet AMSL.

The proposed structure would exceed the following Part 77 surface:

Section 77.19(a): Horizontal Surface-a height exceeding a horizontal plane 150 feet above the established airport elevation. The proposed structure would exceed the OTH Horizontal Surface by 44 feet.

Additionally, the proposed structure would exceed the OTH VFR traffic pattern airspace in the Part 77 VFR Horizontal Surface feet as defined in FAA JO 7400.2L, 6-3-8, Evaluating Effect on VFR Operations.

This proposed structure would exceed the OTH VFR Traffic Pattern Horizontal Surface by 44 feet. The not-to-exceed height of 155 feet AGL (167 AMSL) will avoid penetrating the Horizontal Surface.

The OTH Airport Master Record, http://www.gcr1.com/5010web/airport.cfm?Site=OTH, states there are 36 single engine, eight (8) multi-engine, one (1) jet, and six (6) helicopter aircraft based there with 18,277 total operations for the 12 months ending 31 December 2013 (latest information). RWY 31 is designated Right Traffic.

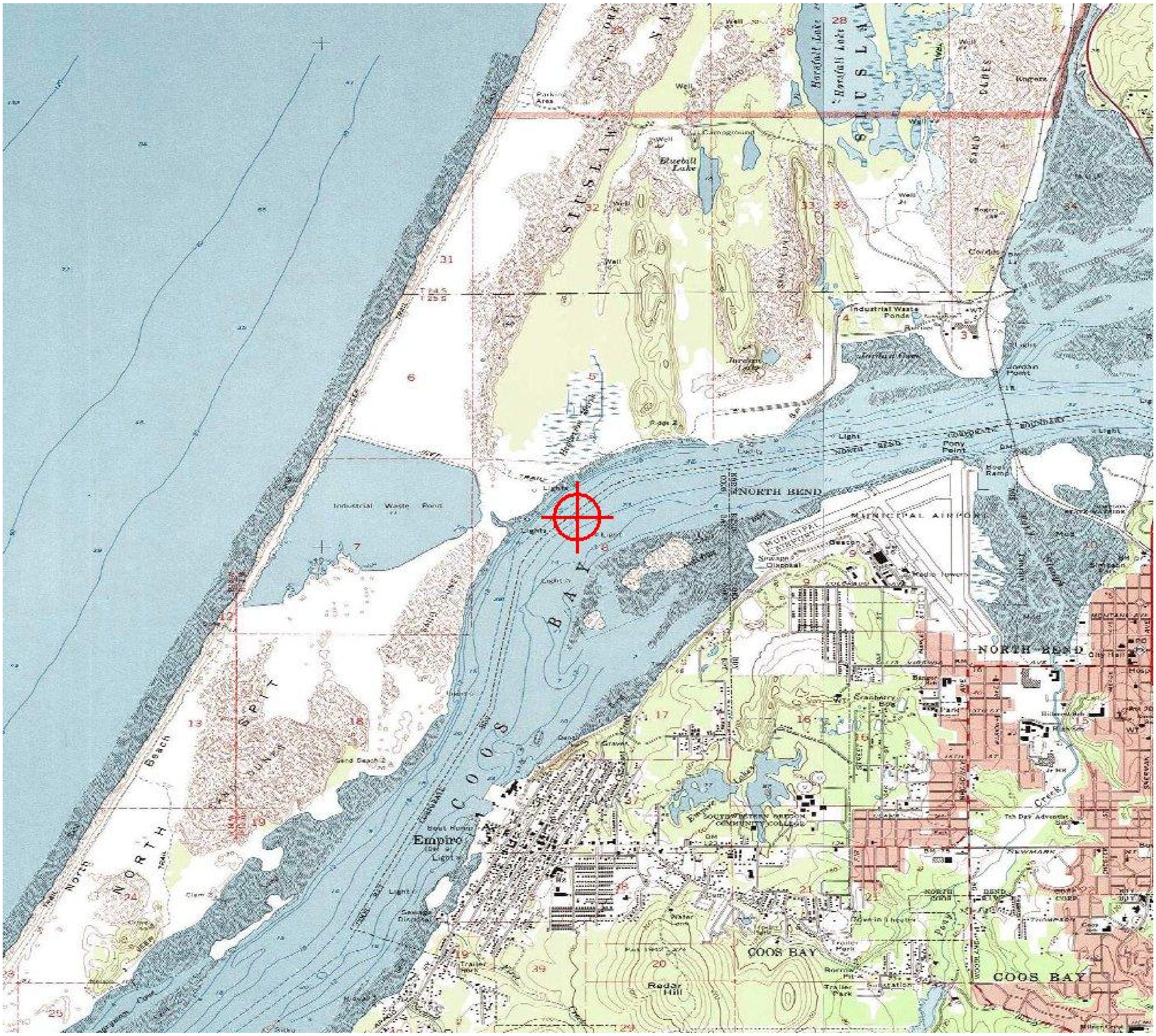
Your options and conditions for this proposal are as follows:

1. You must resolve the 44 foot VFR Traffic Pattern Airspace penetration by lowering the structure height, with all appurtenances, to a maximum height at 155 feet AGL (167 AMSL). If you agree to limit the structure height to 155 feet AGL (167 AMSL), the FAA can then withdraw this objection to the proposed structure as it would not exceed obstruction standards and a favorable determination could be subsequently issued. Further FAA study for any height greater than 155 AGL / 167 AMSL is not an option.

2. You can terminate the proposal at this location.

Please email me within 60 days of the date of this letter at Paul.Holmquist@faa.gov with your intentions and any questions you might have regarding this aeronautical study.

Close Print



NORTH BEND
MUNICIPAL AIRPORT
COOS BAY
Empire
Industrial Waste Pond
NORTH SPIT
SIUSLAW
Pony Point
Jordan Point
Bluebill Lake
Radar Hill
SOUTHWESTERN OREGON COMMUNITY COLLEGE
NEWMARK

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
10101 Hillwood Parkway
Fort Worth, TX 76177

Aeronautical Study No.
2018-ANM-7-OE

Issued Date: 05/07/2018

Drew Jackson
Jordan Cove LNG
5615 Kirby Dr
Houston, TX 77005

**** NOTICE OF PRESUMED HAZARD ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	LNG Carrier Vessel - Stack, Transit Point 4
Location:	North Bend, OR
Latitude:	43-24-55.79N NAD 83
Longitude:	124-16-29.14W
Heights:	12 feet site elevation (SE)
	199 feet above ground level (AGL)
	211 feet above mean sea level (AMSL)

Initial findings of this study indicate that the structure as described exceeds obstruction standards and/or would have an adverse physical or electromagnetic interference effect upon navigable airspace or air navigation facilities. Pending resolution of the issues described below, the structure is presumed to be a hazard to air navigation.

If the structure were reduced in height so as not to exceed 155 feet above ground level (167 feet above mean sea level), it would not create a substantial adverse effect and a favorable determination could subsequently be issued.

Any height exceeding 155 feet above ground level (167 feet above mean sea level), will result in a substantial adverse effect and would warrant a Determination of Hazard to Air Navigation.

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If we can be of further assistance, please contact our office at (206) 231-2990, or paul.holmquist@faa.gov. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2018-ANM-7-OE.

Signature Control No: 352163128-364497902 (NPH)

Paul Holmquist
Specialist

Attachment(s)
Additional Information

ASN 2018-ANM-7-OE

Abbreviations

AGL - above ground level	AMSL - above mean sea level	RWY - runway
VFR - visual flight rules	IFR - instrument flight rules	NM - nautical mile
ASN- Aeronautical Study Number	CAT - category aircraft	
MDA - minimum descent altitude	DA - decision altitude	

Part 77 - Title 14 Code of Federal Regulations (CFR) Part 77, Safe, Efficient Use and Preservation of the Navigable Airspace

Our aeronautical study has disclosed that the proposed 199-foot AGL (211-foot AMSL) liquid natural gas carrier vessel (ship stack) shipping channel transit point location associated with the proposed Jordan Cove Liquid Natural Gas Terminal penetrates 14 CFR Part 77 protected airspace surfaces at Southwest Oregon Regional Airport (OTH) in North Bend, OR. The OTH airport elevation is 17 feet AMSL.

The proposed structure would exceed the following Part 77 surface:

Section 77.19(a): Horizontal Surface-a height exceeding a horizontal plane 150 feet above the established airport elevation. The proposed structure would exceed the OTH Horizontal Surface by 44 feet.

Additionally, the proposed structure would exceed the OTH VFR traffic pattern airspace in the Part 77 VFR Horizontal Surface feet as defined in FAA JO 7400.2L, 6-3-8, Evaluating Effect on VFR Operations.

This proposed structure would exceed the OTH VFR Traffic Pattern Horizontal Surface by 44 feet. The not-to-exceed height of 155 feet AGL (167 AMSL) will avoid penetrating the Horizontal Surface.

The OTH Airport Master Record, http://www.gcr1.com/5010web/airport.cfm?Site=OTH, states there are 36 single engine, eight (8) multi-engine, one (1) jet, and six (6) helicopter aircraft based there with 18,277 total operations for the 12 months ending 31 December 2013 (latest information). RWY 31 is designated Right Traffic.

Your options and conditions for this proposal are as follows:

1. You must resolve the 44 foot VFR Traffic Pattern Airspace penetration by lowering the structure height, with all appurtenances, to a maximum height at 155 feet AGL (167 AMSL). If you agree to limit the structure height to 155 feet AGL (167 AMSL), the FAA can then withdraw this objection to the proposed structure as it would not exceed obstruction standards and a favorable determination could be subsequently issued. Further FAA study for any height greater than 155 AGL / 167 AMSL is not an option.

2. You can terminate the proposal at this location.

Please email me within 60 days of the date of this letter at Paul.Holmquist@faa.gov with your intentions and any questions you might have regarding this aeronautical study.

Close Print

NORTH BEND
MUNICIPAL AIRPORT
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North Beach
Industrial Waste Pond
Jordan Lake
Bluebill Lake
Radar Hill
COOS BAY
NORTH BEND
SOUTHWESTERN OREGON COMMUNITY COLLEGE

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
10101 Hillwood Parkway
Fort Worth, TX 76177

Aeronautical Study No.
2018-ANM-6-OE

Issued Date: 05/07/2018

Drew Jackson
Jordan Cove LNG
5615 Kirby Dr
Houston, TX 77005

**** NOTICE OF PRESUMED HAZARD ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	LNG Carrier Vessel - Stack, Transit Point 3
Location:	North Bend, OR
Latitude:	43-24-32.44N NAD 83
Longitude:	124-16-38.26W
Heights:	12 feet site elevation (SE)
	199 feet above ground level (AGL)
	211 feet above mean sea level (AMSL)

Initial findings of this study indicate that the structure as described exceeds obstruction standards and/or would have an adverse physical or electromagnetic interference effect upon navigable airspace or air navigation facilities. Pending resolution of the issues described below, the structure is presumed to be a hazard to air navigation.

If the structure were reduced in height so as not to exceed 125 feet above ground level (137 feet above mean sea level), it would not create a substantial adverse effect and a favorable determination could subsequently be issued.

Any height exceeding 125 feet above ground level (137 feet above mean sea level), will result in a substantial adverse effect and would warrant a Determination of Hazard to Air Navigation.

See Attachment for Additional information.

NOTE: PENDING RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE, THE STRUCTURE IS PRESUMED TO BE A HAZARD TO AIR NAVIGATION. THIS LETTER DOES NOT AUTHORIZE CONSTRUCTION OF THE STRUCTURE EVEN AT A REDUCED HEIGHT. ANY RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE MUST BE COMMUNICATED TO THE FAA SO THAT A FAVORABLE DETERMINATION CAN SUBSEQUENTLY BE ISSUED.

IF MORE THAN 60 DAYS FROM THE DATE OF THIS LETTER HAS ELAPSED WITHOUT ATTEMPTED RESOLUTION, IT WILL BE NECESSARY FOR YOU TO REACTIVATE THE STUDY BY FILING A NEW FAA FORM 7460-1, NOTICE OF PROPOSED CONSTRUCTION OR ALTERATION.

If we can be of further assistance, please contact our office at (206) 231-2990, or paul.holmquist@faa.gov. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2018-ANM-6-OE.

Signature Control No: 352163127-364500875 (NPH)
Paul Holmquist
Specialist

Attachment(s)
Additional Information

ASN 2018-ANM-6-OE

Abbreviations

AGL - above ground level
AMSL - above mean sea level
RWY - runway
VFR - visual flight rules
IFR - instrument flight rules
NM - nautical mile
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CAT - category aircraft
MDA - minimum descent altitude
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Part 77 - Title 14 Code of Federal Regulations (CFR) Part 77, Safe, Efficient Use and Preservation of the Navigable Airspace

Our aeronautical study has disclosed that the proposed 199-foot AGL (211-foot AMSL) liquid natural gas carrier vessel (ship stack) shipping channel transit point location associated with the proposed Jordan Cove Liquid Natural Gas Terminal penetrates 14 CFR Part 77 protected airspace surfaces at Southwest Oregon Regional Airport (OTH) in North Bend, OR. The OTH airport elevation is 17 feet AMSL.

The proposed structure would exceed the following Part 77 surfaces:

a. Section 77.17(a)(3) -- A structure that causes less than the required obstacle clearance within a terminal obstacle clearance area, including an initial approach segment, a departure area, and a circling approach area resulting in increases to an IFR terminal minimum altitude. The high point on the LNG carrier vessel (stack) would have the following effects on IFR operations at OTH:

Obstacle penetrates OTH RWY 22 40:1 departure surface in the Initial Climb Area (ICA) 73 feet, increases climb gradient from standard and 200 feet per NM to 300-1 or standard with 423 feet per NM to 400 then as published. The height at or below that avoids this effect: 138 AMSL (126 AGL).

OTH RWY 4 ILS or LOC: ILS or LOC RWY 4, S-ILS 4* not authorized (NA). Obstacle penetrates Vertical Guidance Surface (VGS) 23 feet. The height at or below that avoids this effect: 188 AMSL (176 AGL).
At 188 AMSL, increase S-ILS 4* DA from 216 AMSL to 473 AMSL. The height at or below that avoids this effect: 153 AMSL (141 AGL).
OTH RWY 4 ILS or LOC RWY, S-ILS NA. Obstacle penetrates Vertical Guidance Surface (VGS) 23 feet. The height at or below that avoids this effect: 188 AMSL (176 AGL).
At 188 AMSL, increase S-ILS 4 DA from 278 AMSL to 473 AMSL. The height at or below that avoids this effect: 153 AMSL (141 AGL).
Increases S-LOC 4 MDA from 400 AMSL to 520 AMSL. The height at or below that avoids this effect: 139 AMSL (127 AGL).
Penetrates 34:1 Visual Area Surface 56 feet, increase visibility from 1/2 to 3/4 mile. The height at or below that avoids this effect: 155 AMSL (143 AGL)

OTH RWY 4 COPTER ILS or LOC NA, obstacle penetrates Vertical Guidance Surface (VGS) 23 feet. The height at or below that avoids this effect: 188 AMSL (176 AGL).
At 188 AMSL, increase H-ILS 4 DA from 216 AMSL to 473 AMSL. The height at or below that avoids this effect: 153 AMSL (141 AGL).
Increases H-LOC 4 MDA from 400 AMSL to 520 AMSL. The height at or below that avoids this effect: 139 AMSL (127 AGL).

Penetrates 34:1 Visual Area Surface 56 feet, increase visibility from 1/2 to 3/4 mile. The height at or below that avoids this effect: 155 AMSL (133 AGL).

OTH RWY 4 RNAV (GPS) Y, LPV DA NA, obstacle penetrates Vertical Guidance Surface (VGS) 23 feet. The height at or below that avoids this effect: 188 AMSL (176 AGL).
At 188 AMSL, increases LPV DA from 319 AMSL to 513 AMSL. The height at or below that avoids this effect: 154 AMSL (142 AGL).
Penetrates 34:1 Visual Area Surface 56 feet, increase visibility from 1/2 to 3/4 mile. The height at or below that avoids this effect: 155 AMSL (143 AGL).
LNAV/VNAV NA, obstacle penetrates the VGS 24 feet. The height at or below that avoids this effect: 187 AMSL (175 AGL).
At 187 AMSL, no IFR effect.
LNAV, penetrates 34:1 Visual Area Surface 56 feet, increase visibility from 1/2 to 3/4 mile. The height at or below that avoids this effect: 155 AMSL (143 AGL) .

OTH RWY 4 RNAV (RNP) Z, RNP 0.11 DA* NA, obstacle penetrates the VGS 27 feet. The height at or below that avoids this effect: 184 AMSL (172 AGL).
At 184 AMSL, increases RNP 0.11 DA* from 309 to 444. The height at or below that avoids this effect: 137 AMSL (125 AGL).
Penetrates 34:1 Visual Area Surface 56 feet, increase visibility from 1/2 to 3/4 mile, The height at or below that avoids this effect: 155 AMSL (133 AGL).
RNP 0.30 DA# NA, obstacle penetrates the VGS 27 feet. The height at or below that avoids this effect: 184 AMSL (172 AGL).
At 184 AMSL, increases RNP 0.30 DA# from 477 AMSL to 489 AMSL. The height at or below that avoids this effect: 168 AMSL (156 AGL).

RNP 0.30 NA, obstacle penetrates the VGS 27 feet. The height at or below that avoids this effect: 184 AMSL (172 AGL).

The MDA/DA is the minimum altitudes to which an aircraft may descend while on the instrument approach to the airport during periods when reduced visibility and/or low cloud ceiling conditions exist. If the pilot cannot achieve visual reference to the ground upon reaching the MDA/DA, the approach must be abandoned. This results in the aircraft having to proceed to an alternate airport or waiting in a holding pattern for improved weather conditions. Any increase in the MDA/DA would have a significant adverse effect on the benefits derived from the instrument procedures.

b. Section 77.19(a): Horizontal Surface-a height exceeding a horizontal plane 150 feet above the established airport elevation. The proposed structure would exceed the OTH Horizontal Surface by 44 feet.

c. Section 77.19(d) -- Approach Surface - an area designated to protect aircraft during the final approach phase of flight at an airport: The proposed structure would exceed the existing OTH Approach Surface by 102 feet and would exceed the OTH Approach Surface plan on file by 122 feet.

Additionally, the proposed structure would exceed the OTH VFR traffic pattern airspace in the Part 77 VFR Horizontal Surface and the Approach Surface (plan on file) as defined in FAA JO 7400.2L, 6-3-8, Evaluating Effect on VFR Operations.

This proposed structure would exceed the OTH VFR Traffic Pattern Horizontal Surface by 44 feet. The not-to-exceed height of 157 feet AGL (167 AMSL) will avoid penetrating the Horizontal Surface. This proposed structure would exceed the OTH VFR Traffic Pattern Approach Surface (plan on file) by 11 feet. The not-to-exceed height of 188 feet AGL (200 AMSL) will avoid penetrating the Approach Surface (plan on file).

The FAA Technical Operations Branch found the proposal has a physical and/or an electromagnetic radiation effect upon the Visual Approach Slope Indicator (VASI) serving OTH RWY 04 as it penetrates the surface given in the siting standard, Order 6850.2. The proposal will affect the quality and/or availability of the VASI visual guidance signal (service). The effect can be eliminated by lowering the proposal to 145 ft AMSL (132 AGL).

The OTH Airport Master Record, http://www.gcr1.com/5010web/airport.cfm?Site=OTH, states there are 36 single engine, eight (8) multi-engine, one (1) jet, and six (6) helicopter aircraft based there with 18,277 total operations for the 12 months ending 31 December 2013 (latest information). RWY 31 is designated Right Traffic.

Your options and conditions for this proposal are as follows:

1. You must resolve the 74 foot OTH RWY 4 RNAV (RNP) Z, RNP 0.11 DA* penetration by lowering the structure height, with all appurtenances, to a maximum height at 125 AGL (137 AMSL). This would also resolve our objection to the 44 foot VFR Traffic Pattern Airspace penetration which requires lowering the structure height, with all appurtenances, to a maximum height at 167 feet AGL (179 AMSL). If you agree to lower the maximum height to 125 AGL, the FAA can then withdraw this objection to the proposed structure as it would not exceed obstruction standards and a favorable determination could be subsequently issued.

2. You can terminate the proposal at this location.

Please email me within 60 days of the date of this letter at Paul.Holmquist@faa.gov with your intentions and any questions you might have regarding this aeronautical study.

Close Print


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Empire
COOS BAY
NORTH SPIT
Industrial Waste Pond
Redar Hill

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
10101 Hillwood Parkway
Fort Worth, TX 76177

Aeronautical Study No.
2018-ANM-5-OE

Issued Date: 05/07/2018

Drew Jackson
Jordan Cove LNG
5615 Kirby Dr
Houston, TX 77005

**** NOTICE OF PRESUMED HAZARD ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	LNG Carrier Vessel - Stack, Transit Point 2
Location:	North Bend, OR
Latitude:	43-24-07.84N NAD 83
Longitude:	124-16-41.25W
Heights:	12 feet site elevation (SE)
	199 feet above ground level (AGL)
	211 feet above mean sea level (AMSL)

Initial findings of this study indicate that the structure as described exceeds obstruction standards and/or would have an adverse physical or electromagnetic interference effect upon navigable airspace or air navigation facilities. Pending resolution of the issues described below, the structure is presumed to be a hazard to air navigation.

If the structure were reduced in height so as not to exceed 124 feet above ground level (136 feet above mean sea level), it would not create a substantial adverse effect and a favorable determination could subsequently be issued.

Any height exceeding 124 feet above ground level (136 feet above mean sea level), will result in a substantial adverse effect and would warrant a Determination of Hazard to Air Navigation.

See Attachment for Additional information.

NOTE: PENDING RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE, THE STRUCTURE IS PRESUMED TO BE A HAZARD TO AIR NAVIGATION. THIS LETTER DOES NOT AUTHORIZE CONSTRUCTION OF THE STRUCTURE EVEN AT A REDUCED HEIGHT. ANY RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE MUST BE COMMUNICATED TO THE FAA SO THAT A FAVORABLE DETERMINATION CAN SUBSEQUENTLY BE ISSUED.

IF MORE THAN 60 DAYS FROM THE DATE OF THIS LETTER HAS ELAPSED WITHOUT ATTEMPTED RESOLUTION, IT WILL BE NECESSARY FOR YOU TO REACTIVATE THE STUDY BY FILING A NEW FAA FORM 7460-1, NOTICE OF PROPOSED CONSTRUCTION OR ALTERATION.

If we can be of further assistance, please contact our office at (206) 231-2990, or paul.holmquist@faa.gov. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2018-ANM-5-OE.

Signature Control No: 352163126-364502142 (NPH)

Paul Holmquist
Specialist

Attachment(s)
Additional Information

ASN 2018-ANM-5-OE

Abbreviations

AGL - above ground level
AMSL - above mean sea level
RWY - runway
VFR - visual flight rules
IFR - instrument flight rules
NM - nautical mile
ASN- Aeronautical Study Number
CAT - category aircraft
MDA - minimum descent altitude
DA - decision altitude
Part 77 - Title 14 Code of Federal Regulations (CFR) Part 77, Safe, Efficient Use and Preservation of the Navigable Airspace

Our aeronautical study has disclosed that the proposed 199-foot AGL (211-foot AMSL) liquid natural gas carrier vessel (ship stack) shipping channel transit point location associated with the proposed Jordan Cove Liquid Natural Gas Terminal penetrates 14 CFR Part 77 protected airspace surfaces at Southwest Oregon Regional Airport (OTH) in North Bend, OR. The OTH airport elevation is 17 feet AMSL.

The proposed structure would exceed the following Part 77 surfaces:

a. Section 77.17(a)(3) -- A structure that causes less than the required obstacle clearance within a terminal obstacle clearance area, including an initial approach segment, a departure area, and a circling approach area resulting in increases to an IFR terminal minimum altitude. The LNG carrier vessel stack high point would have the following effects on IFR operations at OTH:

Obstacle penetrates OTH RWY 22 40:1 departure surface in the Initial Climb Area (ICA) 38 feet, increases climb gradient from standard and 200 feet per NM to 200-1- 1/4 or standard with 324 feet per NM to 400 then as published. The height at or below that avoids this effect: 173 AMSL (161 AGL).

OTH RWY 4 ILS or LOC: increases S-LOC 4 MDA from 400 AMSL to 480 AMSL. The height at or below that avoids this effect: 188 AMSL (176 AGL).

OTH RWY 4 RNAV (RNP) Z: increases RNP 0.30 DA# from 477 AMSL to 526 AMSL. The height at or below that avoids this effect: 136 AMSL (124 AGL).

OTH RWY 4 COPTER ILS or LOC: increases H-LOC 4 MDA from 400 AMSL to 480 AMSL. The height at or below that avoids this effect: 188 AMSL (176 AGL)

The MDA/DA is the minimum altitudes to which an aircraft may descend while on the instrument approach to the airport during periods when reduced visibility and/or low cloud ceiling conditions exist. If the pilot cannot achieve visual reference to the ground upon reaching the MDA/DA, the approach must be abandoned. This results in the aircraft having to proceed to an alternate airport or waiting in a holding pattern for improved weather conditions. Any increase in the MDA/DA would have a significant adverse effect on the benefits derived from the instrument procedures.

b. Section 77.19(a): Horizontal Surface-a height exceeding a horizontal plane 150 feet above the established airport elevation. The proposed structure would exceed the OTH Horizontal Surface by 44 feet.

Additionally, this proposed structure would exceed the OTH VFR traffic pattern airspace in the Part 77 Conical Surface as defined in FAA JO 7400.2L, 6-3-8, Evaluating Effect on VFR Operations. The VFR Conical

Surface is defined in Part 77 Section 77.19(b) as a surface extending outward and upward from the periphery of the VFR Part 77 Horizontal Surface at a slope of 20:1 for a horizontal distance of 4,000 feet .

This proposed structure would exceed the OTH VFR Traffic Pattern Conical Surface by 25 feet. The not-to-exceed height of 186 feet AGL (198 AMSL) will avoid penetrating the Conical Surface.

The FAA Technical Operations Branch found that while the proposal is laterally beyond the standard ? 10? visual slope approach indicator (VASI) obstacle clearance surface (OCS), however, it is within ? 15? of the extended runway centerline and above the VASI OCS. The proposal may be within the lateral limits of the visible light beam of the VASI serving OTH RWY 04. The height at or below that avoids this effect is 187 AMSL

The OTH Airport Master Record, http://www.gcr1.com/5010web/airport.cfm?Site=OTH, states there are 36 single engine, eight (8) multi-engine, one (1) jet, and six (6) helicopter aircraft based there with 18,277 total operations for the 12 months ending 31 December 2013 (latest information). RWY 31 is designated Right Traffic.

Your options and conditions for this proposal are as follows:

1. You must resolve the 75 foot OTH RWY 4 RNAV (RNP) Z DA penetration by lowering the structure height, with all appurtenances, to a maximum height at 124 AGL (136 AMSL). This would also resolve our objection to the 25 foot VFR Traffic Pattern Airspace penetration which requires lowering the structure height, with all appurtenances, to a maximum height at 174 feet AGL (186 AMSL). If you agree to limit the structure height to 124 feet AGL (136 feet AMSL), the FAA can then withdraw this objection to the proposed structure as it would not exceed obstruction standards and a favorable determination could be subsequently issued. Further FAA study for any height greater than 124 AGL/ 136 AMSL is not an option.

2. You can terminate the proposal at this location.

Please email me within 60 days of the date of this letter at Paul.Holmquist@faa.gov with your intentions and any questions you might have regarding this aeronautical study.

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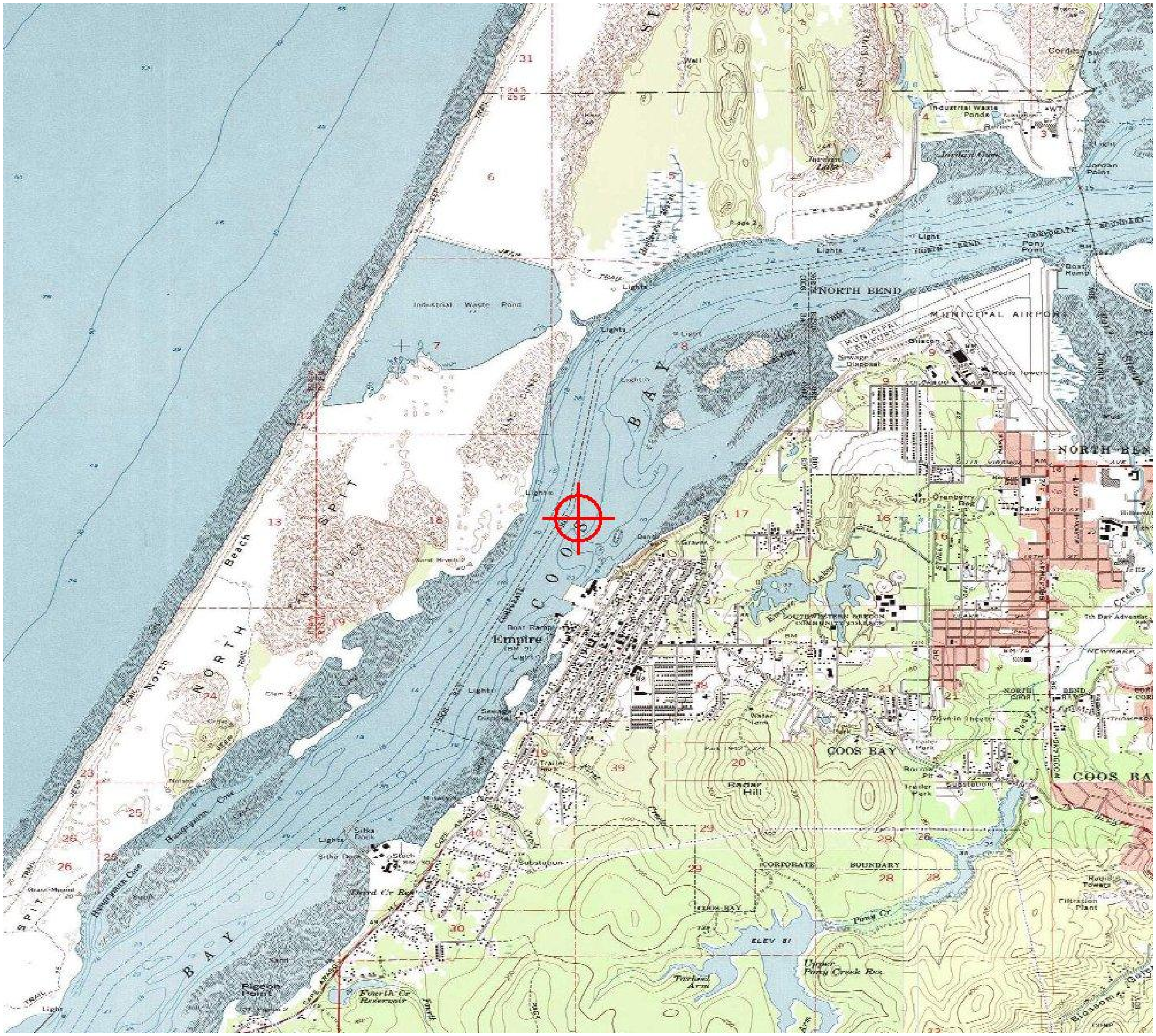
NORTH BEND
MUNICIPAL AIRPORT
COOS BAY
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BAY
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CORPORATE BOUNDARY
Industrial Waste Pond
Pigeon Point
Sitka Dock
Upper Pony Creek Res

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
10101 Hillwood Parkway
Fort Worth, TX 76177

Aeronautical Study No.
2018-ANM-4-OE

Issued Date: 05/07/2018

Drew Jackson
Jordan Cove LNG
5615 Kirby Dr
Houston, TX 77005

**** NOTICE OF PRESUMED HAZARD ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	LNG Carrier Vessel - Stack, Transit Point 1
Location:	North Bend, OR
Latitude:	43-23-49.37N NAD 83
Longitude:	124-16-56.55W
Heights:	12 feet site elevation (SE)
	199 feet above ground level (AGL)
	211 feet above mean sea level (AMSL)

Initial findings of this study indicate that the structure as described exceeds obstruction standards and/or would have an adverse physical or electromagnetic interference effect upon navigable airspace or air navigation facilities. Pending resolution of the issues described below, the structure is presumed to be a hazard to air navigation.

If the structure were reduced in height so as not to exceed 155 feet above ground level (167 feet above mean sea level), it would not create a substantial adverse effect and a favorable determination could subsequently be issued.

Any height exceeding 167 feet above ground level (179 feet above mean sea level), will result in a substantial adverse effect and would warrant a Determination of Hazard to Air Navigation.

See Attachment for Additional information.

NOTE: PENDING RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE, THE STRUCTURE IS PRESUMED TO BE A HAZARD TO AIR NAVIGATION. THIS LETTER DOES NOT AUTHORIZE CONSTRUCTION OF THE STRUCTURE EVEN AT A REDUCED HEIGHT. ANY RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE MUST BE COMMUNICATED TO THE FAA SO THAT A FAVORABLE DETERMINATION CAN SUBSEQUENTLY BE ISSUED.

IF MORE THAN 60 DAYS FROM THE DATE OF THIS LETTER HAS ELAPSED WITHOUT ATTEMPTED RESOLUTION, IT WILL BE NECESSARY FOR YOU TO REACTIVATE THE STUDY BY FILING A NEW FAA FORM 7460-1, NOTICE OF PROPOSED CONSTRUCTION OR ALTERATION.

If we can be of further assistance, please contact our office at (206) 231-2990, or paul.holmquist@faa.gov. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2018-ANM-4-OE.

Signature Control No: 352163125-364503672 (NPH)

Paul Holmquist
Specialist

Attachment(s)
Additional Information

ASN 2018-ANM-4-OE

Abbreviations

AGL - above ground level	AMSL - above mean sea level	RWY - runway
VFR - visual flight rules	IFR - instrument flight rules	NM - nautical mile
ASN- Aeronautical Study Number	CAT - category aircraft	
MDA - minimum descent altitude	DA - decision altitude	

Part 77 - Title 14 Code of Federal Regulations (CFR) Part 77, Safe, Efficient Use and Preservation of the Navigable Airspace

Our aeronautical study has disclosed that the proposed 199-foot AGL (211-foot AMSL) liquid natural gas carrier vessel (ship stack) shipping channel transit point location associated with the proposed Jordan Cove Liquid Natural Gas Terminal penetrates 14 CFR Part 77 protected airspace surfaces at Southwest Oregon Regional Airport (OTH) in North Bend, OR. The OTH airport elevation is 17 feet AMSL.

The proposed structure would exceed the following Part 77 surfaces:

a. Section 77.17(a)(3) -- A structure that causes less than the required obstacle clearance within a terminal obstacle clearance area, including an initial approach segment, a departure area, and a circling approach area resulting in increases to an IFR terminal minimum altitude. The LNG carrier vessel stack high point would have the following effects on IFR operations at OTH:

OTH RWY 4 RNAV (RNP) Z: increases RNP 0.30 DAs from 477 AMSL / 569 AMSL to 584 AMSL. The height at or below that avoids this effect is: 179 AMSL (167 AGL)

The MDA/DA is the minimum altitudes to which an aircraft may descend while on the instrument approach to the airport during periods when reduced visibility and/or low cloud ceiling conditions exist. If the pilot cannot achieve visual reference to the ground upon reaching the MDA/DA, the approach must be abandoned. This results in the aircraft having to proceed to an alternate airport or waiting in a holding pattern for improved weather conditions. Any increase in the MDA/DA would have a significant adverse effect on the benefits derived from the instrument procedures.

b. Section 77.19(a): Horizontal Surface-a height exceeding a horizontal plane 150 feet above the established airport elevation. The proposed structure would exceed the OTH Horizontal Surface by 44 feet.

The OTH Airport Master Record, http://www.gcr1.com/5010web/airport.cfm?Site=OTH, states there are 36 single engine, eight (8) multi-engine, one (1) jet, and six (6) helicopter aircraft based there with 18,277 total operations for the 12 months ending 31 December 2013 (latest information). RWY 31 is designated Right Traffic.

Your options and conditions for this proposal are as follows:

1. You must resolve the 32 foot OTH RWY 4 RNAV (RNP) Z penetration by lowering the structure height, with all appurtenances, to a maximum height at 167 AGL (179 AMSL)

2. If you agree to limit the structure height to 155 feet AGL (167 AMSL), the FAA can then withdraw this objection to the proposed structure as it would not exceed obstruction standards and a favorable determination could be subsequently issued.

3. You can terminate the proposal at this location.

3. You can request further study for any height between 155 AGL and 167 AGL. Further study will include a public notice circularization and 37-day comment period where the outcome cannot be predicted. Further FAA study for any height greater than 167 AGL (179 AMSL) is not an option.

Please email me within 60 days of the date of this letter at Paul.Holmquist@faa.gov with your intentions and any questions you might have regarding this aeronautical study.

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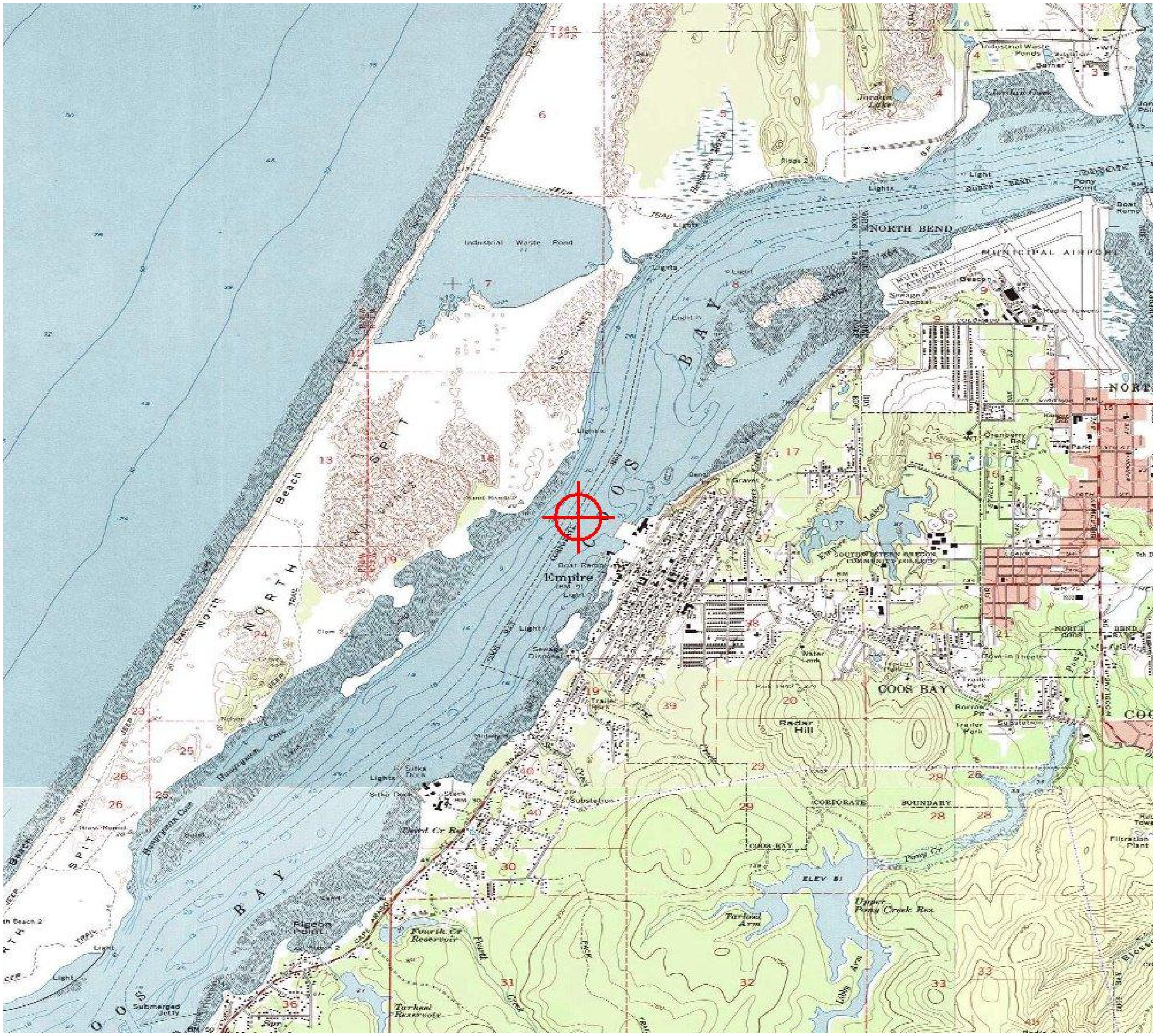

NORTH BEND
MUNICIPAL AIRPORT
COOS BAY
Empire
Radar Hill
NORTH SPIT
Pigeon Point
Upper Pony Creek Res
Tarheel Reservoir
Fourth Cr Reservoir
Industrial Waste Pond
CORPORATE BOUNDARY

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
10101 Hillwood Parkway
Fort Worth, TX 76177

Aeronautical Study No.
2017-ANM-5418-OE

Issued Date: 05/07/2018

Drew Jackson
Jordan Cove LNG
5615 Kirby Dr
Houston, TX 77005

**** NOTICE OF PRESUMED HAZARD ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	LNG Carrier Vessel - Stack
Location:	North Bend, OR
Latitude:	43-25-40.52N NAD 83
Longitude:	124-15-57.06W
Heights:	10 feet site elevation (SE)
	199 feet above ground level (AGL)
	209 feet above mean sea level (AMSL)

Initial findings of this study indicate that the structure as described exceeds obstruction standards and/or would have an adverse physical or electromagnetic interference effect upon navigable airspace or air navigation facilities. Pending resolution of the issues described below, the structure is presumed to be a hazard to air navigation.

If the structure were reduced in height so as not to exceed 157 feet above ground level (167 feet above mean sea level), it would not create a substantial adverse effect and a favorable determination could subsequently be issued.

Any height exceeding 157 feet above ground level (167 feet above mean sea level), will result in a substantial adverse effect and would warrant a Determination of Hazard to Air Navigation.

See Attachment for Additional information.

NOTE: PENDING RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE, THE STRUCTURE IS PRESUMED TO BE A HAZARD TO AIR NAVIGATION. THIS LETTER DOES NOT AUTHORIZE CONSTRUCTION OF THE STRUCTURE EVEN AT A REDUCED HEIGHT. ANY RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE MUST BE COMMUNICATED TO THE FAA SO THAT A FAVORABLE DETERMINATION CAN SUBSEQUENTLY BE ISSUED.

IF MORE THAN 60 DAYS FROM THE DATE OF THIS LETTER HAS ELAPSED WITHOUT ATTEMPTED RESOLUTION, IT WILL BE NECESSARY FOR YOU TO REACTIVATE THE STUDY BY FILING A NEW FAA FORM 7460-1, NOTICE OF PROPOSED CONSTRUCTION OR ALTERATION.

If we can be of further assistance, please contact our office at (206) 231-2990, or paul.holmquist@faa.gov. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2017-ANM-5418-OE.

Signature Control No: 350680505-364504065 (NPH)

Paul Holmquist
Specialist

Attachment(s)
Additional Information

Additional information for ASN 2017-ANM-5418-OE

ASN 2017-ANM-5418-OE

Abbreviations

AGL - above ground level	AMSL - above mean sea level	RWY - runway
VFR - visual flight rules	IFR - instrument flight rules	NM - nautical mile
ASN- Aeronautical Study Number	CAT - category aircraft	
MDA - minimum descent altitude	DA - decision altitude	

Part 77 - Title 14 Code of Federal Regulations (CFR) Part 77, Safe, Efficient Use and Preservation of the Navigable Airspace

Our aeronautical study has disclosed that the proposed 199-foot AGL (209-foot AMSL) liquid natural gas carrier vessel (ship stack) docking location associated with the proposed Jordan Cove Liquid Natural Gas Terminal penetrates 14 CFR Part 77 protected airspace surfaces at Southwest Oregon Regional Airport (OTH) in North Bend, OR. The OTH airport elevation is 17 feet AMSL.

The proposed structure would exceed the following Part 77 surface:

Section 77.19(a): Horizontal Surface-a height exceeding a horizontal plane 150 feet above the established airport elevation. The proposed structure would exceed the OTH Horizontal Surface by 42 feet.

Additionally, the proposed structure would exceed the OTH VFR traffic pattern airspace in the Part 77 VFR Horizontal Surface feet as defined in FAA JO 7400.2L, 6-3-8, Evaluating Effect on VFR Operations.

This proposed structure would exceed the OTH VFR Traffic Pattern Horizontal Surface by 42 feet. The not-to-exceed height of 157 feet AGL (167 AMSL) will avoid penetrating the Horizontal Surface.

The OTH Airport Master Record, http://www.gcr1.com/5010web/airport.cfm?Site=OTH, states there are 36 single engine, eight (8) multi-engine, one (1) jet, and six (6) helicopter aircraft based there with 18,277 total operations for the 12 months ending 31 December 2013 (latest information). RWY 31 is designated Right Traffic.

Your options and conditions for this proposal are as follows:

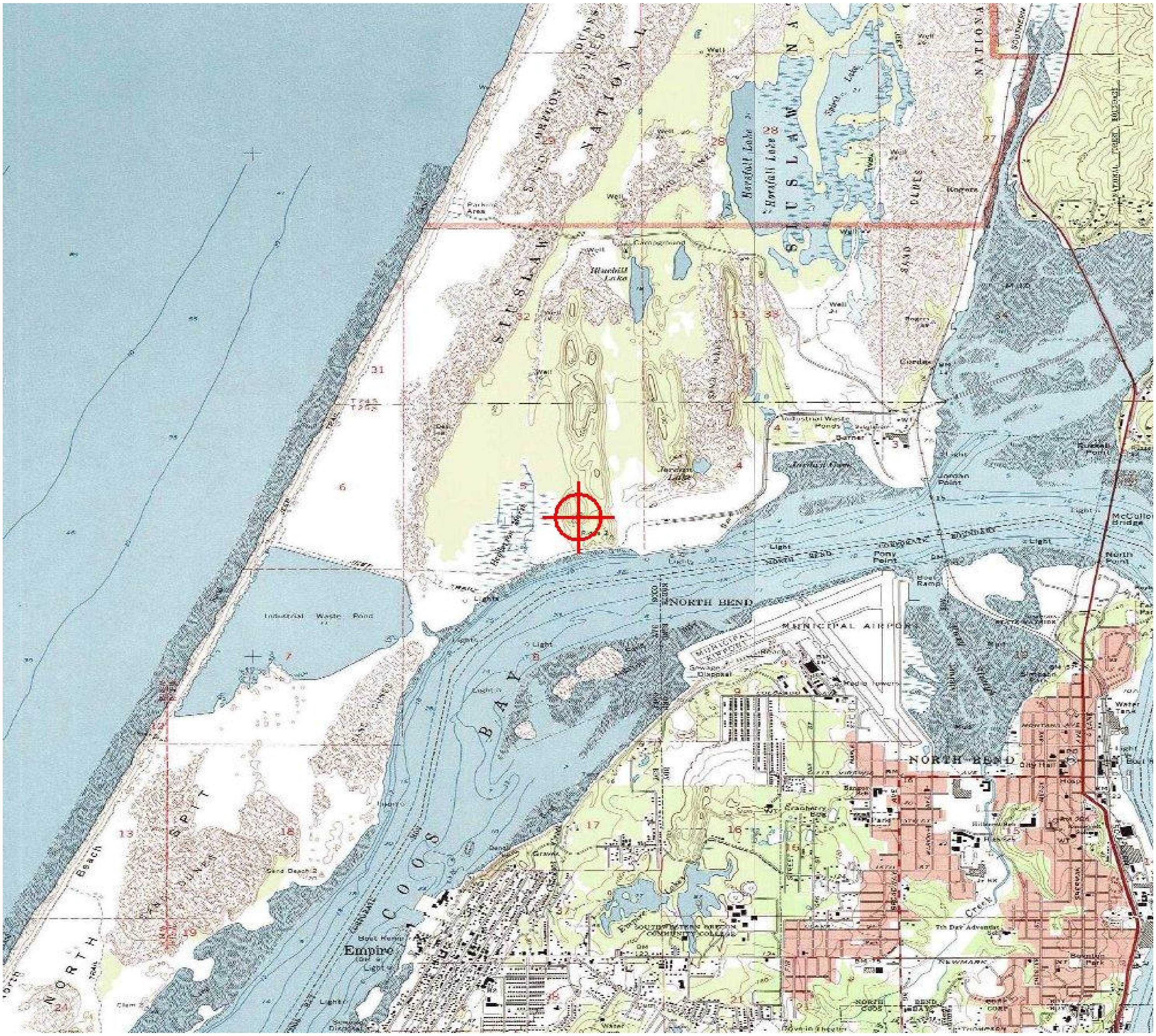
1. You must resolve the 42 foot VFR Traffic Pattern Airspace penetration by lowering the structure height, with all appurtenances, to a maximum height at 157 feet AGL (167 AMSL). The FAA can then withdraw this objection to the proposed structure as it would not exceed obstruction standards and a favorable determination could be subsequently issued.

2. You can terminate the proposal at this location.

Further FAA study for any height greater than 157 feet AGL (167 AMSL) is not an option.

Please email me within 60 days of the date of this letter at Paul.Holmquist@faa.gov with your intentions and any questions you might have regarding this aeronautical study.

Close Print


Industrial Waste Pond
NORTH BEND
MUNICIPAL AIRPORT
Empire
Jordan Point
Pony Point
Boat Ramp
Water Tank
City Hall

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
10101 Hillwood Parkway
Fort Worth, TX 76177

Aeronautical Study No.
2017-ANM-5389-OE

Issued Date: 05/07/2018

Drew Jackson
Jordan Cove LNG
5615 Kirby Dr
Houston, TX 77005

**** NOTICE OF PRESUMED HAZARD ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Amine Regenerator
Location:	North Bend, OR
Latitude:	43-26-01.57N NAD 83
Longitude:	124-16-03.43W
Heights:	42 feet site elevation (SE)
	126 feet above ground level (AGL)
	168 feet above mean sea level (AMSL)

Initial findings of this study indicate that the structure as described exceeds obstruction standards and/or would have an adverse physical or electromagnetic interference effect upon navigable airspace or air navigation facilities. Pending resolution of the issues described below, the structure is presumed to be a hazard to air navigation.

If the structure were reduced in height so as not to exceed 125 feet above ground level (167 feet above mean sea level), it would not create a substantial adverse effect and a favorable determination could subsequently be issued.

See Attachment for Additional information.

NOTE: PENDING RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE, THE STRUCTURE IS PRESUMED TO BE A HAZARD TO AIR NAVIGATION. THIS LETTER DOES NOT AUTHORIZE CONSTRUCTION OF THE STRUCTURE EVEN AT A REDUCED HEIGHT. ANY RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE MUST BE COMMUNICATED TO THE FAA SO THAT A FAVORABLE DETERMINATION CAN SUBSEQUENTLY BE ISSUED.

IF MORE THAN 60 DAYS FROM THE DATE OF THIS LETTER HAS ELAPSED WITHOUT ATTEMPTED RESOLUTION, IT WILL BE NECESSARY FOR YOU TO REACTIVATE THE STUDY BY FILING A NEW FAA FORM 7460-1, NOTICE OF PROPOSED CONSTRUCTION OR ALTERATION.

If we can be of further assistance, please contact our office at (206) 231-2990, or paul.holmquist@faa.gov. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2017-ANM-5389-OE.

Signature Control No: 350680447-364504785 (NPH)
Paul Holmquist
Specialist

Attachment(s)
Additional Information

Additional information for ASN 2017-ANM-5389-OE

ASN 2017-ANM-5389-OE

Abbreviations

AGL - above ground level	AMSL - above mean sea level	RWY - runway
VFR - visual flight rules	IFR - instrument flight rules	NM - nautical mile
ASN- Aeronautical Study Number	CAT - category aircraft	
MDA - minimum descent altitude	DA - decision altitude	

Part 77 - Title 14 Code of Federal Regulations (CFR) Part 77, Safe, Efficient Use and Preservation of the Navigable Airspace

Our aeronautical study has disclosed that the proposed 126-foot AGL (168-foot AMSL) amine regenerator structure associated with the proposed Jordan Cove Liquid Natural Gas Terminal penetrates 14 CFR Part 77 protected airspace surfaces at Southwest Oregon Regional Airport (OTH) in North Bend, OR. The OTH airport elevation is 17 feet AMSL.

The proposed structure would exceed the following Part 77 surface:

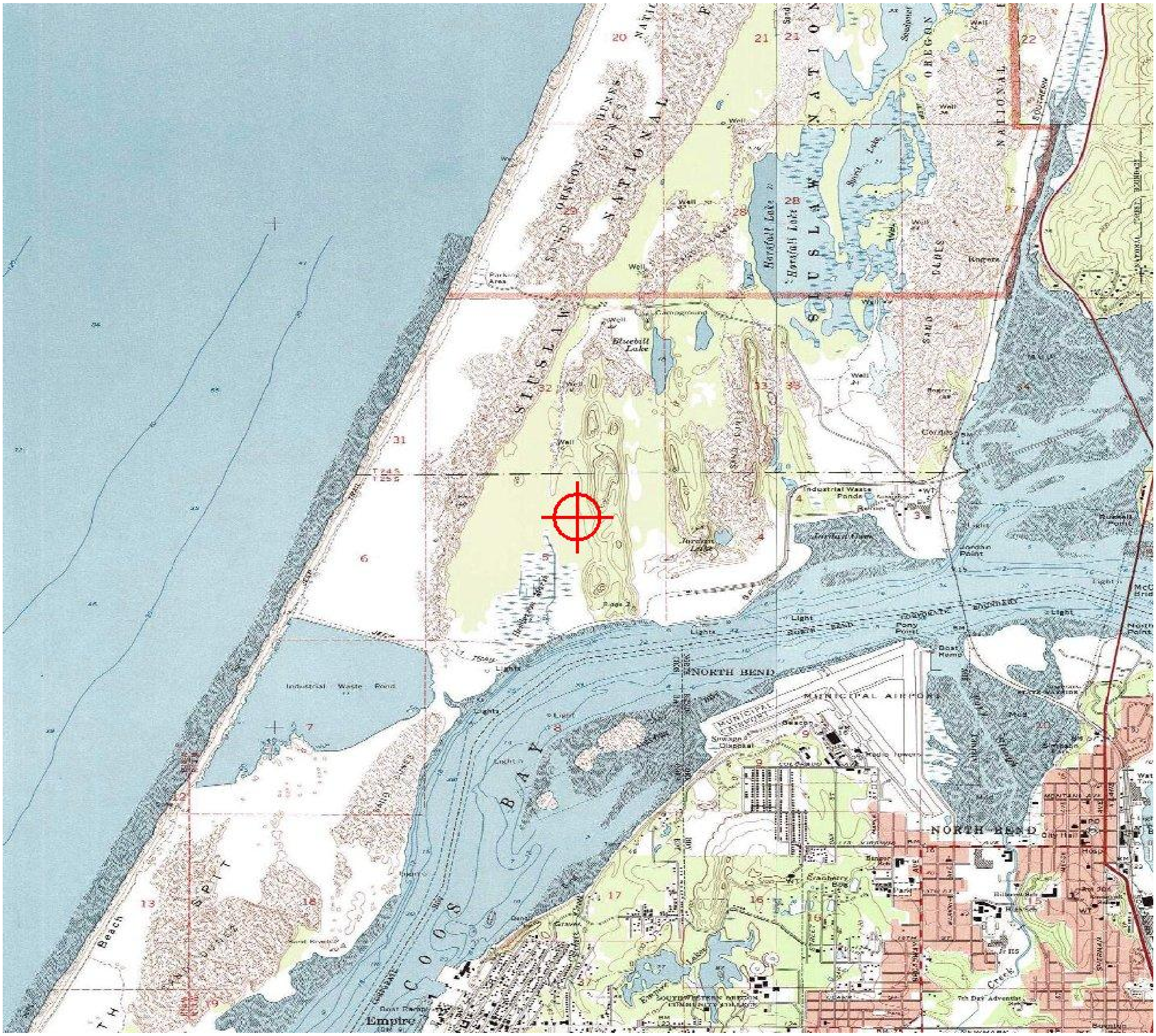
Section 77.19(a): Horizontal Surface-a height exceeding a horizontal plane 150 feet above the established airport elevation. The proposed structure would exceed the OTH Horizontal Surface by one (1) foot.

If you agree to limit the proposed structure height to 125 feet AGL (167 feet AMSL), the FAA can withdraw its objection as it would not exceed obstruction standards and a favorable determination could be subsequently issued.

You also have the option to either terminate the proposal or request further FAA study of the structure at the originally requested height. Further study will include a public notice circularization and 37-day comment period where the outcome cannot be predicted.

Please email me within 60 days of the date of this letter at Paul.Holmquist@faa.gov with your intentions and any questions you might have regarding this aeronautical study.

Close Print


NORTH BEND
MUNICIPAL AIRPORT
Industrial Waste Pond
Industrial Waste Ponds
Horsfall Lake
Beale Lake
Jordan Lake
Jordan Point
Pony Point
Russell Point
Empire
COOS BAY
SIUSLAW NATIONAL
OREGON DUNES
Beach

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
10101 Hillwood Parkway
Fort Worth, TX 76177

Aeronautical Study No.
2017-ANM-5388-OE

Issued Date: 05/07/2018

Drew Jackson
Jordan Cove LNG
5615 Kirby Dr
Houston, TX 77005

**** NOTICE OF PRESUMED HAZARD ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	Oxidizer
Location:	North Bend, OR
Latitude:	43-25-59.24N NAD 83
Longitude:	124-16-00.87W
Heights:	42 feet site elevation (SE)
	131 feet above ground level (AGL)
	173 feet above mean sea level (AMSL)

Initial findings of this study indicate that the structure as described exceeds obstruction standards and/or would have an adverse physical or electromagnetic interference effect upon navigable airspace or air navigation facilities. Pending resolution of the issues described below, the structure is presumed to be a hazard to air navigation.

If the structure were reduced in height so as not to exceed 125 feet above ground level (167 feet above mean sea level), it would not create a substantial adverse effect and a favorable determination could subsequently be issued.

See Attachment for Additional information.

NOTE: PENDING RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE, THE STRUCTURE IS PRESUMED TO BE A HAZARD TO AIR NAVIGATION. THIS LETTER DOES NOT AUTHORIZE CONSTRUCTION OF THE STRUCTURE EVEN AT A REDUCED HEIGHT. ANY RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE MUST BE COMMUNICATED TO THE FAA SO THAT A FAVORABLE DETERMINATION CAN SUBSEQUENTLY BE ISSUED.

IF MORE THAN 60 DAYS FROM THE DATE OF THIS LETTER HAS ELAPSED WITHOUT ATTEMPTED RESOLUTION, IT WILL BE NECESSARY FOR YOU TO REACTIVATE THE STUDY BY FILING A NEW FAA FORM 7460-1, NOTICE OF PROPOSED CONSTRUCTION OR ALTERATION.

If we can be of further assistance, please contact our office at (206) 231-2990, or paul.holmquist@faa.gov. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2017-ANM-5388-OE.

Signature Control No: 350680446-364505031 (NPH)
Paul Holmquist
Specialist

Attachment(s)
Additional Information

Additional information for ASN 2017-ANM-5388-OE

ASN 2017-ANM-5388-OE

Abbreviations

AGL - above ground level	AMSL - above mean sea level	RWY - runway
VFR - visual flight rules	IFR - instrument flight rules	NM - nautical mile
ASN- Aeronautical Study Number	CAT - category aircraft	
MDA - minimum descent altitude	DA - decision altitude	

Part 77 - Title 14 Code of Federal Regulations (CFR) Part 77, Safe, Efficient Use and Preservation of the Navigable Airspace

Our aeronautical study has disclosed that the proposed 131-foot AGL (173-foot AMSL) oxidizer structure associated with the proposed Jordan Cove Liquid Natural Gas Terminal penetrates 14 CFR Part 77 protected airspace surfaces at Southwest Oregon Regional Airport (OTH) in North Bend, OR. The OTH airport elevation is 17 feet AMSL.

The proposed structure would exceed the following Part 77 surface:

Section 77.19(a): Horizontal Surface-a height exceeding a horizontal plane 150 feet above the established airport elevation. The proposed structure would exceed the OTH Horizontal Surface by six (6) feet.

If you agree to limit the proposed structure height to 125 feet AGL (167 feet AMSL), the FAA can withdraw its objection as it would not exceed obstruction standards and a favorable determination could be subsequently issued.

You also have the option to either terminate the proposal or request further FAA study of the structure at the originally requested height. Further study will include a public notice circularization and 37-day comment period where the outcome cannot be predicted.

Please email me within 60 days of the date of this letter at Paul.Holmquist@faa.gov with your intentions and any questions you might have regarding this aeronautical study.

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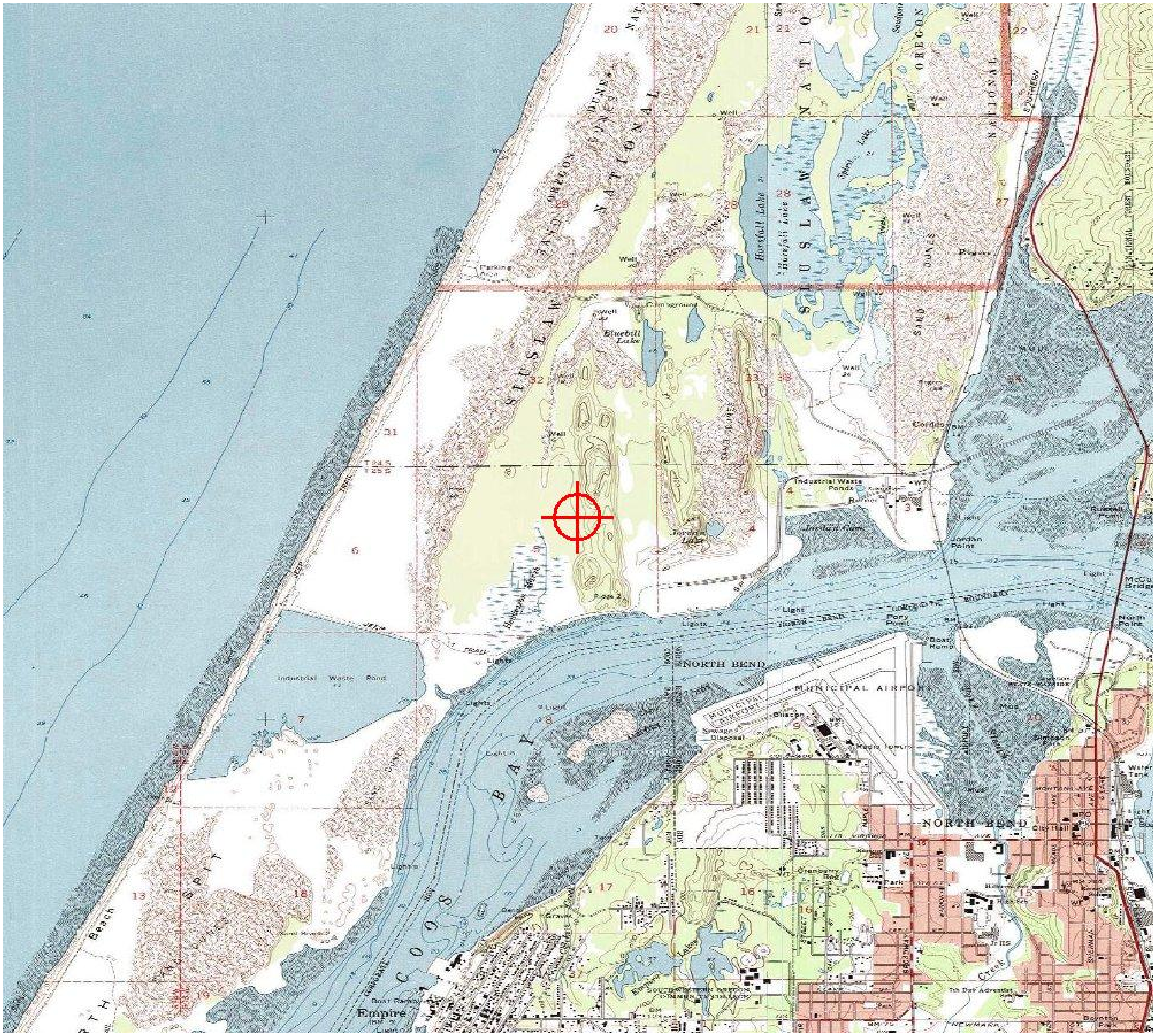

Bluebill Lake
Horsfall Lake
Industrial Waste Ponds
Jordan Lake
Industrial Waste Pond
NORTH BEND
MUNICIPAL AIRPORT
Empire

Mail Processing Center
Federal Aviation Administration
Southwest Regional Office
Obstruction Evaluation Group
10101 Hillwood Parkway
Fort Worth, TX 76177

Aeronautical Study No.
2017-ANM-5387-OE

Issued Date: 05/07/2018

Drew Jackson
Jordan Cove LNG
5615 Kirby Dr
Houston, TX 77005

**** NOTICE OF PRESUMED HAZARD ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	LNG Tank North
Location:	North Bend, OR
Latitude:	43-25-53.61N NAD 83
Longitude:	124-16-01.16W
Heights:	23 feet site elevation (SE)
	219 feet above ground level (AGL)
	242 feet above mean sea level (AMSL)

Initial findings of this study indicate that the structure as described exceeds obstruction standards and/or would have an adverse physical or electromagnetic interference effect upon navigable airspace or air navigation facilities. Pending resolution of the issues described below, the structure is presumed to be a hazard to air navigation.

If the structure were reduced in height so as not to exceed 144 feet above ground level (167 feet above mean sea level), it would not create a substantial adverse effect and a favorable determination could subsequently be issued.

Any height exceeding 203 feet above ground level (226 feet above mean sea level), will result in a substantial adverse effect and would warrant a Determination of Hazard to Air Navigation.

See Attachment for Additional information.

NOTE: PENDING RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE, THE STRUCTURE IS PRESUMED TO BE A HAZARD TO AIR NAVIGATION. THIS LETTER DOES NOT AUTHORIZE CONSTRUCTION OF THE STRUCTURE EVEN AT A REDUCED HEIGHT. ANY RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE MUST BE COMMUNICATED TO THE FAA SO THAT A FAVORABLE DETERMINATION CAN SUBSEQUENTLY BE ISSUED.

IF MORE THAN 60 DAYS FROM THE DATE OF THIS LETTER HAS ELAPSED WITHOUT ATTEMPTED RESOLUTION, IT WILL BE NECESSARY FOR YOU TO REACTIVATE THE STUDY BY FILING A NEW FAA FORM 7460-1, NOTICE OF PROPOSED CONSTRUCTION OR ALTERATION.

If we can be of further assistance, please contact our office at (206) 231-2990, or paul.holmquist@faa.gov. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2017-ANM-5387-OE.

Signature Control No: 350680445-364508370 (NPH)

Paul Holmquist
Specialist

Attachment(s)
Additional Information

Additional information for ASN 2017-ANM-5387-OE

ASN 2017-ANM-5387-OE

Abbreviations

AGL - above ground level	AMSL - above mean sea level	RWY - runway
VFR - visual flight rules	IFR - instrument flight rules	NM - nautical mile
ASN- Aeronautical Study Number	CAT - category aircraft	
MDA - minimum descent altitude	DA - decision altitude	

Part 77 - Title 14 Code of Federal Regulations (CFR) Part 77, Safe, Efficient Use and Preservation of the Navigable Airspace

Our aeronautical study has disclosed that the proposed 219-foot AGL (242-foot AMSL) north liquid natural gas tank structure associated with the proposed Jordan Cove Liquid Natural Gas Terminal penetrates 14 CFR Part 77 protected airspace surfaces at Southwest Oregon Regional Airport (OTH) in North Bend, OR. The OTH airport elevation is 17 feet AMSL.

The proposed structure would exceed the following Part 77 surfaces:

a. Section 77.17(a)(2): A height that is 200 feet above ground level or above the established airport elevation, whichever is higher, within three nautical miles of the established reference point of an airport, excluding heliports, with its longest runway more than 3,200 feet in actual length, and that height increases in the proportion of 100 feet for each additional nautical mile of distance from the airport up to a maximum of 500 feet. This proposed structure would exceed the OTH Part 77.17(a)(2) surface by 19 feet.

b. Section 77.19(a): Horizontal Surface-a height exceeding a horizontal plane 150 feet above the established airport elevation. The proposed structure would exceed the OTH Horizontal Surface by 75 feet.

Additionally, this proposed structure would exceed the OTH VFR traffic pattern airspace in the Part 77 Conical Surface as defined in FAA JO 7400.2L, 6-3-8, Evaluating Effect on VFR Operations. The VFR Conical Surface is defined in Part 77 Section 77.19(b) as a surface extending outward and upward from the periphery of the VFR Part 77 Horizontal Surface at a slope of 20:1 for a horizontal distance of 4,000 feet .

This proposed structure would exceed the OTH VFR Traffic Pattern Conical Surface by 16 feet. The not-to-exceed height of 203 feet AGL (226 AMSL) will avoid penetrating the Conical Surface.

The OTH Airport Master Record, http://www.gcr1.com/5010web/airport.cfm?Site=OTH, states there are 36 single engine, eight (8) multi-engine, one (1) jet, and six (6) helicopter aircraft based there with 18,277 total operations for the 12 months ending 31 December 2013 (latest information). RWY 31 is designated Right Traffic.

Your options and conditions for this proposal are as follows:

1. You must resolve the 16 foot VFR Traffic Pattern Airspace penetration by lowering the structure height, with all appurtenances, to a maximum height at 203 feet AGL (226 AMSL).

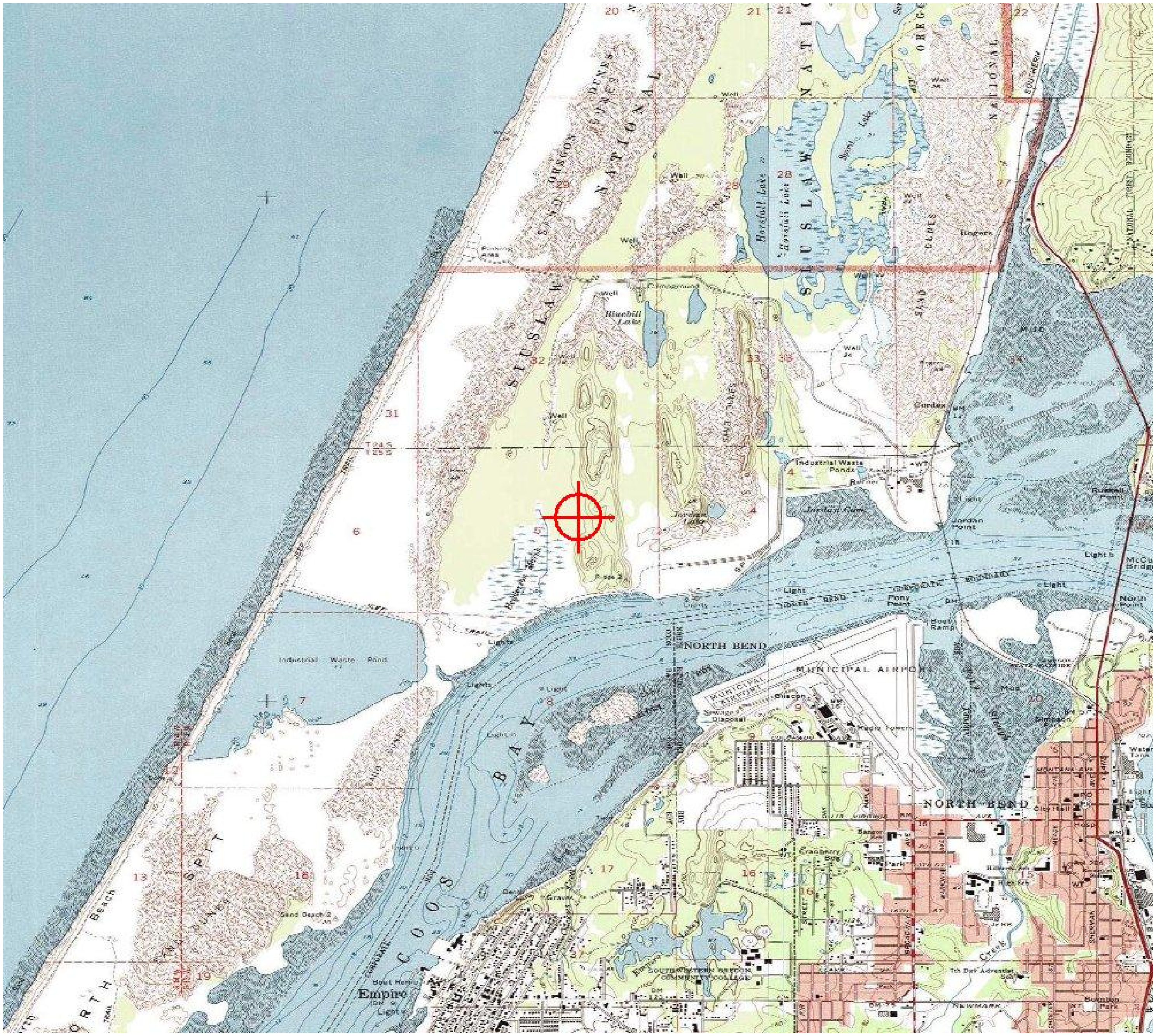
2. You can agree to limit the structure height to 144 feet AGL (167 feet AMSL). The FAA can then withdraw this objection to the proposed structure as it would not exceed obstruction standards and a favorable determination could be subsequently issued.

3. You can terminate the proposal at this location.

4. You can request further study for any height between 144 AGL and 203 AGL. Further study will include a public notice circularization and 37-day comment period where the outcome cannot be predicted. Further FAA study for any height greater than 203 AGL/ 226 AMSL is not an option.

Please email me within 60 days of the date of this letter at Paul.Holmquist@faa.gov with your intentions and any questions you might have regarding this aeronautical study.

Close Print


NORTH BEND
MUNICIPAL AIRPORT
Industrial Waste Pond
Industrial Waste Ponds
Jordan Cove
Jordan Point
Pony Point
Bluebill Lake
Horsfall Lake
Empire
COOS BAY
NORTH SPIT
SOUTHWESTERN OREGON COMMUNITY COLLEGE

Mail Processing Center Federal Aviation Administration Southwest Regional Office Obstruction Evaluation Group 10101 Hillwood Parkway Fort Worth, TX 76177	Aeronautical Study No. 2017-ANM-5386-OE

Issued Date: 05/07/2018

Drew Jackson
Jordan Cove LNG
5615 Kirby Dr
Houston, TX 77005

**** NOTICE OF PRESUMED HAZARD ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	LNG Tank South
Location:	North Bend, OR
Latitude:	43-25-48.88N NAD 83
Longitude:	124-16-00.87W
Heights:	23 feet site elevation (SE)
	219 feet above ground level (AGL)
	242 feet above mean sea level (AMSL)

Initial findings of this study indicate that the structure as described exceeds obstruction standards and/or would have an adverse physical or electromagnetic interference effect upon navigable airspace or air navigation facilities. Pending resolution of the issues described below, the structure is presumed to be a hazard to air navigation.

If the structure were reduced in height so as not to exceed 144 feet above ground level (167 feet above mean sea level), it would not create a substantial adverse effect and a favorable determination could subsequently be issued.

Any height exceeding 181 feet above ground level (204 feet above mean sea level), will result in a substantial adverse effect and would warrant a Determination of Hazard to Air Navigation.

See Attachment for Additional information.

NOTE: PENDING RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE, THE STRUCTURE IS PRESUMED TO BE A HAZARD TO AIR NAVIGATION. THIS LETTER DOES NOT AUTHORIZE CONSTRUCTION OF THE STRUCTURE EVEN AT A REDUCED HEIGHT. ANY RESOLUTION OF THE ISSUE(S) DESCRIBED ABOVE MUST BE COMMUNICATED TO THE FAA SO THAT A FAVORABLE DETERMINATION CAN SUBSEQUENTLY BE ISSUED.

IF MORE THAN 60 DAYS FROM THE DATE OF THIS LETTER HAS ELAPSED WITHOUT ATTEMPTED RESOLUTION, IT WILL BE NECESSARY FOR YOU TO REACTIVATE THE STUDY BY FILING A NEW FAA FORM 7460-1, NOTICE OF PROPOSED CONSTRUCTION OR ALTERATION.

If we can be of further assistance, please contact our office at (206) 231-2990, or paul.holmquist@faa.gov. On any future correspondence concerning this matter, please refer to Aeronautical Study Number 2017-ANM-5386-OE.

Signature Control No: 350680444-364508838 (NPH)

Paul Holmquist
Specialist

Attachment(s)
Additional Information

Additional information for ASN 2017-ANM-5386-OE

ASN 2017-ANM-5386-OE

Abbreviations

AGL - above ground level	AMSL - above mean sea level	RWY - runway
VFR - visual flight rules	IFR - instrument flight rules	NM - nautical mile
ASN- Aeronautical Study Number	CAT - category aircraft	
MDA - minimum descent altitude	DA - decision altitude	

Part 77 - Title 14 Code of Federal Regulations (CFR) Part 77, Safe, Efficient Use and Preservation of the Navigable Airspace

Our aeronautical study has disclosed that the proposed 219-foot AGL (242-foot AMSL) south liquid natural gas tank structure associated with the proposed Jordan Cove Liquid Natural Gas Terminal penetrates 14 CFR Part 77 protected airspace surfaces at Southwest Oregon Regional Airport (OTH) in North Bend, OR. The OTH airport elevation is 17 feet AMSL.

The proposed structure would exceed the following Part 77 surfaces:

a. Section 77.17(a)(2): A height that is 200 feet above ground level or above the established airport elevation, whichever is higher, within three nautical miles of the established reference point of an airport, excluding heliports, with its longest runway more than 3,200 feet in actual length, and that height increases in the proportion of 100 feet for each additional nautical mile of distance from the airport up to a maximum of 500 feet. This proposed structure would exceed this surface by 19 feet.

b. Section 77.19(a): Horizontal Surface-a height exceeding a horizontal plane 150 feet above the established airport elevation. The proposed structure would exceed the OTH Horizontal Surface by 75 feet.

Additionally, this proposed structure would exceed the OTH VFR traffic pattern airspace in the Part 77 Conical Surface as defined in FAA JO 7400.2L, 6-3-8, Evaluating Effect on VFR Operations. The VFR Conical Surface is defined in Part 77 Section 77.19(b) as a surface extending outward and upward from the periphery of the VFR Part 77 Horizontal Surface at a slope of 20:1 for a horizontal distance of 4,000 feet .

This proposed structure would exceed the OTH VFR Traffic Pattern Altitude (TPA) Conical Surface by 37 feet and the OTH VFR TPA Conical Surface plan on file by 38 feet. . The not-to-exceed height of 181 AGL / 204 AMSL will avoid penetrating the Conical Surface (plan on file).

The OTH Airport Master Record, http://www.gcr1.com/5010web/airport.cfm?Site=OTH, states there are 36 single engine, eight (8) multi-engine, one (1) jet, and six (6) helicopter aircraft based there with 18,277 total operations for the 12 months ending 31 December 2013 (latest information). RWY 31 is designated Right Traffic.

Your options and conditions for this proposal are as follows:

1. You must resolve the 38 foot VFR Traffic Pattern Airspace penetration by lowering the structure height, with all appurtenances, to a maximum height at 181 AGL / 204 AMSL.

2. You can agree to limit the structure height to 144 feet AGL (167 feet AMSL). The FAA can then withdraw this objection to the proposed structure as it would not exceed obstruction standards and a favorable determination could be subsequently issued.

3. You can terminate the proposal at this location.

4. You can request further study for any height between 144 AGL and 181 AGL. Further study will include a public notice circularization and 37-day comment period where the outcome cannot be predicted. Further FAA study for any height greater than 181 AGL/ 204 AMSL is not an option.

Please email me within 60 days of the date of this letter at Paul.Holmquist@faa.gov with your intentions and any questions you might have regarding this aeronautical study.

Close Print

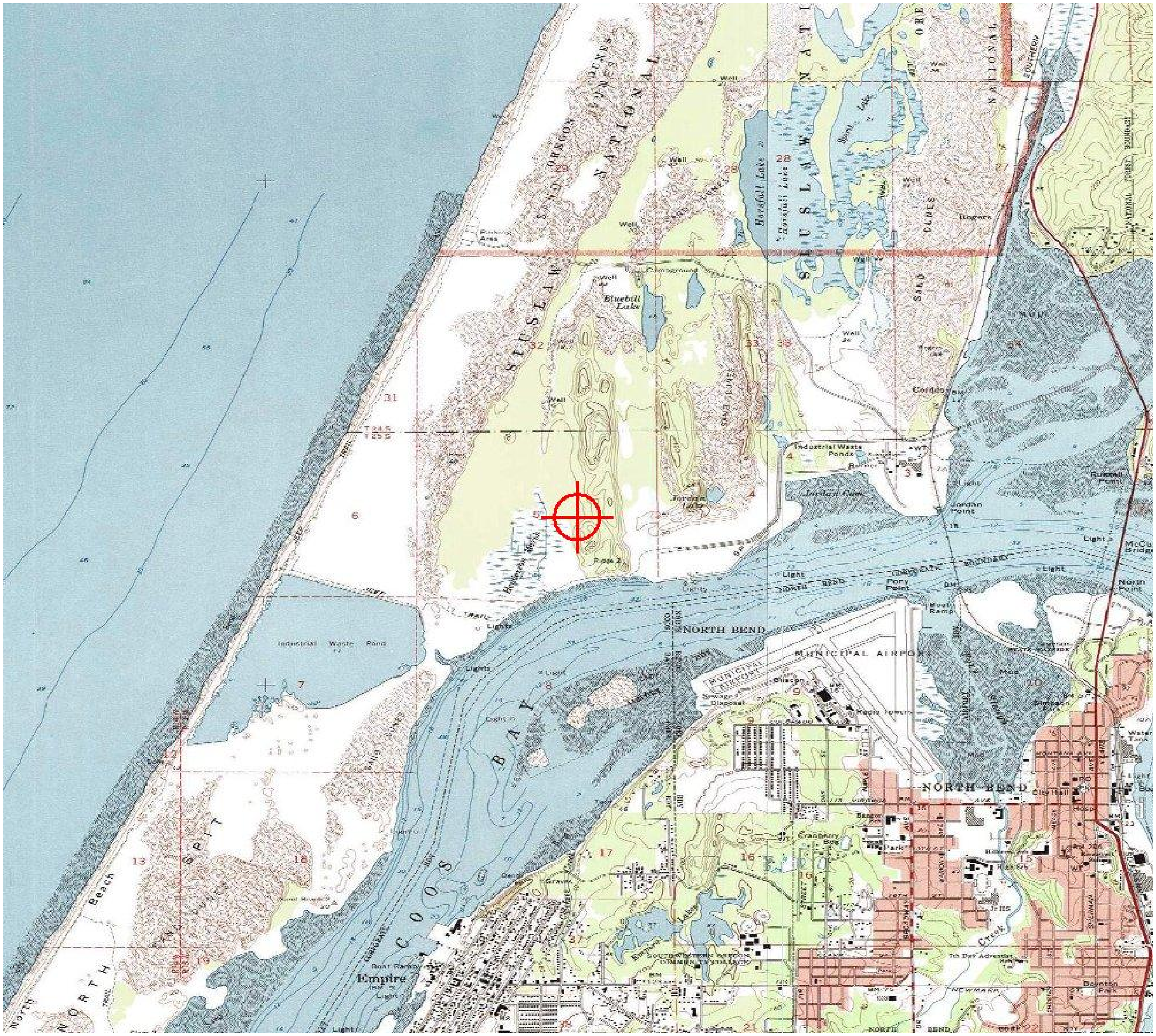


Exhibit 34

Federal Aviation Administration

Memorandum

Date: JAN 21 2015

To: Regional Airports Division Managers
610 Branch Managers
620 Branch Managers
Airports District Office Managers

Elliott Black

From: Director, Office of Airport Planning and Programming (APP-1)

Director, Office of Airport Safety and Standards (AAS-1)

Subject: Technical Guidance and Assessment Tool for Evaluation of Thermal Exhaust Plume Impact on Airport Operations

---

The Federal Aviation Administration (FAA) has received several inquiries and requests from state and local government and airport operators for guidance on the appropriate separation distance between power plants and airports where exhaust plumes from power plant smoke stacks and cooling towers may cause disruption to aircraft near Federally-obligated airports. The only related FAA regulations address the physical restrictions of the exhaust stack height. There are no FAA regulations protecting for plumes and other emissions from exhaust stacks.

In response, the FAA's Airport Obstruction Standards Committee (AOSC) was tasked to study the impact exhaust plumes may have on flight safety. The AOSC study evaluated the following:

1. How much turbulence is created by the exhaust plumes?
2. Is this turbulence great enough to cause loss of pilot control? If so, what size aircraft are impacted?
3. Is there a lack of oxygen (within a plume) causing loss of engine or danger to pilot/passengers?
4. Are there harmful health effects to the pilot or passengers from flying through the plume?

After thorough analysis, the FAA has determined the overall risk associated with thermal exhaust plumes in causing a disruption of flight is low. However, the FAA has determined that thermal exhaust plumes in the vicinity of airports may pose a unique hazard to aircraft in critical phases of flight (particularly takeoff, landing and within the pattern) and therefore are incompatible with airport operations.

Flight within the airport traffic pattern, approach and departure corridors, and existing or planned flight procedures may be adversely affected by thermal exhaust plumes[1]. The FAA-sponsored research indicates that the plume size and severity of impact on flight can vary greatly depending on several factors at a site such as:

- Stack size, number, and height; type of exhaust or effluent (e.g., coolant tower cloud, power plant smoke, etc.);
- Proximity of stacks to the airport flight paths;
- Temperature and vertical speed of the effluent;
- Size and speed of aircraft encountering exhaust plumes; and
- Local winds, ambient temperatures, stratification of the atmosphere at the plume site.

Airport sponsors and land use planning and permitting agencies around airports are encouraged to evaluate and take into account potential flight impacts from existing and planned development that produce plumes (such as power plants or other land uses that employ smoke stacks, cooling towers or facilities that create thermal exhaust plumes).

To aid these reviews the FAA contracted MITRE Corporation to develop a model to predict plume size and severity of flight impact from a site of thermal exhaust plume(s). MITRE developed the “Exhaust-Plume-Analyzer” and it is available for no cost. Access can be found for licensing and downloading from MITRE at: http://www.mitre.org/research/technology-transfer/technology-licensing/exhaust-plume-analyzer

The MITRE Exhaust-Plume-Analyzer can be an effective tool to assess the impact exhaust plumes may impose on flight operations at an existing or proposed site in the vicinity of an airport.

The FAA Advisory Circular (AC) 5190-4, A Model Zoning Ordinance to Limit the Height of Objects Around Airports (Airport Compatible Land Use Planning), is currently being updated to include comprehensive guidance to airport sponsors and local community planners on airport compatible land use issues, including evaluation of thermal exhaust plumes. The updated AC is expected to be issued in FY 2015.

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[1] On July 24, 2014, the FAA issued a change to the Aeronautical Information Manual (AIM) to update terminology and provide more detail regarding the associated hazards of exhaust plumes. See the updated AIM flight instruction to pilots at Section 5-5-15, Avoid Flight in the Vicinity of Exhaust Plumes (Smoke Stacks, Cooling Towers) at http://www.faa.gov/air_traffic/publications/atpubs/aim/aim0705.html.

In the interim, please provide this technical memorandum to airport sponsors to advise them of the availability of the Exhaust-Plume-Analyzer. Sponsors, state and local planning organizations, and permitting jurisdictions now have the opportunity to ensure that their planning and land use development decisions adequately evaluate the potential effects of thermal exhaust plumes on airport operations.

Should you have any questions concerning this memorandum please contact Rick Etter, Airport Planning and Environmental Division (APP-400) at 202-267-8773 or by email at rick.etter@faa.gov.

Exhibit 35

WILLAMETTE WEEK

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April 22nd, 2015 12:01 am NIGEL JAQUISS | News Stories

Hot Air

Pilots say the Port of Portland's plans to sell land for a power plant next to the Troutdale Airport include a fatal flaw.

FLYING SCARED: Mike Rhodes spent four years building his RV-9A plane from a kit. He says a proposed natural gas-fired power plant near the Troutdale Airport presents a "clear and present danger" to aviation. - IMAGE: Will Corwin

Mike Rhodes fell in love with flying nearly 50 years ago at the Troutdale Airport while on a school field trip, and from his first flight, he knew he wanted to be a pilot.

Today, Rhodes, 61, a nuclear engineer who lives in Gresham, keeps a two-seater plane he built himself at the Troutdale Airport, 10 miles east of Portland along I-84. He's logged more than 2,000 hours flying—always conscientious about safety for himself and his passengers.

But Rhodes says he and hundreds of other pilots who regularly use Troutdale, the state's third-busiest airport, now fear for their safety.

“What they want to do,” Rhodes says, “will make flying in an out of Troutdale dramatically more dangerous.”

The “they” posing the threat, Rhodes says, is the airport’s owner, the Port of Portland.

The port wants to sell 38 acres directly north of the Troutdale Airport to the developer of a natural gas-fired power plant. The proposed plant, called the Troutdale Energy Center, would create a powerful heat updraft that experts say could endanger small planes flying in and out of the airport.

That development is currently the subject of a permitting dispute pitting the state’s Energy Facility Siting Council, which issues permits for new electrical generating plants, against a coalition of environmentalists and aviation groups, including the Oregon State Aviation Board and groups representing airplane owners and pilots.

“I understand the port wants to maximize revenue from the real estate it owns,” says Rhodes, “but developing this power plant is detrimental to another part of the port—and to pilots.”

Port spokeswoman Kama Simonds says the developers of the Troutdale Energy Center conducted extensive safety modeling that assured the port of the project’s safety.

“The port believes that the Troutdale Energy Center and the Troutdale Airport can successfully coexist,” Simonds says.

There’s some irony in the port finding itself at loggerheads with pilots and the aviation board. Airports are the cash cow for a port with grim financial challenges elsewhere.

Labor disputes have cost the port its marine container business. That has left the port even more focused on Portland International Airport, whose landing fees and parking revenues are the agency’s lifeblood.

The port is also in the real estate and economic development business. It bought the contaminated site of a shuttered Troutdale aluminum plant in 2007. Selling part of it to the Troutdale Energy Center (for an undisclosed price) would allow the development of the reclaimed industrial land.

The Troutdale Airport, with its 5,400-foot runway, typically handles small planes, although private jets also land and take off there. Flight instructors have moved operations to Troutdale from Hillsboro, the state’s busiest airport. The two airports will generate about $3.5 million in revenue for the port this year, most of that from Hillsboro.

Although the smaller airports generate only a tiny fraction of PDX’s revenue, they play a vital role in the port’s system. The port depends on the Hillsboro and Troutdale airports to handle small aircraft that would otherwise need to use PDX. The smaller airports handle 50 percent more takeoffs and landings than PDX while providing training grounds for domestic and international pilots.

Initially, pilots worried that a power plant at Troutdale would hamper visibility. Gas-fired generating plants work by boiling water to produce steam that drives turbines. When the water is cooled, the steam roiling out of the plant's cooling towers could fog pilots' flight paths and create a hazard.

But the bigger concern now is heat.

Earlier this year, the Federal Aviation Administration directed Troutdale users to an independent consulting firm to analyze the potential impact of the invisible plume of hot air that the combustion of gas by the plant would produce.

"You're putting a known but invisible hazard right into the path that pilots using Troutdale must fly," says Mary Rosenblum, a Canby resident and president of the Oregon Pilots Association.

Rosenblum says modeling shows the plume could suddenly lift one wing and flip a plane upside down.

"This would happen when the plane is 1,000 feet or less off the ground," Rosenblum says. "At that altitude, you cannot recover."

The FAA consultant's initial analysis in March found that the invisible plumes could cause as many as a dozen planes to lose control and crash annually—with fatal consequences. A second run of the same model earlier this month found it could happen even more often.

Risk modeling done for the Troutdale Energy Center in 2013 found no such danger.

Rhodes scoffs at that earlier analysis. The nuclear engineer—who spends his days calculating the proper dosages of radiation for cancer patients—has reviewed the modeling and says the proposed power plant represents "a clear and present danger" to pilots.

"Engineers and mathematicians work hard to 'average out' calculated risk for their clients," Rhodes said in written testimony. "I'm an engineer. I know how the system works. Don't kid yourself, cherry-picking data to support a client's position happens all the time."

The FAA regulates only physical structures, such as towers or smokestacks that exceed 500 feet, not plumes.

But in January, the federal regulator issued guidance on hot air plumes.

"The FAA has determined that thermal exhaust plumes in the vicinity of airports may pose a unique hazard to aircraft in critical phases of flight (particularly takeoff, landing and within the pattern)," says an FAA memo to airport managers dated Jan. 21, 2015, "and therefore are incompatible with airport operations."

That warning would seem to give pause to the Port of Portland, which owns the land where the generating plant would be built, and to the state energy siting council, which in 2013 gave tentative approval to the plant's location next to the Troutdale Airport.

Todd Cornett, an assistant director for the Oregon Department of Energy responsible for staffing the siting council, says his agency's staff recommended proceeding with the project after concluding it met all the criteria for locating a power plant.

The group financing the Troutdale Energy Center, Energy Investors Funds, builds plants all over the country—not without incident. In 2010, a plant in Middletown, Conn., similar to the one proposed for Troutdale, blew up during early testing, killing six people and resulting in a $16.6 million fine by the Occupational Safety and Health Administration—the third-largest in OSHA history. A spokesman for TEC didn't return *WW*'s calls.

The pilots' safety concerns about the Troutdale plant come on top of environmental worries about the pollution the plant would emit.

The conservation group Friends of the Gorge opposes the plant. And the U.S. Forest Service, which enforces the Columbia River Gorge National Scenic Area Act, says locating a power plant at the western gateway to the gorge is a bad idea.

Agency officials say pollutants emitted from the plant would block views in the gorge and endanger sensitive plant species.

The new safety study and the environmental concerns are part of an ongoing contested-case hearing over the permitting of the power plant. Opponents to the site forced the hearing, in which both sides will make their best case for or against the safety and environmental effects of the plant.

Rhodes says he'll be "stunned" if the state siting council proceeds with approval of the plant after the new risk study. Even if someone raises additional information affirming the plant's safety, he adds, the burden of proof still rests on the applicant.

"State agencies are supposed to work on behalf of the people of Oregon, not an applicant," Rhodes says. "In this case, they are working in the licensees' interest. That's a direct conflict of interest."

Exhibit 36

U.S. Department
of Transportation
Federal Aviation Administration

Position Paper

Safety Concerns of Exhaust Plumes

Prepared by:

Federal Aviation Administration

Airport Obstructions Standards Committee Working Group

July 8, 2014

Background:

In 2008, a safety concern was raised to Federal Aviation Administration (FAA) that in some instances exhaust plumes were causing disruption to flights. In addition, California Energy Commission and other organizations were requesting guidance from the FAA on what is the appropriate proximity power plants can be constructed near an airport. The only FAA regulations are on the physical restrictions of the exhaust stack height. There are no FAA regulations protecting for plumes and other emissions from exhaust stacks.

In September 2008, the FAA's Airport Obstruction Standards Committee (AOSC) was tasked to study the impact exhaust plumes may have on flight safety. In 2009, a task was added to an FAA support contract that evaluated the following:

- How much turbulence is created by the Exhaust Plumes?
- Is this turbulence great enough to cause loss of pilot control?
    - If so, what size aircraft are impacted?
- Is there a lack of oxygen causing loss of engine or danger to pilot/passengers?
- Are there harmful health effects to the pilot or passengers in flying through the plume?

In fall 2010, the initial Exhaust Plume Report was completed. After careful review, the AOSC determined that the information in the initial Plume Report needed to be further verified and validated.

In spring 2011, FAA's Federally Funded Research & Development Center operated by the MITRE Corp was tasked to verify and validate the initial study with an agreed upon completion in fall 2012.

MITRE completed their initial task in September 2012 and delivered a study and validated Exhaust Plume model. The study indicates exhaust plumes can create hazards for aircraft in a limited area above the stack in terms of turbulence caused by upward motion of the plume and reduced oxygen content inside the plume. The reduced oxygen is not a danger to pilots, but could cause failure of helicopter engines if hovering over the plume. It also indicated that weather conditions are an important factor in the size of the risk area. The conditions which create the largest risk area are calm winds, low temperatures, and neutral or stable stratification of the atmosphere. The reverse is also true, windy conditions (greater than eight (8) knots) and warmer temperatures, the risk area is minimized.

An industry meeting was hosted by the FAA in January 2013 in which MITRE briefed on the initial study and explained their Exhaust Plume Model. Industry recommended that the Plume Model be updated to include light sport aircraft and when an aircraft crosses over the plume while already in a turn.

The industry group also expressed a desire for the FAA to take affirmative action from the results of the plume model to declare plumes as hazards, as they do with structures under Part 77. The industry group believes preemptive planning is very important for preventing construction of plume emitting facilities in the vicinity of airports. They reiterated a desire for the FAA to declare them hazards as an aid to empower the State's position in that regard.

Final Steps:

1. The FAA Office of Airports will update Advisory Circular (AC)150/5190-4, Airport Land Use Compatibility Planning, to address the compatibility of exhaust plumes near airports; scheduled to be completed by Fall of 2014.
2. The FAA Office of Aviation Safety will further update the Aeronautical Information Manual (AIM) to provide pilots information regarding the potential hazards over exhaust plumes; scheduled to be completed in Fall of 2014.
3. The FAA tasked the MITRE Corporation to update the Exhaust Plume Model to include the industry recommendations, as well as make it a fully executable that can run on a personal computer. The Model will be available the Fall of 2014. How to access the model will be outlined in the AC 150/5190-4.

Conclusion:

After a thorough analysis, the FAA has determined the overall risk associated with thermal exhaust plumes in causing a disruption of flight is very unlikely. However, the FAA determined that thermal exhaust plumes in the vicinity of airports may pose a unique hazard to aircraft in critical phases of flight and therefore are incompatible. We recommend that airport owners, in cooperation with local communities, follow the guidance outlined in Advisory Circular (AC)150/5190-4, Airport Land Use Compatibility Planning.

The information and recommendation provided in this Position Paper supersedes any previous studies or reports on thermal exhaust plumes completed by the FAA.

Prepared by:
Federal Aviation Administration
Airport Obstructions Standards Committee Working Group
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Patrick Zelechoski, Flight Standards
John Bordy, Flight Standards
Robert Bonanni, Airports
John Page, Air Traffic Organization
Ron Singletary, Air Traffic Organization

Exhibit 37

4. Protect your aircraft while on the ground, if possible, from sleet and freezing rain by taking advantage of aircraft hangars.

5. Take full advantage of the opportunities available at airports for deicing. Do not refuse deicing services simply because of cost.

6. Always consider canceling or delaying a flight if weather conditions do not support a safe operation.

c. If you haven't already developed a set of Standard Operating Procedures for cold weather operations, they should include:

1. Procedures based on information that is applicable to the aircraft operated, such as AFM limitations and procedures;

2. Concise and easy to understand guidance that outlines best operational practices;

3. A systematic procedure for recognizing, evaluating and addressing the associated icing risk, and offer clear guidance to mitigate this risk;

4. An aid (such as a checklist or reference cards) that is readily available during normal day−to−day aircraft operations.

d. There are several sources for guidance relating to airframe icing, including:

1. http://aircrafticing.grc.nasa.gov/index.html

2. http://www.ibac.org/is−bao/isbao.htm

3. http://www.natasafety1st.org/bus_deice.htm

4. Advisory Circular (AC) 91−74, Pilot Guide, Flight in Icing Conditions.

5. AC 135−17, Pilot Guide Small Aircraft Ground Deicing.

6. AC 135−9, FAR Part 135 Icing Limitations.

7. AC 120−60, Ground Deicing and Anti−icing Program.

8. AC 135−16, Ground Deicing and Anti−icing Training and Checking.

The FAA Approved Deicing Program Updates is published annually as a Flight Standards Information Bulletin for Air Transportation and contains detailed information on deicing and anti−icing procedures and holdover times. It may be accessed at the following web site by selecting the current year's information bulletins:

http://www.faa.gov/library/manuals/examiners_inspectors/8400/fsat

7−5−15. Avoid Flight in the Vicinity of Thermal Plumes (Smoke Stacks and Cooling Towers)

a. Flight Hazards Exist Around Thermal Plumes. Thermal plumes are defined as visible or invisible emissions from power plants, industrial production facilities, or other industrial systems that release large amounts of vertically directed unstable gases. High temperature exhaust plumes may cause significant air disturbances such as turbulence and vertical shear. Other identified potential hazards include, but are not necessarily limited to, reduced visibility, oxygen depletion, engine particulate contamination, exposure to gaseous oxides, and/or icing. Results of encountering a plume may include airframe damage, aircraft upset, and/or engine damage/failure. These hazards are most critical during low altitude flight, especially during takeoff and landing.

b. When able, a pilot should fly upwind of possible thermal plumes. When a plume is visible via smoke or a condensation cloud, remain clear and realize a plume may have both visible and invisible characteristics. Exhaust stacks without visible plumes may still be in full operation, and airspace in the vicinity should be treated with caution. As with mountain wave turbulence or clear air turbulence, an invisible plume may be encountered unexpectedly. Cooling towers, power plant stacks, exhaust fans, and other similar structures are depicted in FIG 7−5−2. Whether plumes are visible or invisible, the total extent of their unstable air is difficult to ascertain. FAA studies are underway to further characterize the effects of thermal plumes as exhaust effluents. Until the results of these studies are known and possible changes to rules and policy are identified and/or published, pilots are encouraged to exercise caution when flying in the vicinity of thermal plumes. Pilots are encouraged to reference the Airport/Facility Directory where amplifying notes may caution pilots and identify the location of structure(s) emitting thermal plumes.

FIG 7−5−2
Plumes

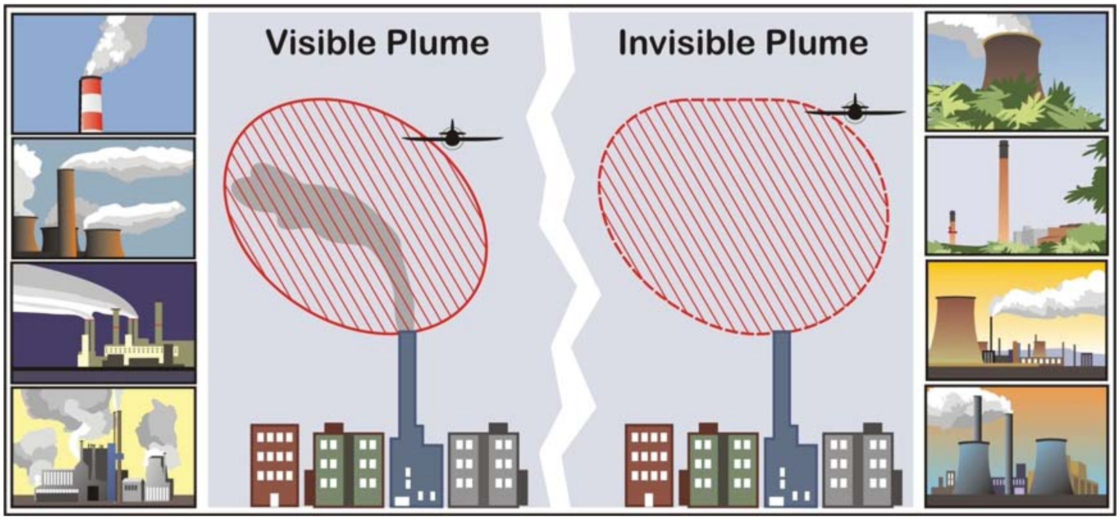

Exhibit 38

15th Annual Coos Basin SALMON DERBY

COOS BAY, OREGON

September 13th & 14th 2014

Presented by: ODFW, Coos County STEP Commission,
Eel Tenmile STEP, South Coast Anglers STEP & Douglas Timber Operators

Over $1,000 in Cash & Prizes!
Including $100 for Kids Biggest Fish

AWARDS GIVEN THROUGH 10TH PLACE

DERBY TICKETS FOR 2 DAY EVENT – $20 PER PERSON

KIDS 13 AND UNDER FISH FREE!!*

**WHEN ACCOMPANIED BY PAYING ADULT FISHERMAN*

Advance tickets at: The Bite's on Bait and Tackle, Coos Bay Marine, Y-Marina and at the kickoff BBQ.
Day-of tickets at: California Street, Eastside, Dora's Place & Myrtle Trees Boat Ramps


Why we do what we do


Teaching the next generation


Fishing heats up on the river

Kickoff BBQ & Silent Auction
Friday, September 12th 5-8 pm

Derby Tickets at Door!

NORTH BEND COMMUNITY CENTER • 2222 BROADWAY, NORTH BEND

FREE TO CONTESTANTS & TICKET HOLDERS • $5 DINNER TICKETS FOR NON-DERBY FAMILY, FRIENDS & AUCTION ATTENDEES (DINNER SERVED UNTIL 7 PM ONLY) • $5 OYSTER BAR

FANTASTIC AUCTION ITEMS!

ROD & REEL COMBOS INCLUDING ONE WITH SET-UP BY RICK HOWARD, CUSTOM ROD WITH COUNTING REEL, CARVED BEAR WITH SALMON, STAINLESS BBQ, ARTWORK, GOLF PACKAGES, AREA RUG, RECLINER, LOTS OF FISHING GEAR, RAMP PASSES, JEWELRY, DOWNRIGGERS, AND MUCH MORE.

MANY THANKS TO OUR GENEROUS DONORS!

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THANK YOU TO THE 2014 ANNUAL COOS BASIN AMATEUR SALMON DERBY SPONSORS. WE COULDN'T DO IT WITHOUT YOU!

TITLE SPONSORS Douglas Timber Operators • Southport Forest Products • Coquille Indian Tribe • Oregon Fish & Wildlife

Major Sponsors The Campbell Group LLC • Columbia distributing • Roseburg Resources Co.

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In addition, the Derby Committee wishes to thank the many dedicated volunteers who make our programs possible and all of the businesses and individuals who have given their support to Salmon Enhancement & Education programs for over 30 years. If any of the 15th Annual sponsors have been inadvertently omitted, please accept our apology.

Exhibit 39

South Coast Basin

Rivers and Streams

Flow Restoration Priorities for Recovery of Anadromous Salmonids in Coastal Basins

The Oregon Plan

Streamflow Restoration Priorities Measure IV.A.8

Instream Water Right Program Habitat Conservation Division

Field and Technical Services Division

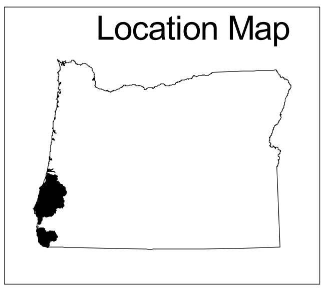

Exhibit 40

Final Environmental Impact Statement

JORDAN COVE ENERGY AND PACIFIC CONNECTOR GAS PIPELINE PROJECT

Jordan Cove Energy Project, L.P.	Docket Nos. CP13-483-000
Pacific Connector Gas Pipeline, L.P.	CP13-492-000

FERC/EIS – 0256F

Federal Energy Regulatory Commission

Office of Energy Projects

Washington, DC 20426

Cooperating Agencies

US Department of Agriculture Forest Service, Pacific Northwest Region
Department of the Army, Corps of Engineers, Portland District
US Department of Energy
US Environmental Protection Agency, Region 10
US Department of Homeland Security Coast Guard, Portland
US Department of the Interior Bureau of Land Management, Oregon State Office
US Department of the Interior Bureau of Reclamation, Klamath Basin Area Office
US Department of the Interior, Fish and Wildlife Service, Oregon State Office
US Department of Transportation, Pipeline and Hazardous Materials Safety Administration

September 2015

(33 CFR 151). Spills of fuel or other oils are more likely to be released into surface waters during fueling or bunkering at the dock when the hazardous materials are being transferred onto the vessel. To reduce the risk of spills during fuel transfer, procedures should be followed by the chief engineer familiar with the system to be involved in operations (78 FR 60099). With the implementation each vessel's shipboard oil pollution emergency plan, impacts resulting from the spill of fuel, or oil, or other hazardous liquids would be minimized.

Water Releases from LNG Vessels at the Terminal Berth

LNG vessels at the Jordan Cove terminal berth would release ballast water and engine cooling water into the marine slip. No wastewater would be discharged from the LNG vessels into the slip. The LNG vessels may arrange with licensed private entities for refueling, provisioning, and collection of sanitary and other waste waters contained within the vessel. The licensed private entities would transport the waste to a permitted treatment facility. Discharges from vessels are subject to regulation by EPA. EPA currently regulates discharges incidental to the normal operation of vessels operating in a capacity as a means of transportation with the Vessel General Permit. This general permit became effective December 2013 and includes general effluent limits applicable to all discharges; general effluent limits applicable to 26 specific discharge streams; narrative water-quality based effluent limits; inspection, monitoring, recordkeeping, and reporting requirements; and additional requirements applicable to certain vessel types. Vessels of 300 gross tons or more or that have the ability to hold or discharge more than 8 cubic meters of ballast must submit a notice of intent in order to receive permit coverage. Jordan Cove would provide permitting requirements to the LNG vessels calling on the Project.

Ballast Water

The Coast Guard mandates a ballast water exchange (BWE) process for vessels arriving at U.S. ports. The BWE process includes complete exchange of ballast water in the open sea at least 200 miles from U.S. waters. Therefore, the ballast water discharged by LNG vessels at the Jordan Cove terminal would have originated in the open sea rather than a foreign port.

LNG vessels at the terminal slip would discharge ballast concurrently with the LNG cargo loading. The amount of ballast water discharged must, at a minimum, be adequate to maintain the LNG ship in a positive stability condition and with an adequate operating draft while the LNG cargo is loaded. Jordan Cove expects its terminal to be visited by 90 LNG vessels per year. Each LNG vessel would discharge approximately 9.2 million gallons of ballast water during the loading cycle to compensate for 50 percent of the mass of LNG cargo loaded.[52]

The LNG loading rate is designed to be 10,000 m^3/hr (with a peak capacity of 12,000 m^3/hr), or 4,600 metric tons per hour (t/hr) (5,520 t/hr peak), consequently the ballast water discharge rate would be approximately 20,250 gpm. Typical LNG vessels have three ballast water pumps, each capable of 3,000 m^3/hr (13,210 gpm) rated capacity. The typical LNG vessel has an upper and a lower ballast water discharge on each side of the hull, referred to as sea chests. The lower unit is just above the keel, approximately 10 meters (33 feet) below the water line. The typical ballast

[52] One cubic meter of LNG is 0.46 metric tons (t), which for the maximum size of LNG vessel authorized to call on the LNG terminal (148,000 m^3) would be 68,080 t of LNG per ship. Assuming 1 t of seawater is 1.027 m^3, the amount of seawater ballast discharged (50 percent of the weight of the LNG loaded) would be approximately 34,959 m^3 (approximately 9.2 million gallons).

water discharge port or sea chest is approximately 3.5 to 4.2 square meters covered by a screen with 4.5 mm bars, spaced every 20 to 25 mm.

A potentially notable difference that may be observed in water quality could be salinity. Coos Bay is an estuary where freshwater runoff from upland rives meets seawater. According to Roye (1979), the zone of change in salinity in Coos Bay occurs at about NCM 8. The findings of the sampling conducted by OIMB (Shanks et al. 2010, 2011) in the bay near the LNG terminal indicated a wide range in salinity between seasons and tidal cycles. Salinity ranged from approximately 16 practical salinity units (psu) at low tide in winter to approximately 33 psu during high tide between May and September. On average, seawater in the world's oceans has a salinity of about 35 psu. Shanks et al. (2010, 2011) estimated the volume of water passing through Coos Bay in the vicinity of the Jordan Cove terminal during lower tidal levels to be 106 million m^3. Therefore, any increase in salinity from the 9.2 million gallons (34,825 m^3) of ballast water discharge would be approximately 0.3 percent of the water passing by the terminal. Consequently, virtually no change in salinity would occur in Coos Bay.

Another physio-chemical water quality parameter that may be influenced by the introduction of ballast water is the dissolved oxygen level. Dissolved oxygen levels are a critical component for the respiration of aquatic organisms. Among many other factors, dissolved oxygen levels in water can be influenced by water temperature, water depth, phytoplankton, wind, and current. Typical water column profiles indicate a decrease in dissolved oxygen with an increase in depth. Some factors that often influence this stratification include sunlight attenuation for photosynthetic organisms that can produce oxygen, wind, wave, and current that results in mixing. ODEQ records indicate that dissolved oxygen is rarely below the 6 mg/l standard below NCM 13 in Coos Bay (Roye 1979).

Water that is collected within the ballast tanks of a ship would lack many of these important influences and could suppress dissolved oxygen levels. However, ballast water that is discharged is not expected to be anoxic (i.e., lacking all oxygen), just lower than what levels would likely be at the surface. In addition, ballast water would be discharged near the bottom of the slip where dissolved oxygen levels may already be lower. Therefore, no significant impacts are likely to occur as a result of discharging ocean water with potentially suppressed dissolved oxygen levels.

Water temperatures and pH in Coos Bay are not likely to be significantly altered as a result of the release of ballast water by LNG vessels in the Jordan Cove marine slip. The temperature of the water in Coos Bay undergoes both seasonal and diurnal fluctuations. In December and March, the ocean and fresh water entering the estuary had similar temperatures, around 50°F. In summer, low stream flows results in a rise of temperatures in the bay, to above 60°F in September at NCM 8 (Roye 1979). Since ballast water is stored in the ship's hull below the waterline, water temperatures are not expected to deviate much from ambient temperatures of the surrounding bay water. The pH of the ballast water (reflective of open ocean conditions) may be slightly higher as compared to that of freshwater estuaries. However, this slight variation is not expected to have any impacts on existing marine organisms.

LNG Vessel Engine Cooling Water

The LNG vessels would also re-circulate water for engine cooling while loading LNG at the berth. No chemicals would be added to the cooling water. The amount of cooling water to be re-circulated is a function of the propulsion system of the LNG vessel. For purposes of this analysis, typical cooling water flow rates were used. Cooling water flows while at the berth are approximately 1,300 m^3/hr (343,421 gallons per hour or 5,723 gpm). For a 148,000 m^3 vessel, this would total approximately 6.1 million gallons while at berth (for 17.5 hours). The intake port for this engine cooling water is approximately the same size and at the same location as the ballast water intake port, 3.5 to 4.2 square meters covered by a screen with 4.5 mm bars, spaced every 25 mm and approximately 32 feet below the water line, or 5.6 feet from the keel of the LNG vessel. The velocity across this port is approximately 0.28 ft/sec with a temperature differential of 3°C.

The effects of engine cooling water discharged by an LNG vessel at the terminal berth on the temperature of the water in the marine slip were evaluated (CHE 2011b). The engines would be running to provide power for standard hotelling activities as well as running the ballast water pumps. The activities that would require LNG vessel power and the assumptions used to develop the engine cooling water flow requirements are as follows:

- hotelling operations require the generation of 1.9 MW of power during the entire time that the LNG vessel remains in the slip. The vessel is anticipated to be within the slip for a total of 17.5 hours; and
- a typical auxiliary power unit for an LNG vessel is the Wartsila 34DF. This is a dual-fuel (liquid and natural gas) unit that is a complete primary driver/generator package capable of being sized upwards to 6.9 MW output. Fuel to power conversion is 7,700 kilojoules per kilowatt-hour (kJ/kWh) (7,305 British thermal units per kWh [Btu/kWh]). This system has an overall fuel to power efficiency of 46.7 percent, thereby resulting in the rejection of 3,893 Btu of heat into the cooling water for each kWh of power generated.

All calculations that follow are based upon the transfer of 148,000 m^3 of LNG from the LNG storage tanks to the LNG vessel. The 148,000 m^3 vessel is set as the basis because it represents the largest vessel authorized by the Coast Guard to call on the LNG terminal.

The total gross waste heat discharged into the slip from the cooling water stream would be due primarily to the hotelling operations (including the power required to run the ballast water discharge pumps) because the shore-side LNG pumps would be used to transfer the LNG from the LNG storage tanks to the LNG vessel. The hotelling operations were assumed to be as follows:

- hotelling operations – 17.5 total hours x 1,900 kW x 3,983 Btu/kWh = 132.5 MMBtu; and
- the total amount of heat discharged into the slip during each vessel call is approximately 132.5 MMBtu.

Two models (the 3-D UM3 model and the DKHW model) were used to study possible slip temperature changes resulting from the discharge of engine cooling water by an LNG vessel at the Jordan Cove berth. The models simulate hydrodynamic mixing processes of submerged discharges and predict temperature fields and dispersion of non-conserved substances in ambient waterbodies. Cooling water numerical modeling requires input of steady-state flow velocity in the modeling domain. The results of tidal flowing modeling using the SELFE model showed that ambient current velocities inside the slip vary, depending on tidal stage. Peak current speeds in the berth only exceed approximately 0.32 fps less than 2 percent of the time. Therefore, for cooling water modeling, two steady state ambient flow velocities were assumed and used further in the analysis: high velocity = 0.32 fps and typical velocity = 0.16 fps.

The modeling assumptions are conservative in that a steam-powered ship was used. Steam-powered ships tend to be older than the newer more modern dual-fuel diesel electric ships that require lower quantities of cooling water.

Results of the modeling showed that for typical ambient flow conditions at a distance of 50 feet from the discharge point (LNG vessel sea chest), temperatures would not exceed 0.3ºC (0.54ºF) above the ambient temperature (CHE 2011b). This temperature difference would decrease with distance from the point of discharge. Considering the volume of water in the Jordan Cove marine slip (an estimated 4.8 cy), and tidal mixing in Coos Bay, the release of heated water from LNG vessel engine cooling operations would not substantially increase water temperatures.

Also ameliorating the impact of the release of warm engine cooling water from an LNG vessel at the Jordan Cove berth would be the decrease in temperature of the surrounding slip water due to the cooling effect that would occur from the addition of LNG cargo to the vessel. The cold LNG cargo could moderate effects on slip water temperature. Because of the extreme differential of the temperature of the cargo in the LNG vessel (-260°F) and that of the surrounding bay water (nominally 50°F) there is a constant uptake of heat by the LNG vessel. This heat uptake is manifested by the amount of LNG cargo that changes state from liquid to vapor on a daily basis. The typical LNG vessel sees 0.25 percent of its liquid cargo converted to the gaseous state each 24 hours because of this warming. In this process, 219 Btu of heat is absorbed for each pound of LNG converted to vapor. This results in a total of 53 MMBtu absorbed by a typical 148,000 m^3 LNG vessel during the 17.5 hours it is within the slip. It is reasonable to assume that 50 percent or more of the heat uptake by the vessel is extracted from the water.[53]

In addition, ballast water discharged from the LNG vessel would also comprise some portion of the water withdrawn for cooling and affected by its discharge. As the greatest predicted temperature increase from the release of engine cooling water is only about 0.5°F and that increase would be reduced further in proximity to the LNG vessel, we conclude that the thermal effect of LNG vessel operations at the berth would have very minimal impact on background water temperatures.

4.4.2.2 Pacific Connector Pipeline

The Pacific Connector pipeline would cross six subbasins including the Coos, Coquille, South Umpqua, Upper Rogue, Upper Klamath, and Lost River. Within the six subbasins, 19

[53] This assumption is further reinforced by the fact that the heat transfer coefficient between water and steel is significantly higher than the heat transfer coefficient between air and steel. Therefore, it is estimated that 26.5 MMBtu would be removed from the water in the slip by the LNG vessel during its stay. Thus, a portion of the 132.5 MMBtu of thermal energy discharged into the slip from the cooling water is offset by the uptake of 26 MMBtu by the LNG vessel itself, resulting in a net heat input to the slip of 106.5 MMBtu per 148,000 m^3 LNG vessel call.

Jordan Cove LNG terminal on individuals conducting those activities. Use of the crabbing and clamming areas in Coos Bay should not be any more affected by the passage of LNG vessels than they are currently affected by the passage of other deep-draft ships. However, if crabbing and clamming activities were to occur within the established security zones, those activities would be required to cease and temporarily move out of the way. Crab pots outside of the navigation channel should not be affected by LNG vessel traffic in the waterway. Passive equipment, such as crab pots, would be permitted to remain within the security zone while an LNG vessel is present, though the attending crabbing vessels would be required to vacate (Berg 2008).

However, there could be indirect impacts on clams and crabs from shoreline erosion or bottom sediment disturbed by LNG vessel traffic in the waterway. Those impacts are addressed in sections 4.4.2.1 and 4.6.2.1 of this EIS. We concluded that wakes from LNG vessels in the navigation channel would not cause major shoreline erosion much beyond natural waves, and propeller wash from LNG vessels would not greatly disturb the channel bottom.

There would also be impacts from the dredging in the bay to create the access channel for the Jordan Cove terminal. Those impacts have been addressed in sections 4.4.2.1 and 4.6.2.2 in this EIS. We concluded that dredging of the access channel would only have temporary impacts on bay water quality, and increased sedimentation from the dredging would be limited in extent. For example, if a hydraulic dredge was used, turbidity would be estimated to increase about 14 mg/l at 200 feet from the cutterhead under high water conditions. The limited time and extent of dredging siltation should not result in long-term or population wide impacts on clams and crabs near the Jordan Cove terminal. In fact, as mitigation for wetland impacts, Jordan Cove would be creating new eelgrass beds in Coos Bay that could serve as nursery habitat for crabs, would also be creating new wetlands at Kentuck Slough, and would be acquiring 3 acres of unvegetated sand as part of its habitat mitigation program. Therefore, we conclude that the Project would not have significant adverse impacts on recreational clamming and crabbing activities in Coos Bay.

<u>Boating and Fishing</u>

The waterway for LNG vessel traffic to and from the terminal, Jordan Cove's access channel to its marine slip, and the proposed eelgrass mitigation area would be within Coos Bay. Coos Bay is utilized for recreational boating, angling, clamming and crabbing, as well as commercial fishing, oyster farming, and commercial shipping. The Coos Bay estuary is discussed in more detail in section 4.4.1. Aquatic resources are addressed in more detail within section 4.6, and commercial shipping and fishing are discussed in section 4.9. Recreational resources located along the waterway for LNG vessel marine traffic were discussed in section 4.7.1.3 in the FERC's May 2009 FEIS for Docket Nos. CP07-441-000 and CP07-444-000. Recreational clamming and crabbing activities are discussed above, while recreational boating and fishing in Coos Bay is discussed below.

According to a 2008 study by the Oregon State Marine Board (OSMB), recreational boaters in Coos Bay took a total of 31,560 boat trips the previous year. Nearly 90 percent of the boat use-days involved fishing (including angling, crabbing, and clamming), 9 percent was for pleasure cruising, and the remainder was for sailing and water skiing. Sixty-eight percent of the boating activities in Coos Bay originated from the Charleston Marina and the Empire ramp, 19 percent at the California Avenue boat ramps, and 4 percent at the North Spit ramps. Most of the recreational boating activities in Coos Bay occur during the summer.

The most popular fish species caught by recreational anglers out of Coos Bay include coho and Chinook salmon. Other recreational catch species include various species of perch, rockfish, flatfish, sturgeon, Pacific herring, and California halibut.

Much of the recreational angling for salmon in Coos Bay occurs in late summer and fall. It usually begins in late summer at jetty areas and moves up the bay as fish move upstream. Bank angler access on the North Spit is limited. Boat angling occurs throughout the bay, but angling is limited in some areas at times by exposure to winds. For example, the Roseburg Forest Products dock area gets less boat angling use due to exposure to wind and tidal action. Much of the boat angling for Chinook and coho salmon in the fall is concentrated around the railroad bridge and downstream. Marshfield Channel can be an area of concentrated angling for fall salmon.

Perch fishing begins in Coos Bay in late February to early March, depending on freshwater runoff into the bay, and can continue through July. Rocks around bridge abutments are targeted by anglers on the outgoing tide.

Recreational fishing for sturgeon in Coos Bay generally occurs between the railroad bridge and McCullough Bridge (U.S. Highway 101), just east of the Jordan Cove terminal, and also above the McCullough Bridge. White sturgeon can be taken year-round, but the best angling is during December through March, and when there is a heavy freshwater plume in the bay.

Recreational boating in the bay would be redirected away from the access channel and terminal slip during the construction period that includes dredging within Coos Bay. Notices would be provided to boaters by the Coast Guard and the OSMB to avoid this area during the dredging activities. Signs would be posted at the shoreline as well as at the boat ramps and marinas, and on buoys in the bay, in advance of this final task to notify boaters of the planned construction activity and the duration of the activity. If the signage and notices are not sufficient to prevent recreational boating from avoiding the construction areas, some form of physical barrier, like a continuous string of highly visible soft material floats, may be extended across the mouth of the slip or around the construction area. Construction safety inspectors would also be responsible to warn any recreational boaters who progress into the construction area. Boaters could avoid the construction area by moving to the south and east side of the bay.

During construction of the terminal, material deliveries would be made by marine transit in the existing Coos Bay navigation channel. This would include visits by about 82 break bulk cargo ships and 18 barges over a two-year period in total. As discussed below, we do not believe that the equipment delivery vessels coming to the terminal would have adverse impacts on recreational bay users much beyond current commercial cargo ship and barge traffic. Currently, the Port is visited by about 60 deep-draft cargo ships and 50 barges per year.

During operation of the LNG terminal, recreational boaters would have to avoid LNG vessels in transit within the waterway. Jordan Cove believes that up to 90 LNG vessels per year would visit its terminal. Recreational boaters using the bay at the same time as an LNG vessel is in transit within the waterway may encounter delays due the moving security zone requirements around an LNG vessel, as specified in Jordan Cove's WSA and the Coast Guard's WSR and LOR. Jordan Cove estimated that it may take an LNG vessel up to 90 minutes to transit the waterway from the buoy to the terminal at speeds between 4 and 10 knots. The maximum waiting period for an LNG vessel to pass a given point would be 30 minutes. The sum of the periods in which LNG vessels would have a potential impact on recreational and other boating activity is about 1.3 percent of all daylight hours (ECONorthwest 2012a). Pilots guiding commercial ships in the Coos Bay navigation channel currently encounter approximately six recreational boats during the transit into and out of the Port. These numbers are typically lower in winter and on weekdays than during the summer and on weekends. The Coast Guard and OSMB would continue to remind boaters of their obligation not to impede deep draft ships, regardless of the cargo.

Other Public and Special Use Areas

The LNG terminal would be approximately 0.9 mile from the Southwest Oregon Regional Airport. Potential impacts of the LNG terminal on the airport are addressed in sections 4.9 and 4.10.

4.8.1.2 Pacific Connector Pipeline

Parks and Recreational Areas or Facilities on Non-Federal Lands

Overall, the pipeline route does not cross any non-federal park lands or developed recreational facilities, and construction and operation of the pipeline should not adversely impact park users. However, construction-related activities would temporarily increase traffic on local roads used to access the parks, and park users may be able to hear construction noise while workers and equipment move through the area to install the pipeline. In addition, the pipeline route does cross a water trail, the Haynes Inlet Water Trail, as discussed below. Construction-related impacts would be temporary and short term, and should not significantly affect recreational use of parks or other recreational areas.

State Lands

Oregon Coast Trail

The Oregon Coast Trail was previously discussed above in section 4.8.1.1. The pipeline route would be within one-quarter mile of the trail where it follows Horsfall Beach road and joins the Trans-Pacific Parkway north of MP 1.5R.

Recreational users of the Oregon Coast Trail would be exposed to pipeline construction traffic along the Trans-Pacific Parkway, which is the only access road to the North Spit and the Jordan Cove Meter Station. Pacific Connector developed *Transit Management Plans* (TMP) to reduce impacts on other road travelers (see section 4.10.2). Project construction activities could be visible and audible to hikers on the Oregon Coast Trail where it joins with the Trans-Pacific Parkway, but these impacts would be temporary and short term. Furthermore, this area is adjacent to a large-scale industrial plant (i.e., Roseburg Forest Products), a railroad, and a road. There are other current noise sources such as OHVs in the ODNRA that are much louder than pipeline construction noise. Therefore, pipeline construction should not significantly affect the trail use or experience.

Haynes Inlet

Coos Bay is used for recreational boating, canoeing, kayaking, angling, clamming, and crabbing, as discussed above in section 4.8.1.1. The Pacific Connector pipeline route would cross the Haynes Inlet portion of Coos Bay between about MPs 1.7R and 4.1R. Coos Bay is a Water of the State, with the bottom managed by ODSL. The pipeline crossing of Haynes Inlet is discussed in detail in section 4.4.2.

Exhibit 41

Top 10 Beach Strolls
Sunset, October 2007

Top 10 Beach Strolls

From uninhabited and windswept to sunny and bustling, a walk for every mood

1 PACIFIC RIM NATIONAL PARK RESERVE, B.C.

LONG BEACH This 10-plus-mile stretch of pristine, surf-swept sand near the towns of Tofino and Ucluelet on Vancouver Island is a beach trekker's paradise. Flanked by rolling Pacific waves and lush temperate rain forests, Long Beach feels like the misty edge of a new world; winter visits offer storm-watching opportunities as ferocious waves pound the shoreline. $6.55 U.S., $3.27 ages 6-16; off Provincial Hwy. 4 in Pacific Rim National Park Reserve; www.pc.gc.ca/pacificrim or 250/726-7721. -KIM GRAY

2 LANAI CITY, HI

SHIPWRECK BEACH A rusting World War II-era Liberty Ship, washed up on a reef, gives the name to this 9-mile stretch of sand and lava along Lanai's northeastern shore. On calm days, the water is crystal clear; other times, you'll be buffeted by strong trade winds, but they're a boon for beachcombers. It's not unusual to come across sea-sculpted driftwood, fishing nets, lobster cages, and the odd glass float. From Lanai City, go north on Lanai Ave. and bear right on Keomuku Rd. until the paved road ends, then follow the dirt road to the left for 2 ½ miles; 800/947-4774. -DAVID LANSING

3 MALIBU, CA

ZUMA COUNTY BEACH Whether you head southeast toward the promontory of Point Dume or northwest toward the oceanfront homes of the rich and richer at Broad Beach, you'll be treated to a sunsplashed cavalcade of surfers, dolphins, and volleyball players. Summertime or not, the living here is easy, and thanks to the well-packed sand along the shoreline, the walking is too. $6 per vehicle; off Pacific Coast Hwy., just west of Kanan Dume Rd.; www.labeaches.info or 310/305-3545. -MATTHEW JAFFE

4 PRAIRIE CREEK REDWOODS STATE PARK, CA

GOLD BLUFFS BEACH Five miles north of Orick, California's northern coast really struts its stuff. For 10 beautiful miles, Gold Bluffs Beach abuts Prairie Creek Redwoods State Park. Redwoods and Sitka spruces tower on bluffs, and agile Roosevelt elk graze behind dunes in meadows carpeted in wild strawberries. You can walk the desolate beach to Fern Canyon, where steep walls covered in ferns press in on a cobbled stream. $6 per vehicle; from US. 101 north of Orick, turn left on Davison Rd., then drive 2 miles to beach parking; parks.ca.gov or 707/465-7354. -KEN MCALPINE

5 NORTH BEND, OR

NORTH SPIT About 1 mile north of the mouth of Coos Bay, the rusting stern of the New Carissa, the most notorious of recent Oregon coast shipwrecks, looms above the surfline. It's an awesome sight best seen on a 4.2-mile round-trip walk over the dunes and down the beach on the North Spit. From U.S. 101 north of North Bend, turn west on Trans Pacific Lane, and follow it AVi miles to the trailhead; blm.gov/or/districts/coosbay or 541/756-0100. -BONNIE HENDERSON

6 PACIFIC GROVE, CA

ASILOMAR STATE BEACH The Monterey Peninsula's beauty is breathtaking and enormous. But the Coast Trail will rein in your focus, guaranteeing a walk full of discovery, especially at low tide. ...

Publication information: Article title: Top 10 Beach Strolls. Contributors: Not available. Magazine title: Sunset. Volume: 219. Issue: 4 Publication date: October 2007. Page number: 34+. © Sunset Publishing Corp. Provided by ProQuest LLC. All Rights Reserved.

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50 Next Great Towns List | Photo Gallery: Top Cities | Spotlight: Brattleboro, VT | Central | East | Rockies | West | Map: 16 Instant Adventures

50 Best Places to Live: The Next Great Adventure Towns

Published: September 2008

Where to Live + Play Now!

The fifty next great adventure towns.

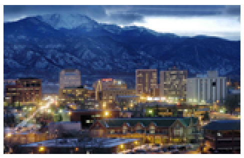
Text by Sarah Tuff and Greg Melville

A change of address can bring instant gratification. You could wake up tomorrow in Missoula and kayak off your own deck at dawn, sneak in singletrack at lunch in Chattanooga—or choose your own adventure in any one of the country's best base camps. But a move is a long-term investment. So this year we selected 50 innovative towns that aren't just prime relocation spots right now, but smart choices for the future. Not only do they have the action. They've got a plan. Now we're giving you a plan too. Inside, you'll find hometown picks that range from adventure 24/7 hubs loaded with outdoor options to urban players that offer a variety of jobs and cultural activities without sacrificing green space. You'll also hear from recent transplants who made the move and have a better quality of life to show for it. So go on—get packing. (Read the full coverage of these towns in the September 2008 issue, on newsstands August 12th.)

Plus: Take a digital tour of these towns with Nat Geo Map's Topo.com. See the maps >>

Here are the 50 next great adventure towns, presented by region and in no particular order (our top 12 picks are shown in bold). Plus: You can now post your comments on our picks in the area provided below.

WALLPAPER



My Shot Adventure Towns
Decorate your desktop with My Shot images of our top 50 places to live and play now.

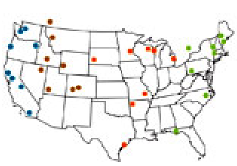
PHOTO GALLERY

Top 12 Towns Weekend Scouting Reports
Here's where to stay, play, and taste the local flavors in our top 12 cities.

BRATTLEBORO, VT

The Adventure Town Experiment
Brave is the couple willing to trade the "hippest neighborhood in America" for a shot at the Live + Play dream.

U.S. MAP INTERACTIVE



Next Weekend: Instant Adventures
Use this U.S. map to find 32 out-the-backdoor escapes.

WEST

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4. Girdwood, Alaska

5. Hood River, Oregon

6. San Francisco, California

7. Joshua Tree, California

8. Leavenworth, Washington

9. Arcata, California

10. Klamath Falls, Oregon

11. Bellingham, Washington

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Exhibit 42

https://kcby.com/news/local/after-a-year-of-planning-coos-bay-has-new-marine-patrol-boat-dock

After a year of planning, Coos Bay has new marine patrol boat dock

by KCBY
Wednesday, March 16th 2016

The recently completed Coos County Marine Patrol dock near Roseburg's (formerly Roseburg Forest Products) Jordan Cove property. (March 8, 2016)

COOS BAY, Ore. -- After a year of planning the Coos County Sheriff's Office now has a marine patrol boat dock in Coos Bay.

Roseburg Forest Products helped with building and financing the new dock on the North Spit.

Sheriff's deputies now have better access to the lower bay, where water rescues happen every summer.

"For the Sheriff's marine division to have a presence out there, they would have to go all the way out to Coquille, get their boat, bring it all the way back out here to the North

Spit, launch it and by the time they get ready to get on the water, it's usually too late," says Richard Dybevik with Roseburg Forest Products. "Now they'll have the ability to have a vessel on location in the lower bay. So it's more of a rescue rather than a collection."

Sheriff Craig Zanni says they also plan to use the dock for new kinds of training.

"We're going to be upgrading the training for all our deputies in boat handling. If LNG comes, there's going to be requirements for us to be able to respond in the bay and it requires better than just being a boat operator, but operating amongst other boats and doing some routine inspections and those types of things."

Dybevik says the lower bay is always crowded with boats during the summer.

He says he's as counted as many as 100 boats in that area at one time.

Exhibit 43

ATTORNEYS SERVING PRIVATELY HELD BUSINESSES AND THEIR OWNERS

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June 24, 2015

VIA U.S. MAIL & EMAIL
SDP.Comments@state.or.us

Andrea Goodwin
Oregon Department of Energy
625 Marion St. NE
Salem, OR 97301

Re: South Dunes Power Plant

Dear Ms. Goodwin:

This correspondence is being submitted on behalf of Oregon Dunes Sand Park, LLC ("Oregon Dunes") in response to the invitation for comments on the South Dunes Power Plant (the "Project") in advance of the Public Hearing to be held June 25, 2015. Oregon Dunes owns land containing The Box Car Hill Campground (the "Campground") adjacent to the proposed site for the Project. Such land might be considered "Noise Sensitive Property" under OAR 340-035-0015(38). Jordan Cove Energy Project, L.P. ("Jordan Cove") has submitted an Application for Site Certification ("ASC") in connection with its application to site, construct and operate the Project. As part of the ASC, Jordan Cove must make certain that the Campground ceases to be classified as a noise sensitive property. In order to accomplish this goal, Jordan Cove leased the Campground from Oregon Dunes.

In the ASC, Jordan Cove stated in Exhibit X, Page 2, that it leased the Campground pursuant to a 99-year lease agreement with Oregon Dunes. While this statement is accurate for the most part, it does not tell the complete story. The lease, which commenced January 1, 2015 and was set to expire on December 31, 2015, contains two options held by Jordan Cove. The first such option entitled Jordan Cove to send written notice to Oregon Dunes by March 1, 2015 extending the term of the lease to December 31, 2016. Jordan Cove exercised that option. The second option entitles Jordan Cove to send written notice to Oregon Dunes by March 1, 2016 extending the term of the lease to December 31, 2113. <u>Jordan Cove has not yet exercised this option</u>, however it still has the right to do so.

Thus, while Jordan Cove has the right to lease the Campground for 99 years, it is not currently obligated to do so. Currently, it is only obligated to lease the Campground until

December 31, 2016. Upon exercise of the remaining option under the lease, Jordan Cove will be obligated to lease the Campground until December 31, 2113 and will have the ability to control the uses on the site. However, if Jordan Cove does not exercise the remaining option on or prior to March 1, 2016 and the lease terminates, Oregon Dunes will again be permitted to use the Campground in a manner so that the Campground could be considered a noise sensitive property.

To ensure that no noise sensitive use can be operated on the Campground for the duration of the useful life of the Project, Jordan Cove will need to control the site for the duration of the Project. Accordingly, in the event the Project goes forward, it should only be permitted to do so subject to the condition that Jordan Cove be required to lease the Box Car Hill Campground until at least December 31, 2113. <u>This condition has not yet been satisfied.</u>

Thank you for your attention to this matter. If you have any questions or comments, or if you need anything further from us at this time, feel free to contact me.

Very truly yours,

MOTSCHENBACHER & BLATTNER LLP

Jeremy G. Tolchin

JGT/mm
cc: Todd Goergen
H:\TONY\OREDUN.2101\LLC.001\CORRESPONDENCE\A. GOODWIN 06.24.2015.DOCX5

Exhibit 44

http://today.oregonstate.edu/archives/2015/feb/study-outlines-threat-ocean-acidification-coastal-communities-us

Study outlines threat of ocean acidification to coastal communities in U.S.

Feb 23, 2015

CORVALLIS, Ore. - Coastal communities in 15 states that depend on the $1 billion shelled mollusk industry (primarily oysters and clams) are at long-term economic risk from the increasing threat of ocean acidification, a new report concludes.

This first nationwide vulnerability analysis, which was funded through the National Science Foundation's National Socio-Environmental Synthesis Center, was published today in the journal Nature Climate Change.

The Pacific Northwest has been the most frequently cited region with vulnerable shellfish populations, the authors say, but the report notes that newly identified areas of risk from acidification range from Maine to the Chesapeake Bay, to the bayous of Louisiana.

"Ocean acidification has already cost the oyster industry in the Pacific Northwest nearly $110 million and jeopardized about 3,200 jobs," said Julie Ekstrom, who was lead author on the study while with the Natural Resources Defense Council. She is now at the University of California at Davis.

George Waldbusser, an Oregon State University marine ecologist and biogeochemist, said the spreading impact of ocean acidification is due primarily to increases in greenhouse gases.

"This clearly illustrates the vulnerability of communities dependent on shellfish to ocean acidification," said Waldbusser, a researcher in OSU's College of Earth, Ocean, and Atmospheric Sciences and co-author on the paper. "We are still finding ways to increase the adaptive capacity of these communities and industries to cope, and refining our understanding of various species' specific responses to acidification.

"Ultimately, however, without curbing carbon emissions, we will eventually run out of tools to address the short-term and we will be stuck with a much larger long-term problem," Waldbusser added.

The analysis identified several "hot zones" facing a number of risk factors. These include:

- The Pacific Northwest: Oregon and Washington coasts and estuaries have a "potent combination" of risk factors, including cold waters, upwelling currents that bring corrosive waters closer to the surface, corrosive rivers, and nutrient pollution from land runoff;
- New England: The product ports of Maine and southern New Hampshire feature poorly buffered rivers running into cold New England waters, which are especially enriched with acidifying carbon dioxide;
- Mid-Atlantic: East coast estuaries including Narragansett Bay, Chesapeake Bay, and Long Island Sound have an abundance of nitrogen pollution, which exacerbates ocean acidification in waters that are shellfish-rich;
- Gulf of Mexico: Terrebonne and Plaquemines Parishes of Louisiana, and other communities in the region, have shellfish economies based almost solely on oysters, giving this region fewer options for alternative - and possibly more resilient - mollusk fisheries.

The project team has also developed an interactive map to explore the vulnerability factors regionally.

One concern, the authors say, is that many of the most economically dependent regions - including Massachusetts, New Jersey, Virginia and Louisiana - are least prepared to respond, with minimal research and monitoring assets for ocean acidification.

The Pacific Northwest, on the other hand, has a robust research effort led by Oregon State University researchers, who already have helped oyster hatcheries reboundfrom near-disastrous larval die-offs over the past decade. The university recently announced plans to launch a Marine Studies Initiative that would help address complex, multidisciplinary problems such as ocean acidification.

"The power of this project is the collaboration of natural and social scientists focused on a problem that has and will continue to impact industries dependent on the sea," Waldbusser said.

Waldbusser recently led a study that documented how larval oysters are sensitive to a change in the "saturation state" of ocean water - which ultimately is triggered by an increase in carbon dioxide. The inability of ecosystems to provide enough alkalinity to buffer the increase in CO_2 is what kills young oysters in the environment.

SOURCE:
George Waldbusser, 541-737-8964;
waldbuss@coas.oregonstate.edu

Exhibit 45

Vulnerability and adaptation of US shellfisheries to ocean acidification

Article *in* Nature Climate Change · February 2015

DOI: 10.1038/nclimate2508

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Ocean Conservancy

Joshua Cinner
James Cook University

nature climate change

PERSPECTIVE

PUBLISHED ONLINE: XX FEBRUARY 2015 | DOI: 10.1038/NCLIMATE2508

Vulnerability and adaptation of US shellfisheries to ocean acidification

Julia A. Ekstrom*†[1], Lisa Suatoni[2], Sarah R. Cooley[3], Linwood H. Pendleton[4,5], George G. Waldbusser[6], Josh E. Cinner[7], Jessica Ritter[8], Chris Langdon[9], Ruben van Hooidonk[10], Dwight Gledhill[11], Katharine Wellman[12], Michael W. Beck[13], Luke M. Brander[14], Dan Rittschof[15], Carolyn Doherty†[15], Peter Edwards[16] and Rosimeiry Portela[17]

Ocean acidification is a global, long-term problem whose ultimate solution requires carbon dioxide reduction at a scope and scale that will take decades to accomplish successfully. Until that is achieved, feasible and locally relevant adaptation and mitigation measures are needed. To help to prioritize societal responses to ocean acidification, we present a spatially explicit, multidisciplinary vulnerability analysis of coastal human communities in the United States. We focus our analysis on shelled mollusc harvests, which are likely to be harmed by ocean acidification. Our results highlight US regions most vulnerable to ocean acidification (and why), important knowledge and information gaps, and opportunities to adapt through local actions. The research illustrates the benefits of integrating natural and social sciences to identify actions and other opportunities while policy, stakeholders and scientists are still in relatively early stages of developing research plans and responses to ocean acidification.

The ocean has absorbed about 25% of anthropogenic atmospheric CO_2 emissions, progressively increasing dissolved CO_2, and lowering seawater pH and carbonate ion levels[1]. On top of this progressive global change in oceanic carbon conditions, local factors such as eutrophication[2,3], upwelling of CO_2-enriched waters[4] and river discharge[5] temporarily increase anthropogenic ocean acidification (OA)[6] in coastal waters[7–9]. Ocean acidification could primarily affect human communities by changing marine resource availability[1]. Studies have shown that, in general, shelled molluscs are particularly sensitive to these changes in marine chemistry[10–12]. Shelled molluscs comprise some of the most lucrative and sustainable fisheries in the United States[13]. Ocean acidification has already cost the oyster industry in the US Pacific Northwest nearly $110 million, and directly or indirectly jeopardized about 3,200 jobs[13]. The emergence of real, economically measurable human impacts from OA has sparked a search for regional responses that can be implemented immediately, while we work towards the ultimate global solution: a reduction of atmospheric CO_2 emissions. Yet there is little understanding about which locations and people will be impacted by OA, to what degree, and why, and what can be done to reduce the risks.

Here, we present the first local-level vulnerability assessment for ocean acidification for an entire nation, adapting a well-established framework and focusing on shelled mollusc harvests in the United States; for other evaluations of OA social vulnerability, see refs 14–16. We explored three key dimensions—exposure, sensitivity and adaptive capacity (Fig. 1, Supplementary Fig. S1)—to assess the spatial distribution of vulnerable people and places to OA. The underlying assumption guiding this assessment is that addressing existing vulnerability can reduce future vulnerability to OA, sometimes called 'human-security vulnerability'[15].

Exposure of marine ecosystems addresses acidification driven by global atmospheric CO_2 and amplified by local factors in coastal waters. We divided the coastal waters around the United States into existing National Estuary Research Reserve System bioregions[17] (Supplementary Fig. S7), and for each bioregion, examined: (1) projected changes to ocean chemistry based on a reduction in aragonite saturation state (Ω_{Ar}) (Supplementary Fig. S2), and (2) the prevalence of key local amplifiers of OA, including upwelling, eutrophication and input of river water with low-aragonite saturation state [**AU: OK?**], for each bioregion (Supplementary Figs S4–S6). Aragonite saturation state (Ω_{Ar}) is a measure of the thermodynamic stability of this mineral form of calcium carbonate that is used by bivalve larvae and other molluscs, which is also commonly used to track OA[1]. Declining Ω_{Ar} makes it more difficult and energetically costly for larval bivalves to build shells even before Ω_{Ar} becomes corrosive [**AU: is it Ω_{Ar} that becomes corrosive, or should this be OA?**], and Ω_{Ar} seems to be the important variable for the most sensitive early stage of bivalve larvae[18]. We evaluated relative exposure to anthropogenic OA as the time [**AU: i.e. 'time until', or 'the**

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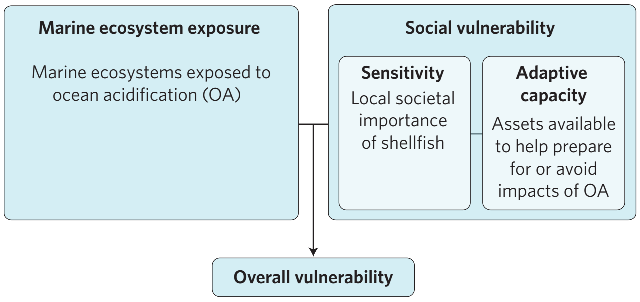

Figure 1 | Conceptual framework structuring the analysis of vulnerability to ocean acidification. Vulnerability analyses can focus on three key dimensions (exposure, sensitivity and adaptive capacity): (1) the extent and degree to which assets are exposed to the hazard of concern; (2) the sensitivity of people to the exposure; and (3) the adaptive capacity of people to prepare for and mitigate the exposure's impacts. These three dimensions together provide a relative view of a place's overall vulnerability. Adapted conceptual model components from refs 16,52–55.

extent of time for which'?] mean annual surface seawater exceeds an empirically informed absolute Ω_{Ar} threshold for several species of bivalve larvae. This indicator for disruption to the biological processes of calcification and development in larval molluscs was favoured over alternatives (for example time until the historic range of Ω_{Ar} is exceeded) because the biological mechanism was clear[19] and empirical evidence exists[20]. For comparison purposes, the Supplementary Information includes the time until the historic range of Ω_{Ar} is exceeded (Supplementary Fig. S3), but below we document the outcomes based on the Ω_{Ar} threshold projections and local amplifiers of OA.

Sensitivity of social systems was evaluated at the scale of 'clusters of coastal counties' around the United States, using three indicators of community dependence on shellfish, adapted from the National Marine Fisheries Service's fishing community vulnerability and resilience index[21]: (1) the 10-year median landed value of shellfish (including both wild and aquaculture harvests); (2) the 10-year median proportional contribution of shellfish to total value of commercial landings; and (3) the 5-year median number of licences (representing jobs) supported by shelled mollusc fishing (Supplementary Information). Sensitivity indicators were re-scaled and combined into a single index (Supplementary Information and Supplementary Fig. S8).

Adaptive capacity of social systems to cope with and adapt to OA is represented by three classes of indicators: status of state government climate and OA policies, local employment alternatives and availability of science. We examined a total of six indicators representing adaptive capacity that are derived largely from the broader economic and policy landscape, yet are directly relevant for dealing with the threat of OA (Supplementary Fig. S9). This is a deliberate departure from studies conducted at broader and finer geographic scales that use general demographic indicators (see Supplementary Information). We assessed 'potential government support for adaptation' through measures of: (1) the status of state legislative action on OA and (2) the status of state climate adaptation planning. These indicators reflect social organization and assets at the state jurisdictional level that could be used by communities to adapt to, cope with, or avoid the impacts of lost shellfish harvests. We examined aspects of employment alternatives through: (3) the diversity of shelled mollusc harvests, suggesting potential alternative shellfish that could be harvested and (4) the diversity of non-shellfish-related employment industries. These reflect the likelihood of job alternatives for shellfish harvesters and those in the aquaculture industry. Finally, we captured 'access to and availability of science' through (5) a score for marine laboratories developed to take into account the high local influence that such laboratories can have as well as the potential contribution beyond their immediate vicinity. For each county cluster, a metric based on the number of university marine laboratories (on-campus and satellite laboratories) in that county cluster was averaged with a metric based on the total number of university marine laboratories in that state (see Supplementary Information for more information) and (6) Sea Grant state budgets normalized by shoreline length. These indicators represent the availability of local scientific capacity, the potential for troubleshooting assistance, and the possibility of access to a range of tools and data products, such as available early warning information. We attributed each county cluster (as used in Sensitivity) to each variable score of the six indicators. We then combined into a single index by averaging re-scaled (0–1) overall component scores for sensitivity and adaptive capacity (Supplementary Information Fig. S9). Coincidence of high marine ecosystem exposure to OA with high sensitivity and low adaptive capacity of social systems reveals the areas at highest overall vulnerability to OA.

Places vulnerable to ocean acidification

Our results show that 16 out of 23 bioregions around the United States are exposed to rapid OA (reaching Ω_{Ar} 1.5 by 2050) or at least one amplifier (Fig. 2; Supplementary Table S1); 10 regions are exposed to two or more threats of acidification (note that Alaska and Hawaii are missing local amplifier data; Fig. 2). The marine ecosystems and shelled molluscs around the Pacific Northwest and Southern Alaska are expected to be exposed soonest to rising global OA, followed by the north-central West Coast and the Gulf of Maine in the northeast United States. Communities highly reliant on shelled molluscs in these bioregions are at risk from OA either now or in the coming decades. In addition, pockets of marine ecosystems along the East and Gulf Coasts will experience acidification earlier than global projections indicate, owing to the presence of local amplifiers such as coastal eutrophication, upwelling and discharge of low-Ω_{Ar} river water (see Supplementary Figs S4–S6, Supplementary Table S1).The inclusion of local amplifiers reveals more coastline segments around the United States that are exposed to acidification risk than when basing exposure solely on global models.

Combining sensitivity and adaptive capacity reveals that the most socially vulnerable communities are spread along the US East Coast and Gulf of Mexico (Fig. 2), yet the sources of high social vulnerability are very different between these two regions (see Supplementary Information for breakdown separated by sensitivity and adaptive capacity, Figs S8 and S9). Specifically, the East Coast is dominated by high levels of sensitivity, or economic dependence, from strong use of shellfish resources. For example, southern Massachusetts measures as having the highest sensitivity. This county cluster ranks in the top four for all three sensitivity indicators (Supplementary Fig. S8), meaning that this area has the highest mollusc harvest revenues of any coastal area in the United States, second highest number of licences and fourth highest proportion of seafood revenues coming from molluscs. In contrast, the Gulf of Mexico region is socially vulnerable from low adaptive capacity, owing to social factors such as low political engagement in OA and climate change, low diversity of shellfish fishery harvest and relatively low science accessibility (Supplementary Fig. S9).

Importantly, our visually combined overall vulnerability analysis reveals that a number of socially vulnerable communities lie adjacent to water bodies that are exposed to a high rate of OA or at least one local amplifier, indicating that these places could be at high overall vulnerability to OA (Fig. 2). The areas that are exposed to OA (including local amplifiers) and high and medium–high social vulnerability coincide include southern Massachusetts, Rhode Island, Connecticut, New Jersey and portions around the

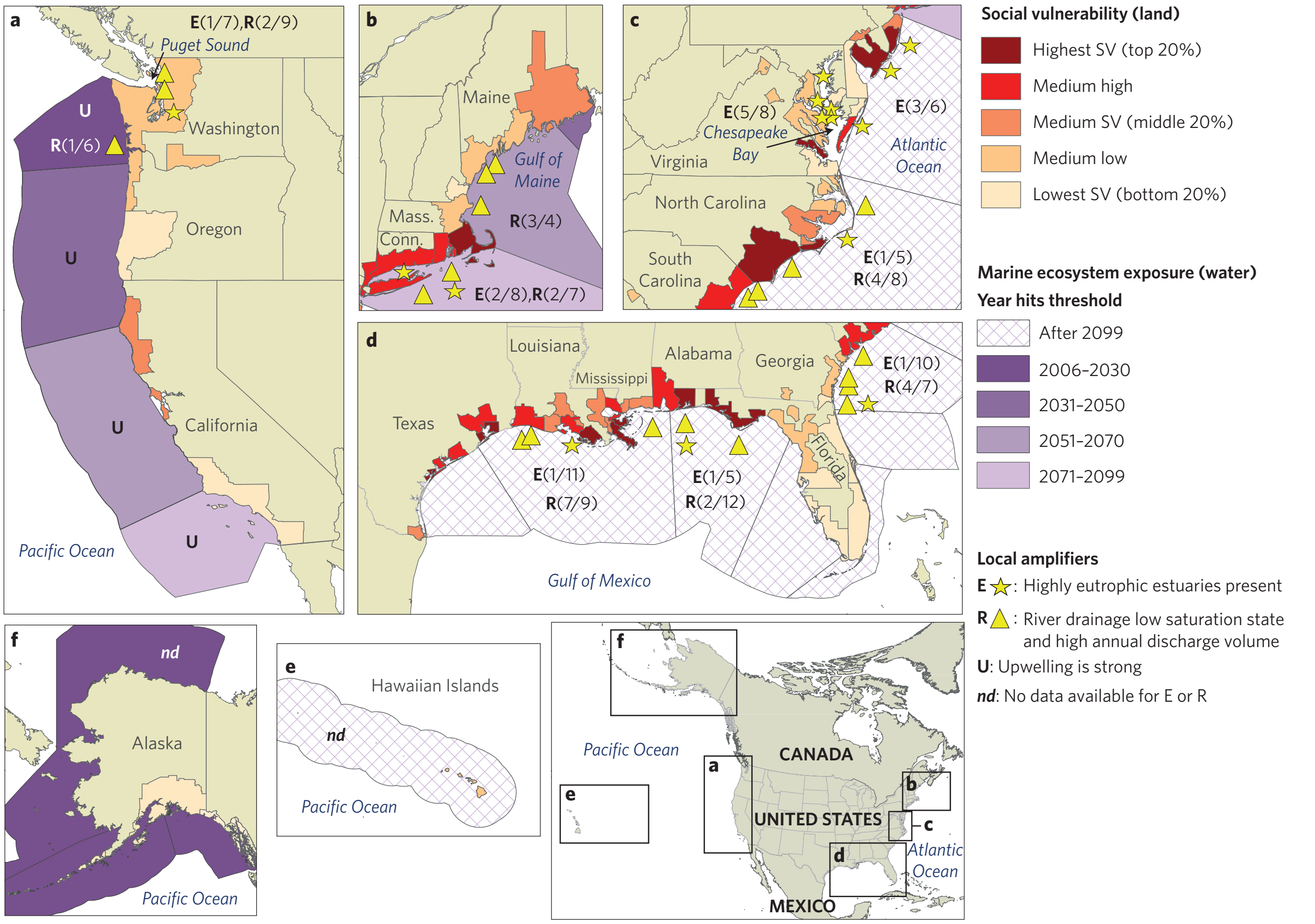

Figure 2 | Overall vulnerability of places to ocean acidification. Scores of relative social vulnerability are shown on land (by coastal county cluster) and the type and degree of severity of OA and local amplifiers to which coastal marine bioregions are exposed, mapped by ocean bioregion: (a) contiguous US West Coast; (b) Northeast; (c) Chesapeake Bay; (d) Gulf of Mexico, and Florida and Georgia's coast; (e) Hawaii Islands; and (f) Alaska. Social vulnerability (red tones) is represented with darker colours where it is relatively high. Exposure (purple tones) is indicated by the year at which sublethal thresholds for bivalve larvae are predicted to be reached, based on climate model projections using the RCP8.5 CO_2 emission scenario[27]. Exposure to this global OA pressure is higher in regions reaching this threshold sooner. Additionally, the presence and degree of exposure to local amplifiers of OA are indicated for each bioregion: E(*x*/*y*) marks bioregions [**AU: OK?**] in which highly eutrophic estuaries are documented, *x* is the number of estuaries scored as high, and *y* is the total number evaluated in each bioregion (source: ref. 56), locations of highly eutrophic estuaries are marked with a star; R(*x*/*y*) marks bioregions in which **sampled river water draining into bioregion scored** [**AU: this description is not clear grammatically: should it be 'bioregions in which... water was scored', or is something missing here? Also, does 'scoring in the top quintile' here mean top quintile of discharge volume only? Please clarify phrasing**] based on very low saturation state and high annual discharge volume (top quintile, calculated by authors from US Geological Survey[57]), *x* is the number of rivers scoring in the top quintile of those evaluated, and *y* is the total number evaluated in this study. Approximate locations of river outflows of those rivers scoring in the top quintile are marked with a delta [**AU: a yellow triangle?**]; and U marks bioregions where upwelling is very strong in at least part of the bioregion (source: ref. 58).

Chesapeake Bay, the Carolinas, and areas across the Gulf of Mexico (Fig. 2b–d). Interestingly, global ocean models that project the advance of OA, primarily as a result of atmospheric CO_2, do not reveal these areas as exposed to global OA until after 2099, based on our study's Ω_{Ar} threshold (Table 1). The marine ecosystem exposure in the areas located along the Atlantic coast and the Gulf of Mexico is from low-Ω_{Ar} conditions caused primarily by the addition of river water and eutrophication, local factors that have only more recently been considered major amplifiers of nearshore acidification[6,7]. These coastal processes are likely to tip coastal oceans past organism thresholds as atmospheric CO_2 uptake continues in the future (see ref. 22). Although the Pacific Northwest, northern California and Maine exhibit only medium and medium–low social vulnerability (Fig. 2a,b), these areas are particularly economically sensitive and lie adjacent to marine ecosystems highly exposed to global OA[23,24] (sensitivity, Supplementary Fig. S8). This profile of relatively high dependency and high exposure in these three regions has already activated significant research and local action/engagement among local scientists, government and shellfish growers (see for example refs 25,26). This engagement has driven up adaptive capacity (based on our study's indicators) in these areas, which reduces their social vulnerability relative to other regions across the United States. In comparison, the lower level of OA-related action in other regions such as the Gulf of Mexico (Fig. 2d), Massachusetts (Fig. 2b) and Mid-Atlantic (Figs 2c,d) with high overall vulnerability profiles might be partly because their marine ecosystem exposure is dominated by the presence of local OA amplifiers rather than global OA (Supplementary Fig. S2, Supplementary Table S1). At the same time, some of these areas (for example Maryland) do have strong advocates for addressing water quality which could provide an opportunity to address locally driven acidification as awareness of the issue grows.

[AU: Please indicate where Table 2 should be cited in the text.]

Table 1 | Indicators of drivers and amplifiers of ocean acidification, and the criterion for each used in this study.

Factors causing and amplifying OA (reducing Ω_{Ar})	Indicator	Scoring scale	Criterion for ranking the risk factor as 'high'
Rising atmospheric CO_2 reduces Ω_{Ar} causing chronic stress to shelled mollusc larvae	Projected year that surface water will reach $1.5\Omega_{Ar}$ (ref. 27)	Continuous scale from current year to 2099	$1.5\Omega_{Ar}$ threshold reached by 2050
Eutrophication increases pCO_2 locally via respiration, leading to reduced Ω_{Ar}	Degree of eutrophication[56]	Eutrophication scored on a five-point scale: low to high	Presence of a high-scoring eutrophic estuary in bioregion
River water can reduce Ω_{Ar} locally in coastal waters	Combined metric of river's aragonite saturation state and annual discharge volume	Rivers scored on a five-point scale: low to high	Presence of high scoring river (for low aragonite saturation and high discharge volume) in bioregion
Significant seasonal upwelling delivers water rich in CO_2 to shallow waters, leading to reduced Ω_{Ar}	Degree of upwelling[58]	Coastal zones scored on a five-point scale: low to high	Presence of high upwelling zone in bioregion

Table 2 | Indicators representing 'sensitivity' (people's dependency) on organisms expected to be affected by ocean acidification (in this study, shelled molluscs).

Indicator or measure	Source	Raw format	Processing for subindex
Landed value (median of 10 years)	Regional fisheries databases (ACCSP, GulfBase, PacFIN), and States of Alaska and Hawaii	US dollars, annual	Calculated median for years 2003–2012 Winsorized the top 10%
Percentage of shellfish by value **[AU: i.e. as percentage of all fish caught?]** (median of 10 years)		For each year: shelled molluscs value/total commercial landed value	Divided landed value of shellfish by landed value of all fish Winsorized the top 10%
Number of licences as proxy for jobs (median over 5 years)		Number of commercial licences, annual	Winsorized the top 10%

All indicators are in units of county clusters.

Robustness of analysis

To examine the robustness of these spatial patterns of vulnerability, we varied the index aggregation methodology and the selection of indicators. To test the difference in index aggregation methods for social vulnerability, we compared the output of adding and multiplying sensitivity and adaptive capacity indices and found little difference; the same set of county clusters made up the top 10 most socially vulnerable places using either aggregation method.

To explore the effect of indicator selection on adaptive capacity (and thus social vulnerability), we compared a set of commonly used generic indicators for adaptive capacity relating to income, poverty, education and age with the set of threat-specific indicators developed for this study (see Table 3 and Supplementary Figs S10 and S11). Using the generic capacity measures to calculate social vulnerability, we found that six of the same county clusters measured within the top 10 highest socially vulnerability places in the United States as those found using the threat-specific indicators (see Supplementary Information for analysis and maps). This is considerable overlap given that the two sets of variables indicate entirely different notions of adaptive capacity. Because the sensitivity indicators were developed and vetted by fisheries social science researchers[21] and alternative potentially appropriate data were not available nationwide, we did not have a useful comparison for this element from which to draw.

To explore the criterion for Ω_{Ar}, we examined one alternative for disruption of biological processes with respect to rising atmospheric CO_2: the time until average surface waters move outside the present range of Ω_{Ar} (that is, exceeding a historic envelope)[27]. The map generated by this 'historic envelope' approach shows that southern areas experience potential OA exposure earlier, which is nearly an inverse pattern to our chosen criterion of a chemical threshold when calcification and development of larval molluscs may decrease (Supplementary Fig. S3). This difference in patterns is because natural variability is much smaller in southern regions, although evidence of greater sensitivity in populations of bivalves that live in tropical and subtropical waters is lacking. This discrepancy underscores the need for targeted research integrating a physiological, ecological and evolutionary perspective on the potential and limitations of strong local biological adaptation to different carbonate regimes for commercially valuable shelled mollusc populations.

Overall, we found that variable selection has stronger effects than aggregation methods, which provides high confidence in our aggregation methods for social vulnerability. The differences found in variable selection identify research needs relating to what factors underlie vulnerability on the ground that are relevant to OA; this conversation has only just begun.

Opportunities to reduce vulnerability to ocean acidification

Social–environmental syntheses, including vulnerability analyses, can help to identify opportunities for actionable solutions to address the potential impacts of ocean acidification. Our analysis reveals where and why the overall vulnerability from OA varies among the many coastal areas of the United States, and thus identifies opportunities to reduce harm.

One way to tackle OA is by reducing marine ecosystem exposure to it. Several portions of the east coast are highly exposed to OA from high levels of eutrophication (Fig. 2b–d). In addition to releasing extra dissolved CO_2 and enhancing acidification, eutrophication can also decrease seawater's ability to buffer further acidification[3]. People in these regions are uniquely positioned to reduce exposure to OA through regional actions by curtailing eutrophication (as compared, for example, with regions exposed to upwelling). Although a significant challenge, reducing nutrient loading to the coastal zone in these areas could provide multiple benefits, making it a no-regrets option. Reducing eutrophication can decrease hypoxia and harmful algal blooms, in addition to reducing risk from fossil-fuel-derived OA at the local and regional level. Policy

Table 3 | Threat-specific indicators used to assess capacity of fishing communities to deal with impacts of ocean acidification.

Group	Indicator	Source	Raw format	Processing for subindex
Access to scientific knowledge	Budget of Sea Grant programmes	National Sea Grant	State-level total funds of budget (state and federal contributions combined, 2013)	• Re-scaled (0–1) • Attributed normalized scores to each county cluster
	Number of university marine laboratories	Direct count from registries and Internet	Latitude/longitude location of laboratories	• Combined score of laboratories per state/ shoreline length and labs per county cluster
Employment alternatives	Shelled mollusc diversity	Regional fisheries databases (ACCSP, GulfBase, PacFIN), and States of Alaska and Hawaii	Ratio of landing revenues for each taxon by county cluster	• Calculated Shannon Weiner Diversity Index
	Economic diversity	ACS Census	Proportion of county population employed in each industry	• Calculated Shannon Weiner Diversity Index for county clusters
Political action	Legislative action for OA	Keyword searches on legislature websites and follow-up calls	Established five-point scale for state's legislative progress on OA	• Re-scaled 0–1 • Attributed score to county clusters
	Climate adaptation planning	Georgetown Law School Climate programme website	Status of climate adaptation plan for state	• Re-scaled 0–1 • Attributed score to country clusters

See Supplementary Information for discussion and presentation of alternative indicators and measures.

instruments to reduce eutrophication exist in the United States[28] and can be leveraged to facilitate efforts to reduce OA[8].

Another important way to combat the effects of OA will be by reducing social vulnerability. In regions where high sensitivity (one component of social vulnerability) arises from the structure of the fishing industry, an entirely different approach to adaptation may be more appropriate than those geared to reduce marine ecosystem exposure. For example, where fishery harvest portfolios are dominated by a single species, such as in the Gulf of Mexico where mollusc production is limited to the eastern oyster (*Crassostrea virginica*), diversification of the species harvested might be a beneficial strategy.

A further way to reduce social vulnerability may be by increasing adaptive capacity of people and regions. Access and availability to science already has helped shellfish aquaculturists in the Pacific Northwest to identify and avoid some of the consequences of OA[20]. Working with local scientists, hatcheries have implemented several strategies to adapt and mitigate OA effects on bivalve seed production. Through local industry–research partnerships in the Pacific Northwest, implementation of real-time monitoring of saturation state, chemical buffering of water, changes in timing of seasonal seed production and use of selectively bred lines of oyster broodstock, this collaboration has prevented collapse of the regional oyster industry.

In every case, when developing a broader array of adaptation strategies, it is critical to work directly with the coastal communities in each region so they can develop context-appropriate and feasible adaptation options. Targeted projects to develop local adaptation plans may even require developing further regionally relevant indicators of adaptive capacity and community resilience that this nationwide study does not capture. In fact, zooming in to assess particular regions at a higher resolution would enable regional stakeholders to provide input into a possible different set of variables that defines vulnerability in their particular region based on values and social or economic context.

Barriers to and path forward for addressing OA

This study offers the first nationwide vulnerability assessment of the spatial distribution of local vulnerability from OA focusing on a valuable marine resource. But it is just a first step to understanding where and how humans and marine resources are at highest risk to OA and its local amplifiers. Another key finding of this assessment is that significant gaps in the scientific understanding of coastal ocean carbonate dynamics, organismal response and people's dependence on impacted organisms limit our ability to develop a full suite of options to prepare for, mitigate and adapt to the threats posed by OA, and these can be considered in a structured way using the framework (Fig. 3). The types of gaps identified—as commonly classified in information science and other disciplines[29,30]—range from data inaccessibility to knowledge deficiencies.

Marine ecosystem exposure. Key gaps remain in understanding how global and local processes interact to drive nearshore OA, and how this will affect marine organisms and ecological systems. Recent studies suggest that the biogeochemical interaction between global OA and local amplifiers is additive[3,22,31]; however, most ocean models used to project future OA cannot adequately resolve these processes, which are also increasingly affected by human activity[7,32]. Even though direct measurements incorporate an ever-growing global network of monitoring instruments, they are often located offshore and remain too sparse in space and time to resolve the dynamics of seawater chemistry near shore, where most shellfish live. Historically, OA monitoring has focused on offshore regions, where long-term, high-accuracy and precise measurements enabled detection and attribution of the rising atmospheric CO_2 acidification signal. But many commercially and nutritionally important organisms live in the coastal zone where they experience the combined effects of multiple processes that alter the carbonate chemistry[7]. This results in greatly variable 'carbonate weather' for a given location[33]. Characterizing this variation, including modelling how rising atmospheric CO_2 will increase the frequency, duration and severity of extreme events **[AU:OK?]**, would provide a fuller picture of how OA is unfolding within the dynamic coastal waters.

To improve our understanding of which marine ecosystems and organisms are most susceptible to ocean acidification, additional information on the Ω_{Ar} thresholds below which reproduction and survival are disrupted is needed. In the US context, the

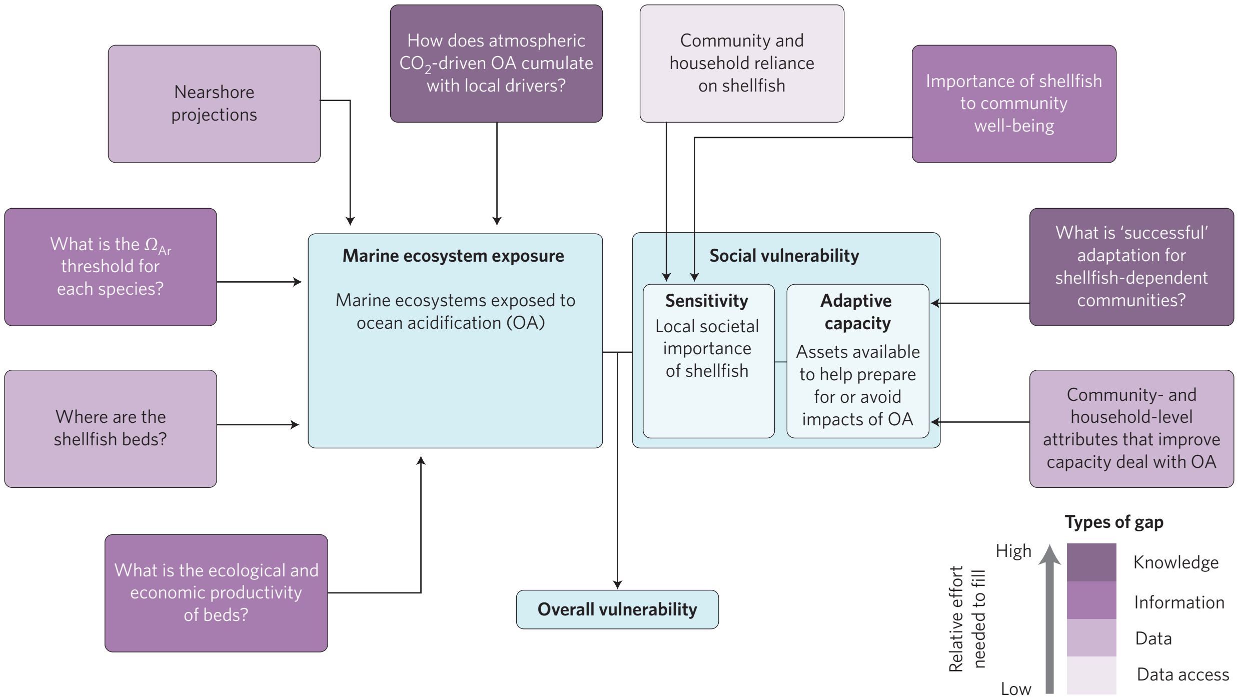

Figure 3 | Sample of gaps in knowledge related to OA vulnerability, information and data organized around components of the framework. Different types of gaps are classified by the level of effort that is required to fill them (gaining knowledge is the most challenging, whereas data access tends to be the most straightforward).

concentration of value in a limited number of shellfish species means that the identification of biologically susceptible and resistant species and populations is both prudent and feasible. Based on total landed value from 2003 to 2012, approximately 95% of shelled-mollusc revenues in the United States come from only 10 species (and 80% from five). These species include sea scallop (52.9%), eastern oyster (11.3%), Pacific geoduck (5.8%), Pacific oyster (5.2%) and six species of clam (that range from 5% to 2.6% of total value)[34]. There is some evidence of local biological adaptation of other marine taxa to varying carbonate chemistry regimes[35–37]. This potential genetic variation, if present, could be documented to aid in the development of resistant strains of cultured or other organisms.

Social vulnerability. Our study also revealed large gaps in information about mollusc-dependent communities to inform measures of social vulnerability. We do not have high-resolution nationwide data on the full cultural and societal significance of shelled molluscs. Even data on the contributions of shellfish to human nutrition, shoreline protection, and water filtration were inadequate nationwide. Incorporation of these other ecosystem services provided by molluscs could alter the social vulnerability landscape. For the commercial fisheries data that we did obtain, confidentiality constraints forced us to aggregate our analysis into county clusters, preventing county-specific or port-level analyses of social vulnerability that might have revealed more spatial heterogeneity. We also lack social science data that describe use at species-, human community-, port- or household levels. We lack data on the value chain that links threatened organisms to harvesters, processors and end-users. Finally, empirically tested adaptive capacity measures could contribute to a more rigorous evaluation of social vulnerability. This includes data on scientific spending and infrastructure directly relevant to end-users, as well as social and demographic data that are reflective of end-users (for this study, fishing and aquaculture communities) and not the general population (for example generic indicators quantifying education and income).

Beyond helping in prioritizing and developing adaptation strategies, social science is also useful to inform and guide planning for social adaptation and mitigation. As with climate change adaptation, preparing for and adapting to the impacts of OA is a social process[1,38,39]. Implementation does not occur automatically once strategies are developed, but instead must often overcome a suite of institutional (including legal), political, psychological and other types of barriers[40]. As learned from climate change initiatives, the 'softer side' of adaptation (such as coordination among stakeholders, industry and scientists) is the first step towards preparing for a threat like OA[41]. Despite its fundamental importance, this type of effort is often overlooked and remains underfunded. Social science can also help practitioners even in early stages of adaptation figure out how to engage public and policy-makers effectively in OA issues[42–44]. Farther along in adaptation processes, social science can inform the development of strategies by accounting for social values[45,46] and existing property rights in use and norms[47,48] and even helping to work out what type of information is salient for and trusted by decision-makers[49,50]. Although important for reducing its risks, social science relevant for understanding OA has been minimal thus far. A budget assessment conducted by the Interagency Working Group on Ocean Acidification reported that federal research in fiscal year 2011 allocated $270,000 of Federal funds for social science research related to OA, which represents 0.9% of the entire OA spending for that year's budget[51].

Conclusions
As with other global environmental changes, acidification of the oceans is a complex and seemingly overwhelming problem. Here we have focused only on OA (and nearshore amplifiers) as the threat to coastal species. Although other stressors also threaten coastal ecosystems, our single-threat assessment allows us to tease out where OA in isolation could hit people and organisms the hardest, which can inform research agendas and decision-making geared specifically to address OA. A vulnerability framework helps to structure our thinking about the ways in which ocean acidification will affect

ecosystems and people. The framework also helps to identify and organize the opportunities and challenges in dealing with these problems. But this study is the beginning; adaptation to OA and other global environmental change is an iterative process that requires both top-down and bottom-up processes. Our analysis of OA as it relates to [**AU: OK?**] US shelled mollusc fisheries makes clear just how much the pieces of the OA puzzle vary around the country. Marine ecosystem exposure, economic dependence and social capacity to adapt create a mosaic of vulnerability nationwide. An even more diverse set of strategies may be needed to help shellfish-dependent coastal communities adapt to OA. Rather than create and apply a nationwide solution, decision-makers and other stakeholders will have to work with fishing and aquaculture communities to develop tailored locally and socially relevant strategies. Meaningful adaptation to OA will require planning and action at all levels, including regional and local levels, which can be supported with resources, monitoring, coordination and guidance at the national level.

Over the past decade, scientists' understanding of ocean acidification has matured, awareness has risen and political action has grown. The next step is to develop targeted efforts tailored to reducing social and ecological vulnerabilities and addressing local needs. Tools like this framework can offer a holistic view of the problem and shed light on where in the social–ecological system to begin searching for locally appropriate solutions.

Received 22 August 2014; accepted 19 December 2014; published online xx February 2015.

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Acknowledgements

This work was supported by the National Socio-Environmental Synthesis Center (SESYNC) under funding received from the National Science Foundation DBI-1052875. Support for R.v.H. to generate model projections was provided by NOAA's Coral Reef Conservation Program. We thank the institutions and individuals that provided data (see Supplementary Information for full details), and W. McClintock and his laboratory for use of SeaSketch.org to enable collaborative discussions of spatial data and analysis. We are grateful for the contributions and advice provided by E. Jewett throughout the project.

Author contributions

All authors provided input into data analysis and research design, and participated in at least one SESYNC workshop; J.A.E. led the drafting of the text with main contributions from L.S., S.R.C., L.H.P., G.G.W. and J.E.C.; R.v.H. contributed projections of ocean acidification; J.A.E., L.S., S.R.C., J.R. and C.D. collected the data; J.A.E. carried out data analysis and mapping.

Additional information

Supplementary information is available in the online version of the paper. Reprints and permissions information is available online at www.nature.com/reprints. Correspondence should be addressed to J.A.E.

Competing financial interests

The authors declare no competing financial interests. [**AUTHORS: OK?]**

EXHIBIT 46

https://newfoodeconomy.org/ocean-acidification-oysters-dungeness-crabs/

The ocean is changing faster than it has in the last 66 million years. Now, Oregon oysters are being farmed in Hawaii. That fix won't work forever.

November 28th, 2017
by H. Claire Brown

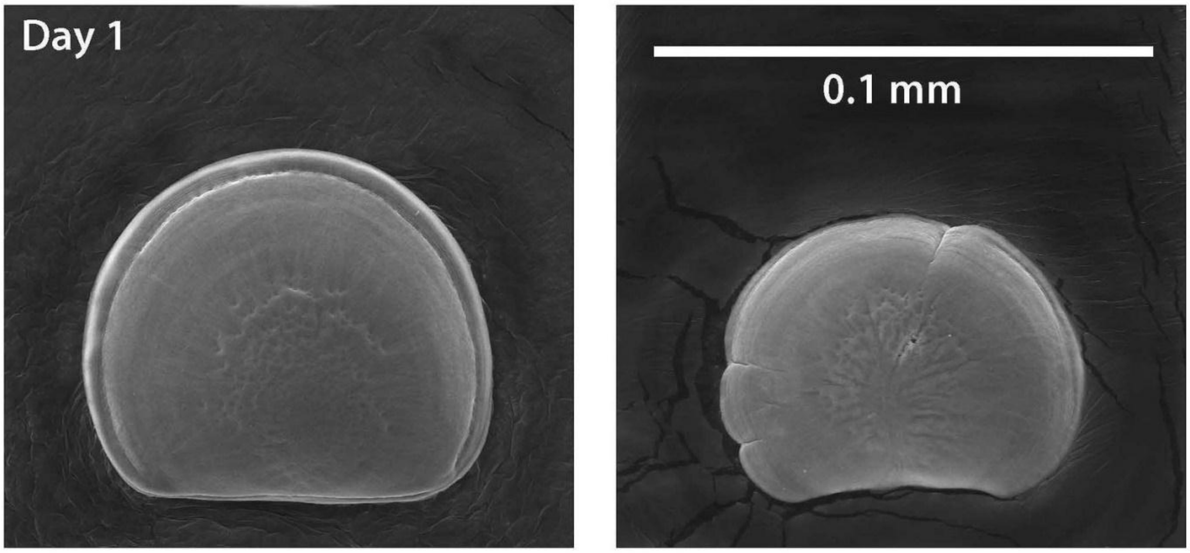
A little more than ten years ago, a mysterious epidemic wiped out baby oyster populations. It started in 2006, when Whiskey Creek shellfish hatchery in Oregon lost 80 percent of its cultured larvae. Around the same time, 200 miles north in Washington, Taylor Shellfish saw similarly high mortality rates. And oysters in the wild weren't faring much better: Oystermen who usually sourced larvae from Washington's Willapa Bay, one of the largest natural oyster-producing estuaries in the country, weren't finding enough stock to seed their beds.

It wasn't long before the epidemic migrated to the East Coast. In the Gulf of Maine, hatchery owner Bill Mook began to notice larval die-offs and slowed growth rates following big storms that pumped fresh water into his hatchery starting in 2009. Sometimes, the surviving organisms were severely deformed. No one knew exactly what had gone wrong.

After two years of massive losses, scientists discovered what was really wrong.

Suspecting bacterial infection or a problem with the feed, Whiskey Creek and Taylor Shellfish invested in machines that kill *vibrio tubiashii,* a bacteria that is a common culprit in oyster larvae die-offs. Survival rates didn't improve.

But after two years of massive losses and no answers, scientists testing the waters discovered what was really wrong: the ocean water flowing into the hatcheries had changed, and the oysters weren't able to build their shells. Without shells, they couldn't survive.



Flickr / Oregon State University

Oyster larvae in normal conditions (left) versus oyster larvae in acidified conditions (right)

Larval oysters experience a crucial phase in their life cycle where they morph from a form not unlike free-floating dust particles into lentil-sized bivalves with the beginnings of a shell. In order to start building that shell, the larvae need to use carbonate ions from their surroundings. But seemingly all of a sudden, the ocean waters flowing into the hatcheries on the Pacific Coast had a lower concentration of carbonate ions than usual, meaning the larvae missed the dust-to-lentil growth phase that turns them into tiny oysters. As a result, most of them died.

But why had the carbonate ions dipped in the first place? Researchers discovered that the underlying cause was more than a couple years of bad luck or a minor disturbance in tidal patterns. In the mid-aughts, a global shift, which had been quietly altering the ocean's chemistry for hundreds of years, had finally washed up on the shores of the Pacific Coast. And oyster larvae, some of the most vulnerable, valuable, and closely-monitored creatures in the sea, were the first recognized victims of a process that had already started to affect aquatic life across the globe: ocean acidification, a climate change-related process that is gradually lowering pH levels in the water that covers 97 percent of the earth.

It took a human story to get the public and local representatives to pay attention to the problems at hand.

The Whiskey Creek hatchery story made the front page of the *Seattle Times* in 2009. Several years later, in 2013, the Royal Swedish Academy of Sciences published a report analyzing the media's treatment of the Whiskey Creek oyster die-offs. In that paper, the authors took a look at the relationship between the hatcheries, the media, and scientific research. What they found was that, at the time of the die-offs, a "landmark" paper had already been published by researchers at Seattle's Pacific Marine Environmental Library showing that ocean acidification was impacting the Pacific Northwest. Which means scientists *knew* the problem was a real threat, but the public hadn't yet caught on. It wasn't the authoritative research paper that got people to pay attention. It was the loss of the seed stock for an entire sector of the economy.

The researchers found that it took a human story—a $136 million industry in the United States, employing thousands of people, turned on its head—to get the public and local representatives to pay attention to the problems at hand. Years of scientific papers couldn't accomplish what the Whiskey Creek story demonstrated in short order: When people's lives are affected, legislators hear about it. Washington's then-governor Christine Gregoire soon formed a Blue Ribbon Panel on Ocean Acidification. The panel made policy recommendations, ultimately positioning Washington State as a national leader in ocean acidification research and planning.

Flickr / Louisiana Sea Grant College Program Louisiana State University

Oyster hatcheries raise larvae into seed oysters, pictured above, then sell them to farmers. Once an oyster as reached this size, it can survive in acidified conditions

But despite one state government's proactive stance on changing seas, ocean acidification-related problems have continued to creep toward other parts of the seafood industry. And now, researchers find themselves racing to grasp the implications of a tangled underwater web that includes global warming, ocean acidification, natural seawater patterns, long-term weather events like El Niño and La Niña, and changing fishery management practices.

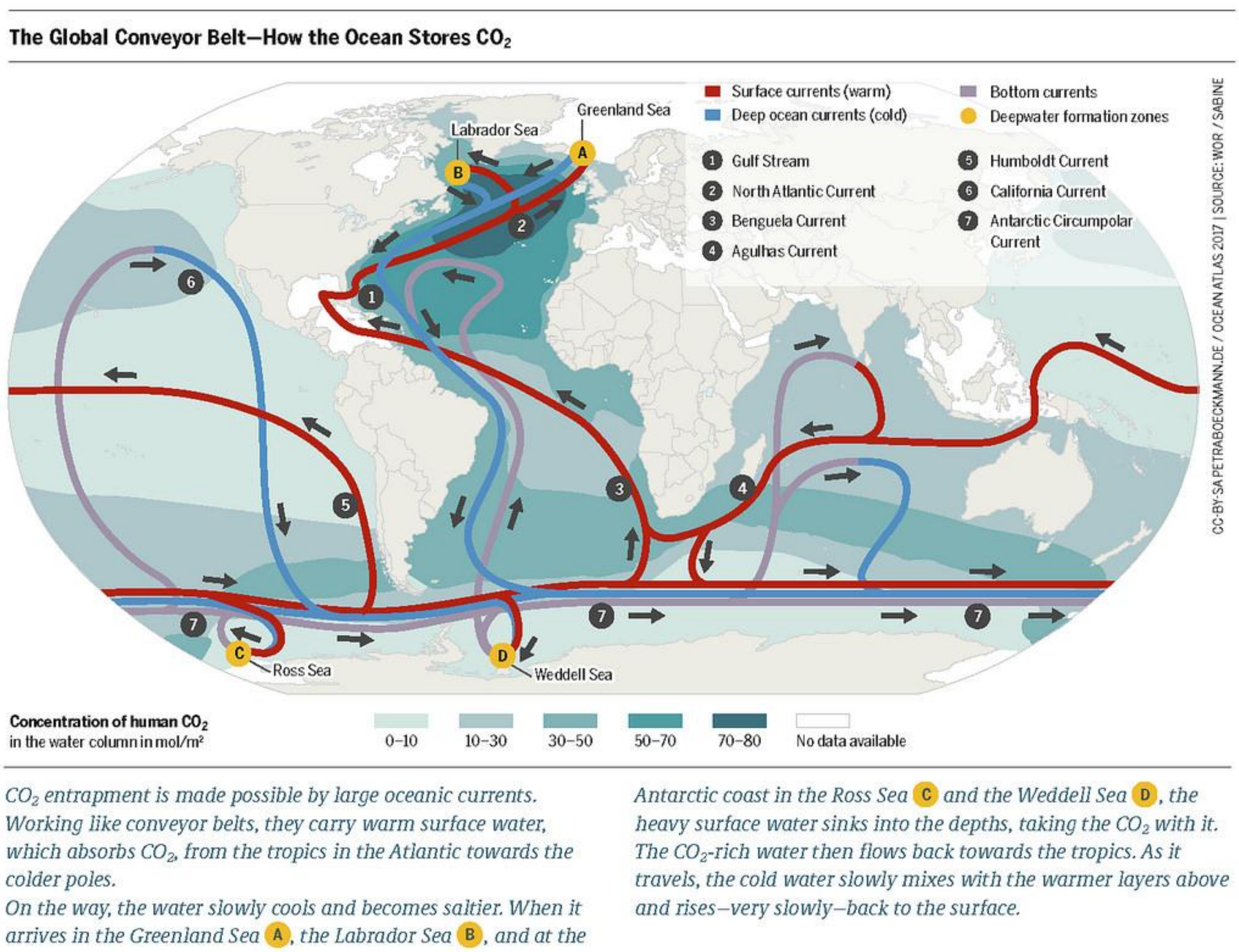
Ocean water has a birth place. It begins as melting ice somewhere in the North Atlantic, where the newly-formed cold water sinks to the bottom and floats slowly past the equator. It then falls into a rhythm, flowing along the depths and rising to the surface in a global "conveyor belt" that has carried water on the same path for millennia. It takes ten thousand years for a droplet to make its way to the end of the belt, where it emerges, marked with chemical signposts dating further back than written language, off the coast of Washington and Oregon.

As we know, the ocean itself is also changing. It absorbs about a quarter of the carbon dioxide that humans release into the atmosphere and most of the heat from human activities. Scientists have been studying the *warming* ocean for a while—that's how we learned about sea-level rise and coral bleaching—but until the mid-1990s, no one really understood that the chemical content of the ocean was being altered, too.

> The change in ocean water pH levels likely has a million different effects on marine life.

The term "ocean acidification" refers to a change in oceanic pH. Whereas the pH of the ocean used to be 8.2, it's now hovering around 8.1. And even though that doesn't *sound* like a big difference, pH is measured on a logarithmic scale—which means, for those of us who haven't thought about logs since the SATs, that the ocean is actually about 30 percent more acidic than it used to be. It's expected to hit pH 7.8 by the end of the century.

Here's another way to look at it: The ocean is currently acidifying faster than it has in the last 66 million years.



Flickr / Heinrich-Böll-Stiftung Follow

Water moves between the surface and the ocean floor as it advances along the conveyor belt

It helps to think about pH in human terms. A healthy human body typically has a pH of around 7.4, and it fluctuates very little. A change of 0.3 or 0.4—the same amount the ocean is expected to change by the end of the century—can induce a coma. If body pH rises or falls by 0.5 or more, the results are deadly. So while we don't know exactly what's happening to the organisms that live in the ocean, we know that their environment is changing more rapidly than ever, at rates that would cause serious problems for the human body.

(It's important to note that the ocean isn't actually going to turn to acid by 2100. Shallin Busch, a scientist at NOAA, explains it this way: "The North Pole is a fundamentally cold place, but we say that it's warming. Not that it's going to get warm, but that it's warm*ing.* So you can say the same thing about ocean waters: they're acidifying or becoming more acidic, but they are not acidic themselves.")

But why did ocean acidification appear in the Pacific Northwest before it showed up in Maine?

> The change in ocean water pH levels likely has a million different effects on marine life.

As I described, water moves between the surface and the ocean floor as it advances along the conveyor belt. In the Pacific Northwest, for instance, the water that welled up during the summer the oyster larvae were dying off had last seen the surface about half a century before, north of Hawaii, where it absorbed some of the atmospheric carbon being released at that time. So it's not as though the waters off Seattle are just carrying carbon emissions from the Amazon headquarters they flowed past two days ago—rather, they're carrying the carbon from all the times they welled up to the surface since the Industrial Revolution. "We know that even if all carbon dioxide emissions ceased today, the waters off the Pacific Northwest would continue to acidify for at least another 50 years, so the train is already coming," says Busch.

The water in the Pacific near Washington is at the end of the conveyor belt, and because it's so old it contains a lot of carbon dioxide from the natural decomposition of the organisms that have been dying in it for thousands of years. So when the *added* carbon dioxide from human emissions is mixed with this already-carbon-rich environment during upwelling events, the combination is enough to kill oyster larvae.

Flickr / Louisiana Sea Grant College Program Louisiana State University

The decrease in concentration of carbonate ions—the change that prevented oysters from building their shells—is the most concrete and observable effect of ocean acidification so far

Here's another way to think about it: If the waters in a hatchery are normally somewhere around pH 8.1, they may dip down to pH 7.8 during annual upwelling events when old, carbon-rich water naturally rises to the surface, as happens every summer. But when that old acidic water is mixed with *new* acidic water (the latter being the surface waters impacted by human-released carbon dioxide 50 years ago), the combination can nudge the pH down to, say, 7.7. And it's that small added difference that kills oyster larvae. The human-generated carbon nudges the water across the threshold.

The change in ocean water pH levels likely has a million different effects on marine life, most of which we still know nothing about. The decrease in concentration of carbonate ions—the change that prevented oysters from building their shells—is the most concrete and observable effect of ocean acidification so far. But scientists and fishermen are now trying to tease out all the other, subtler changes. For instance, how a negative impact on one species could affect an entire food chain, or whether or not a change in pH can alter a fish's ability to make decisions. The predictions are all over the place—remember that *Washington Post* story about "super crabs" invading the Chesapeake Bay? (Probably not gonna happen.) But research has advanced rapidly in the last few years. Here's what we know now.

Oysters on the West Coast

"I was afraid if I didn't do something, then our business would just slowly die."

Once the West Coast hatcheries—which shepherd the larvae through the first stage of life before selling them to farmers as hardy juveniles—diagnosed the problem, they moved quickly to organize a response. The Pacific Coast Shellfish Growers Association recommended that NOAA establish water monitoring systems that give industry players real-time information about the quality of the water flowing into their farms. Hatcheries then used that information to manipulate the water flowing onto their properties—block it when it's too rich in carbon, open the floodgates when the upwelling is over. Many hatcheries have also installed pricey buffering systems that automatically add sodium carbonate to the seawater to balance its chemistry.

But manipulating the incoming water can only work for so long. To escape the West Coast upwelling events, some hatcheries are moving operations as far south as Hawaii.

Flickr / Louisiana Sea Grant College Program Louisiana State University

The oyster industry was the first to be affected by ocean acidification, and it has adapted quickly

Taylor Shellfish—one of the first farms to be impacted by the die-offs—expanded its existing Hawaii hatchery, growing seed oysters and Manila clams. The shellfish are hatched in tropical waters, then shipped northward to mature in places like the Puget Sound.

In 2012, Willapa Bay's Dave Nisbet followed suit. Unlike Taylor Shellfish, which had always relied on its own hatchery for seed oysters, Nisbet's company had depended on harvesting wild oyster seed. He took NOAA's warnings about ocean acidification to heart and decided to build his hatchery in Hawaii, even though it would have been much less expensive to build one in Washington. "I just got nervous," Nisbet told the *Seattle Times* in 2012. "I was afraid if I didn't do something, then our business would just slowly die."

> Even though shellfish represent some the most vulnerable populations, they're also the easiest to fix.

Once shellfish pass through the crucial early development stages where they grow their shells, they're more impervious to changes in ocean water. Adolescent oysters, for instance, can thrive in conditions that kill larval clams. West Coast oystermen haven't yet seen acidification-triggered damage to older shellfish.

The oyster industry was the first to be affected by ocean acidification, and it has adapted quickly. In many ways, even though shellfish represent some the most vulnerable populations, they're also the easiest to fix: The infrastructure to hatch farmed shellfish was in place long before ocean acidification became a concern, and individuals can survive the trip from Hawaii to Seattle. But other species—like Dungeness crabs, which aren't farmed, and Alaskan salmon, which migrate—don't have such a simple life cycle.

California's Dungeness crabs

If larval oysters die-offs were the earliest indicator of the coastal arrival of ocean acidification, then Dungeness crabs are the species researchers and fishermen worry may struggle next. They represent the most valuable fishery on the West Coast, generating $167 million in ex-vessel value in California in 2011. Like oysters, Dungeness crabs are a key driver of the fishing industry, so lucrative that many fishermen rely on them to guarantee an annual income.

Flickr / California Department of Fish and Wildlife

Like oysters, Dungeness crabs rely on carbonate to build their shells. But carbonate isn't the primary molecule they use

Paul McElhany, a researcher at NOAA, has been testing potential impacts of lowered pH levels on Dungeness crabs. In 2016, his Seattle-based team collected egg-laying female crabs and hatched their young in treated water with varying levels of carbon dioxide.

The researchers' results would concern any fisherman. At an acidified pH level of 7.5, which has *already* been observed during upwelling events in the Puget Sound, only about a third of the Dungeness crabs survived into the juvenile stage as compared to those that survived in waters with a normal pH. (Remember, the open ocean is at about pH 8.1 now. It's expected to hit pH 7.8 by the end of the century.)

McElhany says scientists aren't quite sure *why* the acidified conditions led to such a big drop in crab survival rates. Like oysters, Dungeness crabs rely on carbonate to build their shells. But carbonate isn't the *primary* molecule they use. Which means the lower survival rate was probably caused by something other than what killed the larval oysters, something scientists have not yet identified.

Ocean acidification *could* be impacting Dungeness crab life cycles already.

And this experiment only manipulated pH levels in a controlled environment. The results, though stark, don't even come close to mimicking conditions in the wild. "Out in the field you've got multiple things going on at the same time because you've got ocean acidification, you also have temperature, climate change, and changes in fishery practice," McElhany explains. If two-thirds of Dungeness crabs are dying inside a tank that doesn't contain predators, fluctuating temperatures, or hard-to-find food, the results in the open ocean could be much worse.

Out in the field, fisherman John Mellor has been keeping an eye on the impossibly complex oceanic patterns that swirl through the crabs' habitat. And while he doesn't think he's witnessed ocean acidification impacting crab populations first hand, he's seen warming waters directly affect the crab catch.

To be clear, ocean acidification *could* be impacting Dungeness crab life cycles already. But because they aren't farmed and because their West Coast habitat has been so abnormal for the last few years—we'll get to that in a second—it's impossible to separate ocean acidification from everything else that's happening along their migration routes.

Flickr / Oregon Department of Fish & Wildlife

Unlike shellfish, which can start their lives in Hawaiian hatcheries to avoid being damaged by a bit of bad water, Dungeness crabs only grow in the wild

But there *have* been recent events that have impacted the Dungeness crab fishery, and they show how a small environmental change (in this case, so small the crabs didn't even notice) can affect the industry as a whole. It's these types of indirect impacts—problems that involve organisms far down the food chain, not the crabs themselves—that researchers like McElhany can't yet predict in a lab. But that doesn't mean they're insignificant.

Between 2014 and 2016, a mass of warm water known as "The Blob" was hanging out along the West Coast. It hasn't been proven that the blob was a direct result of climate change, though Mellor says many people assume it was. Regardless, scientists expect blob-like conditions to become more common as ocean waters continue to warm.

The blob disrupted local environments, causing die-offs of sea lions and fur seals. It also made a certain type of algae really, really happy. That algae, *Pseudo-nitzschia australis,* produces a toxin called domoic acid. (It has "acid" in its name, but that's where its relationship to ocean acidification ends.) Humans can't eat too much domoic acid without getting sick.

The Dungeness crabs aren't bothered by domoic acid. They can eat a lot of the affected algae and it won't impact their survival rates. But when they eat the algae, the domoic acid stays in their bodies. And it can cause real problems for humans eating cooked crabs—think short-term memory loss, comas, and seizures.

> Crabs are a reminder that our knowledge of this phenomenon is far from complete.

Regulators in California don't let fishermen catch Dungeness crabs if the crabs have eaten too much algae—no one wants to pass domoic acid poisoning off on some unsuspecting diner. But those restrictions are hard on fishermen. A few years back, Mellor's season was delayed by five months as he waited for the crab tests to come back clean.

"You can't really go drive for Uber," he says, adding that he had to be ready to start fishing at any moment.

To recap: The crabs hadn't gone anywhere. They were healthy and thriving, and they hadn't moved from their normal stomping grounds. But warmer-than-usual waters meant higher-than-normal levels of algae, and that algae made the crabs poisonous to humans. This is the kind of butterfly effect that will likely impact Dungeness populations long before pH levels drop down to 7.5, and it's this type of phenomenon scientists are hoping to predict by running computer simulations of entire food webs in acidified conditions.

Jessica Fu

This year, crab fishing season in Oregon has already been delayed because of domoic acid

Shallin Busch, the scientist at NOAA who studies ocean acidification and fisheries, has been working to predict the effects of ocean-wide change on specific populations. "Basically we created a model of the West Coast food web in the computer and we put in this scenario of ocean acidification from the chemistry change," she explains. "We looked to see what might happen to fish populations that we harvest under acidification. The take-home answer is that the Dungeness crab harvest was most impacted by our scenarios," she says. "What this model work was showing was that there's also likely to be some indirect effect, kind of a food web effect of acidification as well."

It'll take years for the gap between lab-generated conclusions and the natural world to narrow.

Unlike shellfish, which can start their lives in Hawaiian hatcheries to avoid being damaged by a bit of bad water, Dungeness crabs only grow in the wild. "The crabs walk in and out of the canyons, and then they'll walk up onto the shelf, and they feed on the clam beds and the worm beds and whatever they can eat, and then they typically will mate in February, March, April—and then after they're done mating, they eat a little more and then molt," Mellor says. All the while, they're migrating throughout different parts of the ocean floor.

This year, Mellor's fishing season started on time. Crab fishermen in Oregon weren't so lucky—their season has already been delayed because of domoic acid.

If oysters show the most direct and observable link between ocean acidification and survival rates, the crabs are a reminder that our knowledge of this phenomenon is far from complete. It'll take years for the gap between lab-generated conclusions and the natural world to narrow. In the meantime, crab populations will continue to live in a changing habitat.

Elsewhere

Though we have the most data about oysters and Dungeness crabs, researchers are also focusing on the potential impacts of ocean acidification on other commercially-valuable species. McElhany says there's some preliminary evidence that shows elevated acidity may impact the part of a salmon's brain that helps it avoid predators—another incidence of a subtle change that could have catastrophic consequences. Earlier this month, biologists began sounding the alarm bells about Alaska's red king crabs, warning that they could be extinct in the next century. King crabs struggle to build their shells in acidified conditions, and researchers hypothesize that they simply can't generate enough energy to maintain a survivable internal pH as external pH levels continue to fall.

Unsplash / Charlotte Coneybeer

There's a little hope, though: In the king crab trials, a few of the juveniles made it out alive in lab conditions that simulated Alaskan waters a hundred years from now. Those crabs may be able to pass their traits onto their young, creating a new generation of crustaceans that can survive in changing waters.

What can we do about the impact of ocean acidification right now? "We don't have that answer for you," Busch says. "We're hoping in the future that we will. There's this massive global effort to better understand species sensitivity, better understand ecosystem changes, do better monitoring. That's one thing."

ENVIRONMENT, **FARM**, **HEALTH**, **POLICYDUNGENESS CRABSOCEAN ACIDIFICATIONOYSTERSSHELLFISHWASHINGTON STATE**

H. Claire Brown

A North Carolina native, Claire Brown joins The New Food Economy after working on the editorial team at *Edible Manhattan* and *Edible Brooklyn.* She won the New York Press Club's Nellie Bly Cub Reporter award in 2017. Follow her at @hclaire_brown.

Exhibit 47

https://www.oregonlive.com/pacific-northwest-news/index.ssf/2018/11/oregon_and_california_crabbers.html

Oregon and California crabbers sue fossil fuel companies

Updated Nov 27, 2018; Posted Nov 26, 2018

Dungeness crab await packing and shipping in unincorporated Coos County. (*Kevin Clark/The Register-Guard via AP/2011*)

By The Associated Press

SALEM, Ore. (AP) — Commercial crabbers in Oregon and California are suing 30 fossil fuel companies, claiming they are to blame for climate change, which has hurt their industry.

The Pacific Coast Federation of Fishermen's Associations filed the lawsuit last week in California State Superior Court in San Francisco against companies including Chevron and Exxon Mobil, news outlets reported.

"The scientific linkage between the combustion of fossil fuels and ocean warming, which leads to domoic acid impacts in our fisheries, is clear," Noah Oppenheim, executive director of the Pacific Coast Federation of Fishermen's Associations, told the San Francisco Chronicle. "We know it, and it's time to hold that industry accountable for the damage they've caused."

West Coast crabbers experienced significant losses starting in the 2015-16 season when massive algal blooms caused by warm ocean temperatures resulted in a domoic acid outbreak that reduced the length of the crabbing season.

The season was cut short again in 2016-2017 for the same reason.

In California, Dungeness crab brought in over $47 million in 2017 and $83 million in 2016; the amount was down to $17 million in 2015, during the industry's first major problem with domoic acid.

Crab is the most valuable single species commercial fishery in Oregon, with an average harvest of 16 million pounds per season, the Statesman Journal in Salem, Oregon, reported .

There are nearly 1,000 Dungeness crab permit holders in California and Oregon.

Scott J. Silvestri, corporate media relations manager of Exxon Mobil Corp., said in an email to the Chronicle that reducing greenhouse gas emissions is a global issue and requires global participation and actions.

"Lawsuits like this — filed by trial attorneys against an industry that provides products we all rely upon to power the economy and enable our domestic life — simply do not do that," he said.

In California, the cities of San Francisco and Oakland also filed lawsuits against five oil companies earlier this year, seeking to recoup the cost of paying for seawalls to fend off sea-level rise. A federal judge tossed those lawsuits in June, saying courts couldn't decide who should be held accountable for an issue as big as climate change.

In October, the Pacific Coast Federation of Fishermen's Associations successfully sued the U.S. Environmental Protection Association to protect salmon and steelhead trout populations in the Columbia River basin from warm water temperatures caused by dams and climate change.

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BY: ROSSALY DE LA VEGA
Deputy Clerk

SUPERIOR COURT OF THE STATE OF CALIFORNIA
IN AND FOR THE COUNTY OF SAN FRANCISCO

PACIFIC COAST FEDERATION OF FISHERMEN'S ASSOCIATIONS, INC.;

Plaintiff,

vs.

CHEVRON CORP.; CHEVRON U.S.A. INC.; EXXON MOBIL CORP.; EXXONMOBIL OIL CORP.; BP P.L.C.; BP AMERICA, INC.; ROYAL DUTCH SHELL PLC; SHELL OIL PRODUCTS CO. LLC; CITGO PETROLEUM CORP.; CONOCOPHILLIPS; CONOCOPHILLIPS CO.; PHILLIPS 66; TOTAL E&P USA INC.; TOTAL SPECIALTIES USA INC.; ENI S.P.A.; ENI OIL & GAS INC.; ANADARKO PETROLEUM CORP.; OCCIDENTAL PETROLEUM CORP.; OCCIDENTAL CHEMICAL CORP.; REPSOL S.A.; REPSOL ENERGY NORTH AMERICA CORP.; REPSOL TRADING USA CORP.; MARATHON OIL CO.; MARATHON OIL CORP.; MARATHON PETROLEUM CORP.; HESS CORP.; DEVON ENERGY CORP.; DEVON ENERGY PRODUCTION CO., L.P.; ENCANA CORP.; APACHE CORP.; and DOES 1 through 100, inclusive,

Defendants.

Case No. CGC-18-571285

COMPLAINT FOR:

1. NUISANCE;
2. STRICT LIABILITY – FAILURE TO WARN;
3. STRICT LIABILITY – DESIGN DEFECT;
4. NEGLIGENCE; and
5. NEGLIGENCE – FAILURE TO WARN.

JURY TRIAL DEMANDED

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I. INTRODUCTION

1. The world's oceans are changing, and commercial fishermen and -women, their businesses, their communities, and their families are paying the price. Climate change is impacting the oceans by increasing average sea temperatures, increasing the frequency and intensity of marine heatwaves, destabilizing and disturbing marine wildlife populations, affecting ocean circulation, and increasing the frequency and severity of harmful algal blooms. These changes threaten both the productivity of commercial fisheries and safety of commercially harvested seafood products. In so doing, they also threaten those that rely on ocean fisheries and ecosystems for their livelihoods, by rendering it at times impossible to ply their trade. With this action, the largest commercial fishing industry trade group on the west coast seeks to hold responsible parties accountable for acute changes to the ocean off of California and Oregon that resulted, over the last three years, in prolonged regulatory closures of the Dungeness crab fisheries—the most lucrative and reliable fisheries on the west coast. Such closures will recur, as the conditions giving rise to them increase in frequency and magnitude as the oceans continue to warm. Accordingly, the crab fishing industry brings this action to force the parties responsible for this severe disruption to fishing opportunity, and the consequent impacts on fishing families, to bear the costs of their conduct.

2. Defendants, major corporate members of the fossil fuel industry, have known for nearly a half century that unrestricted production and use of their fossil fuel products create greenhouse gas pollution that warms the planet, changes our climate, and disrupts the oceans. They have known for decades that those impacts could be catastrophic and that only a narrow window existed to take action before the consequences would be irreversible. They have nevertheless engaged in a coordinated, multi-front effort to conceal and deny their own knowledge of those threats, discredit the growing body of publicly available scientific evidence, and persistently create doubt in the minds of customers, consumers, regulators, the media, journalists, teachers, and the public about the reality and consequences of the impacts of their fossil fuel pollution. At the same time, Defendants have promoted and profited from a massive increase in the extraction and consumption of oil, coal, and natural gas, which has in turn caused an enormous, foreseeable, and

avoidable increase in global greenhouse gas pollution and an accompanying increase in the concentration of greenhouse gases,[1] particularly carbon dioxide ("CO_2") and methane, in the atmosphere. Those disruptions of Earth's otherwise balanced carbon cycle have substantially contributed to a wide range of dire climate-related effects, including global warming, rising atmospheric and ocean temperatures, ocean acidification, melting polar ice caps and glaciers, more extreme and volatile weather, sea level rise, and marine heatwaves with concomitant harmful algal blooms. Families and businesses that depend on the health and productivity of the Dungeness crab fishery to earn their livings suffer the consequences.

3. Defendants are vertically integrated extractors, producers, refiners, manufacturers, distributors, promoters, marketers, and sellers of fossil fuel products. Decades of scientific research show that pollution from the production and use of Defendants' fossil fuel products plays a direct and substantial role in the unprecedented rise in emissions of greenhouse gas pollution and increased atmospheric CO_2 concentrations since the mid-20th century. This dramatic increase in atmospheric CO_2 and other greenhouse gases is the main driver of the gravely dangerous changes occurring to the global climate.

4. Anthropogenic (human-caused) greenhouse gas pollution, primarily in the form of CO_2, is far and away the dominant cause of global warming and the observed increase in ocean temperatures,[2] including marine heatwaves.[3] The primary source of this pollution is the extraction, production and consumption of coal, oil, and natural gas, referred to collectively in this Complaint as "fossil fuel products."[4]

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[1] As used in this Complaint, "greenhouse gases" refers collectively to carbon dioxide, methane, and nitrous oxide. Where a source refers to a specific gas or gases, or when a process relates only to a specific gas or gases, this Complaint refers to them by name.

[2] *See IPCC*, *Climate Change 2014: Synthesis Report*. Contribution of Working Groups I, II, and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)]. IPCC, Geneva, Switzerland (2014), at 6, Figure SMP.3, https://www.ipcc.ch/report/ar5/syr (hereinafter, "IPCC 2014 Synthesis Report").

[3] *See, e.g.*, Emanuele Di Lorenzo & Nathan Mantua, *Multi-year persistence of the 2014/15 North Pacific marine heatwave*, 6 NATURE CLIMATE CHANGE, 1 (July 11, 2016), https://www.nature.com/articles/nclimate3082; Eric C.J. Oliver et al., *The unprecedented 2015/16 Tasman Sea marine heatwave*, NATURE COMMUNICATIONS 8:16101, 1 (July 14, 2017).

[4] *See* C. Le Quéré et al., *Global Carbon Budget 2016*, EARTH SYST. SCI. DATA 8, 632 (2016), http://www.earth-syst-sci-data.net/8/605/2016. Cumulative emissions since the beginning of the industrial revolution to 2015 were 413 GtC attributable to fossil fuels, and 190 GtC attributable to land use change. *Id.* Global CO_2 emissions from fossil fuels

5. The rate at which Defendants have extracted and sold fossil fuel products has exploded since the Second World War, as have emissions from those products. The substantial majority of all anthropogenic greenhouse gas emissions in history has occurred since the 1950s, a period known as the "Great Acceleration."[5] About three quarters of all industrial CO_2 emissions in history have occurred since the 1960s,[6] and more than half have occurred since the late 1980s.[7] The annual rate of carbon dioxide emissions from production, consumption, and use of fossil fuels has increased by more than 60% since 1990.[8]

6. Defendants have known for nearly 50 years that greenhouse gas pollution from their fossil fuel products has a significant impact on Earth's climate, including a warming of the oceans. Defendants' awareness of the negative implications of their own behavior corresponds almost exactly with the Great Acceleration, and with skyrocketing greenhouse gas emissions. With that knowledge, Defendants took steps to protect their own assets from these threats through immense internal investment in research, infrastructure improvements, and plans to exploit new opportunities in a warming world.

7. Instead of working to reduce the use and combustion of fossil fuel products, lower the rate of greenhouse gas emissions, minimize the damage associated with continued high use and combustion of such products, and ease the transition to a lower carbon economy, Defendants concealed the dangers, sought to undermine public support for greenhouse gas regulation, and engaged in massive campaigns to promote the ever-increasing use of their products at ever greater volumes. Thus, each Defendant's conduct has contributed substantially to the buildup of CO_2 in the environment that drives ocean warming.

8. As an actual and proximate consequence of Defendants' conduct, the crab fishing industry has been deprived of valuable fishing opportunities, and consequently suffered severe

and industry remained nearly constant at 9.9 GtC in 2015, distributed among coal (41%), oil (34%), gas (19%), cement (5.6%), and gas flaring (0.7%). *Id.* at 629.

[5] Will Steffen et al., *The Trajectory of the Anthropocene: The Great Acceleration*, 2 THE ANTHROPOCENE REVIEW 81, 81 (2015).

[6] R.J. Andres et al., *A synthesis of carbon dioxide emissions from fossil-fuel combustion*, 9 BIOGEOSCIENCES, 1845, 1851 (2012).

[7] *Id.*

[8] *Global Carbon Budget 2016*, *supra* note 4, at 630.

financial hardships. These injuries derive from rising ocean temperatures in the eastern Pacific Ocean generally and periodic extreme marine heatwaves—the results of anthropogenic ocean warming caused by the foreseeable and intended use of Defendants' products. Recent marine heatwaves along the United States' west coast created the ideal conditions for the toxic algal group *Pseudo-nitzschia* to increase in abundance and invade the marine regions that correspond with some of the most productive Dungeness crab fishery grounds. The massive *Pseudo-nitzschia* bloom generated unprecedented concentrations of the neurotoxin domoic acid, a compound which, when ingested by humans, causes "amnesic shellfish poisoning" which induces symptoms including vomiting, diarrhea, cramps, and other gastrointestinal upset, permanent short-term memory loss, and, in severe cases, death.

9. Rising ocean temperatures and the resultant *Pseudo-nitzschia* blooms allow domoic acid to enter the marine food web and accumulate in crab flesh, rendering it at times dangerous and unfit for human consumption.

10. In response to this public health crisis, the California Department of Fish and Wildlife ("CDFW"), in coordination with the California Department of Public Health ("CDPH"), closed—for the first time ever—significant portions of the California coast to commercial Dungeness crab fishing in the 2015–16 fishing season, and again in 2016–17. The Oregon Department of Fish and Wildlife ("ODFW") and the Oregon Department of Agriculture ("ODA") similarly closed large areas of the Oregon coast to commercial crabbing during the 2015–16, 2016–17, and 2017–18 commercial crab seasons because of domoic acid toxicity. Because of those closures, hundreds of commercial fishermen and -women holding Dungeness crab permits could not untie their boats or deploy their crab traps until crabs became safe to consume. Additional precautionary measures and stigma from negative publicity related to domoic acid contamination have deprived the crab industry of the full value of its harvests these last three seasons by depressing the market demand for crab products.

11. Plaintiff represents commercial Dungeness crab harvesters and onshore crab processors and wholesalers that have suffered, and continue to suffer, substantial economic losses due to those lost fishing opportunities. The severe curtailment of the crab fishery, which is among

the most productive, lucrative, and reliable fisheries on the west coast, had damaging ripple effects throughout California's and Oregon's fishing families and communities, creating severe hardships that many fishermen and fishing businesses, including Plaintiff's members, have struggled to overcome. The severity of the economic loss endured by the crabbing community prompted the federal government to declare the 2015–16 California crab season a federal fishery disaster under the Magnuson–Stevens Fishery Management and Conservation Act.

12. Domoic acid incidents on the west coast, and consequent injuries to the fishing industry and west coast fishing communities generally, are the new normal. These phenomena will increase in severity and frequency as the oceans continue to change with anthropogenic global warming. Indeed, California's 2018–19 crab season—set to begin on November 15, 2018—will be delayed in parts of the fishery because of domoic acid toxicity.

13. Additional crab fishery closures will occur in the future, with increasing frequency and severity, with concomitant impacts on the fishing families, fishing communities, and the west coast fishing industry at large.

14. Defendants are directly responsible for a large and substantial portion of total CO_2 emissions between 1965 and 2015. For example, based on Defendants' direct extractions of fossil fuels, they are responsible for more than two hundred gigatons of emissions representing over 15% of total emissions of that potent greenhouse gas during that period. Defendants are responsible for significantly larger shares of emissions based on their production, wholesale and retail sales of their products. Accordingly, Defendants are directly responsible for a substantial portion of elevated ocean temperatures that caused the domoic acid contamination on the west coast, which in turn caused the substantial and material economic injuries described herein.

15. Defendants' production, promotion, marketing, and use of fossil fuel products, simultaneous concealment of the known hazards of those products, and their championing of anti-regulation and anti-science campaigns, actually and proximately caused Plaintiff's injuries.

16. Accordingly, Plaintiff in its own name, in a representative capacity on behalf of its members and the west coast fishing community, and as the assignee of claims arising from domoic

acid impacts on the crab fishery, brings this action against Defendants for Nuisance, Strict Liability for Failure to Warn, Strict Liability for Design Defect, Negligence, and Negligent Failure to Warn.

17. By this action, the Plaintiff seeks to ensure that the parties responsible for the fishery closures bear the costs of its impacts, rather than Plaintiff and the men, women, families and businesses of the west coast crab industry.

II. PARTIES

A. Plaintiff

18. Plaintiff the **Pacific Coast Federation of Fishermen's Associations, Inc.** ("PCFFA") is the largest trade association of commercial fishermen on the West Coast. PCFFA has led the fishing industry in protecting the rights of west coast fishermen and fishing communities since 1976. PCFFA fights for the long-term survival of commercial fishing—including commercial Dungeness crab fishing—as a productive livelihood and way of life. PCFFA is a 501(c)(5) not-for-profit trade organization incorporated in California and headquartered in the city and county of San Francisco, California. PCFFA represents, *inter alia*, crab fishermen and local fishermen's marketing associations.

19. PCFFA brings these claims in its own name; as a representative of its members that are and will continue to be injured financially and otherwise by Defendants' conduct and consequent domoic acid incidents and domoic acid-induced crab fishery closures; and as assignee of claims assigned to it by individuals and businesses that derive income from the California and Oregon Dungeness crab fisheries that have suffered and will continue to suffer financial and other injuries because of Defendants' conduct and consequent domoic acid blooms and domoic acid-induced crab fishery closures. As used hereinafter, the term "Plaintiff" refers to PCFFA, its members, and businesses that have assigned PCFFA claims arising from the facts described herein.

20. PCFFA has diverted resources to addressing domoic acid impacts on the commercial crab fishery, including by dedicating staff time and energy to address these outbreaks in the media, working with state agencies to determine crab fishery closure and reopening procedures, sharing information on domoic acid and closures with its members, and appealing to state and federal entities for fishery disaster relief, among other activities. Domoic acid outbreaks

and resultant fishery closures have frustrated and will continue to frustrate PCFFA's mission of ensuring that commercial fishing remains a sustainable livelihood, by damaging markets and preventing trade in crab harvested on the west coast.

B. Defendants

21. Defendants are responsible for a substantial portion of the total greenhouse gases emitted since 1965. Defendants, individually and collectively, are responsible for extracting, refining, processing, producing, promoting, and marketing fossil fuel products, the normal and intended use of which has led to the emission of a substantial percentage of the total volume of greenhouse gases released into the atmosphere since 1965. Indeed, between 1965 and 2015, the named Defendants extracted enough fossil fuel materials (i.e. crude oil, coal, and natural gas) to account for more than one in every five tons of carbon dioxide and methane emitted worldwide. Accounting in addition for their wholesale and retail sales of products, as well as their wrongful promotion and marketing activities, Defendants bear a dominant responsibility for global warming generally and for Plaintiff's injuries in particular.

22. When reference in this complaint is made to an act or omission of the Defendants, unless specifically attributed or otherwise stated, such references should be interpreted to mean that the officers, directors, agents, employees, or representatives of the Defendants committed or authorized such an act or omission, or failed to adequately supervise or properly control or direct their employees while engaged in the management, direction, operation or control of the affairs of Defendants, and did so while acting within the scope of their employment or agency.

23. **Chevron Entities**

a. Chevron Corporation is a multinational, vertically integrated energy and chemicals company incorporated in the State of Delaware, with its global headquarters and principal place of business in San Ramon, California.

b. Chevron Corporation controls and has controlled companywide decisions about the quantity and extent of fossil fuel production and sales, including those of its subsidiaries.

c. Chevron Corporation controls and has controlled companywide decisions related to climate change and greenhouse gas emissions from its fossil fuel products, including those of its subsidiaries.

d. Chevron U.S.A. Inc. is a Pennsylvania Corporation with its principal place of business located in San Ramon, California. Chevron USA is a wholly owned subsidiary of Chevron Corporation that acts on Chevron Corporation's behalf and subject to Chevron Corporation's control. Chevron U.S.A. Inc. was formerly known as, and did or does business as, and/or is the successor in liability to Gulf Oil Corporation, Gulf Oil Corporation of Pennsylvania, Chevron Products Company, Chevron Chemical Company, Chevron Energy Solutions Company, ChevronTexaco Products Company, Chevron U.S.A. Production Company, and Chevron U.S.A. Products Company.

e. "Chevron" as used hereafter, means collectively, Defendants Chevron Corp. and Chevron U.S.A. Inc.

f. Chevron operates through a web of U.S. and international subsidiaries at all levels of the fossil fuel supply chain. Chevron's and its subsidiaries' operations consist of exploring for, developing, and producing crude oil and natural gas; processing, liquefaction, transportation, and regasification associated with liquefied natural gas; transporting crude oil by major international oil export pipelines; transporting, storage, and marketing of natural gas; refining crude oil into petroleum products; marketing of crude oil and refined products; transporting crude oil and refined products by pipeline, marine vessel, motor equipment and rail car; basic and applied research in multiple scientific fields including of chemistry, geology, and engineering; and manufacturing and marketing of commodity petrochemicals, plastics for industrial uses, and fuel and lubricant additives.

g. Chevron directs and has directed substantial fossil fuel-related business to California. A substantial portion of Chevron's fossil fuel products are or have been extracted, refined, transported, traded, distributed, marketed, promoted, manufactured, sold, and/or consumed in California, from which Chevron derives and has derived substantial revenue.

24. **Exxon Entities**

a. Exxon Mobil Corporation is a multinational, vertically integrated energy and chemicals company incorporated in the State of New Jersey with its headquarters and principal place of business in Irving, Texas. Exxon is among the largest publicly traded international oil and gas companies in the world. Exxon Mobil Corporation was formerly known as, did or does business as, and/or is the successor in liability to ExxonMobil Refining and Supply Company, Exxon Chemical U.S.A., ExxonMobil Chemical Corporation, ExxonMobil Chemical U.S.A., ExxonMobil Refining & Supply Corporation, Exxon Company, U.S.A., Exxon Corporation, and Mobil Corporation.

a. Exxon Mobil Corporation controls and has controlled companywide decisions about the quantity and extent of fossil fuel production and sales, including those of its subsidiaries. Exxon Mobil Corporation recently represented that its success, including its "ability to mitigate risk and provide attractive returns to shareholders, depends on [its] ability to successfully manage [its] overall portfolio, including diversification among types and locations of our projects."[9]

b. Exxon Mobil Corporation controls and has controlled companywide decisions related to climate change and greenhouse gas emissions from its fossil fuel products, including those of its subsidiaries. Exxon Mobil Corporation's Board, or an individual/sub-set of the Board, or another committee appointed by the Board, holds the highest level of direct responsibility for climate change policy within the company. Exxon Mobil Corporation's Chairman of the Board and Chief Executive Officer, its President and the other members of its Management Committee are actively engaged in discussions relating to greenhouse gas emissions and the risks of climate change on an ongoing basis. Exxon Mobil Corporation requires its subsidiaries to provide an estimate of greenhouse gas-related emissions costs in their economic projections when seeking funding for capital investments.

[9] ExxonMobil, "Factors affecting future results" (Feb. 2018), https://cdn.exxonmobil.com/~/media/global/files/investor-reports/2018/2018-factors-affecting-future-results.pdf.

c. ExxonMobil Oil Corporation is wholly-owned subsidiary of Exxon Mobil Corporation that acts on Exxon Mobil Corporation's behalf and subject to Exxon Mobil Corporation's control. ExxonMobil Oil Corporation is incorporated in the State of New York with its principal place of business in Irving, Texas. ExxonMobil Oil Corporation is qualified to do business in California. ExxonMobil Oil Corporation was formerly known as, did or does business as, and/or is the successor in liability to Mobil Oil Corporation.

d. "Exxon," as used hereafter, means collectively defendants Exxon Mobil Corporation and ExxonMobil Oil Corporation, and their predecessors, successors, parents, subsidiaries, affiliates, and divisions.

e. Exxon consists of numerous divisions and affiliates in all areas of the fossil fuel industry, including exploration for and production of crude oil and natural gas; manufacture of petroleum products; and transportation, marketing, and sale of crude oil, natural gas, and petroleum products. Exxon is also a major manufacturer and marketer of commodity petrochemical products.

f. Exxon directs and has directed substantial fossil fuel product-related business to California, and a substantial portion of its fossil fuel products are extracted, refined, transported, traded, distributed, marketed, and/or sold in California. Among other operations, more than 540 Exxon-, Mobil-, or Esso-branded gas stations operate throughout the state, and Exxon owns and operates a petroleum storage and transport facility in the San Ardo Oil Field in San Ardo, Monterey County, California. From 1966 to 2016, Exxon owned and operated an oil refinery in Torrance, Los Angeles County, California. Exxon Co. USA, an Exxon subsidiary, operated a petroleum refinery in Benicia, Solano County, California, from 1968 to 2000.

25. **<u>BP Entities</u>**

a. BP P.L.C. is a multi-national, vertically integrated energy and petrochemical public limited company, registered in England and Wales with its principal place of business in London, England. BP P.L.C. consists of three main operating segments: (1) exploration and production, (2) refining and marketing, and (3) gas power and renewables.

b. BP P.L.C. is the ultimate parent company for numerous subsidiaries that find and produce oil and gas worldwide, that refine oil into fossil fuel products such as gasoline, and that market and sell oil, refined petroleum products, and natural gas worldwide. BP P.L.C.'s subsidiaries explore for oil and natural gas under a wide range of licensing, joint arrangement, and other contractual agreements.

c. BP P.L.C. controls and has controlled companywide decisions about the quantity and extent of fossil fuel production and sales, including those of its subsidiaries. BP P.L.C. is the ultimate decisionmaker on fundamental decisions about the company's core business, i.e., the level of companywide fossil fuels to produce, including production among BP P.L.C.'s subsidiaries. For instance, BP P.L.C. reported that in 2016–2017 it brought online thirteen major exploration and production projects, which contributed to a 12% increase in the BP group's overall fossil fuel product production. These projects were carried out by BP P.L.C.'s subsidiaries. Based on these projects, BP P.L.C. expects the company to deliver to customers 900,000 barrels of new product per day by 2021. BP P.L.C. further reported that in 2017 it sanctioned three new exploration projects in Trinidad, India, and the Gulf of Mexico and added 143% reserves replacement for the group of entities over which it is the ultimate parent company.

d. BP P.L.C. makes fossil fuel production decisions for the entire BP group based on a number of factors, including climate change. BP P.L.C.'s Board, an individual/subset of the Board, or a committee appointed by the Board, is the highest level within the company with direct responsibility for climate change policy. BP P.L.C.'s chief executive is responsible for maintaining the BP group's system of internal control that governs the BP group's business conduct. BP P.L.C. reviews climate change risks facing the BP group through two executive committees chaired by the group chief executive and one working group chaired by the executive vice president and group chief of staff, as part of BP group's established management structure.

e. BP P.L.C. does substantial fossil-fuel related business in the United States, by marketing through licensure; franchising its petroleum products in the U.S. under the BP, ARCO and ARAL brands; and by operating oil and gas extraction and refining projects in the Gulf of Mexico, Alaska, Arkansas, Colorado, New Mexico, Oklahoma, Texas, and Wyoming.

f. BP America, Inc., is a wholly-owned subsidiary of BP P.L.C. that acts on BP P.L.C.'s behalf and subject to BP P.L.C.'s control. BP America Inc. is a vertically integrated energy and petrochemical company incorporated in the State of Delaware with its headquarters and principal place of business in Houston, Texas. BP America, Inc., consists of numerous divisions and affiliates in all aspects of the fossil fuel industry, including exploration for and production of crude oil and natural gas; manufacture of petroleum products; and transportation, marketing, and sale of crude oil, natural gas, and petroleum products. BP America Inc. was formerly known as, did or does business as, and/or is the successor in liability to BP Products North America Inc., Atlantic Richfield Company, BP Amoco Corporation, Amoco Corporation, Amoco Oil Company, The American Oil Company, BP Exploration & Oil Inc., Sohio Oil Company, Standard Oil of Ohio (SOHIO), Standard Oil (Indiana), BP Amoco Plc, BP Oil Inc., BP Oil Company, Atlantic Richfield Delaware Corporation, Atlantic Richfield Company (a Pennsylvania corporation), ARCO Products Company, and Arco Chemical Company, a division of Atlantic Richfield Company. BP is also a major manufacturer and marketer of commodity petrochemical products. BP America Inc. is registered to do business in the State of California and has a registered agent for service of process with the California Secretary of State.

g. Defendants BP P.L.C. and BP America, Inc. are collectively referred to herein as "BP."

h. BP does substantial fossil fuel product-related business in California, and a substantial portion of its fossil fuel products are extracted, refined, transported, traded, distributed, marketed, and/or sold in California. Among other operations, BP operates 275 ARCO-licensed and branded gas stations in California and more than 70 compressed natural gas and liquefied natural gas fueling stations, provides natural gas used to power more than 6.9 million California households, and distributes and markets petroleum-based lubricants marketed under the "Castrol" brand name throughout the state. From 2000 to 2013, BP also owned and operated an oil refinery in Carson, Los Angeles County, California. BP's marketing and trading business maintains an office in Irvine, Orange County, California. BP maintains an energy research center in San Diego, San Diego County, California.

26. **<u>Shell Entities</u>**

a. Royal Dutch Shell PLC is a vertically integrated, multinational energy and petrochemical company. Royal Dutch Shell is incorporated in England and Wales, with its headquarters and principal place of business in the Hague, Netherlands. Royal Dutch Shell PLC consists of numerous divisions, subsidiaries and affiliates engaged in all aspects of the fossil fuel industry, including exploration, development, extraction, manufacturing and energy production, transport, trading, marketing and sales.

b. Royal Dutch Shell PLC controls and has controlled companywide decisions about the quantity and extent of fossil fuel production and sales, including those of its subsidiaries. Royal Dutch Shell PLC's Board of Directors in the Hague determines whether and to what extent Shell subsidiary holdings around the globe produce Shell-branded fossil fuel products. For instance, Royal Dutch Shell PLC's Board of Directors makes individual decisions on whether and when to initiate drilling in particular oil reserves.

c. Royal Dutch Shell PLC controls and has controlled companywide decisions related to climate change and greenhouse gas emissions from its fossil fuel products, including those of its subsidiaries. Overall accountability for climate change within the Shell group of companies lies with Royal Dutch Shell PLC's Chief Executive Officer and Executive Committee. Additionally, Royal Dutch Shell PLC has directed its subsidiaries to reduce the carbon footprint of all fossil fuel products produced under the Shell brand, including those of its subsidiaries, and across all upstream and downstream segments of its operations.

d. Shell Oil Products Company LLC is a wholly-owned subsidiary of Royal Dutch Shell PLC. Shell Oil Products Company LLC is incorporated in the State of Delaware and maintains its principal place of business in Houston, Texas. Shell Oil Products Company LLC is registered to do business in the State of California and has a registered agent for service of process in California. Shell Oil Products Company LLC is an energy and petrochemical company involved in refining, transportation, distribution and marketing of Shell fossil fuel products.

e. Defendants Royal Dutch Shell PLC and Shell Oil Products Company LLC are collectively referred to as "Shell."

f. Shell does substantial fossil fuel product-related business in California, and a substantial portion of its fossil fuel products are extracted, refined, transported, traded, distributed, marketed and/or sold in California. Among other endeavors, Shell operates a petroleum refinery in Martinez, Contra Costa County, California; operates a distribution center in Carson, California; and produces heavy oil and natural gas within the state. Shell also owned and operated a refinery in Wilmington (Los Angeles), Los Angeles County, California, from 1998 to 2007, and a refinery in Bakersfield, Kern County, California, from 2001 to 2005. Shell also operates hundreds of Shell-branded gas stations in California.

27. **<u>Citgo Petroleum Corporation ("Citgo")</u>**

a. Citgo is a direct, wholly owned subsidiary of PDV America, Incorporated, which is a wholly owned subsidiary of PDV Holding, Incorporated. These organizations' ultimate parent is Petróleos de Venezuela, S.A. ("PDVSA"), an entity wholly owned by the Republic of Venezuela that plans, coordinates, supervises and controls activities carried out by its subsidiaries. Citgo is incorporated in the State of Delaware and maintains its headquarters in Houston, Texas.

b. Citgo controls and has controlled companywide decisions about the quantity and extent of fossil fuel production and sales, including those of its subsidiaries.

c. Citgo controls and has controlled companywide decisions related to climate change and greenhouse gas emissions from its fossil fuel products, including those of its subsidiaries.

d. Citgo and its subsidiaries are engaged in the refining, marketing, and transportation of petroleum products including gasoline, diesel fuel, jet fuel, petrochemicals, lubricants, asphalt, and refined waxes.

e. Citgo is registered to do business in the State of California and has designated an agent for service of process in California. Citgo further does substantial fossil fuel product-related business in California, and a substantial portion of its fossil fuel products are extracted, refined, transported, traded, distributed, marketed, and/or sold in California. For instance, Citgo sells significant volumes of fossil-fuel derived consumer motor oils and automobile lubricants through retail and wholesale distributers. Citgo further sells a wide variety of greases and oils for use in construction, mining, agricultural, and metalworking machinery and vehicles, and in many other industrial and commercial settings, through licensed distributors in California.

28. **ConocoPhillips Entities**

a. ConocoPhillips is a multinational energy company incorporated in the State of Delaware and with its principal place of business in Houston, Texas. ConocoPhillips consists of numerous divisions, subsidiaries, and affiliates engaged in all aspects of the fossil fuel industry, including exploration, extraction, production, manufacture, transport, and marketing.

b. ConocoPhillips controls and has controlled companywide decisions about the quantity and extent of fossil fuel production and sales, including those of its subsidiaries. ConocoPhillips' most recent annual report subsumes the operations of the entire ConocoPhillips group of subsidiaries under its name. Therein, ConocoPhillips represents that its value—for which ConocoPhillips maintains ultimate responsibility—is a function of its decisions to direct subsidiaries to explore for and produce fossil fuels: "Unless we successfully add to our existing proved reserves, our future crude oil, bitumen, natural gas and natural gas liquids production will decline, resulting in an adverse impact to our business." ConocoPhillips optimizes the ConocoPhillips group's oil and gas portfolio to fit ConocoPhillips' strategic plan. For example, in November 2016, ConocoPhillips announced a plan to generate $5 billion to $8 billion over two years by optimizing its business portfolio, including its fossil fuel product business, to focus on low cost-of-supply fossil fuel production projects that strategically fit its development plans.

c. ConocoPhillips controls and has controlled companywide decisions related to global warming and greenhouse gas emissions from its fossil fuel products, including those of its subsidiaries. For instance, ConocoPhillips' Board has the highest level of direct responsibility for climate change policy within the company. ConocoPhillips has developed and implements a corporate Climate Change Action Plan to govern climate change decision-making across all entities in the ConocoPhillips group.

d. ConocoPhillips Company is a wholly owned subsidiary of ConocoPhilliips that acts on ConocoPhillips' behalf and subject to ConocoPhillips' control. ConocoPhillips Company is incorporated in Delaware and has its principal office in Bartlesville, Oklahoma. ConocoPhillips Company is registered to do business in California and has a registered agent for service of process in California.

e. Phillips 66 is a multinational energy and petrochemical company incorporated in Delaware and with its principal place of business in Houston, Texas. It encompasses downstream fossil fuel processing, refining, transport, and marketing segments that were formerly owned and/or controlled by ConocoPhillips. Phillips 66 is registered to do business in the State of California and has a registered agent for service of process in California.

f. Defendants ConocoPhillips, ConocoPhillips Company, and Phillips 66, and their predecessors, successors, parents, subsidiaries, affiliates, and divisions are collectively referred to herein as "ConocoPhillips."

g. ConocoPhillips does substantial fossil fuel product-related business in California, and a substantial portion of its fossil fuel products are extracted, refined, transported, traded, distributed, marketed, and/or sold in California. For instance, ConocoPhillips owns and operates oil and natural gas terminals in California, owns and operates refineries in Arroyo Grande (San Luis Obispo County), Colton (San Bernardino County), and Wilmington (Los Angeles County), California, and distributes its products throughout California. Phillips 66 also owns and operates oil refineries in Rodeo (Contra Costa County), Santa Maria (Santa Barbara County), and Wilmington (Los Angeles County), California, each of which was owned and operated by ConocoPhillips and its predecessors in interest from 1997 to 2012.

29. **<u>Total Entities</u>**

a. Total E&P USA Inc. is a wholly owned subsidiary of Total S.A.—a French energy conglomerate—engaged in the North American segment of Total SA's fossil fuel products-related business. Total E&P USA Inc. and its subsidiaries are involved in the exploration for and extraction, transportation, research, and marketing of Total S.A.'s fossil fuel products. Total E&P

USA Inc. is registered to do business in the State of California and has designated an agent for service of process in California.

b. Total E&P USA Inc. controls and has controlled companywide decisions about the quantity and extent of fossil fuel production and sales, including those of its subsidiaries.

c. Total E&P USA Inc. controls and has controlled companywide decisions related to climate change and greenhouse gas emissions from its fossil fuel products, including those of its subsidiaries.

d. Total Specialties USA Inc., is a wholly owned subsidiary of Total S.A., involved in the marketing and distribution of Total S.A.'s fossil fuel products. Total Specialties USA Inc. is incorporated in the State of Delaware and headquartered in Houston, Texas. Total Specialties USA Inc. is registered to do business in the State of California and has designated an agent for service of process in California. Total Specialties USA Inc. does substantial fossil fuel product-related business in California, and a substantial portion of its fossil fuel products are extracted, refined, transported, traded, distributed, marketed, and/or sold in California. For instance, Total Specialties USA Inc. maintains regular distributorship relationships with several California distributors of Total fossil fuel products, including engine oils, lubricants, greases, and industrial petroleum products.

30. **<u>Eni Entities</u>**

a. Eni S.p.A. ("Eni") is a vertically integrated, multinational energy company focusing on petroleum and natural gas. Eni is incorporated in the Republic of Italy, with its principal place of business in Rome, Italy. With its consolidated subsidiaries, Eni engages in the exploration, development, and production of hydrocarbons; in the supply and marketing of gas, liquid natural gas, and power; in the refining and marketing of petroleum products; in the production and marketing of basic petrochemicals, plastics and elastomers; in commodity trading; and in electricity marketing and generation.

b. Eni controls and has controlled companywide decisions about the quantity and extent of fossil fuel production and sales, including those of its subsidiaries.

c. Eni controls and has controlled companywide decisions related to climate change and greenhouse gas emissions from its fossil fuel products, including those of its subsidiaries.

d. Eni Oil & Gas Inc. is incorporated in Texas, with its principal place of business in Houston, Texas. Eni Oil & Gas Inc. is a wholly owned subsidiary of Eni America Ltd., a Delaware corporation doing business in the United States. Eni America, Ltd. is a wholly owned subsidiary of Eni UHL Ltd., a British corporation with its registered office in London, United Kingdom. Eni UHL Ltd. is a wholly owned subsidiary of Eni ULT, Ltd., a British corporation with its registered office on London, United Kingdom. Eni ULT, Ltd. is a wholly owned subsidiary of Eni Lasmo Plc, a British corporation with its registered office on London, United Kingdom. Eni Investments Plc, a British corporation with its registered office in London, United Kingdom, holds a 99.99% ownership interest in Eni Lasmo Plc (the other 0.01% ownership interest is held by another Eni entity, Eni UK Ltd, a British corporation with its registered office in London, United Kingdom). Eni S.p.A owns a 99.99% interest in Eni Investments Plc. Eni UK Ltd. holds the remainder interest in Eni Investments Plc. Collectively, these entities are referred to as "Eni."

e. Eni Oil & Gas Inc. is a successor-in-interest to Golden Eagle Refining Company, Inc. ("Golden Eagle"). At times relevant to this complaint, Golden Eagle did substantial fossil fuel-related business in California. Specifically, Golden Eagle owned and/or operated oil refineries in Carson (Los Angeles County) and Martinez (Contra Costa County), California, and owned and/or operated oil pipelines in or near Long Beach (Los Angeles County), California.

31. **Anadarko Petroleum Corp.**

a. Anadarko Petroleum Corporation ("Anadarko") is incorporated in the State of Delaware and maintains its principal place of business in The Woodlands, Texas. Anadarko is a multinational, vertically integrated energy company comprised of multiple upstream and downstream segments. These include exploration, production, gathering, processing, treating, transporting, marketing, and selling fossil fuel products derived primarily from petroleum and natural gas. In the United States, Anadarko entities operate fossil fuel product exploration and production concerns in Texas, the Gulf of Mexico, Alaska, the Powder River Basin, Utah, Colorado, and the Marcellus Shale Formation. Anadarko operates fossil fuel product production and exploration activities internationally in Algeria, Ghana, Mozambique, and Columbia, among others. Anadarko Petroleum Corporation is registered to do business in California and has designated an agent for service of process in California.

b. Anadarko Petroleum Corporation is a successor-in-interest to HS Resources Inc. ("HS"). HS was an energy company headquartered in San Francisco, California. It owned natural gas reserves in Colorado, North Dakota, South Dakota, Montana, and along the coasts of Texas and Louisiana, which it extracted and imported to California. HS was acquired by Kerr-McGee Corporation in 2001. Kerr-McGee was an energy exploration and production company owning oil and natural gas rights in the Gulf of Mexico, Colorado, and Utah, with its corporate headquarters in Oklahoma. Anadarko Petroleum Corporation acquired Kerr-McGee Corporation in 2006.

32. **<u>Occidental Entities</u>**

a. Occidental Petroleum Corporation is a multinational, vertically integrated energy and chemical company incorporated in the State of Delaware and with its principal place of business in Houston, Texas. Occidental's operations consist of three segments: Occidental's operations consist of three segments: (1) the exploration for, extraction of, and production of oil and natural gas products; (2) the manufacture and marketing of chemicals and vinyls; and (3) processing, transport, storage, purchase, and marketing of oil, natural gas, and power. Occidental Petroleum Corporation is registered to do business in the State of California and has designated an agent for service of process in the State of California.

b. Occidental Petroleum Corporation controls and has controlled companywide decisions about the quantity and extent of fossil fuel production and sales, including those of its subsidiaries.

c. Occidental Petroleum Corporation controls and has controlled companywide decisions related to climate change and greenhouse gas emissions from its fossil fuel products, including those of its subsidiaries.

d. Occidental Chemical Corporation, a manufacturer and marketer of petrochemicals, such as polyvinyl chloride resins, is a wholly owned subsidiary of Occidental Petroleum Corporation. Occidental Chemical Corporation is registered to do business in the State of California and has designated an agent for service of process in the State of California.

e. Defendants Occidental Petroleum Corporation and Occidental Chemical Corporation are collectively referred to as "Occidental."

f. Occidental does substantial fossil fuel product-related business in the State of California, and a substantial portion of its fossil fuel products are extracted, refined, transported, traded, distributed, marketed, and/or sold in California. For instance, Occidental has extracted and transported its fossil fuel products from approximately 30,900 drilling locations within the San Joaquin, Los Angeles, Ventura, and Sacramento Basins in California.

33. **Repsol S.A.**

a. Repsol S.A. ("Repsol") is a vertically integrated, multinational global energy company, incorporated in the Kingdom of Spain, with its principal place of business in Madrid, Spain. Repsol is involved in multiple aspects of the fossil fuel industry, including exploration, production, marketing, and trading. Repsol engages in significant fossil fuel exploration and production activities in the United States, including in the Gulf of Mexico, the Marcellus Shale in Pennsylvania, the Eagle Ford Shale in South Texas, the Mississippi Lime in Oklahoma and Kansas, the North Slope in Alaska, and the Trenton-Black River in New York.

b. Repsol controls and has controlled companywide decisions about the quantity and extent of fossil fuel production and sales, including those of its subsidiaries.

c. Repsol controls and has controlled companywide decisions related to climate change and greenhouse gas emissions from its fossil fuel products, including those of its subsidiaries.

d. Repsol does substantial fossil fuel product-related business in the State of California, and a substantial portion of its fossil fuel products are extracted, refined, transported, traded, distributed, marketed, and/or sold in California. For instance, Repsol subsidiary Repsol Energy North America Corporation, incorporated in the State of Texas and with its principal place of business in The Woodlands, Texas, is listed as a natural gas procurement, storage, transportation, scheduling, and risk management provider by Pacific Gas and Electric Co. ("PG&E"), a California utility. Repsol Energy North America Corporation is registered to do business in California and has designated an agent for service of process in California. Repsol subsidiary Repsol Trading USA Corporation, incorporated in the State of Texas and with its principal place of business in The Woodlands, Texas, is also registered do business in California and has designated an agent for service of process in California. Additionally, Repsol represents on its website that it is engaging in strategic opportunities involving its fossil fuel products in California, which may consist of crude oil, gasoline, diesel, and/or jet fuel.

34. **Marathon Entities**

a. Marathon Oil Company is an energy company incorporated in the State of Ohio and with its principal place of business in Houston, Texas. Marathon Oil Company is registered to do business in California and has designated an agent for service of process in California. Marathon Oil Company is a corporate ancestor of Marathon Oil Corporation and Marathon Petroleum Company.

b. Marathon Oil Company is a successor-in-interest to Husky Oil Ltd. ("Husky"), which it acquired in 1984. During times relevant to this Complaint, Husky operated oil production facilities near Santa Maria (Santa Barbara County), California, where it produced nearly 1,100 barrels per day. During the period relevant to this litigation, Husky did substantial fossil fuel product-related business in California.

c. Marathon Oil Corporation is a multinational energy company incorporated in the State of Delaware and with its principal place of business in Houston, Texas. Marathon Oil Corporation consists of multiple subsidiaries and affiliates involved in the exploration for, extraction, production, and marketing of fossil fuel products.

d. Marathon Petroleum Corporation is a multinational energy company incorporated in Delaware and with its principal place of business in Findlay, Ohio. Marathon Petroleum Corporation was spun off from Marathon Oil Corporation operations in 2011. It consists of multiple subsidiaries and affiliates involved in fossil fuel product refining, marketing, retail, and transport, including both petroleum and natural gas products.

e. Marathon Oil Corporation and Marathon Petroleum Corporation control and have controlled their companywide decisions about the quantity and extent of fossil fuel production and sales, including those of their subsidiaries.

f. Marathon Oil Corporation and Marathon Petroleum Corporation control and have controlled their companywide decisions related to climate change and greenhouse gas emissions from its fossil fuel products, including those of its subsidiaries.

g. Defendants Marathon Oil Company, Marathon Oil Corporation, and Marathon Petroleum Corporation are collectively referred to as "Marathon."

35. **Hess Corporation**

a. Hess Corporation ("Hess") is a global, vertically integrated petroleum exploration and extraction company incorporated in the State of Delaware with its headquarters and principal place of business in New York, New York. Hess is registered to do business in California and has designated an agent for service of process in California.

b. Hess controls and has controlled companywide decisions about the quantity and extent of fossil fuel production and sales, including those of its subsidiaries.

c. Hess controls and has controlled companywide decisions related to climate change and greenhouse gas emissions from its fossil fuel products, including those of its subsidiaries.

d. Hess is engaged in the exploration, development, production, transportation, purchase, marketing, and sale of crude oil and natural gas. Its oil and gas production operations are located primarily in the United States, Denmark, Equatorial Guinea, Malaysia, Thailand, and Norway. Prior to 2014, Hess also conducted extensive retail operations in its own name and through subsidiaries. Hess owned and operated more than 1,000 gas stations throughout the United States, including in California, during times relevant to this complaint. Prior to 2013, Hess also operated oil refineries in the continental United States and U.S. Virgin Islands.

36. **Devon Energy Entities**

a. Devon Energy Corporation is an independent energy company engaged in the exploration, development, and production of oil, and natural gas. It is incorporated in the State of Delaware and maintains its principal place of business in Oklahoma City, Oklahoma. Devon is engaged in multiple aspects of the fossil fuel industry, including exploration, development, production, and marketing of its fossil fuel products.

b. Devon Energy Corporation controls and has controlled companywide decisions about the quantity and extent of fossil fuel production and sales, including those of its subsidiaries.

c. Devon Energy Corporation controls and has controlled companywide decisions related to climate change and greenhouse gas emissions from its fossil fuel products, including those of its subsidiaries.

d. Devon Energy Production Company, L.P., is a Devon subsidiary registered to do business in the State of California and with a designated agent for service of process in California. Devon Energy Production Company, L.P., does substantial fossil fuel product-related business in California.

e. Devon Energy Corporation is a successor-in-interest to the Pauley Petroleum Company ("Pauley"). At times relevant to this complaint, Pauley did substantial fossil-fuel related business in California. Specifically, this included owning and operating a petroleum refinery in Newhall (Los Angeles County), California, from 1959 to 1989, and a refinery in Wilmington (Los Angeles County), California, from 1988 to 1992. Pauley merged with Hondo Oil and Gas Co. ("Hondo") in 1987. Subsequently, Devon Energy Corp. acquired Hondo in 1992.

f. Defendants Devon Energy Corporation and Devon Energy Production Company, L.P., are collectively referred to as "Devon."

37. **<u>Encana Corporation</u>**

a. Encana Corporation ("Encana") is a Canadian corporation with its principal place of business in Calgary, Alberta, Canada. Encana is an extractor and marketer of oil and natural gas and has facilities including gas plants and gas wells in Colorado, Texas, Wyoming, Louisiana, and New Mexico. By approximately 2005, Encana was the largest independent owner and operator of natural gas storage facilities in North America.

b. Encana has done and continues to do substantial fossil fuel product-related business in California. Between 1997 and 2006, Encana owned and operated the Wild Goose Storage underground natural gas storage facility in Butte County, California. In 2003, Encana began transporting natural gas through a 25-mile pipeline from the Wild Goose Station to a PG&E compressor station in Colusa County, California, where gas entered the main PG&E pipeline. Encana invested in a 100 billion cubic foot expansion of the facility in 2004, bringing gas storage capacity at Wild Goose to 24 billion cubic feet.

38. **<u>Apache Corporation</u>**

a. Apache Corporation is a publicly traded Delaware corporation with its principal place of business in Houston, Texas. Apache is an oil and gas exploration and production company, with crude oil and natural gas exploration and extraction operations in the United States, Canada, Egypt, and in the North Sea.

b. During the time at issue, Apache extracted natural gas from wells developed on approximately seven million acres of land held in the Canadian provinces of British Columbia, Alberta, and Saskatchewan, and Apache did substantial fossil fuel product-related business in California. Apache transported a substantial volume of the natural gas extracted from its Canadian holdings to California, where it sold that gas to electric utilities, end-users, other fossil fuel companies, supply aggregators, and other fossil fuel marketers. Apache directed sales of its natural gas to California in addition to markets in Washington state, Chicago, and western Canada, to intentionally retain a diverse customer base and maximize profits from the differential price rates and demand levels in those respective markets.

39. **<u>Doe Defendants</u>**

a. The true names and capacities, whether individual, corporate, associate, or otherwise of Defendants Does 1 through 100, inclusive, are unknown to Plaintiff, who therefore sues said Defendants by such fictitious names pursuant to California Code of Civil Procedure Section 474. Plaintiff is informed and believes, and on that basis alleges, that each of the fictitiously named Defendants is responsible in some manner for the acts and occurrences herein alleged, and that Plaintiff's injuries and damages were caused by such Defendants.

C. Relevant Non-Parties: Fossil Fuel Industry Associations

40. As set forth in greater detail below, each Defendant had actual knowledge that its fossil fuel products were hazardous. Defendants obtained knowledge of the hazards of their products independently and through their membership and involvement in trade associations.

41. Each Defendant's fossil fuel promotion and marketing efforts were assisted by the trade associations described below. Acting on behalf of the Defendants, the industry associations engaged in a long-term course of conduct to misrepresent, omit, and conceal the dangers of Defendants' fossil fuel products.

a. **<u>The American Petroleum Institute (API)</u>**: API is a national trade association representing the oil and gas industry, formed in 1919. At least the following Defendants and/or their predecessors in interest are and/or have been API members at times relevant to this litigation: Chevron, Exxon, BP, Shell, ConocoPhillips, Hess, Anadarko, Occidental, Repsol, Marathon, Devon, Encana, and Apache.[10]

b. **<u>The Western States Petroleum Association (WSPA)</u>**: WSPA is a trade association representing oil producers in Arizona, California, Nevada, Oregon, and Washington.[11] Its members include, and at times relevant to this Complaint, have included, at least Defendants Chevron, BP, ConocoPhillips, Shell, and Exxon.[12]

c. **<u>The American Fuel and Petrochemical Manufacturers (AFPM)</u>** is a national association of petroleum and petrochemical companies. At relevant times, its members included, but were not limited to, at least BP Petrochemicals, BP Products North America, Chevron U.S.A. Inc., CITGO Petroleum Corporation, Exxon Mobil Corporation, Occidental

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[10] American Petroleum Institute (API), *Members*, http://www.api.org/membership/members (accessed Nov. 5, 2018).
[11] WSPA, *About*, https://www.wspa.org/about (accessed Nov. 5, 2018).
[12] *Id.*

Chemical Corporation, Phillips 66, Shell Chemical Company, and Total Petrochemicals & Refining USA, Inc.[13]

d. **<u>The Information Council for the Environment (ICE)</u>**: ICE was formed by coal companies and their allies, including Western Fuels Association and the National Coal Association. Associated companies included at least Pittsburg and Midway Coal Mining (Chevron),[14] and Island Creek Coal Company (Occidental).

e. **<u>The Global Climate Coalition (GCC)</u>**: GCC was an industry group formed to oppose greenhouse gas emission reduction policies and the Kyoto Protocol. It was founded in 1989 shortly after the first Intergovernmental Panel on Climate Change meeting was held, and disbanded in 2001. Founding members included the National Association of Manufacturers, the Edison Electric Institute, and the United States Chamber of Commerce. The GCC's early individual corporate members included Amoco (BP), API, Chevron, Exxon, Shell Oil, Texaco (Chevron) and Phillips Petroleum (ConocoPhillips). During its existence, other members and funders included ARCO (BP), the National Mining Association, and the Western Fuels Association. The coalition also operated for several years out of the National Association of Manufacturers' offices.

III. <u>AGENCY</u>

42. At all times herein mentioned, each of the Defendants was the agent, servant, partner, aider and abettor, co-conspirator, and/or joint venturer of each of the remaining Defendants herein and was at all times operating and acting within the purpose and scope of said agency, service, employment, partnership, conspiracy, and joint venture and rendered substantial assistance and encouragement to the other Defendants, knowing that their conduct was wrongful and/or constituted a breach of duty.

IV. <u>JURISDICTION AND VENUE</u>

43. This court's personal jurisdiction over Defendants named herein is proper because each Defendant maintains substantial contacts with California by and through its fossil fuel

[13] AFPM, *Membership Directory*, https://www.afpm.org/membership-directory (accessed Nov. 5, 2018).

[14] Hereinafter, parenthetical references to Defendants indicate corporate ancestry and/or affiliation.

business operations in this state, as described above, and because Plaintiff's injuries described herein arose out of and relate to those operations and occurred in California.

44. The Superior Court of California for San Francisco County is a court of general jurisdiction and therefore has subject matter jurisdiction over this action.

45. Venue is proper in San Francisco County pursuant to Code of Civil Procedure section 395.5 because Defendants are corporations and/or associations, and because a substantial portion of the injuries giving rise to Defendants' liability occurred in San Francisco County.

V. <u>FACTUAL BACKGROUND</u>

A. Global Land and Ocean Warming—Observed Effects and Known Cause

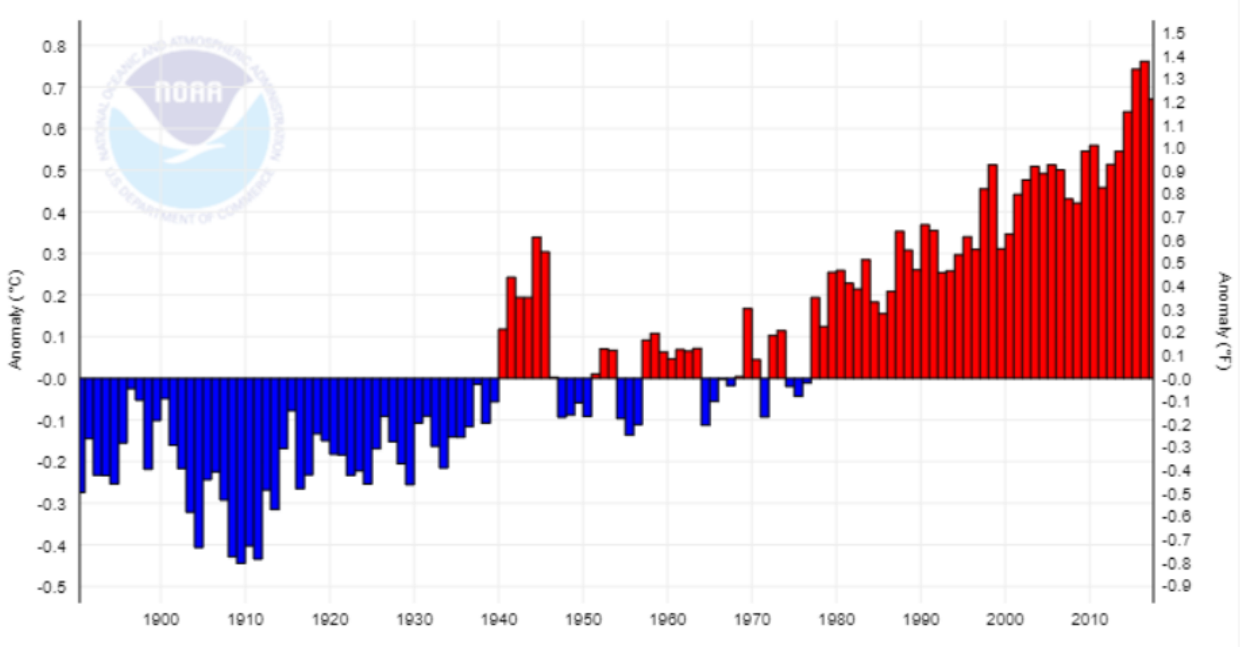
46. Warming of the climate system is unequivocal, and since the 1950s, many of the observed changes to the climate system are unprecedented over decades to millennia.

47. The average ocean temperature in 2016 was approximately 1.7° F warmer than the 20th-century baseline, which is the greatest positive anomaly observed since at least 1880.[15] The increase in hotter temperatures and more frequent positive anomalies during the Great Acceleration is occurring both globally and locally. The graph below shows the increase in global land and ocean temperature anomalies since 1880, as measured against the 1910–2000 global average temperature.[16]

[15] NOAA, National Centers for Environmental Information, *Climate at a Glance (Global Time Series)* (June 2017) https://www.ncdc.noaa.gov/cag/time-series/global/globe/land_ocean/ytd/12/1880-2016.

[16] *Id.*

Figure 1: Global Ocean Temperature Anomalies, January - December



48. The mechanism by which human activity causes the oceans to warm is well established: ocean warming, like atmospheric warming, is overwhelmingly caused by anthropogenic greenhouse gas emissions.[17]

49. When emitted, greenhouse gases trap heat within Earth's atmosphere that would otherwise radiate into space.

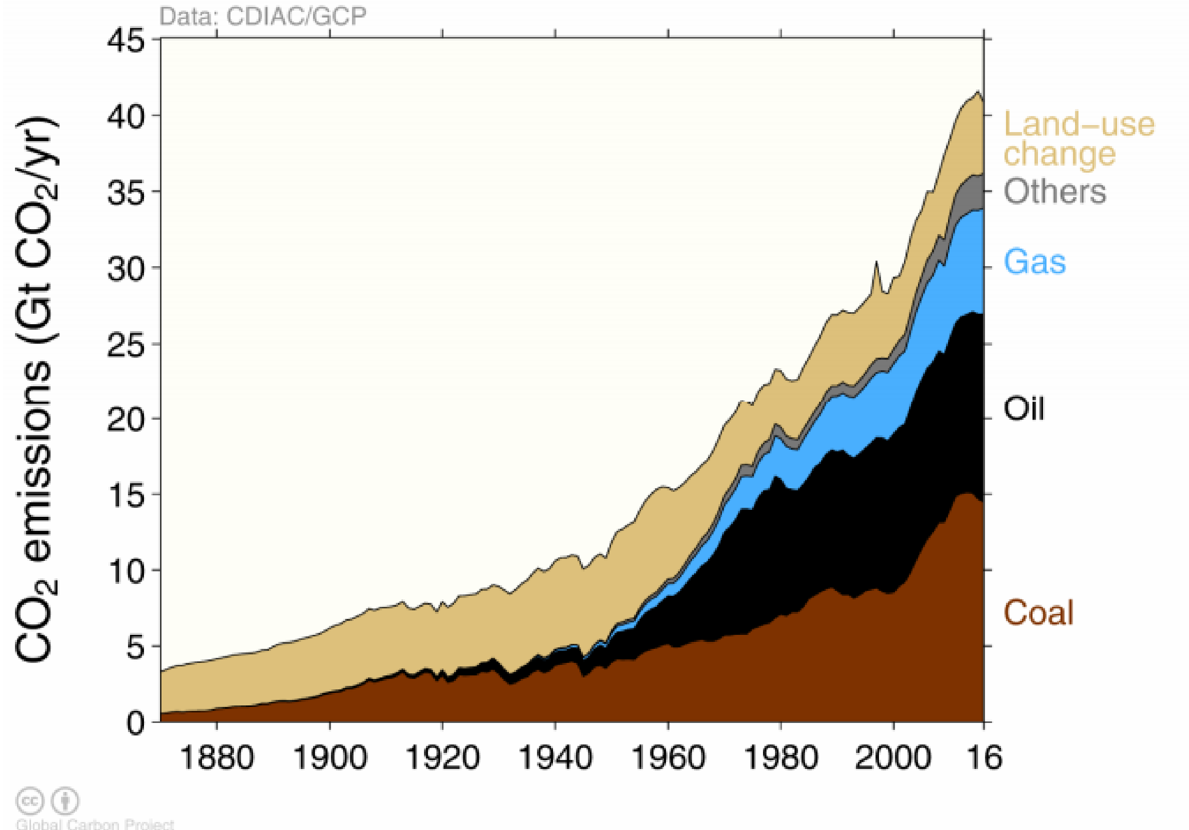
50. Greenhouse gases are largely byproducts of humans burning fossil fuels to produce energy, and using fossil fuels to create petrochemical products.

51. Human activity, particularly greenhouse gas emissions, is the primary cause of global ambient air and ocean warming, and associated effects on Earth's climate.

52. Prior to World War II, most anthropogenic CO_2 emissions were caused by land-use practices, such as forestry and agriculture, which altered the ability of the land and global biosphere to absorb CO_2 from the atmosphere; the impacts of such activities on Earth's climate were relatively minor. Since the beginning of the Great Acceleration, however, both the annual rate and total volume of human CO_2 emissions have increased enormously following the advent of major

[17] IPCC 2014 Synthesis Report, *supra* note 2, at 4.

uses of oil, gas, and coal. The graph below shows that while CO_2 emissions attributable to forestry and other land-use change have remained relatively constant, total emissions attributable to fossil fuels have increased dramatically since the 1950s.[18]



<u>Figure 2: Total Annual Carbon Dioxide Emissions by Source, 1860–2016:</u>

53. As human reliance on fossil fuels for industrial and mechanical processes has increased, so too have greenhouse gas emissions, especially of CO_2. The Great Acceleration is marked by a massive increase in the annual rate of fossil fuel emissions: more than half of all cumulative CO_2 emissions have occurred since 1988.[19] The rate of CO_2 emissions from fossil fuels and industry, moreover, has increased threefold since the 1960s, and by more than 60% since

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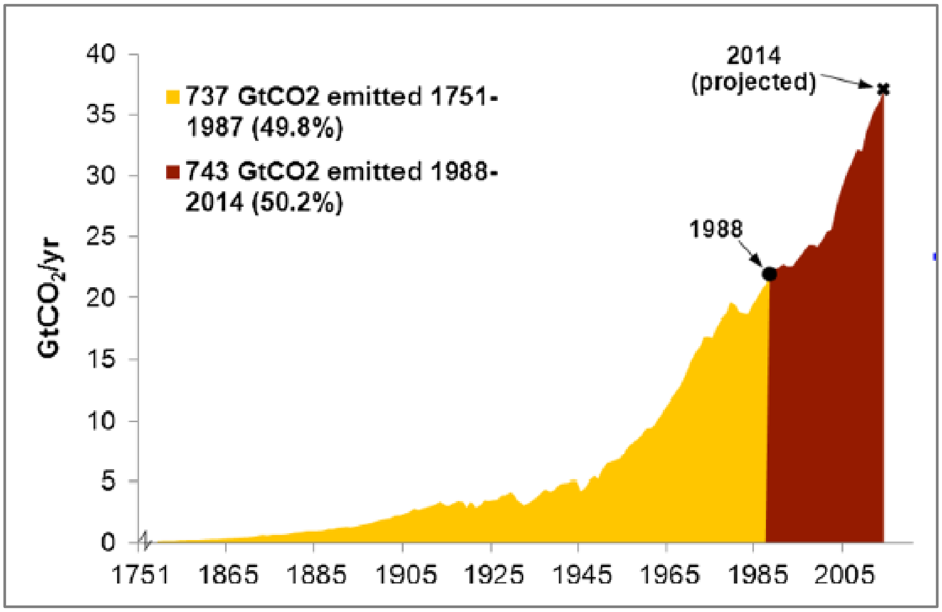
[18] Global Carbon Project, Global Carbon Budget 2017 (Nov. 13, 2017), http://www.globalcarbonproject.org/carbonbudget/17/files/GCP_CarbonBudget_2017.pdf (*citing* CDIAC; R.A. Houghton & Alexander A. Nassikas, *Global and Regional Fluxes of Carbon from Land Use and Land Cover Change 1850–2015*, 31 GLOBAL BIOCHEMICAL CYCLES 3, 456 (Feb. 2017)).

[19] R.J. Andres et al., *A synthesis of carbon dioxide emissions from fossil-fuel combustion*, BIOGEOSCIENCES, 9, 1851 (2012), http://www.biogeosciences.net/9/1845/2012.

1990.[20] The graph below illustrates the increasing rate of global CO_2 emissions since the industrial era began.[21]



<u>Figure 3: Cumulative Annual Anthropogenic Carbon Dioxide Emissions, 1751–2014:</u>

54. Because of the increased use of fossil fuel products, concentrations of greenhouse gases in the atmosphere are now at a level unprecedented in at least 800,000 years.[22] The graph below illustrates the nearly 30% increase in atmospheric CO_2 concentration above pre-Industrial levels since 1960.[23]

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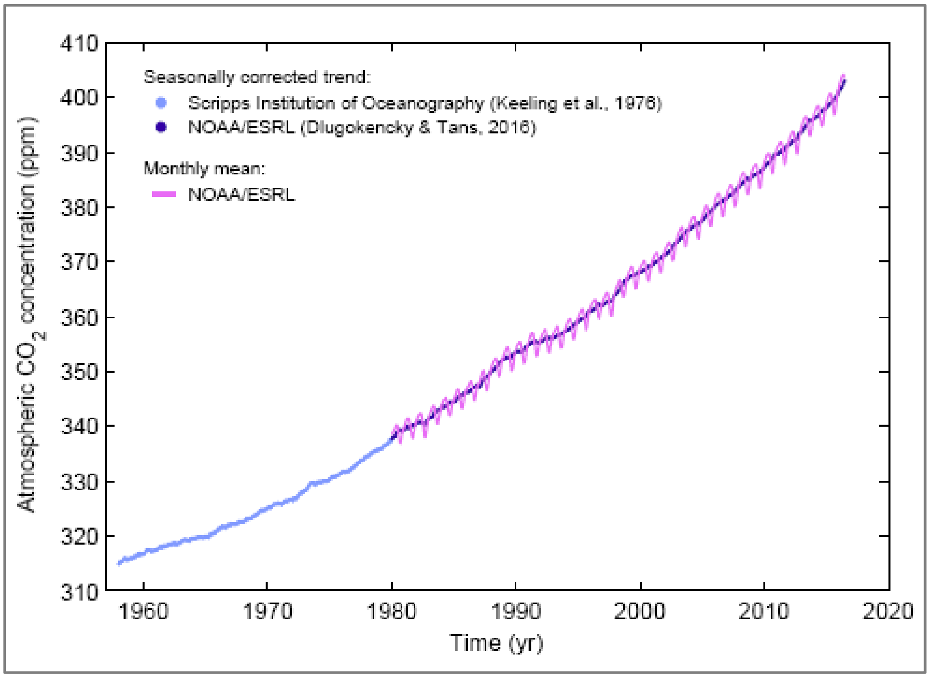
[20] *Global Carbon Budget 2016*, *supra* note 4, at 630 ("Global CO_2 emissions from fossil fuels and industry have increased every decade from an average of 3.1±0.2 GtC/yr in the 1960s to an average of 9.3±0.5 GtC/yr during 2006–2015.").

[21] Peter Frumhoff et al., *The Climate Responsibilities of Industrial Carbon Producers*, 132 CLIMATIC CHANGE 157, 164 (2015).

[22] IPCC 2014 Synthesis Report, *supra* note 2, at 4.

[23] *Global Carbon Budget 2016*, *supra* note 4, at 608.

<u>Figure 4: Atmospheric Carbon Dioxide Concentration in Parts Per Million, 1960–2015:</u>



55. Of the increase in energy that has accumulated in Earth's atmosphere between 1971 and 2010, more than 90% is stored in the oceans.[24]

56. In addition to the positive (increasing) trend in ocean surface temperature, marine heatwaves—prolonged, discrete, anomalously warm water events that can be described by their duration, intensity, rate of evolution, and spatial extent[25]—have become more frequent under continued anthropogenic warming.[26] This trend will continue and worsen in the future.

B. Domoic Acid Outbreaks

57. Domoic acid is a neurotoxin produced by species of marine algae, including the diatom *Pseudo-nitzschia australis*, that when ingested by humans causes "amnesic shellfish

[24] IPCC 2014 Synthesis Report, *supra* note 2, at 4.

[25] Alistair J. Hobday et al., *A hierarchical approach to defining marine heatwaves*, PROGRESS IN OCEANOGRAPHY 141, 227–38 (Feb. 2016).

[26] *See, e.g.*, Evan Weller et al., *Human Contribution to the 2014 Record High Sea Surface Temperatures Over the Western Tropical and Northeast Pacific*, BULLETIN OF THE AMERICAN METEOROLOGICAL SOCIETY, Vol. 96, No. 12, S103 (Dec. 2015).

poisoning," which induces symptoms including vomiting, diarrhea, cramps, and other gastrointestinal upset, permanent short-term memory loss, and, in severe cases, death.

58. The U.S. Food and Drug Administration ("FDA") has established a domoic acid action level in Dungeness crab viscera of 30 parts per million ("ppm"). Above that action level, crab is considered "adulterated" and illegal to sell. California and Oregon both adhere to that action level and impose precautionary measures when crabs in those states contain domoic acid at levels exceeding the action level.

59. Members of the algal genus *Pseudo-nitzschia* thrive in warming oceans.[27] In particular, *Pseudo-nitzschia australis* increases its growth rate, photosynthesis, and toxigenicity in warmer water temperatures.[28]

60. In late 2013, a sea surface temperature anomaly developed in the Northeastern Pacific Ocean, including along the California coast. Eventually dubbed "the Blob" by scientists,[29] this mass of warm water would persist through 2016,[30] extend from Alaska to Mexico,[31] and feature positive temperature anomalies of greater than 4.5º F—more than three standard deviations above the expected sea surface temperature in the area.[32]

61. Conditions within the Blob were characterized by unusually warm waters, particularly before the initiation of the upwelling season.[33]

62. The conditions brought by the Blob favored *Pseudo-nitzschia* and allowed small seed populations to become established, specifically in those temperature ranges present along the California coast.[34]

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[27] Zhi Zhu et al., *Understanding the blob bloom: Warming increases toxicity and abundance of the harmful bloom diatom Pseudo-Nitzschia in California Coastal Waters*, 67 HARMFUL ALGAE 36, 36 (2017).

[28] *Id*.

[29] *See* Nicholas A. Bond et al., *Causes and impacts of the 2014 warm anomaly in the NE Pacific*, GEOPHYSICAL RESEARCH LETTERS 42, 3414 (May 5, 2015).

[30] *See* Dr. Raphael Kudela, California Joint Committee on Fisheries and Aquaculture Hearing Testimony (Oct. 4, 2016) (Blob persisted into July 2016, causing late *Pseudo-nitzschia* bloom).

[31] Di Lorenzo & Mantua, *supra* note 3, at 1.

[32] *See* Bond et al., *supra* note 29, at 3414.

[33] "Upwelling" is the phenomenon by which the Northwest winds blowing out of the Gulf of Alaska displace surface water and bring cooler, nutrient-rich water from depth. This annual phenomenon is the principal reason that the California Current ecosystem is among the most productive, diverse marine ecosystems on the planet.

[34] *Id.*

63. With the onset of upwelling came a deluge of nutrients that caused *Pseudo-nitzschia* seed populations to explode in abundance, resulting in a harmful algal bloom unprecedented in its extent and persistence.[35] The sheer biomass and extent of *Pseudo-nitzschia* produced similarly unprecedented concentrations of domoic acid.[36] The toxin entered the marine trophic chain, where it accumulated in crabs feeding on other contaminated organisms. Domoic acid contamination persists in ocean sediments and therefore continues to impact organisms living and feeding on the bottom of the ocean floor ("benthic organisms") long after the toxin-producing algal species have dissipated.[37]

64. In response to testing showing that crabs off the west coast contained domoic acid concentrations greater than FDA's 30-ppm action level, CDFW and ODFW have closed large swaths of those states' coasts to commercial crabbing. ODFW also has imposed additional precautionary measures, such as requiring crabs harvested from areas that had been under a domoic acid-induced closure to be eviscerated (thereby removing the viscera, or guts, which typically contain the highest concentration of domoic acid) before proceeding to the retail market.

65. As the sea surface temperature warming trend continues, domoic acid outbreaks will become a recurring facet of the California Current ecosystem, [38] and will continue to impact commercial fisheries. Indeed, testing in California and Oregon ahead of the 2018–19 commercial Dungeness crab season has shown crabs that exceed the 30-ppm action level. In response, CDFW has already announced the closure of a large section of the California coast from Bodega Head to the Sonoma/Mendocino County line to commercial crabbing at the outset of the 2018–19 season. Continued ocean warming through the 21st century will promote the intensification and

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[35] Ryan M. McCabe et al., *The unprecedented coastwide toxic algal bloom linked to anomalous ocean conditions*, GEOPHYSICAL RESEARCH LETTERS 43, 10,369 (2016); *see also* S. Morgaine McKibben, *Climatic regulation of the neurotoxin domoic acid*, PROCEEDINGS OF THE NATIONAL ACADEMY OF SCIENCES 114, 240 (Jan. 10, 2017).

[36] McCabe et al., *supra* note 35, at 10,372.

[37] *Id.* at 10,371 (citing R.A. Horner et al., *Retention of domoic acid by Pacific Razor Clams, Siliqua patula, Preliminary Study*, 12 JOURNAL OF SHELLFISH RESEARCH 451, 451–56 (1993)).

[38] *Id.* at 10,373; Zhu, *supra* note 27, at 40 (noting that anticipated summertime sea surface temperature increases will correspond with the temperatures observed in the Blob).

redistribution of harmful algal blooms around the world,[39] including *Pseudo-nitzschia* blooms on the west coast.

C. Attribution

66. "Carbon factors" analysis, devised by the International Panel on Climate Change (IPCC), the United Nations International Energy Agency, and the U.S. Environmental Protection Agency, quantifies the amount of CO_2 emissions attributable to a unit of raw fossil fuel extracted from the ground.[40] Emissions factors for oil, coal, liquid natural gas, and natural gas are different for each material but are nevertheless known and quantifiable for each.[41] This analysis accounts for the use of Defendants' fossil fuel products, including non-combustion purposes that sequester CO_2 rather than emit it (e.g., production of asphalt).

67. Defendants' historical and current fossil fuel extraction and production records are publicly available in various fora. These include university and public library collections, company websites, company reports filed with the U.S. Securities and Exchange Commission, company histories, and other sources. The cumulative CO_2 and methane emissions attributable to Defendants' fossil fuel products were calculated by reference to such publicly available documents.

68. While it is possible to distinguish CO_2 derived from fossil fuels from other sources, it is not possible to determine the source of any particular individual molecule of CO_2 in the atmosphere attributable to anthropogenic sources because such greenhouse gas molecules do not bear markers that permit tracing them to their source, and because greenhouse gasses quickly diffuse and comingle in the atmosphere. However, cumulative carbon analysis allows an accurate calculation of net annual CO_2 and methane emissions attributable to each Defendant by quantifying the amount and type of fossil fuels products each Defendant extracted and placed into the stream of commerce, and multiplying those quantities by each fossil fuel product's carbon factor.

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[39] *See* Cristopher J. Gobler, et al., *Ocean warming since 1982 has expanded the niche of toxic algal blooms in the North Atlantic and North Pacific oceans*, Proceedings of the National Academy of Sciences (March 23, 2017).

[40] *See* Richard Heede, *Tracing Anthropogenic Carbon Dioxide and Methane Emissions to Fossil Fuel and Cement Producers, 1854–2010*, CLIMATIC CHANGE 122, 232–33 (2014).

[41] *See, e.g., id.*

69. Defendants, through their extraction, promotion, marketing, and sale of their fossil fuel products, caused more than 15% of global fossil fuel product-related CO_2 between 1965 and 2015, with contributions currently continuing unabated. This constitutes a substantial portion of all such emissions in history, and the attendant increase in mean sea surface temperature; increase in frequency and intensity of marine heatwaves, including the Blob; increase in the expanse, persistence, and severity of harmful algal blooms; increase in *Pseudo-nitzschia* toxigenicity; and the associated domoic acid-related injuries.

70. By quantifying CO_2 and methane pollution attributable to Defendants by and through their fossil fuel products, ocean temperature responses to those emissions are also calculable, and can be attributed to Defendants on an individual and aggregate basis. Individually and collectively, Defendants' extraction, sale, and promotion of their fossil fuel products at the extraction, wholesale and retail levels are responsible for substantial increases in ocean temperature, harmful algal blooms, anomalous weather conditions and events, and specifically the domoic acid outbreaks and related injuries endured by Plaintiff, as described herein.

71. Marine outbreaks of domoic acid are climatically regulated.[42] The warmer the ocean conditions, the more likely domoic acid concentrations are to surpass alert thresholds during upwelling season, and the more toxic and/or widespread a domoic acid event has the potential to become.[43]

72. A marine heatwave as massive and warm as the Blob is "extremely rare" without the influence of anthropogenic climate forcing on the atmosphere.[44] Anthropogenic climate forcing has already increased the risk for extreme sea surface temperature events like the Blob by at least a factor of five.[45] Despite the known influence of normal sea surface temperature variability observed in Northeast Pacific on semi-decadal, decadal, and other relatively short timeframes, the Blob was still "significantly attributable to anthropogenic forcing."[46]

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[42] McKibben, *supra* note 35, at 239–44.
[43] *Id.* at 243.
[44] Weller et al., *supra* note 26, at S103.
[45] Di Lorenzo & Mantua, *supra* note 3, at 6.
[46] Weller et al., *supra* note 27.

73. But for the Blob, caused by Defendants' actions, the California and Oregon commercial Dungeness crab fisheries would not have been closed as described herein. As ocean warming and circulation anomalies continue and domoic acid outbreaks increase in frequency and severity, such closures will continue to occur and continue to injure Plaintiff and the west coast crab industry.

74. Defendants, through their extraction, promotion, marketing, and sale of their fossil fuel products, caused a substantial portion of both those emissions and the attendant domoic acid outbreaks that forced California and Oregon to close their commercial crab fisheries during each of the last three seasons and will compel them to close the fisheries during future seasons.

75. As explained above, this analysis considers only the volume of raw material actually extracted from the earth by these Defendants. Many of these Defendants actually are responsible for far greater volumes of emissions because they also refine, manufacture, produce, market, promote, and sell more fossil fuel derivatives than they extract themselves by purchasing fossil fuel products extracted by independent third parties.

76. In addition, considering the Defendants' lead role in promoting, marketing, and selling their fossil fuels products between 1965 and 2015; their efforts to conceal the hazards of those products from consumers; their promotion of their fossil fuel products despite knowing the dangers associated with those products; their dogged campaign against regulation of those products based on falsehoods, omissions, and deceptions; and their failure to pursue less hazardous alternatives available to them, Defendants, individually and together, have substantially and measurably contributed to Plaintiff's domoic acid-related injuries.

D. Defendants Went to Great Lengths to Understand the Hazards Associated With and Knew or Should Have Known of the Dangers Associated with the Extraction, Promotion, and Sale of Their Fossil Fuel Products.

77. By 1965, concern about the risks of anthropogenic greenhouse gas emissions reached the highest level of the United States' scientific community. In that year, President Lyndon B. Johnson's Science Advisory Committee Panel on Environmental Pollution reported that by the year 2000, anthropogenic CO_2 emissions would "modify the heat balance of the atmosphere to such an extent that marked changes in climate . . . could occur," and that atmospheric warming

would create an equivalent sea temperature increase that could impact fisheries.[47] President Johnson announced in a special message to Congress that "[t]his generation has altered the composition of the atmosphere on a global scale through . . . a steady increase in carbon dioxide from the burning of fossil fuels."[48]

78. These statements from the Johnson Administration, at a minimum, put Defendants on notice of the potentially substantial dangers to people, communities, and the planet associated with unabated use of their fossil fuel products. Moreover, Defendants had amassed a considerable body of knowledge on the subject through their own independent efforts.

79. A 1963 Conservation Foundation report on a conference of scientists referenced in the 1966 World Book Encyclopedia, as well as in presidential panel reports and other sources around that time, described many specific consequences of rising greenhouse gas pollution in the atmosphere. It warned that

> a continuing rise in the amount of atmospheric carbon dioxide is likely to be accompanied by a significant warming of the surface of the earth which by melting the polar ice caps would raise sea level and by warming the oceans would change considerably the distributions of marine species including commercial fisheries.

It warned of the possibility of "wiping out the world's present commercial fisheries." The report, in fact, noted that "the changes in marine life in the North Atlantic which accompanied the temperature change have been very noticeable."[49]

80. In 1968, a Stanford Research Institute (SRI) report commissioned by the American Petroleum Institute ("API") and made available to all of its members, concluded, among other things:

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[47] President's Science Advisory Committee, *Restoring the Quality of Our Environment: Report of the Environmental Pollution Panel*, at 9, 123–24 (Nov. 1965), https://hdl.handle.net/2027/uc1.b4315678.

[48] President Lyndon B. Johnson, *Special Message to Congress on Conservation and Restoration of Natural Beauty* (Feb. 8, 1965), http://acsc.lib.udel.edu/items/show/292.

[49] The Conservation Foundation, *Implications of Rising Carbon Dioxide Content of the Atmosphere: A statement of trends and implications of carbon dioxide research reviewed at a conference of scientists* (Mar. 1963), https://babel.hathitrust.org/cgi/pt?id=mdp.39015004619030;view=1up;seq=5.

> If the Earth's temperature increases significantly, a number of events might be expected to occur including the melting of the Antarctic ice cap, a rise in sea levels, warming of the oceans and an increase in photosynthesis. . . .
>
> It is clear that we are unsure as to what our long-lived pollutants are doing to our environment; however, there seems to be no doubt that the potential damage to our environment could be severe. . . .[T]he prospect for the future must be of serious concern.[50]

81. In a supplement to the 1968 report prepared for API in 1969, authors Robinson and Robbins projected that based on current fuel usage, atmospheric CO_2 concentrations would reach 370 ppm by 2000—almost exactly what it turned out to be (369.34 ppm, according to data from NASA).[51] The report also drew the connection between rising atmospheric CO_2 concentrations and the use of fossil fuels, stating that "balance between environmental sources and sinks has been disturbed by the emission to the atmosphere of additional CO_2 from the increased combustion of carbonaceous fuels" and that it seemed "unlikely that the observed rise in atmospheric CO_2 has been due to changes in the biosphere." The authors warn repeatedly of the temptations and consequences of ignoring CO_2 as a problem and pollutant:

> CO_2 is so common and such an integral part of all our activities that air pollution regulations typically state that CO_2 emissions are not to be considered as pollutants. This is perhaps fortunate for our present mode of living, centered as it is around carbon combustion. However, this seeming necessity, the CO_2 emission, is the only air pollutant, as we shall see, that has been shown to be of global importance as a factor that could change man's environment on the basis of a long period of scientific investigation.[52]

82. In 1969, Shell memorialized an ongoing, 18-month project to collect ocean data from oil platforms to develop and calibrate environmental forecasting theories related to predicting wave, wind, storm, sea level, and current changes and trends.[53] Several Defendants and/or their predecessors participated in the project, including Esso Production Research Company (Exxon), Mobil Research and Development Company (Exxon), Pan American Petroleum Corporation (BP),

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[50] Elmer Robinson & R.C. Robbins, *Sources, Abundance, and Fate of Gaseous Atmospheric Pollutants*, Stanford Research Institute (Feb. 1968), https://www.smokeandfumes.org/documents/document16.

[51] "Global Mean CO_2 Mixing Ratios (ppm): Observations," NASA Goddard Institute for Space Studies, https://data.giss.nasa.gov/modelforce/ghgases/Fig1A.ext.txt (webpage) (accessed June 16, 2018).

[52] Elmer Robinson & R.C. Robbins, *Sources, Abundance, and Fate of Gaseous Atmospheric Pollutants Supplement*, Stanford Research Institute (June 1969).

[53] M.M. Patterson, *An Ocean Data Gathering Program for the Gulf of Mexico*, Society of Petroleum Engineers (1969), https://www.onepetro.org/conference-paper/SPE-2638-MS.

Gulf Oil Corporation (Chevron), Texaco Inc. (Chevron), and the Chevron Oil Field Research Company.

83. In a 1970 report by H.R. Holland from the Engineering Division of Imperial Oil (Exxon), he stated: "Since pollution means disaster to the affected species, the only satisfactory course of action is to prevent it—to maintain the addition of foreign matter at such levels that it can be diluted, assimilated or destroyed by natural processes—to protect man's environment from man." He also noted that "a problem of such size, complexity and importance cannot be dealt with on a voluntary basis." CO_2 was listed as an air pollutant in the document.[54]

84. In 1972, API members, including Defendants, received a status report on all environmental research projects funded by API. The report summarized the 1968 SRI report describing the impact of Defendants' fossil fuel products on the environment, including global surface and ocean warming. Industry participants who received this report include: American Standard of Indiana (BP), Asiatic (Shell), Ashland (Marathon), Atlantic Richfield (BP), British Petroleum (BP), Chevron Standard of California (Chevron), Cities Service (Citgo), Continental (ConocoPhillips), Dupont (former owner of Conoco), Esso Research (Exxon), Ethyl (formerly affiliated with Esso, which was subsumed by Exxon Mobil), Getty (Exxon), Gulf (Chevron, among others), Humble Standard of New Jersey (Exxon/Chevron/BP), Marathon, Mobil (Exxon), Pan American (BP), Phillips (ConocoPhillips), Shell, Standard of Ohio (BP), Texaco (Chevron), Union (Chevron), Edison Electric Institute (representing electric utilities), Bituminous Coal Research (coal industry research group), Mid-Continent Oil & Gas Association (presently the U.S. Oil & Gas Association, a national trade association), Western Oil & Gas Association, National Petroleum Refiners Association (presently the American Fuel and Petrochemical Manufacturers Association, a national trade association), Champlin (Anadarko), Skelly (Exxon), Colonial Pipeline (ownership has included BP, Citgo, Exxon, ConocoPhillips, Chevron entities, among others) and Caltex (Chevron), among others.[55]

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[54] H.R. Holland, "Pollution is Everybody's Business," Imperial Oil (1970), https://www.desmogblog.com/sites/beta.desmogblog.com/files/DeSmogBlog-Imperial%20Oil%20Archive-Pollution-Everyone-Business-1970.pdf.

[55] American Petroleum Institute, *Environmental Research, A Status Report*, Committee for Air and Water Conservation (Jan. 1972), *available at* http://files.eric.ed.gov/fulltext/ED066339.pdf.

85. In a 1977 presentation and again in a 1978 briefing, Exxon scientists warned the Exxon Corporation Management Committee that CO_2 concentrations were building in Earth's atmosphere at an increasing rate, that CO_2 emissions attributable to fossil fuels were retained in the atmosphere, and that CO_2 was contributing to global warming.[56] The report stated:

> There is general scientific agreement that the most likely manner in which mankind is influencing the global climate is through carbon dioxide release from the burning of fossil fuels . . . [and that] Man has a time window of five to ten years before the need for hard decisions regarding changes in energy strategies might become critical.[57]

The report concluded that "doubling in CO_2 could increase average global temperature 1°C to 3°C by 2050 A.D. (10°C predicted at poles)."[58]

86. Thereafter, Exxon engaged in a research program to study the environmental fate of fossil fuel-derived greenhouse gases and their impacts, which included publication of peer-reviewed research by Exxon staff scientists and the conversion of a supertanker into a research vessel to study the greenhouse effect and the role of the oceans in absorbing anthropogenic CO_2. Much of this research was communicated in a variety of industry fora, symposia, and papers shared through trade associations and directly with other Defendants.

87. Exxon scientists made the case internally for using company resources to build corporate knowledge about the impacts of the promotion, marketing, and consumption of Defendants' fossil fuel products. Exxon climate researcher Henry Shaw wrote in 1978: "The rationale for Exxon's involvement and commitment of funds and personnel is based on our need to assess the possible impact of the greenhouse effect on Exxon business. Exxon must develop a credible scientific team that can critically evaluate the information generated on the subject and be able to carry bad news, if any, to the corporation."[59] Moreover, Shaw emphasized the need to

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[56] Memo from J.F. Black to F.G. Turpin, *The Greenhouse Effect*, Exxon Research and Engineering Co. (June 6, 1978), http://www.climatefiles.com/exxonmobil/1978-exxon-memo-on-greenhouse-effect-for-exxon-corporation-management-committee.

[57] *Id.*

[58] *Id.*

[59] Memo from Henry Shaw to Edward David Jr., *The "Greenhouse Effect,"* Exxon Research and Engineering Company (Dec. 7, 1978), http://insideclimatenews.org/sites/default/files/documents/Credible%20Scientific%20Team%201978%20Letter.pdf.

collaborate with universities and government to more completely understand what he called the "CO_2 problem."[60]

88. In 1979, API and its members, including Defendants, convened a Task Force to monitor and share cutting edge climate research among the oil industry. The group was initially called the CO_2 and Climate Task Force, but changed its name to the Climate and Energy Task Force in 1980 (hereinafter referred to as "API CO_2 Task Force"). Membership included senior scientists and engineers from nearly every major U.S. and multinational oil and gas company, including Exxon, Mobil (Exxon), Amoco (BP), Phillips (ConocoPhillips), Texaco (Chevron), Shell, Sunoco, Sohio (BP) as well as Standard Oil of California (BP) and Gulf Oil (Chevron, among others). The Task Force was charged with assessing the implications of emerging science on the petroleum and gas industries and identifying where reductions in greenhouse gas emissions from Defendants' fossil fuel products could be made.[61]

89. In 1979, API sent its members a background memo related to the API CO_2 and Climate Task Force's efforts, stating that CO_2 concentrations were rising steadily in the atmosphere, and predicting when the first clear effects of climate change might be felt.[62]

90. Also in 1979, Exxon scientists advocated internally for additional fossil fuel industry-generated research in light of the growing consensus that consumption of fossil fuel products was changing the planet's climate:

> "We should determine how Exxon can best participate in all these [atmospheric science research] areas and influence possible legislation on environmental controls. It is important to begin to anticipate the strong intervention of environmental groups and be prepared to respond with reliable and credible data. It behooves [Exxon] to start a very aggressive defensive program in the indicated areas of atmospheric science and climate because there is a good probability that legislation affecting our business will be passed. Clearly, it is in our interest for such legislation to be based on hard scientific data. The data obtained from research

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[60] *Id.*

[61] American Petroleum Institute, *AQ-9 Task Force Meeting Minutes* (Mar. 18, 1980), http://insideclimatenews.org/sites/default/files/documents/AQ-9%20Task%20Force%20Meeting%20%281980%29.pdf (AQ-9 refers to the "CO_2 and Climate" Task Force).

[62] Neela Banerjee, *Exxon's Oil Industry Peers Knew About Climate Dangers in the 1970s, Too*, INSIDE CLIMATE NEWS (Dec. 22, 2015), https://insideclimatenews.org/news/22122015/exxon-mobil-oil-industry-peers-knew-about-climate-change-dangers-1970s-american-petroleum-institute-api-shell-chevron-texaco.

on the global damage from pollution, e.g., from coal combustion, will give us the needed focus for further research to avoid or control such pollutants."[63]

91. That same year, Exxon Research and Engineering reported that: "The most widely held theory [about increasing CO_2 concentration] is that the increase is due to fossil fuel combustion, increasing CO_2 concentration will cause a warming of the earth's surface, and the present trend of fossil fuel consumption will cause dramatic environmental effects before the year 2050."[64] According to the report, "ecological consequences of increased CO_2" to 500 ppm (1.7 times 1850 levels) could mean that "marine life would be markedly changed;" and, by way of example, that "maintaining runs of salmon and steelhead and other subarctic species in the Columbia River system would become increasingly difficult."[65] With a doubling of the 1860 CO_2 concentration, "ocean levels would rise four feet" and "the Arctic Ocean would be ice free for at least six months each year, causing major shifts in weather patterns in the northern hemisphere."[66]

92. Further, the report stated that unless fossil fuel use was constrained, there would be "noticeable temperature changes" associated with an increase in atmospheric CO_2 from about 280 parts per million before the Industrial Revolution to 400 parts per million by the year 2010.[67] Those projections proved remarkably accurate—atmospheric CO_2 concentrations surpassed 400 parts per million in May 2013, for the first time in millions of years.[68] In 2015, the annual average CO_2 concentration rose above 400 parts per million, and in 2016 the annual low surpassed 400 parts per million, meaning atmospheric CO_2 concentration remained above that threshold all year.[69]

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[63] Henry Shaw, *Exxon Memo to H.N. Weinberg about "Research in Atmospheric Science"*, Exxon Inter-Office Correspondence (Nov. 19, 1979), https://insideclimatenews.org/sites/default/files/documents/Probable%20Legislation%20Memo%20(1979).pdf.

[64] W.L. Ferrall, *Exxon Memo to R.L. Hirsch about "Controlling Atmospheric CO_2"*, Exxon Research and Engineering Co. (Oct. 16, 1979), http://insideclimatenews.org/sites/default/files/documents/CO2%20and%20Fuel%20Use%20Projections.pdf.

[65] *Id.*

[66] *Id.*

[67] *Id.*

[68] Nicola Jones, *How the World Passed a Carbon Threshold and Why it Matters*, YALE ENVIRONMENT 360 (Jan. 26, 2017), http://e360.yale.edu/features/how-the-world-passed-a-carbon-threshold-400ppm-and-why-it-matters.

[69] *Id.*

93. In 1980, API's CO_2 Task Force members discussed the oil industry's responsibility to reduce CO_2 emissions by changing refining processes and developing fuels that emit less CO_2. The minutes from the Task Force's February 29, 1980, meeting included a summary of a presentation on "The CO_2 Problem" given by Dr. John Laurmann, which identified the "scientific consensus on the potential for large future climatic response to increased CO2 levels" as a reason for API members to have concern with the "CO_2 problem" and informed attendees that there was "strong empirical evidence that rise [in CO_2 concentration was] caused by anthropogenic release of CO_2, mainly from fossil fuel combustion."[70] Moreover, Dr. Laurmann warned that the amount of CO_2 in the atmosphere could double by 2038, which he said would likely lead to a 2.5° C (4.5º F) rise in global average temperatures with "major economic consequences." He then told the Task Force that models showed a 5°C (9º F) rise by 2067, with "globally catastrophic effects."[71] A taskforce member and representative of Texaco leadership present at the meeting posited that the API CO_2 Task Force should develop ground rules for energy release of fuels and the cleanup of fuels as they relate to CO_2 creation.

94. In 1980, the API CO_2 Task Force also discussed a potential area for investigation: alternative energy sources as a means of mitigating CO_2 emissions from Defendants' fossil fuel products. These efforts called for research and development to "Investigate the Market Penetration Requirements of Introducing a New Energy Source into World Wide Use." Such investigation was to include the technical implications of energy source changeover, research timing, and requirements.[72]

95. By 1980, Exxon's senior leadership had become intimately familiar with the greenhouse effect and the role of CO_2 in the atmosphere. In that year, Exxon Senior Vice President and Board member George Piercy questioned Exxon researchers on the minutiae of the ocean's role in absorbing atmospheric CO_2, including whether there was a net CO_2 flux out of the ocean

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[70] American Petroleum Institute, *AQ-9 Task Force Meeting Minutes*, *supra* note 59 (AQ-9 refers to the "CO_2 and Climate" Task Force).

[71] *Id.*

[72] *Id.*

into the atmosphere in certain zones where upwelling of cold water to the surface occurs, because Piercy evidently believed that the oceans could absorb and retain higher concentrations of CO_2 than the atmosphere.[73] This inquiry aligns with Exxon supertanker research into whether the ocean would act as a significant CO_2 sink that would sequester atmospheric CO_2 long enough to allow unabated emissions without triggering dire climatic consequences. As described below, Exxon eventually scrapped this research before it produced sufficient data to derive a conclusion.[74]

96. Also in 1980, Imperial Oil (Exxon) reported to Esso and Exxon managers and environmental staff that increases in fossil fuel usage aggravates CO_2 in the atmosphere. Noting that the United Nations was encouraging research into the carbon cycle, Imperial reported that "[t]echnology exists to remove CO_2 from [fossil fuel power plant] stack gases but removal of only 50% of the CO_2 would double the cost of power generation."

97. Exxon scientist Roger Cohen warned his colleagues in a 1981 internal memorandum that "future developments in global data gathering and analysis, along with advances in climate modeling, may provide strong evidence for a delayed CO_2 effect of a truly substantial magnitude," and that under certain circumstances it would be "very likely that we will unambiguously recognize the threat by the year 2000."[75] Cohen had expressed concern that the memorandum mischaracterized potential effects of unabated CO_2 emissions from Defendants' fossil fuel products: "[I]t is distinctly possible that the . . . [Exxon Planning Division's] scenario will produce effects which will indeed be catastrophic (at least for a substantial fraction of the world's population)."[76]

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[73] Neela Banerjee, *More Exxon Documents Show How Much It Knew About Climate 35 Years Ago*, INSIDE CLIMATE NEWS (Dec. 1, 2015), https://insideclimatenews.org/news/01122015/documents-exxons-early-co2-position-senior-executives-engage-and-warming-forecast.

[74] Neela Banerjee et al., *Exxon Believed Deep Dive Into Climate Research Would Protect Its Business*, INSIDE CLIMATE NEWS (Sept. 17, 2015), https://insideclimatenews.org/news/16092015/exxon-believed-deep-dive-into-climate-research-would-protect-its-business.

[75] Roger W. Cohen, *Exxon Memo to W. Glass about possible "catastrophic" effect of CO_2*, Exxon Inter-Office Correspondence (Aug. 18, 1981), http://www.climatefiles.com/exxonmobil/1981-exxon-memo-on-possible-emission-consequences-of-fossil-fuel-consumption.

[76] *Id.*

98. In 1981, Exxon's Henry Shaw, the company's lead climate researcher at the time, prepared a summary of Exxon's current position on the greenhouse effect for Edward David Jr., president of Exxon Research and Engineering, stating in relevant part:

- "Atmospheric CO_2 will double in 100 years if fossil fuels grow at 1.4%/ a^2.
- 3°C global average temperature rise and 10°C at poles if CO_2 doubles.
  - Major shifts in rainfall/agriculture
  - Polar ice may melt"[77]

99. In 1982, another report prepared for API by scientists at the Lamont-Doherty Geological Observatory at Columbia University recognized that atmospheric CO_2 concentration had risen significantly compared to the beginning of the industrial revolution from about 290 parts per million to about 340 parts per million in 1981 and acknowledged that despite differences in climate modelers' predictions, all models indicated a temperature increase caused by anthropogenic CO_2 within a global mean range of 4º C (7.2° F). The report advised that there was scientific consensus that "a doubling of atmospheric CO_2 from [] pre-industrial revolution value would result in an average global temperature rise of (3.0 ± 1.5)°C [5.4 ± 2.7° F]." It went further, warning that "[s]uch a warming can have serious consequences for man's comfort and survival since patterns of aridity and rainfall can change, the height of the sea level can increase considerably and the world food supply can be affected."[78] Exxon's own modeling research confirmed this, and the company's results were later published in at least three peer-reviewed scientific papers.[79]

100. Also in 1982, Exxon's Environmental Affairs Manager distributed a primer on climate change to a "wide circulation [of] Exxon management . . . intended to familiarize Exxon

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[77] Henry Shaw, *Exxon Memo to E. E. David, Jr. about "CO_2Position Statement"*, Exxon Inter-Office Correspondence (May 15, 1981), https://insideclimatenews.org/sites/default/files/documents/Exxon%20Position%20on%20CO2%20%281981%29.pdf.

[78] American Petroleum Institute, *Climate Models and CO_2 Warming: A Selective Review and Summary*, Lamont-Doherty Geological Observatory (Columbia University) (Mar. 1982), https://assets.documentcloud.org/documents/2805626/1982-API-Climate-Models-and-CO2-Warming-a.pdf.

[79] *See* Roger W. Cohen, *Exxon Memo summarizing findings of research in climate modeling*, Exxon Research and Engineering Co. (Sept. 2, 1982), https://insideclimatenews.org/sites/default/files/documents/%2522Consensus%2522%20on%20CO2%20Impacts%20(1982).pdf (discussing research articles).

personnel with the subject."[80] The primer also was "restricted to Exxon personnel and not to be distributed externally."[81] The primer compiled science on climate change available at the time, and confirmed fossil fuel combustion as a primary anthropogenic contributor to global warming. The report estimated a CO_2 doubling around 2090 based on Exxon's long-range modeled outlook. The author warned that "there are some potentially catastrophic events that must be considered," including increased sea surface temperatures, and the loss of Antarctic ice sheets.[82] It noted that some scientific groups were concerned "that once the effects are measurable, they might not be reversible."[83]

101. In a summary of Exxon's climate modeling research from 1982, Director of Exxon's Theoretical and Mathematical Sciences Laboratory Roger Cohen wrote that "the time required for doubling of atmospheric CO_2 depends on future world consumption of fossil fuels." Cohen concluded that Exxon's own results were "consistent with the published predictions of more complex climate models" and "in accord with the scientific consensus on the effect of increased atmospheric CO_2 on climate."[84]

102. At the fourth biennial Maurice Ewing Symposium at the Lamont-Doherty Geophysical Observatory in October 1982, attended by members of API, Exxon Research and Engineering Company president E.E. David delivered a speech titled: "Inventing the Future: Energy and the CO_2 'Greenhouse Effect.'"[85] His remarks included the following statement: "[F]ew people doubt that the world has entered an energy transition away from dependence upon fossil fuels and toward some mix of renewable resources that will not pose problems of CO_2 accumulation." He went on, discussing the human opportunity to address anthropogenic climate change before the point of no return:

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[80] M. B. Glaser, *Exxon Memo to Management about "CO_2 'Greenhouse' Effect"*, Exxon Research and Engineering Co. (Nov. 12, 1982), http://insideclimatenews.org/sites/default/files/documents/1982%20Exxon%20Primer%20on%20CO2%20Greenhouse%20Effect.pdf.

[81] *Id.*

[82] *Id.*

[83] *Id.*

[84] Cohen, *Exxon Memo summarizing findings of research in climate modeling*, *supra* note 77.

[85] E. E. David, Jr., *Inventing the Future: Energy and the CO_2 Greenhouse Effect: Remarks at the Fourth Annual Ewing Symposium, Tenafly, NJ* (1982), *available at* http://sites.agu.org/publications/files/2015/09/ch1.pdf.

> It is ironic that the biggest uncertainties about the CO_2 buildup are not in predicting what the climate will do, but in predicting what people will do. . . .[It] appears we still have time to generate the wealth and knowledge we will need to invent the transition to a stable energy system.

103. Throughout the early 1980s, at Exxon's direction, Exxon climate scientist Henry Shaw forecasted emissions of CO_2 from fossil fuel use. Those estimates were incorporated into Exxon's 21st century energy projections and were distributed among Exxon's various divisions. Shaw's conclusions included an expectation that atmospheric CO_2 concentrations would double in 2090 per the Exxon model, with an attendant 2.3–5.6º F average global temperature increase. Shaw compared his model results to those of the U.S. EPA, the National Academy of Sciences, and the Massachusetts Institute of Technology, indicating that the Exxon model predicted a longer delay than any of the other models, although its temperature increase prediction was in the mid-range of the four projections.[86]

104. During the 1980s, many Defendants formed their own research units focused on climate modeling. The API, including the API CO_2 Task Force, provided a forum for Defendants to share their research efforts and corroborate their findings related to anthropogenic greenhouse gas emissions.[87]

105. During this time, Defendants' statements express an understanding of their obligation to consider and mitigate the externalities of unabated promotion, marketing, and sale of their fossil fuel products. For example, in 1988, Richard Tucker, the president of Mobil Oil, presented at the American Institute of Chemical Engineers National Meeting, the premier educational forum for chemical engineers, where he stated:

> [H]umanity, which has created the industrial system that has transformed civilities, is also responsible for the environment, which sometimes is at risk because of unintended consequences of industrialization. . . . Maintaining the health of this life-support system is emerging as one of the highest priorities. . . .[W]e must all be environmentalists.
>
> The environmental covenant requires action on many fronts…the low-atmosphere ozone problem, the upper-atmosphere ozone problem and the greenhouse effect, to

[86] Banerjee, More Exxon Documents Show How Much It Knew About Climate 35 Years Ago, *supra* note 77.

[87] Banerjee, *Exxon's Oil Industry Peers Knew About Climate Dangers in the 1970s, Too*, *supra* note 620.

> name a few. . . .Our strategy must be to reduce pollution before it is ever generated – to prevent problems at the source.
>
> Prevention means engineering a new generation of fuels, lubricants and chemical products…. Prevention means designing catalysts and processes that minimize or eliminate the production of unwanted byproducts. . . .Prevention on a global scale may even require a dramatic reduction in our dependence on fossil fuels—and a shift towards solar, hydrogen, and safe nuclear power. It may be possible that—just possible—that the energy industry will transform itself so completely that observers will declare it a new industry. . . .Brute force, low-tech responses and money alone won't meet the challenges we face in the energy industry.[88]

106. Also in 1988, the Shell Greenhouse Effect Working Group issued a confidential internal report, "The Greenhouse Effect," which acknowledged global warming's anthropogenic nature: "Man-made carbon dioxide released into and accumulated in the atmosphere is believed to warm the earth through the so-called greenhouse effect." The authors also noted the burning of fossil fuel as a primary driver of CO_2 buildup and warned that ocean warming would impact marine species populations and that "shifts in ranges and migration patterns could result in local losses of food source revenues, and could require [fishing] operations in other (more distant) grounds."[89]

107. Similar to early warnings by Exxon scientists, the Shell report notes that "by the time the global warming becomes detectable it could be too late to take effective countermeasures to reduce the effects or even to stabilize the situation." The authors mention the need to consider policy changes on multiple occasions, noting that "the potential implications for the world are…so large that policy options need to be considered much earlier" and that research should be "directed more to the analysis of policy and energy options than to studies of what we will be facing exactly."[90]

108. In 1991, Shell produced a film called "Climate of Concern." The film advises that while "no two [climate change projection] scenarios fully agree…[they] have each prompted the same serious warning. A warning endorsed by a uniquely broad consensus of scientists in their

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[88] Richard E. Tucker, *High Tech Frontiers in the Energy Industry: The Challenge Ahead*, AIChE National Meeting (Nov. 30, 1988), *available at* https://hdl.handle.net/2027/pur1.32754074119482?urlappend=%3Bseq=522.

[89] Shell Internationale Petroleum Greenhouse Effect Working Group, *The Greenhouse Effect* (May 30, 1988), https://www.documentcloud.org/documents/4411090-Document3.html#document/p9/a411239.

[90] *Id.*

report to the UN at the end of 1990." The video concludes with a stark admonition: "Global warming is not yet certain, but many think that the wait for final proof would be irresponsible. Action now is seen as the only safe insurance."[91]

109. The fossil fuel industry, including Defendants, was at the forefront of carbon dioxide research for much of the latter half of the 20th century. They developed cutting edge and innovative technology and worked with many of the field's top researchers to produce exceptionally sophisticated studies and models. For instance, in the mid-nineties Shell began using scenarios to plan how the company could respond to various global forces in the future. In one scenario published in a 1998 internal report, Shell paints an eerily prescient scene:

> In 2010, a series of violent storms causes extensive damage to the eastern coast of the U.S. Although it is not clear whether the storms are caused by climate change, people are not willing to take further chances. The insurance industry refuses to accept liability, setting off a fierce debate over who is liable: the insurance industry or the government. After all, two successive IPCC reports since 1995 have reinforced the human connection to climate change….Following the storms, a coalition of environmental NGOs brings a class-action suit against the US government and fossil-fuel companies on the grounds of neglecting what scientists (including their own) have been saying for years: that something must be done. A social reaction to the use of fossil fuels grows, and individuals become 'vigilante environmentalists' in the same way, a generation earlier, they had become fiercely anti-tobacco. Direct-action campaigns against companies escalate. Young consumers, especially, demand action.[92]

110. Climate change research conducted by Defendants and their industry associations frequently acknowledged uncertainties in their climate modeling—those uncertainties, however, were merely with respect to the magnitude and timing of climate impacts resulting from fossil fuel consumption, not that significant changes would eventually occur. The Defendants' researchers and the researchers at their industry associations harbored little doubt that climate change was occurring and that fossil fuel products were, and are, the primary cause.

111. Despite the overwhelming information about the threats to people and the planet posed by continued unabated use of their fossil fuel products, Defendants failed to act as they

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[91] Jelmer Mommers, *Shell made a film about climate change in 1991 (then neglected to heed its own warning)*, DE CORRESPONDENT (Feb. 27, 2017), https://thecorrespondent.com/6285/shell-made-a-film-about-climate-change-in-1991-then-neglected-to-heed-its-own-warning/692663565-875331f6.

[92] Royal Dutch/Shell Group, *Group Scenarios 1998–2020*, 115 (1998), http://www.documentcloud.org/documents/4430277-27-1-Compiled.html.

reasonably should have to mitigate or avoid those dire adverse impacts. Defendants instead adopted the position, as described below, that the absence of meaningful regulations on the consumption of their fossil fuel products was the equivalent of a social license to continue the unfettered pursuit of profits from those products. This position was an abdication of Defendants' responsibility to consumers and the public, including Plaintiff, to act on their unique knowledge of the reasonably foreseeable hazards of unabated production and consumption of their fossil fuel products.

E. Defendants Did Not Disclose Known Harms Associated with the Extraction, Promotion, and Consumption of Their Fossil Fuel Products and Instead Affirmatively Acted to Obscure Those Harms and Engaged in a Concerted Campaign to Evade Regulation.

112. By 1988, Defendants had amassed a compelling body of knowledge about the role of anthropogenic greenhouse gases, and specifically those emitted from the normal use of Defendants' fossil fuel products, in causing global warming, increased mean sea surface temperature, marine heatwaves, harmful algal blooms, and the attendant consequences for human communities and the environment. On notice that their products were causing global climate change and dire effects on the planet, Defendants were faced with the decision of whether to take steps to limit the damages their fossil fuel products were causing and would continue to cause for virtually every one of Earth's inhabitants, including Plaintiff.

113. Defendants at any time before or thereafter could and should reasonably have taken any of a number of steps to mitigate the damages caused by their fossil fuel products, and their own comments reveal an awareness of what some of these steps may have been. Defendants should have made reasonable warnings to consumers, the public, and regulators of the dangers known to them of the unabated consumption of their fossil fuel products, and they should have taken reasonable steps to limit the potential greenhouse gas emissions arising out of those products.

114. But several key events during the period 1988–1992 appear to have prompted Defendants to change their tactics from general research and internal discussion on climate change to a public campaign aimed at evading regulation of their fossil fuel products and/or emissions therefrom. These include:

a. In 1988, National Aeronautics and Space Administration ("NASA") scientists confirmed that human activities were actually contributing to global warming.[93] On June 23 of that year, NASA scientist James Hansen's presentation of this information to Congress engendered significant news coverage and publicity for the announcement, including coverage on the front page of the New York Times.

b. On July 28, 1988, Senator Robert Stafford and four bipartisan co-sponsors introduced S. 2666, "The Global Environmental Protection Act," to regulate CO_2 and other greenhouse gases. Four more bipartisan bills to significantly reduce CO_2 pollution were introduced over the following ten weeks, and in August, U.S. Presidential candidate George H.W. Bush pledged that his presidency would "combat the greenhouse effect with the White House effect."[94] Political will in the United States to reduce anthropogenic greenhouse gas emissions and mitigate the harms associated with Defendants' fossil fuel products was gaining momentum.

c. In December 1988, the United Nations formed the Intergovernmental Panel on Climate Change ("IPCC"), a scientific panel dedicated to providing the world's governments with an objective, scientific analysis of climate change and its environmental, political, and economic impacts.

d. In 1990, the IPCC published its First Assessment Report on anthropogenic climate change,[95] in which it concluded that (1) "there is a natural greenhouse effect which already keeps the Earth warmer than it would otherwise be," and (2) that

> emissions resulting from human activities are substantially increasing the atmospheric concentrations of the greenhouse gases carbon dioxide, methane, chlorofluorocarbons (CFCs)

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[93] *See* Frumhoff et al., *The Climate Responsibilities of Industrial Carbon Producers*, *supra* note 211.

[94] N.Y. TIMES, *The White House and the Greenhouse* (May 9, 1998), http://www.nytimes.com/1989/05/09/opinion/the-white-house-and-the-greenhouse.html.

[95] *See* IPCC, *Reports*, http://www.ipcc.ch/publications_and_data/publications_and_data_reports.shtml.

> and nitrous oxide. These increases will enhance the greenhouse effect, resulting on average in an additional warming of the Earth's surface. The main greenhouse gas, water vapour, will increase in response to global warming and further enhance it.[96]

The IPCC reconfirmed these conclusions in a 1992 supplement to the First Assessment Report.[97]

e. The United Nations began preparation for the 1992 Earth Summit in Rio de Janeiro, Brazil, a major, newsworthy gathering of 172 world governments, of which 116 sent their heads of state. The Summit resulted in the United Nations Framework Convention on Climate Change ("UNFCCC"), an international environmental treaty providing protocols for future negotiations aimed at "stabiliz[ing] greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system."[98]

115. These world events marked a shift in public discussion of climate change, and the initiation of international efforts to curb anthropogenic greenhouse emissions—developments that had stark implications for, and would have diminished the profitability of, Defendants' fossil fuel products.

116. But rather than collaborating with the international community by acting to forestall, or at least decrease, their fossil fuel products' contributions to global warming, increased mean sea surface temperature, marine heatwaves, harmful algal blooms, and marine toxin outbreaks, and consequent injuries to Plaintiff, Defendants embarked on a decades-long campaign designed to maximize continued dependence on their products and undermine national and international efforts to rein in greenhouse gas emissions.

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[96] IPCC, *Climate Change: The IPCC Scientific Assessment*, "Policymakers Summary" (1990), http://www.ipcc.ch/ipccreports/far/wg_I/ipcc_far_wg_I_spm.pdf.

[97] IPCC, *1992 Supplement to the First Assessment Report* (1992), http://www.ipcc.ch/publications_and_data/publications_ipcc_90_92_assessments_far.shtml.

[98] United Nations, *United Nations Framework Convention on Climate Change*, Article 2 (1992), https://unfccc.int/resource/docs/convkp/conveng.pdf.

117. Defendants' campaign, which focused on concealing, discrediting, and/or misrepresenting information that tended to support restricting consumption of (and thereby decreasing demand for) Defendants' fossil fuel products, took several forms. The campaign enabled Defendants to accelerate their business practice of exploiting fossil fuel reserves, and concurrently externalize the social and environmental costs of their fossil fuel products. These activities stood in direct contradiction to Defendants' own prior recognition that the science of anthropogenic climate change was clear and that the greatest uncertainties involved responsive human behavior, not scientific understanding of the issue.

118. Defendants took affirmative steps to conceal, from Plaintiff and the general public, the foreseeable impacts of the use of their fossil fuel products on Earth's climate and associated harms to people and communities. Defendants embarked on a concerted public relations campaign to cast doubt on the science connecting global climate change to fossil fuel products and greenhouse gas emissions, in order to influence public perception of the existence of anthropogenic global warming. The effort included promoting their hazardous products through advertising campaigns and the initiation and funding of climate change denialist organizations, designed to influence consumers to continue using Defendants' fossil fuel products irrespective of those products' damage to communities and the environment.

119. For example, in 1988, Joseph Carlson, an Exxon public affairs manager, described the "Exxon Position," which included among others, two important messaging tenets: (1) "[e]mphasize the uncertainty in scientific conclusions regarding the potential enhanced Greenhouse Effect;" and (2) "[r]esist the overstatement and sensationalization [sic] of potential greenhouse effect which could lead to noneconomic development of non-fossil fuel resources."[99]

120. A 1994 Shell report entitled "The Enhanced Greenhouse Effect: A Review of the Scientific Aspects" by Royal Dutch Shell environmental advisor Peter Langcake stands in stark contrast to the company's 1988 report on the same topic. Whereas before, the authors recommended consideration of policy solutions early on, Langcake warned of the potentially

[99]Joseph M. Carlson, *Exxon Memo on "The Greenhouse Effect"* (Aug. 3, 1988), https://assets.documentcloud.org/documents/3024180/1998-Exxon-Memo-on-the-Greenhouse-Effect.pdf.

dramatic "economic effects of ill-advised policy measures." While the report recognized the IPCC conclusions as the mainstream view, Langcake still emphasized scientific uncertainty, noting, for example, that "the postulated link between any observed temperature rise and human activities has to be seen in relation to natural variability, which is still largely unpredictable." The Group position is stated clearly in the report: "Scientific uncertainty and the evolution of energy systems indicate that policies to curb greenhouse gas emissions beyond 'no regrets' measures could be premature, divert resources from more pressing needs and further distort markets."[100]

121. In 1991, for example, the Information Council for the Environment ("ICE"), whose members included affiliates, predecessors and/or subsidiaries of Defendants, including Pittsburg and Midway Coal Mining (Chevron), and Island Creek Coal Company (Occidental), launched a national climate change science denial campaign with full-page newspaper ads, radio commercials, a public relations tour schedule, "mailers," and research tools to measure campaign success. Included among the campaign strategies was to "reposition global warming as theory (not fact)." Its target audience included older less-educated males who are "predisposed to favor the ICE agenda, and likely to be even more supportive of that agenda following exposure to new information."[101]

122. An implicit goal of ICE's advertising campaign was to change public opinion and avoid regulation. A memo from Richard Lawson, president of the National Coal Association asked members to contribute to the ICE campaign with the justification that "policymakers are prepared to act [on global warming]. Public opinion polls reveal that 60% of the American people already believe global warming is a serious environmental problem. Our industry cannot sit on the sidelines in this debate."[102]

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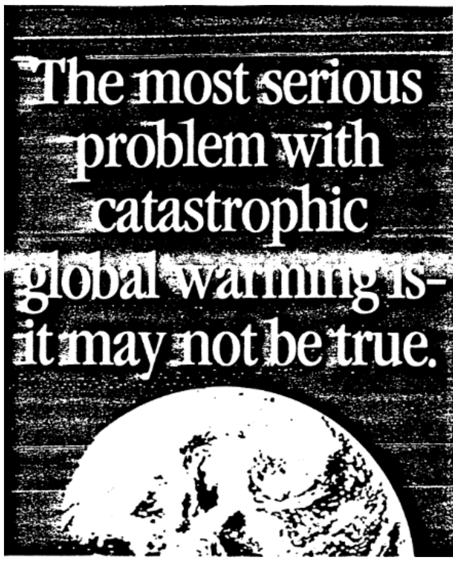
[100] P. Langcake, *The Enhanced Greenhouse Effect: A review of the Scientific Aspects*, (Dec. 1994), https://www.documentcloud.org/documents/4411099-Document11.html#document/p15/a411511.

[101] Union of Concerned Scientists, *Deception Dossier #5: Coal's "Information Council on the Environment" Sham*, (1991), http://www.ucsusa.org/sites/default/files/attach/2015/07/Climate-Deception-Dossier-5_ICE.pdf.

[102] Naomi Oreskes, *My Facts Are Better Than Your Facts: Spreading Good News about Global Warming* (2010), in Peter Howlett et al., *How Well Do Facts Travel?: The Dissemination of Reliable Knowledge*, 136–66. Cambridge University Press. doi:10.1017/CBO9780511762154.008.8

123. The following images are examples of ICE-funded print advertisements challenging the validity of climate science and intended to obscure the scientific consensus on anthropogenic climate change and induce political inertia to address it.[103]



124. In 1996, Exxon released a publication called "Global Warming: Who's Right? Facts about a debate that's turned up more questions than answers." In the publication's preface, Exxon CEO Lee Raymond stated that "taking drastic action immediately is unnecessary since many scientists agree there's ample time to better understand the climate system." The subsequent article described the greenhouse effect as "unquestionably real and definitely a good thing," while ignoring the severe consequences that would result from the influence of the increased CO_2 concentration on Earth's climate. Instead, it characterized the greenhouse effect as simply "what makes the earth's atmosphere livable." Directly contradicting their own internal reports and peer-reviewed science, the article ascribed the rise in temperature since the late 19th century to "natural fluctuations that occur over long periods of time" rather than to the anthropogenic emissions that Exxon and other scientists had confirmed were responsible. The article also falsely challenged the computer models that projected the future impacts of unabated fossil fuel product consumption, including those developed by Exxon's own employees, as having been "proved to be inaccurate." The article contradicted the numerous reports circulated among Exxon's staff, and by the API, by

[103] Union of Concerned Scientists, *Deception Dossier #5*, *supra* note 98.

stating that “the indications are that a warmer world would be far more benign than many imagine . . . moderate warming would reduce mortality rates in the US, so a slightly warmer climate would be more healthful.” Raymond concluded his preface by attacking advocates for limiting the use of his company’s fossil fuel products as “drawing on bad science, faulty logic, or unrealistic assumptions”—despite the important role that Exxon’s own scientists had played in compiling those same scientific underpinnings.[104]

125. API published an extensive report in the same year warning against concern over CO_2 buildup and any need to curb consumption or regulate the industry. The introduction states that “there is no persuasive basis for forcing Americans to dramatically change their lifestyles to use less oil.” The authors discourage the further development of certain alternative energy sources, writing that “government agencies have advocated the increased use of ethanol and the electric car, without the facts to support the assertion that either is superior to existing fuels and technologies” and that “policies that mandate replacing oil with specific alternative fuel technologies freeze progress at the current level of technology, and reduce the chance that innovation will develop better solutions.” The paper also denies the human connection to climate change, saying that no “scientific evidence exists that human activities are significantly affecting sea levels, rainfall, surface temperatures or the intensity and frequency of storms.” The message the report repeatedly sends is clear: “Facts don’t support the arguments for restraining oil use.”[105]

126. In a speech presented at the World Petroleum Congress in Beijing in 1997 at which many of the Defendants were present, Exxon CEO Lee Raymond reiterated these views. This time, he presented a false dichotomy between stable energy markets and abatement of the marketing, promotion, and sale of fossil fuel products known to Defendants to be hazardous. He stated:

> Some people who argue that we should drastically curtail our use of fossil fuels for environmental reasons…my belief [is] that such proposals are neither prudent nor practical. With no readily available economic alternatives on the horizon, fossil fuels will continue to supply most of the world’s and this region’s energy for the foreseeable future.

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[104] Exxon Corp., *Global warming: who’s right?* (1996), https://www.documentcloud.org/documents/2805542-Exxon-Global-Warming-Whos-Right.html.

> Governments also need to provide a stable investment climate…They should avoid the temptation to intervene in energy markets in ways that give advantage to one competitor over another or one fuel over another.
>
> We also have to keep in mind that most of the greenhouse effects comes from natural sources.…Leaping to radically cut this tiny sliver of the greenhouse pie on the premise that it will affect climate defies common sense and lacks foundation in our current understanding of the climate system.
>
> Let's agree there's a lot we really don't know about how climate will change in the 21st century and beyond.…It is highly unlikely that the temperature in the middle of the next century will be significantly affected whether policies are enacted now or 20 years from now. It's bad public policy to impose very costly regulations and restrictions when their need has yet to be proven.[106]

127. Imperial Oil (Exxon) CEO Robert Peterson falsely denied the established connection between Defendants' fossil fuel products and anthropogenic climate change in the Summer 1998 Imperial Oil Review, "A Cleaner Canada":

> [T]his issue [referring to climate change] has absolutely nothing to do with pollution and air quality. Carbon dioxide is not a pollutant but an essential ingredient of life on this planet…. [T]he question of whether or not the trapping of 'greenhouse' gases will result in the planet's getting warmer…has no connection whatsoever with our day-to-day weather.
>
> There is absolutely no agreement among climatologists on whether or not the planet is getting warmer, or, if it is, on whether the warming is the result of man-made factors or natural variations in the climate….I feel very safe in saying that the view that burning fossil fuels will result in global climate change remains an unproved hypothesis.[107]

128. Mobil (Exxon) paid for a series of "advertorials," advertisements located in the editorial section of the New York Times and meant to look like editorials rather than paid ads. These ads discussed various aspects of the public discussion of climate change and sought to undermine the justifications for tackling greenhouse gas emissions, referring to it as unsettled

[106] Lee R. Raymond, *Energy – Key to growth and a better environment for Asia-Pacific nations*, World Petroleum Congress (Oct. 13, 1997), https://assets.documentcloud.org/documents/2840902/1997-Lee-Raymond-Speech-at-China-World-Petroleum.pdf.

[107] Robert Peterson, *A Cleaner Canada in Imperial Oil Review* (1998), http://www.documentcloud.org/documents/2827818-1998-Imperial-Oil-Robert-Peterson-A-Cleaner-Canada.html.

science. The 1997 advertorial below[108] argued that economic analysis of emissions restrictions was faulty and inconclusive and therefore a justification for delaying action on climate change.

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When facts don't square with the theory, throw out the facts

That seems to characterize the administration's attitude on two of its own studies which show that international efforts to curb global warming could spark a big run-up in energy prices.

For months, the administration—playing its cards close to the vest—has promised to provide details of the emission reduction plan it will put on the table at the climate change meeting in Kyoto, Japan, later this year. It also promised to evaluate the economics of that policy and measure its impact. Those results are important because the proposals submitted by other countries thus far would be disruptive and costly to the U.S. economy.

Yet, when the results from its own economic models were finally generated, the administration started distancing itself from the findings and models that produced them. The administration's top economic advisor said that economic models can't provide a "definitive answer" on the impact of controlling emissions. The effort, she said, was "futile." At best, the models can only provide a "range of potential impacts."

Frankly, we're puzzled. The White House has promised to lay the economic facts before the public. Yet, the administration's top advisor said such an analysis won't be based on models and it will "preclude . . . detailed numbers." If you don't provide numbers and don't rely on models, what kind of rigorous economic examination can Congress and the public expect?

We're also puzzled by ambivalence over models. The administration downplays the utility of economic models to forecast cost impacts 10–15 years from now, yet its negotiators accept as gospel the 50–100-year predictions of global warming that have been generated by climate models—many of which have been criticized as seriously flawed.

The second study, conducted by Argonne National Laboratory under a contract with the Energy Department, examined what would happen if the U.S. had to commit to higher energy prices under the emission reduction plans that several nations had advanced last year. Such increases, the report concluded, would result in "significant reductions in output and employment" in six industries—aluminum, cement, chemical, paper and pulp, petroleum refining and steel.

Hit hardest, the study noted, would be the chemical industry, with estimates that up to 30 percent of U.S. chemical manufacturing capacity would move offshore to developing countries. Job losses could amount to some 200,000 in that industry, with another 100,000 in the steel sector. And despite the substantial loss of U.S. jobs and manufacturing capacity, the net emission reduction could be insignificant since developing countries will not be bound by the emission targets of a global warming treaty.

Downplaying Argonne's findings, the Energy Department noted that the study used outdated energy prices (mid-1996), didn't reflect the gains that would come from international emissions trading and failed to factor in the benefits of accelerated developments in energy efficiency and low-carbon technologies.

What it failed to mention is just what these new technologies are and when we can expect their benefits to kick in. As for emissions trading, many economists have theorized about the role they could play in reducing emissions, but few have grappled with the practicality of implementing and policing such a scheme.

We applaud the goals the U.S. wants to achieve in these upcoming negotiations—namely, that a final agreement must be "flexible, cost-effective, realistic, achievable and ultimately global in scope." But until we see the details of the administration's policy, we are concerned that plans are being developed in the absence of rigorous economic analysis. Too much is at stake to simply ignore facts that don't square with preconceived theories.

Mobil The energy to make a difference.

http://www.mobil.com

[108] Mobil, *When Facts Don't Square with the Theory, Throw Out the Facts*, N.Y. TIMES, A31 (Aug. 14, 1997), https://www.documentcloud.org/documents/705550-mob-nyt-1997-aug-14-whenfactsdontsquare.html.

129. In 1998, API, on behalf of Defendants, among other fossil fuel companies and organizations supported by fossil fuel corporate grants, developed a Global Climate Science Communications Plan that stated that unless "climate change becomes a non-issue . . . there may be no moment when we can declare victory for our efforts." Rather, API proclaimed that "[v]ictory will be achieved when . . . average citizens 'understand' (recognize) uncertainties in climate science; [and when] recognition of uncertainties becomes part of the 'conventional wisdom.'"[109] The multi-million-dollar, multi-year proposed budget included public outreach and the dissemination of educational materials to schools to "begin to erect a barrier against further efforts to impose Kyoto-like measures in the future."[110]

130. Soon after, API distributed a memo to its members identifying public agreement on fossil fuel products' role in climate change as its highest priority issue.[111] The memorandum illuminates API's and Defendants' concern over the potential regulation of Defendants' fossil fuel products: "Climate is at the center of the industry's business interests. Policies limiting carbon emissions reduce petroleum product use. That is why it is API's highest priority issue and defined as 'strategic.'"[112] Further, the API memo stresses many of the strategies that Defendants individually and collectively utilized to combat the perception of their fossil fuel products as hazardous. These included:

a. Influencing the tenor of the climate change "debate" as a means to establish that efforts to reduce greenhouse gas emissions were not necessary to responsibly address climate change;

b. Maintaining strong working relationships between government regulators and communications-oriented organizations like the Global Climate Coalition, the Heartland Institute, and other groups carrying Defendants'

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[109] Joe Walker, *E-mail to Global Climate Science Team, attaching the Draft Global Science Communications Plan* (Apr. 3, 1998), https://assets.documentcloud.org/documents/784572/api-global-climate-science-communications-plan.pdf.

[110] *Id.*

[111] Committee on Oversight and Government Reform, *Allegations of Political Interference with Government Climate Change Science*, page 51 (Mar. 19, 2007), https://ia601904.us.archive.org/25/items/gov.gpo.fdsys.CHRG-110hhrg37415/CHRG-110hhrg37415.pdf.

[112] *Id.*

message minimizing the hazards of the unabated use of their fossil fuel products and opposing regulation thereof;

c. Building the case for (and falsely dichotomizing) Defendants' positive contributions to a "long-term approach" (ostensibly for regulation of their products) as a reason for society to reject short term fossil fuel regulations, and engaging in climate change science uncertainty research; and

d. Presenting Defendants' positions on climate change in domestic and international forums, including by preparing rebuttals to IPCC reports.

131. Additionally, Defendants mounted a campaign against regulation of their business practices in order to continue placing their fossil fuel products into the stream of commerce, despite their own knowledge and the growing national and international scientific consensus about the hazards of doing so. These efforts came despite Defendants' recognition that "risks to nearly every facet of life on Earth . . . could be avoided only if timely steps were taken to address climate change."[113]

132. The Global Climate Coalition (GCC), on behalf of Defendants and other fossil fuel companies, funded advertising campaigns and distributed material to generate public uncertainty around the climate debate, with the specific purpose of preventing U.S. adoption of the Kyoto Protocol, despite the leading role that the U.S. had played in the Protocol negotiations.[114] Despite an internal primer stating that various "contrarian theories" [i.e., climate change skepticism] do not "offer convincing arguments against the conventional model of greenhouse gas emission-induced climate change," GCC excluded this section from the public version of the backgrounder and instead funded efforts to promote some of those same contrarian theories over subsequent years.[115]

133. A key strategy in Defendants' efforts to discredit scientific consensus on climate change and the IPCC was to bankroll scientists who, although accredited, held fringe opinions that

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[113] Banerjee, *Exxon's Oil Industry Peers Knew About Climate Dangers in the 1970s, Too, supra* note 60.

[114] *Id.*

[115] Gregory J. Dana, *Memo to AIAM Technical Committee Re: Global Climate Coalition (GCC) – Primer on Climate Change Science – Final Draft*, Association of International Automobile Manufacturers (Jan. 18, 1996), http://www.webcitation.org/6FyqHawb9.

were even more questionable given the sources of their research funding. These scientists obtained part or all of their research budget from Defendants directly or through Defendant-funded organizations like API,[116] but they frequently failed to disclose their fossil fuel industry underwriters.[117]

134. Creating a false sense of disagreement in the scientific community (despite the consensus that its own scientists, experts, and managers had previously acknowledged) has had an evident impact on public opinion. A 2007 Yale University-Gallup poll found that while 71% of Americans personally believed global warming was happening, only 48% believed that there was a consensus among the scientific community, and 40% believed there was a lot of disagreement among scientists over whether global warming was occurring.[118]

135. 2007 was the same year the IPCC published its Fourth Assessment Report, in which it concluded that "there is *very high confidence* that the net effect of human activities since 1750 has been one of warming."[119] The IPCC defined "very high confidence" as at least a 9 out of 10 chance.[120]

136. Defendants borrowed pages out of the playbook of prior denialist campaigns. A "Global Climate Science Team" ("GCST") was created that mirrored a front group created by the tobacco industry, known as The Advancement of Sound Science Coalition, whose purpose was to sow uncertainty about the fact that cigarette smoke is carcinogenic. The GCST's membership included Steve Milloy (a key player on the tobacco industry's front group) for Exxon; an API public relations representative; and representatives from Chevron and Southern Company that drafted API's 1998 Communications Plan. There were no scientists on the "Global Climate

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[116] Willie Soon & Sallie Baliunas, *Proxy Climatic and Environmental Changes of the Past 1000 Years*, 23 CLIMATE RESEARCH 88, 105 (Jan. 31, 2003), http://www.int-res.com/articles/cr2003/23/c023p089.pdf.

[117] Newsdesk, *Smithsonian Statement: Dr. Wei-Hock (Willie) Soon*, SMITHSONIAN (Feb. 26, 2015), http://newsdesk.si.edu/releases/smithsonian-statement-dr-wei-hock-willie-soon.

[118] *American Opinions on Global Warming: A Yale/Gallup/Clearvision Poll*, Yale Program on Climate Change Communication (July 31, 2007), http://climatecommunication.yale.edu/publications/american-opinions-on-global-warming.

[119] IPCC, 2007: Summary for Policymakers, page 3 (emphasis in original), *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change* (2007), https://www.ipcc.ch/pdf/assessment-report/ar4/wg1/ar4-wg1-spm.pdf.

[120] *Id.*

Science Team." GCST developed a strategy to spend millions of dollars manufacturing climate change uncertainty. Between 2000 and 2004, Exxon donated $110,000 to Milloy's efforts and another organization, the Free Enterprise Education Institute and $50,000 to the Free Enterprise Action Institute, both registered to Milloy's home address.[121]

137. Defendants by and through their trade association memberships, worked directly, and often in a deliberately obscured manner, to evade regulation of the emissions resulting from use of their fossil fuel products.

138. Defendants have funded dozens of think tanks, front groups, and dark money foundations pushing climate change denial. These include the Competitive Enterprise Institute, the Heartland Institute, Frontiers for Freedom, Committee for a Constructive Tomorrow, and Heritage Foundation. From 1998 to 2014 Exxon spent almost $31 million funding numerous organizations misrepresenting the scientific consensus that Defendants' fossil fuel products were causing climate change. Several Defendants have been linked to other groups that undermine the scientific basis linking Defendants' fossil fuel products to climate change, including the Frontiers of Freedom Institute and the George C. Marshall Institute.

139. Exxon acknowledged its own previous success in sowing uncertainty and slowing mitigation through funding of climate denial groups. In its 2007 Corporate Citizenship Report, Exxon declared: "In 2008, we will discontinue contributions to several public policy research groups whose position on climate change could divert attention from the important discussion on how the world will secure the energy required for economic growth in an environmentally responsible manner."[122] Despite this pronouncement, Exxon remained financially associated with several such groups after the report's publication.

140. Today, Defendants, including Exxon, Chevron, BP, Shell, and ConocoPhillips publicly purport to accept the consensus embodied in the most recent IPCC reports, that global warming is occurring, and that human activity has been the dominant cause of global warming and

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[121] Seth Shulman et al. *Smoke, Mirrors & Hot Air: How ExxonMobil Uses Big Tobacco's Tactics to Manufacture Uncertainty on Climate Science*, Union of Concerned Scientists, 19 (Jan. 2007), http://www.ucsusa.org/sites/default/files/legacy/assets/documents/global_warming/exxon_report.pdf.

[122] ExxonMobil, *2007 Corporate Citizenship Report* (Dec. 31, 2007), http://www.documentcloud.org/documents/2799777-ExxonMobil-2007-Corporate-Citizenship-Report.html.

related climactic changes since the beginning of the Great Acceleration. At the same time, however, Defendants continue to play up the uncertainty of future climate modeling, and the purported historic uncertainty, imprecision, and inconsistency of climate science to disguise and distract from their own knowledge and intensive research dating back to at least 1960s. While Defendants claim to accept the scientific consensus on climate change, moreover, they still continue to promote and expand their exploration, production, promotion, marketing, and sale of fossil fuels that are the dominant cause of anthropogenic global warming.

141. Defendants could have contributed to the global effort to mitigate the impacts of greenhouse gas emissions by, for example, delineating practical policy goals and regulatory structures that would have allowed them to continue their business ventures while reducing greenhouse gas emissions and supporting a transition to a lower carbon future. Instead, Defendants undertook a momentous effort to evade international and national regulation of greenhouse gas emissions to enable them to continue unabated fossil fuel production.

142. As a result of Defendants' tortious, false and misleading conduct, reasonable consumers of Defendants' fossil fuel products, members of the public, and policy-makers, have been deliberately and unnecessarily deceived about: the role of fossil fuel products in causing ocean warming and consequent harmful algal blooms and domoic outbreaks; the acceleration of global warming since the mid-20th century and the continuation thereof; and about the fact that the continued increase in fossil fuel product consumption creates severe environmental threats and significant economic costs for members of the ocean-dependent economy. Reasonable consumers and policy makers have also been deceived about the depth and breadth of the state of the scientific evidence on anthropogenic climate change, and in particular, on the strength of the scientific consensus demonstrating the role of fossil fuels in causing climate change and its potentially destructive impacts.

F. In Contrast to Their Public Statements, Defendants' Internal Actions Demonstrate Their Awareness of and Intent to Profit from the Unabated Use of Fossil Fuel Products.

143. In contrast to their public-facing efforts challenging the validity of the scientific consensus about anthropogenic climate change, Defendants' acts and omissions evidence their

internal acknowledgement of the reality of climate change and its likely consequences. These actions include, but are not limited to, making multi-billion-dollar infrastructure investments for their own operations that acknowledge the reality of coming anthropogenic climate-related change. These investments included (among others), raising offshore oil platforms to protect against sea level rise; reinforcing offshore oil platforms to withstand increased wave strength and storm severity; and developing and patenting designs for equipment intended to extract crude oil and/or natural gas in areas previously unreachable because of the presence of polar ice sheets.[123]

144. For example, in 1973 Exxon obtained a patent for a cargo ship capable of breaking through sea ice[124] and for an oil tanker[125] designed specifically for use in previously unreachable areas of the Arctic.

145. In 1974, Chevron obtained a patent for a mobile arctic drilling platform designed to withstand significant interference from lateral ice masses,[126] allowing for drilling in areas with increased ice floe movement due to elevated temperature.

146. That same year, Texaco (Chevron) worked toward obtaining a patent for a method and apparatus for reducing ice forces on a marine structure prone to being frozen in ice through natural weather conditions,[127] allowing for drilling in previously unreachable Arctic areas that would become seasonally accessible.

147. Shell obtained a patent similar to Texaco's (Chevron) in 1984.[128]

148. In 1989, Norske Shell, Royal Dutch Shell's Norwegian subsidiary, altered designs for a natural gas platform planned for construction in the North Sea to account for anticipated sea

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[123] Amy Lieberman & Suzanne Rust, *Big Oil braced for global warming while it fought regulations*, L.A. TIMES (Dec. 31, 2015), http://graphics.latimes.com/oil-operations.

[124] Patents, *Icebreaking cargo vessel*, Exxon Research Engineering Co. (Apr. 17, 1973), https://www.google.com/patents/US3727571.

[125] Patents, *Tanker vessel*, Exxon Research Engineering Co. (July 17, 1973), https://www.google.com/patents/US3745960.

[126] Patents, *Arctic offshore platform*, Chevron Research & Technology Co. (Aug. 27, 1974) https://www.google.com/patents/US3831385.

[127] Patents, *Mobile, arctic drilling and production platform*, Texaco Inc. (Feb. 26, 1974) https://www.google.com/patents/US3793840.

[128] Patents, *Arctic offshore platform*, Shell Oil Co. (Jan. 24, 1984) https://www.google.com/patents/US4427320.

level rise. Those design changes were ultimately carried out by Shell's contractors, adding substantial costs to the project.[129]

a. The Troll field, off the Norwegian coast in the North Sea, was proven to contain large natural oil and gas deposits in 1979, shortly after Norske Shell was approved by Norwegian oil and gas regulators to operate a portion of the field.

b. In 1986, the Norwegian parliament granted Norske Shell authority to complete the first development phase of the Troll field gas deposits, and Norske Shell began designing the "Troll A" gas platform, with the intent to begin operation of the platform in approximately 1995. Based on the very large size of the gas deposits in the Troll field, the Troll A platform was projected to operate for approximately 70 years.

c. The platform was originally designed to stand approximately 100 feet above sea level—the amount necessary to stay above waves in a once-in-a-century strength storm.

d. In 1989, Shell engineers revised their plans to increase the above-water height of the platform by 3–6 feet, specifically to account for higher anticipated average sea levels and increased storm intensity due to global warming over the platform's 70-year operational life.[130]

e. Shell projected that the additional 3–6 feet of above-water construction would increase the cost of the Troll A platform by as much as $40 million.

G. Defendants' Actions Prevented the Development of Alternatives That Would Have Eased the Transition to a Less Fossil Fuel Dependent Economy.

149. The harms and benefits of Defendants' conduct can be balanced in part by weighing the social benefit of extracting and burning a unit of fossil fuels against the costs that a unit of fuel imposes on society, known as the "social cost of carbon" or "SCC."

[129] *Greenhouse Effect: Shell Anticipates A Sea Change*, N.Y. TIMES (Dec. 20, 1989) http://www.nytimes.com/1989/12/20/business/greenhouse-effect-shell-anticipates-a-sea-change.html.

[130] *Id.*; Lieberman & Rust, *Big Oil braced for global warming while it fought regulations*, *supra* note 123.

150. Because climatic responses to atmospheric temperature increases are non-linear, and because greenhouse gas pollution accumulates in the atmosphere, some of which does not dissipate for potentially thousands of years (namely CO_2), there is broad agreement that SCC increases as emissions rise, and as the climate warms. Relatedly, as atmospheric CO_2 levels and surface temperature increase, the costs associated with remediating environmental injuries—such as the domoic acid outbreaks described herein—also increases. In short, each additional ton of CO_2 emitted into the atmosphere will have a greater net social cost as emissions increase, and each additional ton of CO_2 will have a greater net social cost as global warming accelerates.

151. A critical corollary of the non-linear relationship between atmospheric CO_2 concentrations and SCC is that delayed efforts to curb those emissions have increased environmental harms and increase the magnitude and cost to remediate harms that have already occurred or are locked in by previous emissions. Therefore, Defendants' campaign to obscure the science of climate change and to expand the extraction and use of fossil fuels greatly increased and continues to increase the harms and rate of harms suffered by Plaintiff.

152. The consequences of delayed action on climate change, exacerbated by Defendants' actions, has already drastically increased the cost of mitigating further harm. Had concerted action begun even as late as 2005, an annual 3.5% reduction in CO_2 emissions to lower atmospheric CO_2 to 350 ppm by the year 2100 would have restored Earth's energy balance[131] and halted future global warming, although such efforts would not forestall committed sea level rise already locked in.[132] If efforts do not begin until 2020, however, a 15% annual reduction will be required to restore Earth's energy balance by the end of the century.[133] Earlier steps to reduce emissions would have led to smaller—and less disruptive—measures needed to mitigate the impacts of fossil fuel production.

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[131] "Climate equilibrium" is the balance between Earth's absorption of solar energy and its own energy radiation. Earth is currently out of equilibrium due to the influence of anthropogenic greenhouse gases, which prevent radiation of energy into space. Earth therefore warms and move back toward energy balance. Reduction of global CO_2 concentrations to 350 ppm is necessary to re-achieve energy balance, if the aim is to stabilize climate without further global warming. *See* James Hansen et al., *Assessing "Dangerous Climate Change": Required Reduction of Carbon Emissions to Protect Young People, Future Generations and Nature*, 8 PLOS ONE 1, 4–5 (Dec. 3, 2013).

[132] Hansen et al., *Assessing "Dangerous Climate Change": Required Reduction of Carbon Emissions to Protect Young People, Future Generations and Nature*, *supra* note 1310, at 10.

[133] *Id.*

153. The costs of inaction and the opportunities to confront anthropogenic climate change caused by normal consumption of their fossil fuel products, were not lost on Defendants. In a 1997 speech by John Browne, Group Executive for BP America, at Stanford University, Browne described Defendants' and the entire fossil fuel industry's responsibility and opportunities to reduce use of fossil fuel products, reduce global CO_2 emissions, and mitigate the harms associated with the use and consumption of such products:

> A new age demands a fresh perspective of the nature of society and responsibility. We need to go beyond analysis and to take action. It is a moment for change and for a rethinking of corporate responsibility. . . .
>
> [T]here is now an effective consensus among the world's leading scientists and serious and well informed people outside the scientific community that there is a discernible human influence on the climate, and a link between the concentration of carbon dioxide and the increase in temperature.
>
> The prediction of the IPCC is that over the next century temperatures might rise by a further 1 to 3.5 degrees centigrade [1.8º – 6.3º F], and that sea levels might rise by between 15 and 95 centimetres [5.9 and 37.4 inches]. Some of that impact is probably unavoidable, because it results from current emissions. . . .
>
> [I]t would be unwise and potentially dangerous to ignore the mounting concern.
>
> The time to consider the policy dimensions of climate change is not when the link between greenhouse gases and climate change is conclusively proven … but when the possibility cannot be discounted and is taken seriously by the society of which we are part. . . .
>
> We [the fossil fuel industry] have a responsibility to act, and I hope that through our actions we can contribute to the much wider process which is desirable and necessary.
>
> BP accepts that responsibility and we're therefore taking some specific steps.
>
> To control our own emissions.
>
> To fund continuing scientific research.
>
> To take initiatives for joint implementation.
>
> To develop alternative fuels for the long term.
>
> And to contribute to the public policy debate in search of the wider global answers to the problem.[134]

154. Despite Defendants' knowledge of the foreseeable, measurable harms associated

[134] John Browne, *BP Climate Change Speech to Stanford*, Climate Files (May 19, 1997), http://www.climatefiles.com/bp/bp-climate-change-speech-to-stanford.

with the unabated consumption and use of their fossil fuel products, and despite the existence and Defendants' knowledge of technologies and practices that could have helped to reduce the foreseeable dangers associated with their fossil fuel products, Defendants continued to market and promote heavy fossil fuel use, dramatically increasing the cost of abatement. At all relevant times, Defendants were deeply familiar with opportunities to reduce the use of their fossil fuel products, reduce global CO_2 emissions associated therewith, and mitigate the harms associated with the use and consumption of such products. Examples of that recognition include, but are not limited to the following:

a. In 1963, Esso (Exxon) obtained multiple patents on technologies for fuel cells, including on the design of a fuel cell and necessary electrodes,[135] and on a process for increasing the oxidation of a fuel, specifically methanol, to produce electricity in a fuel cell.[136]

b. In 1970, Esso (Exxon) obtained a patent for a "low-polluting engine and drive system" that used an interburner and air compressor to reduce pollutant emissions, including CO_2 emissions, from gasoline combustion engines (the system also increased the efficiency of the fossil fuel products used in such engines, thereby lowering the amount of fossil fuel product necessary to operate engines equipped with this technology).[137]

155. Defendants could have made major inroads to mitigate Plaintiff's injuries through technology by developing and employing technologies to capture and sequester greenhouse gases emissions associated with conventional use of their fossil fuel products. Defendants had knowledge dating at least back to the 1960s, and indeed, internally researched and perfected many such technologies. For instance:

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[135] Patents, *Fuel cell and fuel cell electrodes*, Exxon Research Engineering Co. (Dec. 31, 1963), https://www.google.com/patents/US3116169.

[136] Patents, *Direct production of electrical energy from liquid fuels*, Exxon Research Engineering Co. (Dec. 3, 1963), https://www.google.com/patents/US3113049.

[137] Patents, *Low-polluting engine and drive system*, Exxon Research Engineering Co. (May 16, 1970), https://www.google.com/patents/US3513929.

a. The first patent for enhanced oil recovery technology, a process by which CO_2 is captured and reinjected into oil deposits, was granted to an ARCO (BP) subsidiary in 1952.[138] This technology could have been further developed as a carbon capture and sequestration technique;

b. Phillips Petroleum Company (ConocoPhillips) obtained a patent in 1966 for a "Method for recovering a purified component from a gas" outlining a process to remove carbon from natural gas and gasoline streams;[139] and

c. In 1973, Shell patented a process to remove acidic gases, including CO_2, from gaseous mixtures.

156. Despite this knowledge, Defendants' later forays into the alternative energy sector were largely pretenses. For instance, in 2001, Chevron developed and shared a sophisticated information management system to gather greenhouse gas emissions data from its explorations and production to help regulate and set reduction goals.[140] Beyond this technological breakthrough, Chevron touted "profitable renewable energy" as part of its business plan for several years and launched a 2010 advertising campaign promoting the company's move towards renewable energy. Despite all this, Chevron rolled back its renewable and alternative energy projects in 2014.[141]

157. Similarly, ConocoPhillips' 2012 Sustainable Development report declared developing renewable energy a priority in keeping with their position on sustainable development and climate change.[142] Their 10-K filing from the same year told a different story: "As an independent E&P company, we are solely focused on our core business of exploring for,

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138 James P. Meyer, *Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2EOR) Injection Well Technology*, American Petroleum Institute, at 1, http://www.api.org/~/media/Files/EHS/climate-change/Summary-carbon-dioxide-enhanced-oil-recovery-well-tech.pdf.

139 Patents, *Method for recovering a purified component from a gas*, Phillips Petroleum Co. (Jan. 11, 1966), https://www.google.com/patents/US3228874.

140 Chevron, *Chevron Introduces New System to Manage Energy Use* (press release) (Sept. 25, 2001), https://www.chevron.com/stories/chevron-introduces-new-system-to-manage-energy-use.

141 Benjamin Elgin, *Chevron Dims the Lights on Green Power*, BLOOMBERG (May 29, 2014), https://www.bloomberg.com/news/articles/2014-05-29/chevron-dims-the-lights-on-renewable-energy-projects.

142 ConocoPhillips, *Sustainable Development* (2013) http://www.conocophillips.com/sustainable-development/Documents/2013.11.7%201200%20Our%20Approach%20Section%20Final.pdf.

developing and producing crude oil and natural gas globally."[143]

158. Likewise, while Shell orchestrated an entire public relations campaign around energy transitions towards net zero emissions, a fine-print disclaimer in its 2016 net-zero pathways report reads: "We have no immediate plans to move to a net-zero emissions portfolio over our investment horizon of 10–20 years."[144]

159. BP, appearing to abide by the representations Lord Browne made in his speech described in paragraph 153 above, engaged in a rebranding campaign to convey an air of environmental stewardship and renewable energy to its consumers. This included renouncing its membership in the GCC in 2007, changing its name from "British Petroleum" to "BP" while adopting the slogan "Beyond Petroleum," and adopting a conspicuously green corporate logo. However, BP's self-touted "alternative energy" investments during this turnaround included investments in natural gas, a fossil fuel, and in 2007 the company reinvested in Canadian tar sands, a particularly high-carbon source of oil.[145] The company ultimately abandoned its wind and solar assets in 2011 and 2013, respectively, and even the "Beyond Petroleum" moniker in 2013.[146]

160. After posting a $10 billion quarterly profit, Exxon in 2005 stated that "We're an oil and gas company. In times past, when we tried to get into other businesses, we didn't do it well. We'd rather re-invest in what we know."[147]

161. Even if Defendants did not adopt technological or energy source alternatives that would have reduced use of fossil fuels, reduced global greenhouse gas pollution, and/or mitigated the harms associated with the use and consumption of such products, Defendants could have taken other practical, cost-effective steps to reduce the use of their fossil fuel products, reduce global greenhouse gas pollution associated therewith, and mitigate the harms associated with the use and

[143] ConocoPhillips Form 10-K, U.S. Securities and Exchange Commission Webpage (Dec. 31, 2012), https://www.sec.gov/Archives/edgar/data/1163165/000119312513065426/d452384d10k.htm.

[144] *Energy Transitions Towards Net Zero Emissions*, Shell (2016), https://drive.google.com/file/d/0B_L1nw8WLu0Bbi1QWnJRcHlZblE/view (accessed Nov. 6, 2018).

[145] Fred Pearce, *Greenwash: BP and the Myth of a World 'Beyond Petroleum'*, THE GUARDIAN (Nov. 20, 2008), https://www.theguardian.com/environment/2008/nov/20/fossilfuels-energy.

[146] Javier E. David, *'Beyond Petroleum' No More? BP Goes Back to Basics*, CNBC (Apr. 20, 2013), http://www.cnbc.com/id/100647034.

[147] James R. Healy, *Alternate Energy Not in Cards at ExxonMobil*, USA TODAY (Oct. 28, 2005), https://usatoday30.usatoday.com/money/industries/energy/2005-10-27-oil-invest-usat_x.htm.

consumption of such products. These alternatives could have included, among other measures:

a. Accepting scientific evidence on the validity of anthropogenic climate change and the damages it will cause people and communities, including Plaintiff, and the environment. Mere acceptance of that information would have altered the debate from *whether* to combat global warming to *how* to combat it; and avoided much of the public confusion that has ensued over nearly 30 years, since at least 1988;

b. Forthrightly communicating with Defendants' shareholders, banks, insurers, the public, regulators, and Plaintiff about the global warming and ocean temperature increase hazards of Defendants' fossil fuel products that were known to Defendants, would have enabled those groups to make material, informed decisions about whether and how to address climate change vis-à-vis Defendants' products;

c. Refraining from affirmative efforts, whether directly, through coalitions, or through front groups, to distort public debate, and to cause many consumers and business and political leaders to think the relevant science was far less certain that it actually was;

d. Sharing their internal scientific research with the public, and with other scientists and business leaders, so as to increase public understanding of the scientific underpinnings of climate change and its relation to Defendants' fossil fuel products;

e. Supporting and encouraging policies to avoid dangerous climate change, and demonstrating corporate leadership in addressing the challenges of transitioning to a low-carbon economy;

f. Prioritizing alternative sources of energy through sustained investment and research on renewable energy sources to replace dependence on Defendants' inherently hazardous fossil fuel products;

g. Adopting their shareholders' concerns about Defendants' need to protect their businesses from the inevitable consequences of profiting from their fossil fuel products. Over the period of 1990–2015, Defendants' shareholders proposed hundreds of resolutions to change Defendants' policies and business practices regarding climate change. These included increasing renewable energy investment, cutting emissions, and performing carbon risk assessments, among others.

162. Despite their knowledge of the foreseeable harms associated with the consumption of Defendants' fossil fuel products, and despite the existence and fossil fuel industry knowledge of opportunities that would have reduced the foreseeable dangers associated with those products, Defendants wrongfully and falsely promoted, campaigned against regulation of, and concealed the hazards of use of their fossil fuel products.

H. Defendants Caused Plaintiff's Injuries

163. Defendants individually and collectively extracted a substantial percentage of all raw fossil fuels extracted globally since 1965.

164. CO_2 emissions that are attributable to fossil fuels that Defendants extracted from the earth and injected into the market are responsible for a substantial percentage of greenhouse gas pollution since 1965.

165. Defendants' individual and collective conduct—including, but not limited to, their extraction, refining, and/or formulation of fossil fuel products; their introduction of fossil fuel products into the stream of commerce; their wrongful promotion of their fossil fuel products and concealment of known hazards associated with use of those products; and their failure to pursue less hazardous alternatives available to them—is a substantial factor in causing the increase in global mean sea surface temperature, marine heatwaves, harmful algal blooms, marine toxin outbreaks, and related injuries, among other consequences.

166. Defendants have actually and proximately caused the increase in mean sea surface temperature, marine heatwaves, harmful algal blooms, and domoic acid outbreaks; and the

consequent social and economic injuries associated with those physical and environmental impacts, which are the causes of Plaintiff's injuries and damages as described herein.

167. Plaintiff has already incurred, and will foreseeably continue to incur, injuries and damages because of domoic acid outbreaks caused by Defendants' conduct.

168. California's commercial Dungeness crab fishery is seasonal and normally runs for eight months (from November 15 to June 15 south of the Sonoma/Mendocino County line and from December 1 to July 1 north of that line to the California/Oregon border). In Oregon, the season runs from December 1 to August 14 under normal conditions. The early part of crab season is by far the most productive because at that time there are the most crabs on the crab grounds, the crabs' meat content (the ratio of meat weight to total weight) is at its highest, and the demand for crab spikes around the Thanksgiving, Christmas, New Year and Lunar New Year holidays, and the Super Bowl.

169. As a precaution to avoid poisoning humans with domoic acid, the State of California delayed opening the Dungeness crab season at the beginning of the 2015–16 and 2016–17 commercial seasons, and will delay the beginning of the 2018–19 season:

a. In 2015–16, the fishery south of the Sonoma/Mendocino County line opened approximately four-and-a-half months late; the fishery north of the Sonoma/Mendocino County line did not fully open until nearly six months after the normal opening date;

b. In 2016–17, the fishery opened piecemeal, with a large section of the southern management area and a portion of the northern management area from the Oregon border to Redwood Creek opening on time, and six distinct areas north of Point Reyes in Marin County opening either on time, or with a delay in the range of 18 days to one-and-a-half months.

c. The area from Bodega Head to the Sonoma/Mendocino County line will be closed to commercial crabbing indefinitely; the season will not open as scheduled on November 15, 2018. Sampling farther north has shown that crabs at fishing grounds accessible from ports in Crescent City and

Trinidad, in Del Norte and Humboldt Counties, have levels of domoic acid that exceed the action threshold.

170. As a precaution to avoid poisoning humans with domoic acid, the State of Oregon delayed the opening of the Dungeness crab season at the beginning of the 2015–16, 2016–17, and 2017–18 commercial Dungeness crab seasons:

a. In 2015–16, the entire coast of Oregon was closed to commercial crabbing until nearly five weeks after the normal season opening date.

b. In 2016–17, the commercial crabbing season was delayed by approximately one month. After being open for approximately one month, the season was interrupted when domoic acid was again identified in crab at levels exceeding the action threshold. In response, ODFW and ODA curtailed the fishery in several ways, including by closing large areas of the ocean to crabbing and by issuing mandatory evisceration orders, which prohibit crab wholesalers from purveying live crabs or any crab product containing the crab viscera.

c. In 2017–18, the statewide commercial crab season was again delayed over six weeks in response to domoic acid contamination. ODFW and ODA also imposed mandatory evisceration orders for certain times and areas.

d. As of this writing, the 2018 Oregon recreational crab fishery (which operates on a different schedule than the commercial fishery) is closed from Cape Blanco to the Oregon/California border due to high levels of domoic acid in crab.

171. Additional domoic acid-induced Dungeness crab fishery closures will occur in the future, with increasing frequency and severity, and with concomitant impacts on and injuries to Plaintiff and west coast fishing families, communities and businesses.

172. Due to domoic acid contamination and the resultant crab fishery closures, commercial fishermen were deprived of valuable opportunities to fish for Dungeness crab during substantial portions of the 2015–16, 2016–17, and 2017–18 crab seasons, and will be deprived of

crabbing opportunities in the 2018–19 crab season and future seasons. Fishermen and fishery-dependent businesses, including Plaintiff, were therefore deprived of a substantial portion of their annual revenue from the Dungeness crab fishery for those seasons, and many suffered additional financial injuries by incurring debt to pay for operating and living expenses during the closures. Fishermen and fishery-dependent businesses, including Plaintiff, will continue to suffer such injuries during future domoic acid-induced fishery closures.

173. Because fisheries are seasonal, fishermen often pursue multiple different fisheries throughout the year. The delayed opening of the crab fishery in 2015–16, 2016–17, and 2017–18, caused many fishermen, including Plaintiff, to delay their entry into other fisheries they would normally have pursued earlier, including salmon, coonstripe shrimp, albacore, and others. Because those other fisheries are open only for limited portions of the calendar year, those fishermen were deprived of valuable fishing opportunities, thereby diminishing their earnings in those fisheries. Fishermen and fishery-dependent businesses, including Plaintiff, were therefore deprived of a substantial portion of their annual revenue from those other fisheries during years impacted by domoic acid-induced crab fishery closures, and will continue to suffer such injuries during future domoic acid-induced fishery closures.

174. Onshore crab wholesalers and processors, including Plaintiff, were deprived of a substantial portion of their annual revenue during the 2015–16, 2016–17, and 2017–18 crab seasons, and will continue to suffer such injuries during future domoic acid-induced fishery closures. That revenue substantially depends on the supply of Dungeness crab and other species harvested by commercial fishermen, which were not available due to the crab fishery delays that curtailed and will continue to curtail fishing opportunity.

175. The market for crab products, including Plaintiff's, was and during future crab seasons will be artificially depressed because of the stigma that Plaintiff's crab products were and are unsafe for human consumption, which adversely affects Plaintiff and its members. That depressed market has caused Plaintiff and its members a substantial loss of income, and will continue to do so as long as domoic acid outbreaks threaten the crab fishery.

176. Due to domoic acid contamination and the resultant past and future fishery closures, Plaintiff and west coast fishing families, communities, and businesses have suffered and will continue to suffer other harms beyond direct economic harms, including, but not limited to, the loss of the iconic west coast commercial fishing lifestyle, loss of a regional commercial fishing culture and identity, and loss of public confidence in the safety and quality of west coast Dungeness crab products and the fishery itself.

177. Defendants' conduct as described herein is therefore an actual, substantial, and proximate cause of Plaintiff's domoic acid-related injuries.

178. Future injuries arising out of domoic acid contamination in the crab fishery are abatable. Examples of technologies that could be used to prevent or mitigate to Plaintiff and the crab industry include, but are not limited to, monitoring and testing technologies that could permit real-time domoic acid testing, which would permit fishermen to separate contaminated crabs from clean ones at the time of harvest, thereby assuaging the public health concerns that currently induce fishery closures;[148] or "depuration," the process by which crabs in an environment and food free of domoic acid will naturally rid themselves of domoic acid.[149] Given large enough depuration facilities, commercially harvested crabs could be depurated on an industrial scale, and thereafter brought to market even if they contain domoic acid at the time of harvest.

VI. CAUSES OF ACTION

FIRST CAUSE OF ACTION

(Nuisance)

(Against All Defendants)

179. Plaintiff incorporates by reference each and every allegation contained above, as though set forth herein in full.

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[148] *See, e.g.*, Nat'l Ctrs. For Coastal Ocean Science, "Fast Tool to Detect Toxic Shellfish" (2017) (announcing development of an antibody-based test kit for domoic acid that provides quick results), https://coastalscience.noaa.gov/project/fast-tool-detect-toxic-shellfish; Nat'l Science & Tech. Council Subcommittee on Ocean Science & Tech., *Harmful Algal Blooms and Hypoxia – Comprehensive Research Plan and Action Strategy; An Interagency Report* (Feb. 2016), http://www.whoi.edu/fileserver.do?id=230904&pt=10&p=19132 (discussing how development of a toxin test-kit enabled fishermen to determine when and where clams were safe to harvest, re-enabling access to valuable shellfish resources).

[149] *See, e.g.*, J.A.K. Lund, et al., *Domoic acid uptake and depuration in dungeness crab (Cancer magister Dana 1852)*, 16 JOURNAL OF SHELLFISH RESEARCH 225 (1997).

180. Defendants, and each of them, by their acts and omissions, created a condition and permitted that condition to persist, which constitutes a nuisance in the form of increased mean sea surface temperature and intense marine heatwaves, which caused recurring *Pseudo-nitzschia* algal blooms unprecedented in their range and toxicity, which caused and will continue to cause domoic acid to contaminate Dungeness crabs at potentially dangerous concentrations, all of which resulted in past injuries and will cause future injuries to Plaintiff.

181. The condition created by Defendants substantially and negatively affects the interests of the public at large. In particular, increased mean sea surface temperature, marine heatwaves, harmful algal blooms, and domoic acid contamination: (1) are harmful and dangerous to human health; (2) are indecent and offensive to the senses of the ordinary person; and (3) obstruct and threaten to obstruct the free use of natural resources held in the public trust, so as to interfere with the comfortable enjoyment of life and property.

182. The condition created by Defendants affected, and will continue to affect, Plaintiff, because the economic impacts of fishery closures cascaded to impact entire fishery-dependent communities and businesses, and because the public was deprived of safe, local, and sustainable seafood.

183. The seriousness of the harms to Plaintiff caused by increased mean sea surface temperature, marine heatwaves, harmful algal blooms, and domoic acid contamination are extremely grave, and outweigh the public benefit of Defendants' wrongful over-marketing and overpromotion of their dangerous fossil fuel products with knowledge of the harm that would result, and their long-standing efforts to sow doubt about the science surrounding the effects of their products on the world's climate and oceans, and campaigns to avoid regulation. The seriousness of the harm to Plaintiff outweighs the public benefit of Defendants' and each of their conduct, because

a. the interference with natural resources held in the public trust are expected to become regular, recurrent, and increasingly severe, so as to become a permanent ecological feature of the crab fishery;

b. the nature of the harm is the deprivation of the right to use and enjoy natural resources held in the public trust, as well as potential physical injury to consumers, rather than mere annoyance;

c. the interference borne by Plaintiff is the deprivation of the right to obtain and use natural resources held in the public trust, deprivation of the right to use commercial fishing privileges, the loss of normal and expected revenue from the use of those resources and privileges, and the deprivation of a livelihood that depends on those resources;

d. The natural resources contaminated with domoic acid as a direct consequence of Defendants' conduct are not suitable for such contamination because those resources are consumed by humans and other organisms;

e. the burden on Plaintiff to mitigate and prevent the interference with the natural resources held in the public trust, fishing privileges, and the right to use and enjoy those resources and privileges to pursue fishing community livelihoods, is significant and severe, as costs associated with preventing such interference or contamination are prohibitive;

f. the social benefit of placing fossil fuels into the stream of commerce, if any, is outweighed by the availability of other sources of energy that could have been placed into the stream of commerce that would not have caused increased mean sea surface temperature, marine heatwaves, harmful algal blooms, and domoic acid contamination; Defendants, and each of them, knew of the external costs of placing their fossil fuel products into the stream of commerce, and rather than striving to mitigate those externalities, instead acted affirmatively to obscure them from public consciousness; and Defendants' over-promotion and over-marketing of their products with knowledge of the harm that would result, and their long-standing efforts to sow doubt about the science surrounding the effects of their products on the world's climate and oceans, and campaigns to avoid regulation, have no social utility;

g. the social cost of each ton of CO_2 emitted into the atmosphere increases as total global emissions increase, so that unchecked extraction and consumption of fossil fuel products is more harmful and costly than moderated extraction and consumption; and

h. it was practical for Defendants, and each of them, in light of their extensive knowledge of the hazards of placing fossil fuel products into the stream of commerce and extensive scientific engineering expertise, to develop better technologies and to pursue and adopt known, practical, and available technologies, energy sources, and business practices that would have mitigated their greenhouse gas pollution and eased the transition to a lower carbon economy.

184. In addition to the harms suffered by the public at large, Plaintiff has suffered, and will continue to suffer, special injuries that are different in kind. Among other harms, Plaintiff suffered economic losses due to the prohibition on harvesting and transacting in Dungeness crabs, which constitute a substantial and significant portion of Plaintiff's revenue. Additionally, the markets for Plaintiff's products were artificially depressed because of public health concerns over the potential presence of domoic acid in those products. The public at large has not suffered the same deprivation of a livelihood as has Plaintiff.

185. Defendants' wrongful conduct was oppressive, malicious, and fraudulent, in that their conduct was willful, intentional, and in conscious disregard for the rights of others. Defendants' conduct was so vile, base, and contemptible that it would be looked down upon and despised by reasonable people, justifying an award of punitive and exemplary damages in an amount subject to proof at trial, and justifying equitable disgorgement of all profits Defendants obtained through their unlawful and outrageous conduct.

186. As a direct and proximate result of Defendants' conduct, as set forth above, Plaintiff has been unreasonably interfered with because Defendants knew or should have known that their

conduct would create a continuing problem with long-lasting significant negative effects on the rights of the public.

187. Defendants' actions are a direct and legal cause of the public nuisance.

188. Defendants' acts and omissions as alleged herein are substantial and indivisible causes of Plaintiff's injuries and damages as alleged herein.

189. Plaintiff is entitled to recover damages and other appropriate relief for the foregoing public nuisance.

190. Wherefore, Plaintiff prays for relief as set forth below.

SECOND CAUSE OF ACTION

(Strict Liability – Failure to Warn)

(Against All Defendants)

191. Plaintiff incorporates by reference each and every allegation contained above, as though set forth herein in full.

192. Defendants, and each of them, extracted raw fossil fuel products, including crude oil, coal, and natural gas from the earth, and placed those fossil fuel products into the stream of commerce.

193. Defendants, and each of them, extracted, refined, formulated, designed, packaged, distributed, tested, constructed, fabricated, analyzed, recommended, merchandised, advertised, promoted and/or sold fossil fuel products, which were intended by Defendants, and each of them, to be burned for energy, refined into petrochemicals, and refined and/or incorporated into petrochemical products including fuels and plastics.

194. Defendants, and each of them, heavily marketed, promoted, and advertised fossil fuel products and their derivatives, which were sold or used by their respective affiliates and subsidiaries. Defendants received direct financial benefit from their affiliates' and subsidiaries' sales of fossil fuel products. Defendants' role as promoter and marketer was integral to their respective businesses and a necessary factor in bringing fossil fuel products and their derivatives to the consumer market, such that Defendants had control over, and a substantial ability to influence, the manufacturing and distribution processes of their affiliates and subsidiaries.

195. Throughout the times at issue, Defendants individually and collectively knew or should have known, in light of the scientific knowledge generally accepted at the time, that fossil fuel products, whether used as intended or misused in a foreseeable manner, release greenhouse gases into the atmosphere that inevitably cause *inter alia* global warming, increased mean sea surface temperature, marine heatwaves, and harmful algal blooms with a capacity for producing marine toxins.

196. Throughout the times at issue and continuing today, fossil fuel products presented and still present a substantial risk of injury to Plaintiff through the climate and ocean temperature effects described above, whether used as intended or misused in a reasonably foreseeable manner.

197. Throughout the times at issue, the ordinary consumer would not recognize that the use or foreseeable misuse of fossil fuel products causes global and localized changes in climate and the world's oceans, including those effects described herein.

198. Throughout the times at issue, Defendants individually and in concert widely disseminated marketing materials, refuted the generally accepted scientific knowledge at the time, and advanced pseudo-scientific theories of their own, and developed public relations campaigns and materials that prevented reasonable consumers from recognizing the risk that fossil fuel products would cause grave climate changes, including those described herein.

199. Defendants, and each of them, failed to adequately warn customers, consumers, elected officials and regulators of known and foreseeable risk of climate change and the consequences that inevitably follow from the normal, intended use and foreseeable misuse of Defendants' fossil fuel products.

200. Defendants' wrongful conduct was oppressive, malicious, and fraudulent, in that their conduct was willful, intentional, and in conscious disregard for the rights of others. Defendants' conduct was so vile, base, and contemptible that it would be looked down upon and despised by reasonable people, justifying an award of punitive and exemplary damages in an amount subject to proof at trial, and justifying equitable disgorgement of all profits Defendants obtained through their unlawful and outrageous conduct.

201. As a direct and proximate result of the defects previously described, fossil fuel products caused and will continue to cause Plaintiff to sustain the injuries and damages set forth in this Complaint, including economic loss, damage to natural resources held in the public trust, deprivation of the right to use fishing privileges, and the creation and maintenance of a nuisance that interferes with the rights of Plaintiff and commercial fishery-dependent communities along the west coast.

202. Defendants' acts and omissions as alleged herein are indivisible causes of Plaintiff's injuries and damages as alleged herein.

203. Plaintiff is entitled to recover damages and other appropriate relief for the foregoing failure to warn of product defects.

204. Wherefore, Plaintiff prays for relief as set forth below.

THIRD CAUSE OF ACTION

(Strict Liability – Design Defect)

(Against All Defendants)

205. Plaintiff incorporates by reference each and every allegation contained above, as though set forth herein in full.

206. Defendants, and each of them, extracted raw fossil fuel products, including crude oil, coal, and natural gas from the earth and placed those fossil fuel products into the stream of commerce.

207. Defendants, and each of them, extracted, refined, formulated, designed, packaged, distributed, tested, constructed, fabricated, analyzed, recommended, merchandised, advertised, promoted and/or sold fossil fuel products, which were intended by Defendants, and each of them, to be burned for energy, refined into petrochemicals, and refined and/or incorporated into petrochemical products including but not limited to fuels and plastics.

208. Defendants, and each of them, heavily marketed, promoted, and advertised fossil fuel products and their derivatives, which were sold or used by their respective affiliates and subsidiaries. Defendants' received direct financial benefit from their affiliates' and subsidiaries' sales of fossil fuel products. Defendants role as promoter and marketer was integral to their

respective businesses and a necessary factor in bringing fossil fuel products and their derivatives to the consumer market, such that Defendants had control over, and a substantial ability to influence, the manufacturing and distribution processes of their affiliates and subsidiaries.

209. Throughout the time at issue, fossil fuel products have not performed as safely as an ordinary consumer would expect them to because greenhouse gas emissions from their use cause numerous global and local changes to Earth's climate. In particular, ordinary consumers did not expect that:

a. fossil fuel products are the primary cause of global warming since the dawn of the industrial revolution, and by far the primary cause of global warming acceleration in the 20th and 21st centuries;

b. fossil fuel products would cause increase mean sea surface temperature;

c. fossil fuel products would cause increased frequency and intensity of marine heatwaves;

d. unmitigated use of fossil fuel products causes increased frequency and intensity of harmful algal blooms;

e. fossil fuel products cause increased frequency and intensity of marine toxin outbreaks and contamination of natural resources held in the public trust, including Dungeness crabs, necessitating commercial fishery closures and concordant economic injuries;

f. the social cost of each ton of CO_2 emitted into the atmosphere increases as total global emissions increase, so that unchecked extraction and consumption of fossil fuel products is more harmful and costly than moderated extraction and consumption; and

g. for these reasons and others, the unmitigated use of fossil fuel products present significant threats to the environment and human health and welfare, especially to coastal and ocean-dependent communities.

210. Throughout the times at issue, Defendants individually and in concert widely disseminated marketing materials, refuted the generally accepted scientific knowledge at the time,

advanced pseudo-scientific theories of their own, and developed public relations materials, among other public messaging efforts, that prevented reasonable consumers from forming an expectation that fossil fuel products would cause grave climate changes, including those described herein.

211. Additionally, and in the alternative, Defendants' fossil fuel products are defective because the risks they pose to consumers and to the public, including and especially to Plaintiff, outweigh their benefits.

a. The gravity of the potential harms caused by fossil fuel products is extreme; global warming and its attendant consequences are guaranteed to occur following the use or foreseeable misuse of fossil fuel products because fossil fuel products inherently release greenhouse gases into the atmosphere; and global warming would continue to occur for decades even if all greenhouse gas emissions ceased.

b. The social benefit of the purpose of placing fossil fuels into the stream of commerce is overshadowed by the availability of other sources of energy that could have been placed into the stream of commerce that would not have caused increased mean sea surface temperature, marine heatwaves, harmful algal blooms, and marine toxin outbreaks, and accordingly Plaintiff's injuries; Defendants, and each of them, knew of the external costs of placing their fossil fuel products into the stream of commerce, and rather than striving to mitigate those externalities, instead acted affirmatively to obscure them from public consciousness.

c. Defendants' campaign of disinformation regarding global warming and the climatic effects of fossil fuel products prevented customers, consumers, regulators, and the general public from taking steps to mitigate the inevitable consequences of fossil fuel consumption, and incorporating those consequences into either short-term decisions or long-term planning.

d. The cost to society of each ton of CO_2 emitted into the atmosphere increases as total global emissions increase so that unchecked extraction and consumption of fossil fuel products is more harmful and costly than moderated extraction and consumption.

e. It was practical for Defendants, and each of them, in light of their extensive knowledge of the hazards of placing fossil fuel products into the stream of commerce, to pursue and adopt known, practical, and available technologies, energy sources, and business practices that would have mitigated their greenhouse gas pollution and eased the transition to a lower carbon economy, reduced global CO_2 emissions, and mitigated the harms associated with the use and consumption of such products.

212. Defendants' individual and aggregate fossil fuel products were used in a manner for which they were intended to be used, or misused in a manner foreseeable to Defendants and each of them, by individual and corporate consumers, the result of which was the addition of CO_2 emissions to the global atmosphere with attendant global and local consequences.

213. As a direct and proximate result of the defects in fossil fuel products described herein, Plaintiff sustained and will continue to sustain the injuries and damages set forth in this Complaint, including, but not limited to, economic losses due to commercial fishery closures.

214. Defendants' wrongful conduct was oppressive, malicious, and fraudulent, in that their conduct was willful, intentional, and in conscious disregard for the rights of others. Defendants' conduct was so vile, base, and contemptible that it would be looked down upon and despised by reasonable people, justifying an award of punitive and exemplary damages in an amount subject to proof at trial, and justifying equitable disgorgement of all profits Defendants obtained through their unlawful and outrageous conduct.

215. Defendants' acts and omissions as alleged herein are indivisible causes of Plaintiff's injuries and damages as alleged herein.

216. Plaintiff is entitled to recover damages and other appropriate relief for the foregoing design defects.

217. Wherefore, Plaintiff prays for relief as set forth below.

FOURTH CAUSE OF ACTION

(Negligence)

(Against All Defendants)

218. Plaintiff incorporates by reference each and every allegation contained above, as though set forth herein in full.

219. Defendants knew or should have known of the climate effects inherently caused by the normal use and operation of their fossil fuel products, including the likelihood and likely severity of increased mean sea surface temperature, marine heatwaves, harmful algal blooms, and marine toxin outbreaks, and including Plaintiff's injuries and damages alleged herein.

220. Defendants, collectively and individually, had a duty to use due care in developing, designing, testing, inspecting and distributing their fossil fuel products. That duty obligated Defendants collectively and individually to, *inter alia*, prevent defective products from entering the stream of commerce, and prevent reasonably foreseeable harm that could have resulted from the ordinary use or reasonably foreseeable misuse of Defendants' products.

221. Defendants, and each of them, breached their duty of due care by, *inter alia*:

a. allowing fossil fuel products to enter the stream of commerce, despite knowing them to be defective due to their inevitable propensity to cause increased mean sea surface temperature, marine heatwaves, harmful algal blooms, marine toxin outbreaks, and related injuries;

b. failing to act on the information and warnings they received from their own internal research staff, as well as from the international scientific community, that the unabated extraction, promotion and sale of their fossil fuel products would result in material dangers to the public, including to Plaintiff;

c. failing to take actions including but not limited to pursuing and adopting known, practical, and available technologies, energy sources, and business practices that would have mitigated their greenhouse gas pollution and eased the transition to a lower carbon economy; shifting to non-fossil fuel products, and researching and/or offering technologies to mitigate CO_2 emissions in conjunction with sale and distribution of their fossil fuel products; and pursuing other available alternatives that would have prevented or mitigated the injuries to Plaintiff caused by increased mean sea surface temperature, marine heatwaves, harmful algal blooms, and marine toxin outbreaks that Defendants, and each of them, knew or should have foreseen would inevitably result from use of Defendants' fossil fuel products;

d. engaging in a campaign of disinformation regarding global warming and the climatic effects of fossil fuel products that prevented customers, consumers, regulators, and the general public from staking steps to mitigate the inevitable consequences of fossil fuel consumption, and incorporating those consequences into either short-term decisions or long-term planning.

222. Defendants' individual and collective acts and omissions were actual, substantial causes of increased mean sea surface temperature, marine heatwaves, harmful algal blooms, marine toxin outbreaks, and related consequences, including Plaintiff's injuries and damages set forth herein, because the oceanographic conditions that caused Plaintiff's injuries would not have happened, or would not have reached expanse and toxicity that they did, but for Defendants' introduction of their fossil fuel products into the stream of commerce.

223. Defendants' individual and collective acts and omissions were proximate causes of increased mean sea surface temperature, marine heatwaves, harmful algal blooms, marine toxin outbreaks, and their consequences, including Plaintiff's injuries and damages set forth herein. No other act, omission, or natural phenomenon intervened in the chain of causation between Defendants' conduct and Plaintiff's injuries and damages, or superseded Defendants' breach of their duties' substantiality in causing Plaintiff's injuries and damages.

224. As a direct and proximate result of Defendants' and each of their acts and omissions, Plaintiff sustained and will continue to sustain injuries and damages as set forth herein.

225. Defendants' acts and omissions as alleged herein are indivisible causes of Plaintiff's injuries and damages as alleged herein.

226. Defendants' wrongful conduct was oppressive, malicious, and fraudulent, in that their conduct was willful, intentional, and in conscious disregard for the rights of others. Defendants' conduct was so vile, base, and contemptible that it would be looked down upon and despised by reasonable people, justifying an award of punitive and exemplary damages in an amount subject to proof at trial, and justifying equitable disgorgement of all profits Defendants obtained through their unlawful and outrageous conduct.

227. Plaintiff is entitled to recover damages and other appropriate relief for the foregoing negligent conduct.

228. Wherefore, Plaintiff prays for relief as set forth below.

FIFTH CAUSE OF ACTION

(Negligence – Failure to Warn)

(Against All Defendants)

229. Plaintiff incorporates by reference each and every allegation contained above, as though set forth herein in full.

230. Defendants knew or should have known, based on information passed to them from their internal research divisions and affiliates and/or from the international scientific community, of the climate effects inherently caused by the normal use and operation of their fossil fuel products, including global warming, and the likely increases in frequency and severity of increased mean sea surface temperature, marine heatwaves, harmful algal blooms, marine toxin outbreaks, and the consequences of those phenomena, including Plaintiff's injuries and damages described herein.

231. Defendants knew or should have known, based on information passed to them from their internal research divisions and affiliates and/or from the international scientific community, that the climate effects described above rendered their fossil fuel products dangerous, or likely to be dangerous, when used as intended or misused in a reasonably foreseeable manner.

232. Throughout the times at issue, Defendants failed to adequately warn any consumers or any other party of the climate effects that inevitably flow from the use or foreseeable misuse of their fossil fuel products.

233. Throughout the times at issue, Defendants individually and in concert widely disseminated marketing materials, refuted the generally accepted scientific knowledge at the time, advanced pseudo-scientific theories of their own, and developed public relations materials that prevented reasonable consumers from recognizing the risk that fossil fuel products would cause grave climate changes, undermining and rendering ineffective any warnings that Defendants may have also disseminated.

234. Given the grave dangers presented by the climate effects that inevitably flow from the normal use or foreseeable misuse of fossil fuel products, a reasonable extractor, manufacturer, formulator, seller, or other participant responsible for introducing fossil fuel products into the stream of commerce, would have warned of those known, inevitable climate effects.

235. Defendants' conduct was a direct and proximate cause of Plaintiff's injuries and a substantial factor in the harms suffered by Plaintiff as described in this Complaint.

236. Defendants' acts and omissions as alleged herein are indivisible causes of Plaintiff's injuries and damages as alleged herein.

237. Defendants' wrongful conduct was oppressive, malicious, and fraudulent, in that their conduct was willful, intentional, and in conscious disregard for the rights of others. Defendants' conduct was so vile, base, and contemptible that it would be looked down upon and despised by reasonable people, justifying an award of punitive and exemplary damages in an amount subject to proof at trial, and justifying equitable disgorgement of all profits Defendants obtained through their unlawful and outrageous conduct.

238. Plaintiff is entitled to recover damages and other appropriate relief for the foregoing negligent failure to warn.

239. Wherefore, Plaintiff prays for relief as set forth below.

VII. PRAYER FOR RELIEF

WHEREFORE, Plaintiff prays for judgment against Defendants as follows:

1. Compensatory damages in an amount according to proof;
2. Equitable relief, including abatement of the nuisance described herein;
3. Reasonable attorneys' fees pursuant to California Code of Civil Procedure 1021.5 or otherwise;
4. Punitive damages;
5. Disgorgement of profits;
6. Costs of suit; and
7. For such and other relief as the court may deem proper.

Dated: November 14, 2018

SHER EDLING LLP

By: Victor Sher

VICTOR M. SHER
MATTHEW K. EDLING
TIMOTHY R. SLOANE
KATIE H. JONES
MARTIN D. QUIÑONES
MEREDITH S. WILENSKY

Attorneys for Pacific Coast Federation of Fishermen's Associations Inc.

VIII. <u>JURY DEMAND</u>

Plaintiff demands a jury trial on all issues so triable.

Dated: November 14, 2018

SHER EDLING LLP

By: ______________________

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UNITED STATES DISTRICT COURT
WESTERN DISTRICT OF WASHINGTON
AT SEATTLE

COLUMBIA RIVERKEEPER, et al., Plaintiffs, v. SCOTT PRUITT, et al., Defendants.	Case No. C17-289RSM ORDER RE: MOTIONS FOR SUMMARY JUDGMENT

This matter comes before the Court on the Parties' Cross Motions for Summary Judgment. Dkts. #19 and #31. For the reasons stated below, the Court GRANTS IN PART Plaintiffs' Motion and DENIES Defendant's Motion.

I. BACKGROUND

A. Salmon and Other At-risk Fish of the Columbia and Snake Rivers

The Columbia River is the largest river in the Pacific Northwest, with the Snake River as its largest tributary. The Columbia flows more than 1,200 miles from its source in the Canadian Rockies to the Pacific Ocean. *See* Dkt. #1 at 9. The Snake River forms in Wyoming and flows over 1,000 miles across Southern Idaho, along the Idaho-Oregon border, and through Eastern Washington. Dkt. #1 at 9. The drainage basin of the Columbia and Snake Rivers extends into seven U.S. states and up into Canada, encompassing an area roughly the size of France. *See* Dkt. #31 at 16-17.

Today, the Columbia and lower Snake Rivers are native habitat to multiple species of salmon and steelhead trout. Dkts. #1 at 9, #19 at 9-11, and #31 at 17. The Columbia River Basin once held the largest salmon populations in the world, with the Snake River historically sustaining at least a third of those salmon runs. *See* Dkt. #31 at 9. However, populations of these salmon and steelhead have since declined, with 13 species or populations in the Columbia and Snake River now being listed as "endangered" or "threatened" under the Endangered Species Act, and several populations having now gone extinct. Dkt. #19 at 11. Currently, 65 percent of remaining populations are listed at "high risk" of extinction, while only 6.5 percent are listed as "viable" or "highly viable." *Id.*

Salmon and steelhead native to the Columbia and Snake Rivers hatch in fresh water and migrate downstream to the Pacific Ocean as juveniles, returning as adults to the same river tributaries to spawn. Dkt. #1 at 9. These fish species are generally suited to cold-water, and depend on cold water temperatures for migration, spawning, and rearing. Dkt. #31 at 17. During their trips up and down the Columbia and Snake Rivers, these salmon and steelhead are particularly vulnerable to harm caused by warm water temperatures, specifically as the water reaches or exceeds 68° Fahrenheit ("F") for extended periods. Dkts. #19 at 6 and #31 at 18. When water temperatures approach 68° F, adult salmon have difficulty migrating upstream, and at 72-73° F, migration stops altogether. *Id*. Salmon that have stopped or slowed in their migration may end up staying in the warm water, where they are at risk of death, disease, decreased spawning productivity, and delayed spawning. Dkt. #27-14 at 23-25.

The parties agree that much of the focus for potential causes of increases in water temperature in both the Columbia and Snake Rivers appropriately lies on the presence of dams and point source dischargers located on both rivers. *See* Dkt. #31 at 17. There are a number of federal and non-federal dams on both rivers, with the federal dams operating for a variety of purposes, including hydroelectric power, flood risk management, navigation, and fish and wildlife conservation. *Id.* In addition, as of 2003, there were around 100 point source dischargers on the two rivers. *Id.*

In recent years, water temperature in the Columbia and Snake Rivers has consistently exceeded 68° F, especially during the summertime salmon and steelhead runs, presenting a problem for the continued survival of those native fish populations. Dkts. #1 at 10 and #19 at 7 and 9-10. Temperature issues are projected to worsen as the effects of human activities and climate change continue to increase water temperatures, negatively impacting the ability of salmon and steelhead to successfully migrate to and from the Pacific Ocean to spawn. *Id.* The presence of these high water temperatures led the states of Washington and Oregon to place and maintain both rivers on their respective Clean Water Act ("CWA") § 303(d) lists of impaired waters. Dkt. #27-22 at 10 and 24.

B. Washington and Oregon States' 303(d) Programs

The State of Washington prepared its first 303(d) list in 1994, placing segments of the Columbia and lower Snake Rivers on that list in 1998. *See* Dkt. #31 at 14-15. Presently, 40 of 77 segments of the Columbia River and 9 of 19 segments of the Snake River are listed as having an impaired water temperature under Washington's current water temperature standards. *Id.* at 15. The current Washington water temperature standards require that temperatures must stay below 60.8-68° F depending upon the time of year, location, and fish present. *Id.*

The State of Oregon first listed segments of the Columbia and lower Snake Rivers on its own 303(d) list in 1996. *Id.* at 16. At present, the entire length of the Columbia River in Oregon is listed as impaired by temperature. *Id.* Oregon's current water temperature standards range from 55.4° F for some fish spawning areas from the months of October to April, to 68° F year-round. *Id.*

Both Washington and Oregon's water temperature standards include "natural conditions criteria" for temperature, which provide that "if the natural temperatures in the water body exceed the numeric biologically-based criteria, then the natural temperatures constitute the applicable temperature criteria for that water body." *Id.* at 15-16. While the Environmental Protection Agency ("EPA") approved both states' natural condition criteria in the past, that EPA approval was overruled in part after litigation in Oregon, and is currently involved in pending litigation in Washington. *Id.*

C. The 2000 Memorandum of Agreement and State-EPA Agreements on TMDL Responsibilities

After both Washington and Oregon listed the Columbia and Snake Rivers on their respective 303(d) lists, the EPA, Washington, Oregon, and Idaho signed a Memorandum of Agreement ("MOA"). Dkt. #27-15. The MOA was signed on October 16, 2000, and outlined a cooperative multi-state and federal approach to address temperature related impairments in the two rivers. *Id.*

The main focus of the MOA was to "document a mutual understanding on the approach and roles among Idaho [Department of Environmental Quality], Washington [Department of Ecology], Oregon [Department of Environmental Quality], EPA Region X, and the Columbia Basin Tribes to complete a total dissolved gas and temperature Total Maximum Daily Load

(TMDL) for the mainstem[1] Columbia and Snake Rivers." *Id.* at 5. Further describing the approach to be taken, the MOA outlines that the EPA "will produce," a TMDL for temperature for the Snake/Columbia Mainstem in cooperation with the States. *Id*. at 8. Each state, under the MOA, is required to produce the TMDL for total dissolved gas ("TDG") in cooperation with the dam operators for their water-ways within their boundaries. *Id*. Additionally, each state is designated to assist the EPA with the production of "significant portions" of the implementation plans for the temperature TMDL, particularly with regards to those sections related to non-point sources. *Id*. at 9.

On April 16, 2001, the EPA prepared a Work Plan designed to outline the key dates associated with drafting and finalizing the TMDL in accordance with the MOA, as well as the roles of the EPA and the States in that process. Dkt. #27-17. In the Work Plan, the EPA outlined that the EPA would take the lead for developing the temperature TMDL, and the States would be responsible for issuing that TMDL. *Id*. at 5. The States, on the other hand, would be solely responsible for taking the lead in developing and issuing the TDG TMDL for their waters. *Id*.

Further, while the EPA "oversees the entire 303(d)/TMDL process with responsibility for approving or disapproving state issued 303(d) lists and TMDLs," under the Work Plan "[i]f EPA disapproves a State TMDL, EPA is required to develop a TMDL to replace the disapproved one." *Id*. The Work Plan set the date for the submission of the draft TMDL at February 1, 2002, and the release of the final TMDL in July or August of 2002. *Id*. at 3.

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[1] Mainstem is defined in common-usage as a "main channel," such as, the "main course of a river or stream." *See Definition of Main Stem*, MERRIAM-WEBSTER.COM, https://www.merriam-webster.com/dictionary/main%20stem (last visited October 16, 2018).

D. The 2003 Draft Temperature TMDL and Current Developments

On September 4, 2001, Washington State, through its Department of Ecology, wrote to EPA Region X seeking clarification on which agencies would lead, develop, and produce the temperature and TDG TMDLs. Dkt. #27-18 at 2. In that letter Washington sought to clarify its expectations that the EPA would lead the development of, and issue the TMDLs for Washington, so that Washington state could then implement those EPA-issued TMDLs. *Id*. Oregon State submitted its own letter to the EPA on October 4, 2001, echoing the Washington State letter and requesting that the EPA issue the TMDL, so that the state could then implement that EPA-issued TMDL in Oregon. Dkt. #27-20 at 2-3.

In a January 15, 2002, letter written to the Columbia River Inter-Tribal Fish Commission, the EPA responded to a request regarding the status of the TMDLs, indicating that its role in that process was to conduct technical analysis, issue a federal TMDL, and approve or disapprove the TDG TMDLs submitted by Oregon and Washington. Dkt. #27-21 at 2. The EPA letter specially addressed the requests of the two states in defining its actions, stating: "at the request of the states of Oregon and Washington, EPA will be doing the technical analysis and issuing temperature TMDLs for the Columbia/Snake River Mainstem in Oregon and Washington." *Id*.

Just under one month later, on February 12, 2003, Washington and Oregon wrote a joint letter to the Council on Environmental Quality, a federal executive administrative agency, expressing the understanding of both States that they would be taking the lead on the TDG TMDL, while the EPA would be taking the lead on the temperature TMDL. Dkt. #27-23 at 2. In a March 18, 2003, document entitled "EPA Strategy for Consultation and Coordination with Indian Tribal Government for Completing Mainstem Columbia River and Snake River

TMDLs," the EPA included a section noting that it was currently working in coordination with the states of Oregon and Washington to develop TDG and temperature TMDLs in the Columbia and Snake Rivers. Dkt. #27-24 at 2. The document specifically states, "at the request of the states of Oregon and Washington, EPA will be doing the technical analysis and issuing temperature TMDLs for the Columbia/Snake River Mainstem in Oregon and Washington." *Id*.

Finally, in July 2003, the EPA released a "Preliminary Draft" of the temperature TMDL for the Columbia and Snake Rivers. Dkt. #27-22. In the draft, the EPA noted that while the responsibility for development of TMDLs generally falls to the States, because of the interstate and international nature of the waters, its relationship with tribal-trust duties, and the technical expertise required, the EPA had agreed to take responsibility in this case. *Id*. at 7. Outlining further steps in the plan toward issuing the final TMDL, the draft states that after being released it would undergo a 90 day public comment period, where, after consideration of public comments and appropriate changes, the EPA would issue the final temperature TMDL for the Columbia and Snake River Mainstem. *Id*.

Since July 2003, the EPA has not issued a final temperature TMDL, indicating in an internal EPA document that the EPA worked "extensively on a draft TMDL until late 2003," with that work then suspended due to disagreements between federal agencies at the national level. Dkt. #27-25 at 2. In a February 20, 2007, letter from the EPA to the U.S. Army Core of Engineers, the EPA acknowledged that it remained responsible for development of the temperature TMDL for the mainstem Columbia and Snake Rivers. Dkt. #27-26 at 2.

Since 2003, the native salmon and steelhead populations of the Columbia and Snake Rivers have continued to be affected by warm water temperatures. In 2015, warm water temperatures in the Columbia and Snake Rivers were responsible for the deaths of roughly

250,000 migrating adult sockeye salmon. Dkt. #12 at 2. Of those migrating salmon, upper Columbia River sockeye had the lowest survival rate in the past six years, and endangered Snake River sockeye had a survival rate of only four percent, down from the 44-77 percent survival rates of the past five years. Dkt. #27-9 at 4. Native steelhead populations have been similarly affected, with predictions on the 2017 run indicating that it had "collapsed," and with the Idaho Department of Fish and Game for the first time prohibiting anglers from taking Snake River steelhead. Dkts. #22 at 5 and #25 at 5.

After the instant litigation had begun, the EPA sent a letter to the states of Oregon, Washington, and Idaho, dated August 10, 2017, requesting a modification of the MOA, so that direct work on the final TMDL could be resumed. Dkt. #18-1 at 2. In its letter, the EPA states that changed circumstances involving technology, natural conditions, and legal challenges to previous EPA and state standards necessitate a modification to the MOA prior to the EPAs ability to issue any final temperature TMDL. *Id*. at 2-7.

II. DISCUSSION

A. Legal Standard for Summary Judgment

Summary judgment is appropriate where "the movant shows that there is no genuine dispute as to any material fact and the movant is entitled to judgment as a matter of law." Fed. R. Civ. P. 56(a); *Anderson v. Liberty Lobby, Inc.*, 477 U.S. 242, 247 (1986). Material facts are those which might affect the outcome of the suit under governing law. *Anderson*, 477 U.S. at 248. In ruling on summary judgment, a court does not weigh evidence to determine the truth of the matter, but "only determine[s] whether there is a genuine issue for trial." *Crane v. Conoco, Inc.*, 41 F.3d 547, 549 (9th Cir. 1994) (citing *Federal Deposit Ins. Corp. v. O'Melveny & Meyers*, 969 F.2d 744, 747 (9th Cir. 1992)).

On a motion for summary judgment, the court views the evidence and draws inferences in the light most favorable to the non-moving party. *Anderson*, 477 U.S. at 255; *Sullivan v. U.S. Dep't of the Navy*, 365 F.3d 827, 832 (9th Cir. 2004). The Court must draw all reasonable inferences in favor of the non-moving party. *See O'Melveny & Meyers*, 969 F.2d at 747, *rev'd on other grounds*, 512 U.S. 79 (1994). However, the nonmoving party must make a "sufficient showing on an essential element of her case with respect to which she has the burden of proof" to survive summary judgment. *Celotex Corp. v. Catrett*, 477 U.S. 317, 323 (1986).

B. Clean Water Act

The Court will address Plaintiffs' Motion for Summary Judgment first. Plaintiffs argue that the EPA has violated the CWA, 33 U.S.C. § 1313(d)(2), by failing to issue a TMDL for the Columbia and lower Snake Rivers. Plaintiffs contend that Washington and Oregon have made a "constructive submission" to the EPA under the CWA by clearly and unambiguously indicating that they will not produce a TMDL. Dkt. #19 at 11 (citing *Sierra Club v. McLerran*, No. 11-cv-1759-BJR, 2015 WL 1188522 at *7 (W.D. Wash. Mar. 16, 2015). Evidence of this can be found in the 2000 MOA, which provided that "EPA will produce" the temperature TMDL, *see* Dkt. #27-15 at 7, and subsequent letters to the EPA in the fall of 2001 where Washington and Oregon requested the EPA to issue the TMDL, *see* Dkts. #27-18 and #27-20. Once a constructive submission occurs, the EPA has a mandatory duty under the CWA to disapprove the constructively submitted TMDL within 30 days and to issue a TMDL within 30 more days; if the EPA fails to take these steps, the courts can order the EPA to prepare a TMDL under the CWA. *Id.*; *Alaska Ctr. for Env't v. Reilly*, 762 F. Supp. 1422, 1429 (W.D. Wash. 1991) ("*ACE I*"). Plaintiffs assert that the 2000 MOA and the other correspondence above serve as evidence of this constructive submission, and that the EPA has therefore violated the CWA by failing to issue a timely TMDL.

The EPA argues that the constructive submission theory does not apply here. Dkt. #31 at 25.[2] The agency argues that this judicial theory has been adopted by the Ninth Circuit "only with respect to wholesale programmatic failures by a state to submit any TMDLs." *Id.* (citing *Baykeeper v. Whitman*, 297 F.3d 877, 882 (9th Cir. 2002)). The EPA also cites to *Friends of the Wild Swan, Inc. v. EPA*, 130 F. Supp. 2d 1184, 1190-91 (D. Mont. 1999), *Idaho Sportsmen's Coal. v. Browner*, 951 F. Supp. 962, 967-968 (W.D. Wash. 1996), and several out of circuit cases. *Id.* at 29–30. The EPA argues that finding a constructive submission of a single, particular TMDL "would run counter to the intent of Congress – which allowed states to set priorities – and to the implicit limitations recognized by courts in adopting and applying the theory over the last three decades." *Id.* at 31. The EPA points out that Washington and Oregon have been busy issuing 2,800 other TMDLs during this time period. *Id.* at 32. The EPA further argues that Plaintiffs are citing dicta in *Sierra Club v. McLerran*. *Id.* at 32–33. Citing *Alaska Center for Environment v. Browner*, 20 F.3d 981, 985 (9th Cir. 1994), the EPA states:

> The Ninth Circuit has, therefore, already weighed the question at bar here: whether the constructive submission theory allows individual plaintiffs or interest groups to pick and choose particular TMDLs that they determine are of the highest priority, notwithstanding express statutory language giving state officials the authority to set that prioritization to best advance the interests of all their citizens. The Ninth Circuit concluded that it does not. Because the *McLerran* dicta is at odds with the Ninth Circuit's conclusion that compelling particular TMDLs impermissibly interferes with state prioritization, it must be rejected.

[2] The EPA also argues that the constructive submission theory is a legal fiction, an exercise in judicial lawmaking, contrary to the intent of Congress, and unlawful except as applied in *Baykeeper, infra*. The Court acknowledges these arguments, but will rely on Ninth Circuit precedent permitting the application of this theory. *See City of Arcadia v. U.S. EPA*, 411 F.3d 1103 (9th Cir. 2005); *Sierra Club*, 2015 WL 1188522 at *6.

Id. at 35. The EPA argues that "Plaintiffs have failed to identify a single court that has found a constructive submission triggering EPA's obligations under Section 303(d)(2) as to a particular TMDL." *Id.* at 36. The EPA goes on, "[t]he theory, to the extent it is lawful, is an extraordinary and extra-statutory gloss reserved for only the most egregious instances of state refusal to participate in the Clean Water Act's statutory scheme." *Id.* The EPA also argues that, even if the Court were to apply the constructive submission theory to this case, Plaintiffs' claims fail as a factual matter because "the state's actions [do not] clearly and unambiguously express a decision not to submit TMDLs." *Id.* at 36 (quoting *Baykeeper*, 297 F.3d at 882). The EPA goes through the documents and communications cited by Plaintiffs and detailed above. *Id.* at 36–46. Finally, the EPA argues that "should this Court find merit in Plaintiffs' non-discretionary duty claim, the relief afforded must be limited to an order to approve or disapprove the constructive submissions and may not extend to an order to issue the TMDL." *Id.* at 50. As stated previously, the EPA has a duty under the CWA to disapprove the constructively submitted TMDL within 30 days and to issue a TMDL within 30 more days, only if those deadlines are missed can the Court order the EPA to issue the TMDL

Plaintiffs retort that "every court that has specifically considered this issue has concluded that the [constructive submission] doctrine applies to individual TMDLs." Dkt. #33 at 7. Plaintiffs rely on *Scott v. City of Hammond*, 741 F.2d 992 (7th Cir. 1984); *City of Arcadia, supra*; *Hayes v. Whitman*, 264 F.3d 1017, 1023 (10th Cir. 2001); *Sierra Club, supra*; *Ohio Valley Envt'l. Coal. v. McCarthy*, No. 3:15-0271, 2017 WL 600102, *9–*10 (S.D. W.Va. Feb. 14, 2017) (*OVEC I*); *Ohio Valley Envt'l. Coal. v. Pruitt*, No. 3:15-0271, 2017 WL 1712527 (S.D. W.Va. May 2, 2017) (*OVEC II*); and *Las Virgenes Municipal Water District v. McCarthy*, C 14-01392 SBA, 2016 WL 393166 (N.D. Cal. Feb. 1, 2016). Plaintiffs say that, despite

"Washington's and Oregon's otherwise-robust TMDL programs," "the temperature TMDL is not on, and has not been on, Washington's or Oregon's mandatory TMDL development schedules" for a reason—the States asked the EPA to prepare and issue the TMDL previously. *Id*. at 14. Plaintiffs argue that the 19-year delay since Washington and Oregon placed temperature-impaired segments of the Columbia and lower Snake Rivers on their CWA 303(d) "impaired waters" lists is itself sufficient evidence of a "prolonged failure" amounting to constructive submission. *Id*. at 15 (citing *City of Arcadia*, 411 F.3d at 1105–06; *ACE I*, 762 F. Supp. at 1429).

The EPA also filed a Reply brief in support of their cross-motion, largely repeating previous arguments. Dkt. #35. The EPA contends that the Ninth Circuit's view on the constructive submission theory is "apparent" and that it "does not allow a plaintiff to compel issuance of a specific TMDL where a state is otherwise engaged in TMDL development and complying with Congress' command that it issue TMDLs 'from time to time.'" Id. at 3–4. The EPA requests supplemental briefing in a footnote. *Id*. at 12 n.4.

Plaintiffs filed a surreply moving to strike the EPA's request for additional briefing. Dkt. #38. The Court agrees that, procedurally speaking, the EPA's request is improperly contained in a reply brief and contrary to the joint litigation schedule. Accordingly, the Court will not consider this request.

The CWA and Ninth Circuit law provide for the constructive submission doctrine to apply when a state completely fails to issue TMDLs. *See Baykeeper, supra*. However, the Court is convinced that the EPA is misconstruing *Baykeeper* by arguing that a "complete failure by [the states] to submit TMDLs" is required. *See Baykeeper*, 297 F.3d at 881–882. The following dicta in *Sierra Club v. McLerran* provides the correct analysis of the instant situation:

Defendants assert that a constructive submission occurs only when a state produces few or no TMDLs for the whole state over a substantial period of time: If a state has a robust TMDL program, its decision to abandon a particular TMDL does not trigger the EPA's non-discretionary duty. Doc. No. 91 at 27. The Court questions this narrow interpretation of the doctrine for the reasons set forth below.

In making this argument, Defendants rely on *BayKeeper*'s holding and language, which focused on the state-wide TMDL program. This reliance is misplaced. The issue in *BayKeeper* was whether California's failure to produce a significant number of TMDLs constituted a programmatic failure for the entire state. *Id*. at 880–82. Clearly, California's producing several TMDLs and committing to more demonstrates that California had not abandoned its TMDL program. *See id*. However, the question here is whether Washington has abandoned a specific component of its CWA obligations—a question that was not before the *BayKeeper* court and one not resolved by looking to a state's general compliance. Accordingly, the Court finds it insignificant that the Ninth Circuit did not address an issue not raised by the facts of the case. Moreover, far from foreclosing the application of the constructive submission doctrine to a particular pollutant or waterbody segment, the *BayKeeper* court cited with approval to *Scott*, which applied the constructive submission doctrine to TMDLs for a particular waterbody segment, Lake Michigan. *See BayKeeper*, 297 F.3d at 882 (characterizing ruling as "consistent" with *Scott*).

….

Applying the constructive submission doctrine to individual TMDLs does not invade state prioritization. A constructive submission occurs only when a state has clearly and unambiguously abandoned its obligation to produce a TMDL or TMDLs. *See, e.g., San Francisco BayKeeper*, 297 F.3d at 883; *see also Alaska Ctr. for the Env't*, 762 F.Supp. at 1427(constructive submission when Alaska clearly and unambiguously abandoned its TMDL obligation). It does not occur merely because a state has prioritized one TMDL over another. *See Hayes*, 264 F.3d at 1024.

….

More importantly, while a state's failure to produce any TMDLs is perhaps the clearest indication that it has abandoned its statutory obligations, the Court finds nothing in the text of the CWA or its

> purpose to support Defendants' contention that a state's abandonment of a specific statutory obligation should be treated differently from a state's wholesale failure. To the contrary, a state's discretion to prioritize TMDLs over other TMDLs does not remove its ultimate obligation to produce a TMDL for each water pollutant of concern in every 303(d) water segment. *See* 33 U.S.C. § 1313(d)(2). In light of this statutory obligation, it would be absurd for the Court to hold that a state could perpetually avoid this requirement under the guise of prioritization; such an administrative purgatory clearly contravenes the goal and purpose of the CWA. 33 U.S.C.A. § 1251(a)(1) ("it is the national goal that the discharge of pollutants into the navigable waters be eliminated by 1985").

Sierra Club v. McLerran, 2015 WL 1188522 at 6–7. The Court adopts this analysis and finds that the constructive submission doctrine does apply when a state abandons an individual TMDL.

Turning to the particular facts of this case, the Court agrees with Plaintiffs that the EPA has violated the CWA by failing to issue a TMDL for the Columbia and lower Snake Rivers. Considering the 2000 MOA and all the subsequent communications between the states and the EPA, cited above, the Court concludes that Washington and Oregon have clearly and unambiguously indicated that they will not produce a TMDL for these waterways. Whether rightly or wrongly, they placed the ball in the EPA's court, and the subsequent 17-year delay is strong evidence that the states have abandoned any initial step the EPA could possibly be awaiting. Recent communication between the EPA and the states indicates a desire to further delay this process. The Court agrees with Plaintiffs that there are key factual differences between this case and *Sierra Club v. McLerran*, including an insufficient basis for the states and the EPA to pivot away from issuing a temperature TMDL in 2003 and the sheer number of years that have elapsed in this case. *See* Dkt. #33 at 16–20. Accordingly, a constructive submission of "no TMDL" has occurred, but the EPA has failed to undertake its mandatory duty to issue a temperature TMDL under the CWA. *See* 33 U.S.C. § 1313(d)(2). The Court will grant summary judgment on Plaintiffs' first claim.

C. Unreasonable Delay under the APA

Plaintiffs next contend that the EPA has violated the Administrative Procedure Act ("APA") by failing to act for over 17 years. Dkt. #19 at 14–20. The Court need not address this claim, having found that the EPA has violated the CWA.

D. Defendant EPA's Cross-Motion for Summary Judgment

Having reached the rulings above, the Court finds it can deny EPA's Motion at this time.

E. Requested Relief

Plaintiffs request that the Court order the EPA to issue a temperature TMDL by a date certain, preferably within one year of this Order. Dkt. #19 at 20 (citing to 33 U.S.C. § 1365(a)(2); 5 U.S.C. § 706(1)). The Court agrees with the EPA that Plaintiffs are limited to the remedy provided under the applicable and specific waiver of sovereign immunity, and that the Court can only order the EPA to perform "any act or duty . . . which is not discretionary with the Administrator." Dkt. #31 at 47 (citing 33 U.S.C. § 1365(a)(2)). The Court thus agrees with the EPA's requested relief, and the applicable law; the EPA thus has 30 days from the date of this Order to approve or disapprove the constructively submitted TMDL, and, if disapproved, 30 days after the disapproval to issue a new TMDL. *See* 33 U.S.C. § 1313(d)(2). The Court does not see how the EPA can approve the constructively submitted TMDL consistent with its obligations under the CWA. Plaintiffs warn the Court that "based on EPA's track record and its August 2017 letter inviting further delay, it is unlikely EPA would take such prompt action and would instead try to further delay critical work on temperature in the Columbia and Snake

Rivers." Dkt. #33 at 37. The Court believes that the parties can and should work together to resolve this issue and avoid further Court action.

III. CONCLUSION

Having reviewed the relevant briefing and the remainder of the record, the Court hereby finds and ORDERS that:

1) Plaintiffs' Motion for Summary Judgment, Dkt. #19, is GRANTED IN PART. The EPA has 30 days from the date of this Order to approve or disapprove the constructively submitted TMDL at issue in this case, and 30 days after a disapproval to issue a new TMDL.

2) Defendant EPA's Motion for Summary Judgment, Dkt. #31, is DENIED.

DATED this 17 day of October, 2018.

RICARDO S. MARTINEZ
CHIEF UNITED STATES DISTRICT JUDGE

Exhibit 48

Received: 12 September 2018 | Accepted: 6 November 2018
DOI: 10.1111/gcb.14532

PRIMARY RESEARCH ARTICLE

WILEY Global Change Biology

Elevated CO_2 impairs olfactory-mediated neural and behavioral responses and gene expression in ocean-phase coho salmon (*Oncorhynchus kisutch*)

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Funding information
National Institute of Environmental Health Sciences, Grant/Award Number: P42ES004696; Washington Ocean Acidification Center; Ocean Acidification Program, NOAA Fisheries; Washington Sea Grant, University of Washington, Grant/Award Number: NA10OAR4170057; National Oceanic and Atmospheric Administration; University of Washington Superfund Research Program, Grant/Award Number: NIEHS P42ES004696; NOAA Fisheries Northwest Fisheries Science Center

Abstract

Elevated concentrations of CO_2 in seawater can disrupt numerous sensory systems in marine fish. This is of particular concern for Pacific salmon because they rely on olfaction during all aspects of their life including during their homing migrations from the ocean back to their natal streams. We investigated the effects of elevated seawater CO_2 on coho salmon (*Oncorhynchus kisutch*) olfactory-mediated behavior, neural signaling, and gene expression within the peripheral and central olfactory system. Ocean-phase coho salmon were exposed to three levels of CO_2, ranging from those currently found in ambient marine water to projected future levels. Juvenile coho salmon exposed to elevated CO_2 levels for 2 weeks no longer avoided a skin extract odor that elicited avoidance responses in coho salmon maintained in ambient CO_2 seawater. Exposure to these elevated CO_2 levels did not alter odor signaling in the olfactory epithelium, but did induce significant changes in signaling within the olfactory bulb. RNA-Seq analysis of olfactory tissues revealed extensive disruption in expression of genes involved in neuronal signaling within the olfactory bulb of salmon exposed to elevated CO_2, with lesser impacts on gene expression in the olfactory rosettes. The disruption in olfactory bulb gene pathways included genes associated with GABA signaling and maintenance of ion balance within bulbar neurons. Our results indicate that ocean-phase coho salmon exposed to elevated CO_2 can experience significant behavioral impairments likely driven by alteration in higher-order neural signal processing within the olfactory bulb. Our study demonstrates that anadromous fish such as salmon may share a sensitivity to rising CO_2 levels with obligate marine species suggesting a more wide-scale ecological impact of ocean acidification.

KEYWORDS
GABA, ocean acidification, olfactory bulb, olfactory rosette, salmon

1 | INTRODUCTION

The substantial rise in atmospheric CO_2 observed over the past 100 years has led to increased concentrations of dissolved CO_2 in marine waters, resulting in lowered pH, a process known as ocean acidification (OA). The degree of pH change and the rate at which these changes are occurring may ultimately exceed many marine organism's ability to adapt to this changing environment (Hoegh-Guldberg & Bruno, 2010). Marine biota have evolved to live in ocean waters with a consistent range in chemical composition, and therefore, even small changes in mineral content, pH, and/or temperature outside of the normal range can have large impacts on marine organisms at different life stages (Fabry, Seibel, Feely, & Orr, 2008; Kroeker et al., 2013; Marshall et al., 2017). Hard corals, hard-shelled mollusks, and plankton are among the more well-known examples of marine organisms that are sensitive to shifts in water chemistry induced by elevated CO_2 (Busch, Maher, Thibodeau, & McElhany, 2014; Hofmann et al., 2010; Orr et al., 2005).

While the effects of elevated CO_2 on calcifying organisms such as corals and mollusks have received considerable attention, the possible effects of elevated CO_2 on the neurophysiology and behavior of marine fish are an increasing concern (Ashur, Johnston, & Dixson, 2017). Elevated CO_2 has been linked to abnormal neuronal and behavioral responses in several species of marine fish including effects on auditory function (Simpson et al., 2011), vision (Chung, Marshall, Watson, Munday, & Nilsson, 2014; Ferrari et al., 2012), lateralization (Domenici, Allan, McCormick, & Munday, 2011), and elevated anxiety (Hamilton, Holcombe, & Tresguerres, 2014). In particular, a number of studies have implicated changes in CO_2 and pH levels on altered olfactory-mediated behaviors in marine fish from both tropical and temperate environments (Chivers et al., 2014; Cripps, Munday, & McCormick, 2011; Devine, Munday, & Jones, 2012; Dixson, Munday, & Jones, 2010; Ferrari et al., 2012; Hamilton et al., 2014; Leduc, Munday, Brown, & Ferrari, 2013; Miller, Watson, Donelson, McCormick, & Munday, 2012; Porteus et al., 2018).

The olfactory system is critical for many aspects of a fish's life including locating appropriate habitat, finding prey, avoiding predators, social and reproductive interactions with conspecifics, orientation, and navigation (Dittman & Quinn, 1996; Gerlach, Atema, Kingsford, Black, & Miller-Sims, 2007; Hara, 1992; McIntyre, Baldwin, Beauchamp, & Scholz, 2012; Quinn, 2011; Yambe et al., 2006). Fish rely on their olfactory system for survival, and any olfactory impairment may have profound effects on wild fish populations (Baldwin, Sandahl, Labenia, & Scholz, 2003; Sandahl, Baldwin, Jenkins, & Scholz, 2007). The olfactory system in most fish consists of a peripheral sensory epithelium (olfactory rosette) that connects directly to the olfactory bulb. Odorants in the environment bind to receptors on olfactory sensory neurons in the sensory epithelia, eliciting axon potentials that send a signal to the olfactory bulb. At the olfactory bulb, the signal is modulated and relayed to secondary neurons and higher brain centers, ultimately leading to behavioral responses (Hamdani & Doving, 2007). Neural signaling within this complex process, from odorant detection to behavioral outcome, is highly dependent upon tightly controlled ion gradients across neuronal membranes (Schild & Restrepo, 1998) and is highly sensitive to changes in water chemistry (Tierney et al., 2010).

Elevated CO_2-mediated interference of olfactory function could have profound effects on marine fish survival. For example, tropical reef fish exposed to CO_2 concentrations predicted to occur within the next 50–100 years demonstrated altered responses to odors that allowed fish to discriminate healthy reef habitat and that facilitated homing and dispersal (Devine et al., 2012; Munday et al., 2009). Furthermore, elevated CO_2 levels altered normal avoidance responses of fish to predator odors and chemical alarm cues (Dixson et al., 2010; Welch, Watson, Welsh, McCormick, & Munday, 2014) and interfered with prey detection abilities in reef predators (Cripps et al., 2011) and sharks, a group of fish known for their reliance on their highly sensitive olfactory system (Dixson, Jennings, Atema, & Munday, 2014). Finally, OA-related conditions interfered with the process of olfactory learning by reef fish (Ferrari et al., 2012). Several studies have extended these findings to directly demonstrate that CO_2-mediated interference of olfactory function may have direct effects on survival (Dixson et al., 2010; Ferrari et al., 2015). However, if a fish is exposed to elevated CO_2 and survives to successfully reproduce, recent research on multigenerational effects of parental exposure to elevated CO_2 has shown that offspring can exhibit enhanced resistance to the effects of elevated CO_2 (Allan, Miller, McCormick, Domenici, & Munday, 2014; Murray, Malvezzi, Gobler, & Baumann, 2014; Schunter et al., 2017; Welch & Munday, 2017; Welch et al., 2014).

Pacific salmon are a critical component of Pacific Northwest coastal ecosystems (Quinn, 2011). Anadromous (rear in saltwater but spawn in freshwater) salmon populations may be particularly impacted by ecosystem changes (Crozier et al., 2008) because they rely on both the freshwater and marine environment for different life cycle stages (Quinn, 2011). In this respect, salmon, and other anadromous fishes, may be particularly interesting species to study in the context of the sensitivity or resistance to the effects of elevated CO_2 because elevated CO_2 is likely to have different physiological effects in freshwater and saltwater. Some obligate marine fish species (e.g., benthic dwellers) have displayed a potential resistance to the effects of elevated CO_2 on neuronal function and behavior due to the seawater chemistry of their preferred habitat (Hamilton et al., 2017; Jutfelt & Hedgärde, 2015; Schmidt et al., 2017). While some initial studies have examined the effects of elevated CO_2 on salmon in freshwater (Ou et al., 2015), there are no studies to date that have investigated the neural and behavioral responses of ocean-phase, juvenile salmon to elevated CO_2 in the marine environment. In this study, we examined the potential effects of elevated CO_2 on olfactory-mediated behaviors and the potential mechanisms underlying these behavioral changes in coho salmon (*Oncorhynchus kisutch*) adapted to saltwater. Proper olfactory function is critical for all aspects of a salmon's life cycle, especially during their extraordinary homing migrations, wherein they use olfactory cues to identify their natal stream (Dittman & Quinn, 1996). Therefore, even minor impairment of olfactory function due to OA may ultimately have profound effects on salmon survival and population sustainability in the Pacific Ocean. We hypothesized that elevated CO_2, at levels predicted to occur over the next 50–100 years, would significantly alter behaviors, neuronal signaling, and gene expression in the olfactory system of coho salmon.

2 | MATERIALS AND METHODS

2.1 | Animals and housing

Coho salmon for these experiments were the offspring of anadromous adults spawned at the Washington Department of Fish and Wildlife's Issaquah Creek Hatchery, Issaquah, WA, USA. Experimental fish were transferred as embryos from the Issaquah Hatchery in January 2016 and 2017, reared in freshwater at the Northwest Fisheries Science Center until undergoing the parr–smolt transformation (1.5 year of age; 15.0 g ± 5.7 g), and then transferred to saltwater at the Northwest Fisheries Science Center's Mukilteo Marine Research Station (Mukilteo, WA, USA) on May 5, 2016, and May 24, 2017. After transfer to saltwater, fish were maintained under a natural photoperiod and fed BioVita Fry Feed (Bio-Oregon, Longview, WA). Water quality, fish health, and water delivery systems were monitored daily in fresh and salt water. All animal care and procedures were in accordance with University of Washington's Institutional Animal Care and Use Committee rules and approval, protocol # 4097-1.

2.2 | Seawater chemistry/exposures

Maintenance of seawater CO_2 concentrations followed previously described methodologies (Busch et al., 2014). Exposures consisted of three different CO_2 concentrations, including a control (ambient) nominal concentration of 700 µatm, which approximates the present-day average value of CO_2 in Puget Sound Marine Waters (Reum et al., 2015), a medium CO_2 level (nominal concentration of 1,600 µatm) predicted to periodically occur over the next 50 years, and a high CO_2 level (nominal concentration of 2,700 µatm) predicted to periodically occur over the next 100 years (Busch et al., 2014). Duplicate exposure tanks (2 foot diameter × 2 foot high, 178-L cylindrical tanks) for each treatment were maintained as a flow-through system, supplied by a unique head tank for each exposure tank (Supporting Information Figure S1). Water turnover rate was approximately once every hour. Source water for the head tanks was pumped from a depth of 60 feet from Puget Sound, degassed, and filtered prior to CO_2 manipulation. A Honeywell universal data analyzer controller and Durafet pH probe monitored and maintained the pH via CO_2 injection within each head tank. Target pH levels (as measured on a total pH scale) were 7.8 for control, 7.5 for medium, and 7.2 for high CO_2 exposure levels. To ensure proper water chemistry was maintained throughout exposures, water samples were collected from each exposure tank three times during each experiment (day 0, day 7, and day 14) for measurement of total alkalinity (TA) and dissolved inorganic carbon (DIC). Water samples were analyzed at the NOAA Pacific Marine Environmental Laboratory using standard test procedures for all analyses (Dickson, Sabine, & Christian, 2007). Water temperature, pH, and salinity were checked daily throughout the experiment. Water temperature in the exposure tanks remained at 12°C for the duration of the exposures. The ambient water temperature of the source water from Puget Sound averaged 11–12°C at the time of the exposures.

The start of the exposures was staggered over a month for logistical reasons to allow for behavioral and neurophysiological testing following each of the 14-day exposures. To begin the experiment, fish were transferred from their rearing tanks to their exposure tanks (n = 4 fish/tank) and acclimated for 24 hr in 700 µatm CO_2 control water. After acclimation, fish were exposed to experimental CO_2 levels for 14 days and tested for behavioral responses (n = 48 fish/treatment). A subset of these fish (n = 24) was used for electro-olfactogram (EOG)/electroencephalogram (EEG) neurophysiological and RNA-Seq (n = 8 fish per treatment) analysis.

2.3 | Odorant preparation

To investigate the effects of elevated CO_2 on olfactory-mediated salmon behavior, we used salmon skin extract, a prototypical predation odor that elicits a reliable and measurable avoidance response (Brown & Smith, 1997; Sandahl et al., 2007; Williams et al., 2016). Salmon skin extract was prepared as described previously with minor modifications (Williams et al., 2016). Briefly, skin tissue collected from coho salmon was homogenized in artificial seawater (Instant Ocean, Blacksburg, VA), filtered, and centrifuged to remove particulates. Protein content of the skin extract was determined using the Bradford assay (Bio-Rad, Hercules, CA), and stock concentrations were normalized to 2.4 mg/ml protein concentration in artificial seawater and stored at −80°C until needed. Working stocks of L-alanine and L-serine (Sigma-Aldrich, St. Louis, MO) for use in the EOG and EEG analysis were prepared on the day of use in artificial seawater. Working concentrations of the odorants were as follows: 10 µg/L skin extract (behavioral analysis), 2.4 mg/L skin extract (EOG and EEG analysis), and 10^{-2} M L-alanine and L-serine (EOG and EEG analysis). A higher concentration of the skin extract was used for electrophysiological analysis than for behavioral analysis due to the fact that measurable neuronal signal intensity is reduced in ocean-phase salmon due to the effect of high saltwater conductivities on electrophysiological recording (Sommers, Mudrock, Labenia, & Baldwin, 2016).

2.4 | Behavioral analysis

Following the 14-day exposure, behavioral analysis was conducted as previously described (Williams & Gallagher, 2013) using two-choice mazes surrounded by a black curtain and illuminated from below with infrared light to minimize stress. Each maze (100 × 40 × 25 cm) consisted of two arms (50 cm long and 20 cm wide) that terminated at a holding chamber (40 × 40 cm). A perforated gate separated the arms from the holding chamber. A dye test confirmed that no mixing between the arms occurred. The maze received water (flow rate of 3 L/min) from the same head tanks used to generate the exposure water, thus ensuring that salmon were tested in the same water chemistry they experienced during exposures. Individual coho salmon from each CO_2 treatment (n = 48) were allowed to acclimate for 10 min in the holding chamber, and then behaviors were recorded for 10 min prior to odorant addition. After the 10-min pre-odor period, skin extract (10 μg/L) was delivered into one arm (randomized each trial) using a peristaltic pump and behaviors were recorded for an additional 10 min. An overhead infrared light-sensitive video camera (EverFocus® EQ900, Duarte, CA) provided video recordings of the behavioral responses. Proportion of time spent on odor side of the maze was analyzed using EthoVision XT 10 behavioral software (Noldus, Leesburg, VA). Following each behavioral trial, each maze was flushed with exposure water (without odorants) for 20 min.

Differences in response to CO_2 exposure were evaluated with a beta regression model that included CO_2 exposure and pre-odor period movement as covariates using the "betareg" R package (Zeileis, Cribari-Neto, Gruen, & Kosmidis, 2016). We selected a final model based on Akaike information criterion (AIC) comparison of models with CO_2 exposure and pre-odor fraction alone and as interactions. Bootstrap 95% prediction intervals on the beta regression-modeled treatment means were calculated based on 5,000 resamples using the "boot" R package (Canty & Ripley, 2017).

2.5 | Neurophysiological analysis

EOG and EEG recordings were performed the day after behavioral testing using methods previously described with minor modifications (Baldwin & Scholz, 2005). Fish were anesthetized with 50 mg/L tricaine methanesulfonate (MS-222; Western Chemicals Inc., WA) and injected intramuscularly with gallamine triethiodide (0.3 mg/kg body weight; Sigma-Aldrich, MO). A small tube inserted in the fish's mouth delivered artificial seawater (10°C) containing MS-222 (50 mg/L) to their gills. A gravity-fed glass capillary tube perfused the rosette with artificial seawater at a rate of 2 ml/min. Fish were acclimated for 5 min before the start of electrophysiological recordings. The recording microelectrode was placed at the midline of the rosette at the base of the posterior lamella for EOGs, and against the surface of the right mediodorsal cluster of the olfactory bulb for EEGs (Figure 1). Because there is spatial variation in responsiveness to different odorants in the olfactory bulb, before the start of the experimental recording, the location of the maximal EEG responses to the odorants was determined for each individual by positioning the microelectrode at different points across the olfactory bulb. The two regions that gave the most consistent signal were used as the recording sites for the entire experiment. A reference electrode was placed on the midline of the posterior-dorsal surface of the head, and a ground electrode was placed in the caudal muscle during recordings. Odorant-induced neural signals were acquired and filtered with an AC/DC amplifier (A-M Systems Inc.® Model 3000, Sequim, WA). Seawater/odors were delivered to the rosette using gravity-assisted flow, regulated by electronic valves and into a single manifold output through a thermoelectric chiller (temp 10°C). Fish received three pulses of each odorant (skin extract, L-serine, and L-alanine) with 2-min intervals between pulses. Based on an averaged and integrated recorded response curve, the amplitude of each EOG response was measured in microvolts (μV) as the maximum evoked peak minus the prestimulus basal activity level. Based on an averaged and integrated recorded response curve, the maximum odorant-evoked response for the EEG was the peak signal amplitude minus the prestimulus basal activity level. Signal duration for the EEG responses was calculated from the moment an odorant-induced signal was detected until the moment the signal returned to basal (pre-odor) levels. Triplicate responses to each odorant were averaged to produce a single response value for each odorant. EEGs were not performed on the medium CO_2 exposure group due to the logistics of the procedure, that is, length of time needed for each fish on the rig and number of fish that could be

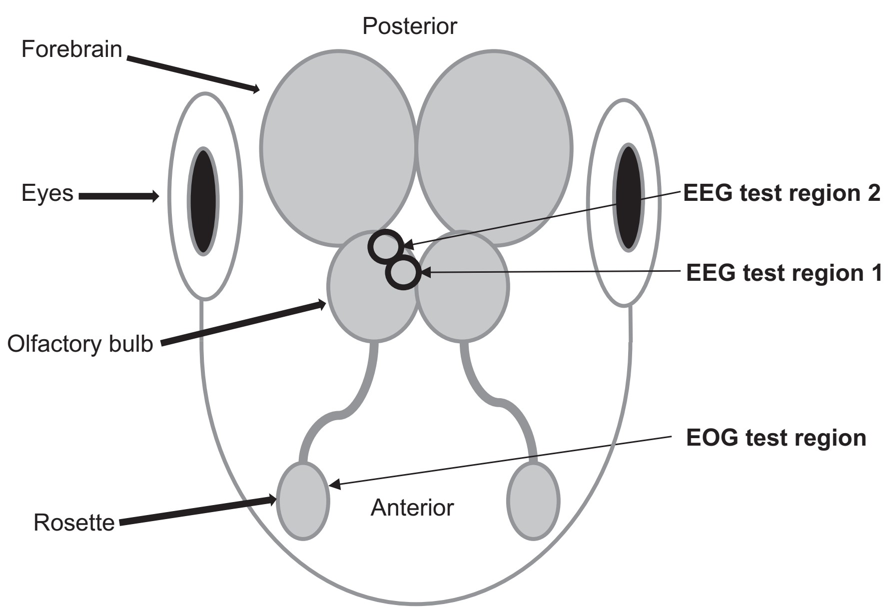

FIGURE 1 Diagram of salmon olfactory system and test sites used for EOG and EEG analysis of odorant-induced signals following exposures to varying levels of CO_2

recorded each day. Example EOG and EEG traces are located in Supporting Information Figure S2.

For the EOG analysis, a one-way ANOVA was used to test for significant differences between control and exposure groups, followed by a Dunn's multiple comparison test. For the EEG analysis, a *t* test was used to test for differences between control and high exposure groups. All analyses were done using GraphPad Prism 5 software. Differences were considered significant at $p < 0.05$.

2.6 | RNA-Seq analysis

Olfactory rosette and bulb tissues were collected from $n = 5$ individuals from the control, medium, and high CO_2 exposure groups following EOG analysis. Tissues were immediately stored in RNA*later*® before being frozen at −80°C (Thermo Fisher Scientific, Waltham, MA).

2.6.1 | RNA QC

RNA purity was assessed measuring $OD_{260/280}$ and $OD_{260/230}$ ratios with a NanoDrop ND-1000 Spectrophotometer (Thermo Fisher Scientific, Waltham, MA). RNA integrity was determined using the Agilent RNA 6000 Nano Kit with an Agilent 2100 Bioanalyzer (Agilent Technologies, Santa Clara, CA). All RNA samples were of appropriate size, quantity, and quality ($OD_{260/280}$ and $OD_{260/230}$ ratios of 1.8–2.1) and were used for RNA-Seq analysis (n = 5 for each exposure group/tissue).

2.6.2 | Sample processing and sequencing

cDNA libraries were prepared from 1 μg of total RNA using the TruSeq Stranded mRNA kit (Illumina, San Diego, CA) and the Sciclone NGSx Workstation (Perkin Elmer, Waltham, MA). Prior to cDNA library construction, ribosomal RNA was removed by means of poly-A enrichment. Each library was uniquely barcoded and subsequently amplified using a total of 13 cycles of PCR. Library concentrations were quantified using Qubit fluorometric quantitation (Life Technologies, Carlsbad, CA). Average fragment size and overall quality were evaluated with the DNA 1000 assay on an Agilent 2100 Bioanalyzer. Each library was sequenced with paired-end 100 bp reads to a minimum depth of 30 million reads on an Illumina HiSeq 4000. The average number of reads was 44.99 ± 6.47 million (mean ± *SE*) from olfactory rosette samples and 46.11 ± 4.41 million from olfactory bulb samples (Supporting Information Table S1).

We aligned the reads for each sample to the Atlantic salmon (*Salmo salar*) transcriptome (NCBI ICSASG_v2 build, downloaded 9/29/2017) using the Salmon aligner, accounting for GC, and sequencing bias (Patro, Duggal, & Kingsford, 2015; Patro, Duggal, Love, Irizarry, & Kingsford, 2017). Although there is a completed genome and transcriptome for coho salmon available (https://www.ncbi.nlm.nih.gov/genome/13127?genome_assembly_xml:id=309046), the functional Gene Ontology (GO) annotation for this species is not well developed relative to that for Atlantic salmon. Therefore, we chose to align the RNA-Seq data against the Atlantic salmon transcriptome, because the alignment results were similar between the two species (*S. salar*—60% of reads mapped; *O. kisutch*—73% of reads mapped). The aligned counts were imported into R (r-project.org) using the Bioconductor tximport package and then summarized at the gene level (Soneson, Love, & Robinson, 2015). We excluded any gene that was not expressed in at least four samples (i.e., any gene that had fewer than ten counts in less than four samples), to remove any data that were likely to be primarily noise. We then fit a generalized linear model with a negative binomial link function using the Bioconductor edgeR package and made comparisons between groups using likelihood ratio tests. We selected differentially expressed genes based on a false discovery rate (FDR) of 0.1 (i.e., we expect that at most 10% of the selected genes are false positives). To identify biological function that may have been perturbed due to changes in CO_2 exposure, we computed Fisher's exact tests based on GO terms, selecting those terms with a *p*-value <0.05.

3 | RESULTS

3.1 | Exposure water chemistry

Measured pH values for each exposure were consistent across the experiments and varied little within each exposure over the course of each experiment (standard deviation ≤0.03; Table 1). pH values from the Durafet sensors were consistent with discrete spectrophotometric measurements of pH from each exposure tank. Alkalinity in all exposure conditions, within and across experiments, was similar. Mean temperature in the exposure tanks ranged from 11.9–12.8°C, with small variation in each treatment over each experiment (standard deviation ≤0.2°C).

3.2 | Effects of elevated CO_2 on salmon behaviors

Using AIC analysis, the beta regression model containing only the interaction term between the CO_2 treatment and the pre-odor behavior covariate was selected ($p < 0.001$; pseudo-R^2 = 0.24) (Figure 2, Supporting Information Figure S3). This model indicated that fish exposed to control CO_2 levels avoided the side of the maze scented with skin extract (Figure 2, 26.7% ± 3.6% of time in odor (mean ± *SE*)), while fish that experienced the medium (Figure 2, 35.0% ± 4.5% of time in odor) and high (Figure 2, 52.3% ± 5.5% of time in odor) CO_2 treatments did not show a significant attraction or avoidance to the alarm odor. Individual fish from the medium and high CO_2 treatments tended to move around the maze less during the 20-min trials compared to controls. Conversely, fish in the control CO_2 treatment did not show a reduced tendency to explore the maze during the trial.

3.3 | Effects of elevated CO_2 on olfactory neurophysiological function

Neuronal responses in the olfactory epithelium to skin extract, L-alanine, and L-serine, as measured by EOG, were not affected by prior

TABLE 1 Water chemistry parameters

					System pH					
Exposure	Dates	Head tank	Salinity (psu)	Temperature (°C)	Durafet setting	Spec	(µatm)pCO_2*	Ω_a*	TA (µmol/kg)	DIC (µmol/kg)
1	8/18–9/23/16	A	29.9 ± 0.2	12.9 ± 0.4	7.2	7.2 ± 0.01	2,848.6 ± 143.9	0.31 ± 0.02	2,055.8 ± 11.4	2,127.4 ± 6.9
		B	29.9 ± 0.2	12.7 ± 0.2	7.8	7.8 ± 0.03	807.2 ± 16.2	0.98 ± 0.00	2,058.3 ± 12.4	2,001.4 ± 15.7
		A + B	29.9 ± 0.2	12.9 ± 0.3	7.5	7.4 ± 0.01	1,739.8 ± 28.3	0.49 ± 0.01	2,057.4 ± 12.1	2,083.1 ± 16.2
		C	29.9 ± 0.2	12.8 ± 0.3	7.2	7.3 ± 0.09	2,728.4 ± 15.6	0.32 ± 0.00	2,058.0 ± 11.9	2,137.9 ± 20.1
		D	29.9 ± 0.2	12.8 ± 0.2	7.8	7.8 ± 0.03	748.0 ± 72.0	1.05 ± 0.07	2,057.7 ± 11.9	1,994.5 ± 23.6
		C + D	29.9 ± 0.2	12.9 ± 0.2	7.5	7.4 ± 0.02	1,679.9 ± 83.1	0.51 ± 0.02	2,057.1 ± 11.8	2,078.7 ± 26.4
2	7/12–8/29/17	A	29.4 ± 0.3	11.9 ± 0.4	7.8	7.8 ± 0.03	630.1 ± 38.2	1.10 ± 0.03	2,017.5 ± 34.2	1,932.3 ± 37.3
		B	29.4 ± 0.2	12.0 ± 0.4	7.2	7.2 ± 0.08	2,698.4 ± 47.2	0.30 ± 0.01	2,016.7 ± 36.9	2,089.6 ± 29.8
		A + B	29.4 ± 0.2	12.0 ± 0.4	7.5	7.5 ± 0.05	1,424.3 ± 27.4	0.54 ± 0.00	2,019.0 ± 34.5	2,014.5 ± 34.3
		C	29.4 ± 0.2	11.7 ± 0.3	7.8	7.8 ± 0.03	636.9 ± 70.3	1.10 ± 0.08	2,005.2 ± 48.8	1,931.3 ± 40.3
		D	29.4 ± 0.2	11.8 ± 0.2	7.2	7.2 ± 0.00	2,587.7 ± 75.5	0.31 ± 0.00	2,015.4 ± 32.5	2,087.1 ± 29.0
		C + D	29.4 ± 0.2	11.9 ± 0.2	7.5	7.4 ± 0.01	1,565.9 ± 65.9	0.50 ± 0.00	2,018.4 ± 35.2	2,032.0 ± 39.3

Notes. DIC: dissolved inorganic carbon; Spec.: spectrophotometer; TA: total alkalinity.
*Ω_a and pCO_2 values were calculated via the "seacarb" package in R studio using data from DIC analysis and pH measured via spectrophotometry.

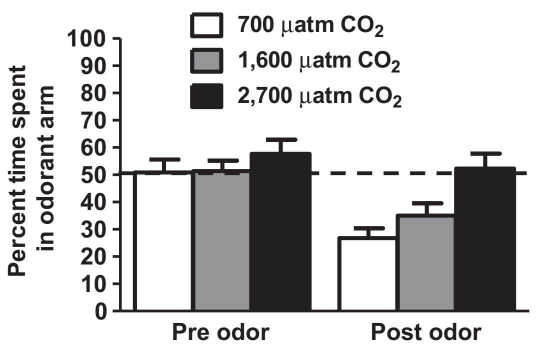

FIGURE 2 Behavioral responses to skin extract (alarm odor) odorant following CO_2 exposures. 700 µatm is the control CO_2 exposure level, 1,600 µatm is the medium CO_2 exposure level, and 2,700 µatm is the high CO_2 exposure level. Percent time juvenile coho salmon spent in the side of a two-choice maze receiving skin extract odorant before (pre-odor) and after (post-odor) introduction of the odorant. Dashed line indicates 50% level. All data represent mean ± *SEM* of n = 48 individuals

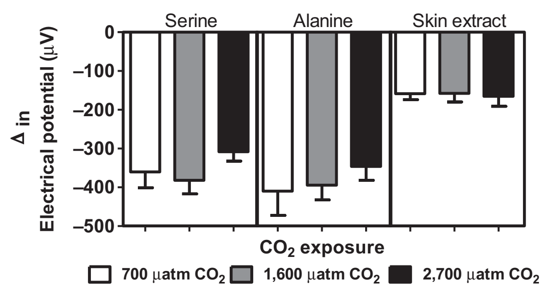

FIGURE 3 Electro-olfactogram (EOG) recorded responses of odorant-induced signaling within the olfactory rosettes of coho salmon exposed to three levels of CO_2. 700 µatm is the control CO_2 exposure level, 1,600 µatm is the medium CO_2 exposure level, and 2,700 µatm is the high CO_2 exposure level. Bars indicate the magnitude of the odorant-induced response relative to background water recorded from the olfactory epithelium. All data represent a mean ± *SEM* of n = 12 individuals

exposure to elevated CO_2 (Figure 3). However, EEG recordings revealed significant differences in peak odor-induced signaling in the right mediodorsal cluster (Figure 1, test region 1) of the olfactory bulbs of control and high CO_2 exposure coho salmon (p = 0.0068 and F = 4.754, Figure 4). High CO_2 exposure increased the mean peak signal amplitude of responses in this bulb region to skin extract (49.6% ± 39.1% increase (mean ± *SD*) and L-alanine (59.1% ± 78.7% increase) relative to responses in control fish (Figure 4a). Furthermore, the duration of EEG responses to skin extract and L-alanine tended to be longer in coho salmon exposed to high CO_2 levels compared to control fish (20.1 ± 4.0 s vs. 16.2 ± 6.5 s and 18.5 ± 4.4 s vs. 14.1 ± 5.0 s, respectively), but this difference was not significant (Figure 4b). Peak odor signal (skin extract: 0.024 ± 0.014 vs. 0.028 ± 0.015; L-alanine: 0.017 ± 0.008 vs. 0.021 ± 0.013) and duration (skin extract: 15.7 ± 4.8 s vs. 19.59 ± 5.9 s; L-alanine: 14.1 ± 4.4 s vs. 16.9 ± 9.5 s) in the right mediodorsal cluster test region 2 did not significantly differ between high CO_2 and control fish for either test odor (Figure 5) suggesting that CO_2 effects are specific to discrete bulbar regions and neurons.

3.4 | Effects of elevated CO_2 on gene expression in the salmon olfactory system

There were significant changes in gene expression in the olfactory system of coho salmon exposed to elevated CO_2. In particular, we observed considerable change in gene expression within the olfactory bulbs following exposure to the high CO_2 level (over 800 differentially expressed genes) relative to controls (Figure 6, Supporting

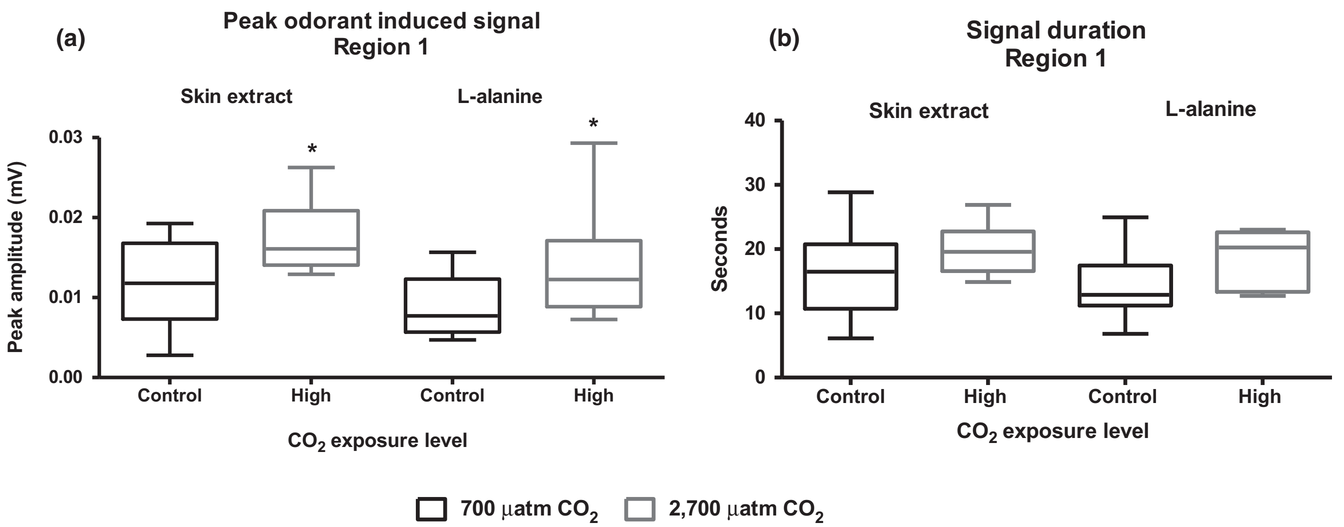

FIGURE 4 Electroencephalogram (EEG) recording data of odorant-induced signaling in test region one of the olfactory bulb from salmon exposed to two levels of CO_2. Data represented as a box and whisker plot showing median peak amplitude with whiskers representing the 5th and 95th percentile. 700 µatm is the control CO_2 exposure level, and 2,700 µatm is the high CO_2 exposure level. (a) Peak odorant-induced signaling by L-alanine and skin extract (alarm odor). (b) Duration of odorant-induced signaling by L-alanine and skin extract (alarm odor). Asterisks indicate significant differences between control and high exposure groups ($p \leq 0.05$)

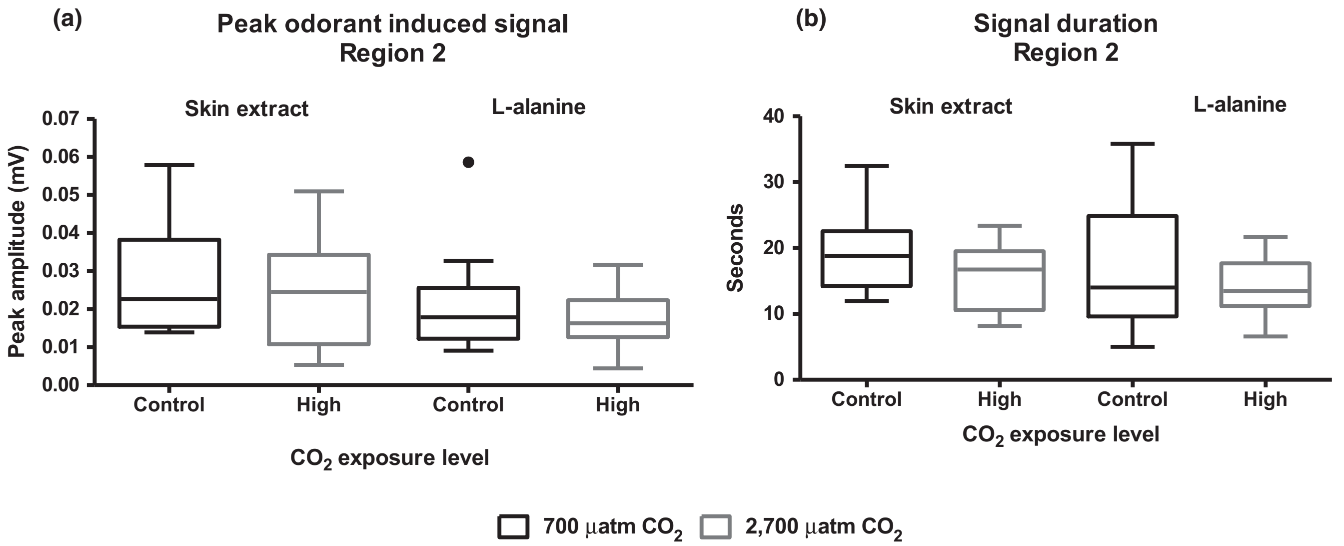

FIGURE 5 Electroencephalogram (EEG) recording data of odorant-induced signaling in test region two of the olfactory bulb from salmon exposed to two levels of CO_2. Data represented as a box and whisker plot showing median peak amplitude with whiskers representing the 5th and 95th percentile. 700 µatm is the control CO_2 exposure level, and 2,700 µatm is the high CO_2 exposure level. (a) Peak odorant-induced signaling by L-alanine and skin extract (alarm odor). (b) Duration of odorant-induced signaling by L-alanine and skin extract (alarm odor). The black dot indicates an outlier data point

Information Figure S4). A large number of these genes were involved in neural signaling/signal transduction, ion transport, and energy homeostasis (Supporting Information Figure S5). There were also significant differences in gene expression in the olfactory bulbs of medium CO_2 exposure fish relative to controls (61 differentially expressed genes) although these genes were predominantly associated with cytoskeletal function and not relevant to neural signaling. In contrast, there were relatively fewer changes in gene expression in the olfactory rosettes between control and medium (50 differentially expressed genes) or high exposure groups (20 differentially expressed genes) (Figure 6). None of the genes were significantly associated with olfactory neural signaling pathways.

We did not observe significant changes in gene expression of the GABA type A receptor, which has been hypothesized to play a role in CO_2-linked disruption of neuronal and behavioral signaling in marine fish (Schunter et al., 2017). Interestingly, however, the

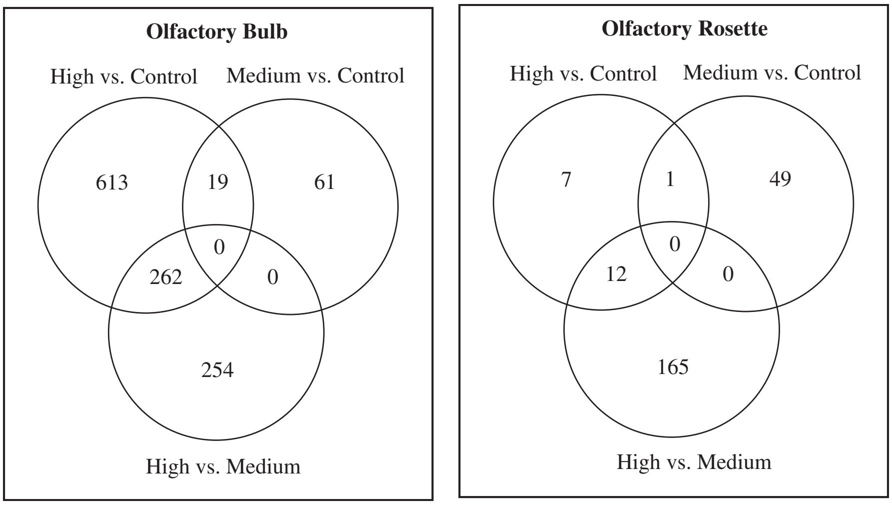

FIGURE 6 Venn diagram of RNA-Seq analysis of olfactory bulb and olfactory rosette gene expression in coho salmon exposed to three levels of CO_2. Venn diagrams show the number of significantly changed genes between each exposure group comparison. Numbers of genes listed in overlapping portion of the circles indicate number of significantly changed genes shared between each exposure comparison. Control = 700 μatm CO_2 exposure, Medium = 1,600 μatm CO_2 exposure, High = 2,700 μatm CO_2 exposure

expression of the GABA type B receptor subunit 2 (*gaba*$_{b2}$) was significantly elevated in the olfactory bulb following the high CO_2 exposure (Table 2, FDR <0.1). We also observed CO_2-induced changes in many other genes associated with GABA signaling, including increases in *hcn2*, *snap25*, and *kcc1*, which are associated with GABA-linked ion transport and synaptic activity, and significant decreases in expression of *slc6a13* and *aldh9a1*, two genes involved in GABA uptake and synthesis, respectively (Table 2). In addition to GABA signaling genes, other genes linked to neurotransmitter function (including glutamate and serotonin signaling), ion transport (*slc26a6*), G protein receptor function, neural differentiation, and melatonin production (*asmt* and *aanat*) displayed altered gene expression after elevated CO_2 exposure (Table 2). Genes important in neural energy production were also significantly altered following elevated CO_2 exposures, including a downregulation of the gene *slc22a16* (l-carnitine transport), and an upregulation of *slc2a6*, involved in glucose transport.

Interestingly, we also observed changes in gene expression of many genes associated with the photoreception system in the olfactory bulb of high exposure fish (Supporting Information Figure S5). Some of these genes included rhodopsin, parapinopsin, and various voltage-dependent ion channel genes. The reason for the inclusion of photoreception-related genes within the expression profile of the olfactory bulbs remains unclear; however, it is likely that genes involved in the olfactory and photoreception systems may share similar signal transduction function in both tissues. This hypothesis is supported by at least two other studies that reported the expression of olfactory genes in the visual system (Jovancevic et al., 2017; Pronin et al., 2014).

4 | DISCUSSION

Collectively, our results indicate that elevated CO_2 concentrations altered neural signaling pathways within the olfactory bulb and impaired olfactory-mediated behavioral responses of ocean-phase coho salmon. Given the primary need for a functional olfactory system for salmon living in the ocean to find prey, avoid predators, and ultimately find their natal stream during homing migrations, these results suggest that future predicted CO_2 concentrations in the ocean may have a profound effect on Pacific salmon and their ecosystems. Our behavioral results indicated that ocean-phase coho salmon were sensitive to acute exposures to elevated CO_2 concentrations that have been predicted to occur within the next 50–100 years. The strong avoidance behavior elicited by skin extract in the control group was decreased or eliminated in coho salmon exposed to either the medium (1,600 μatm) or high (2,700 μatm) CO_2 treatments. These results indicate that anadromous salmon may be just as sensitive to the effects of elevated CO_2 as obligate marine species that have shown behavioral impairments at similar [CO_2] levels (Chung et al., 2014; Devine et al., 2012; Hamilton et al., 2017, 2014; Munday et al., 2009; Porteus et al., 2018). While future oceanic CO_2 concentrations may not reach such high steady-state levels, exposures to transient CO_2 concentrations at these levels may already occur in some regions and will likely be more common. Juvenile coho salmon spend up to a year rearing in freshwater (Quinn, 2011) before migrating downstream to the ocean, undergoing the physiological transformation of smoltification that prepares them for life in seawater, including changes in osmoregulation and ion balance regulation (Maryoung et al., 2015; McCormick, 2012; Quinn, 2011). Our results suggest that despite having an adaptable olfactory system that functions in both marine and freshwater environments with very different pHs and water chemistries, the relative sensitivity of these anadromous fish to elevated CO_2 in the ocean is similar to other marine fish.

Tightly controlled ion balances play a key role in proper olfactory neuronal signaling, and it has been hypothesized that elevated CO_2-induced changes in transmembrane ionic gradients impair neuronal signaling and, ultimately, olfactory-mediated behaviors (Heuer, Welch, Rummer, Munday, & Grosell, 2016; Tresguerres & Hamilton, 2017). This is consistent with our analysis of neuronal signaling in the olfactory epithelium and the olfactory bulb. Elevated CO_2 did not alter neuronal responses to odorants in the olfactory epithelium suggesting that odorant-induced signaling within olfactory sensory neurons was not impacted following a shift in CO_2 concentration

TABLE 2 Significantly changed genes of relevance to neural function and signaling within the olfactory bulbs from coho exposed to high CO_2 vs. control CO_2

ENTREZID	Accession number	Gene name	Putative name	$\log_2$ fold change	FDR
106562041	LOC106562041	Guanine nucleotide-binding protein subunit alpha-14-like	*gna14*	3.307	2.81197E−10
106574723	LOC106574723	Gamma-aminobutyric acid type B receptor subunit 2-like	*gabbr2*	2.645	9.1231E−06
106575665	LOC106575665	Cyclic nucleotide-gated channel cone photoreceptor subunit alpha-like	*cnga3*	2.660	0.000141938
106611384	LOC106611384	Synaptosomal-associated protein 25-B-like	*snap25*	1.883	0.000460991
106588157	LOC106588157	Potassium/sodium hyperpolarization-activated cyclic nucleotide-gated channel 2-like	*hcn*	3.968	0.00053587
106603743	LOC106603743	Glutamate receptor ionotropic, kainate 4-like	*grik4*	1.012	0.001089553
106569207	LOC106569207	Solute carrier family 12 member 7-like	*kcc1*	1.368	0.001601933
106602119	LOC106602119	Neuronal acetylcholine receptor subunit alpha-3-like	*chrna3*	2.201	0.001653337
106592065	LOC106592065	Neuronal acetylcholine receptor subunit alpha-3	*chrna3*	2.227	0.001665897
106573978	LOC106573978	Excitatory amino acid transporter 5-like	*slc1a7*	1.792	0.001803254
106577203	LOC106577203	Potassium voltage-gated channel subfamily H member 1-like	*kcnh7*	2.466	0.001981873
106584365	LOC106584365	Diencephalon/mesencephalon homeobox protein 1-like	*dmbx1*	4.100	0.002118515
106583073	LOC106583073	Guanine nucleotide-binding protein G(t) subunit alpha-2-like	*gnai2b*	2.588	0.002170767
106573780	LOC106573780	Solute carrier organic anion transporter family member 3A1-like	*slc21a11*	0.860	0.003012925
106572933	LOC106572933	Voltage-dependent L-type calcium channel subunit alpha-1D-like	*cacna1d*	2.282	0.003645407
106567981	LOC106567981	Neuropeptide Y receptor type 1-like	*npy1r*	−0.649	0.004204007
106605869	LOC106605869	Gamma-aminobutyric acid type B receptor subunit 2-like	*gabbr2*	1.773	0.004302948
106613596	LOC106613596	Excitatory amino acid transporter 5-like	*slc1a7*	3.902	0.004457749
106571997	LOC106571997	Guanine nucleotide-binding protein G(I)/G(S)/G(T) subunit beta-1	*gbb1*	0.574	0.004760336
106578273	LOC106578273	Vesicular glutamate transporter 1-like	*vglut1*	1.625	0.005044121
106607367	LOC106607367	Serotonin *N*-acetyltransferase-like	*aanat*	4.020	0.005443605
106600164	LOC106600164	Aldehyde dehydrogenase family 9 member A1-like	*aldh9a1*	−5.891	0.005486887
106573635	LOC106573635	Large neutral amino acids transporter small subunit 1-like	*slc7a5*	1.072	0.008210081
106572937	LOC106572937	Voltage-dependent L-type calcium channel subunit alpha-1F-like	*cacna1f*	1.879	0.008455018
106612651	LOC106612651	Sodium-dependent serotonin transporter-like	*slc6a4*	1.050	0.009377377
106587671	LOC106587671	Guanine nucleotide-binding protein subunit beta-5-like	*gnb5*	2.359	0.009479934
106561149	LOC106561149	Solute carrier organic anion transporter family member 3A1-like	*slc21a11*	1.019	0.011541751
106613200	LOC106613200	Short transient receptor potential channel 2-like	*trpc2*	−1.432	0.011879951
106572934	LOC106572934	Voltage-dependent L-type calcium channel subunit alpha-1D-like	*cacna1d*	1.807	0.01216225
106562494	LOC106562494	Guanine nucleotide-binding protein subunit beta-5-like	*gnb5*	1.104	0.012539596
106568477	cplx4	Complexin 4	*cplx4*	4.491	0.012892164
106611148	LOC106611148	Neurexin-1a	*nrxn1*	−0.464	0.015068892
106592915	LOC106592915	Regulator of G protein signaling 9-like	*rgs9*	3.017	0.015068892
106585038	LOC106585038	Phosphatidylinositol 4-phosphate 5-kinase type-1 beta-like	*pip5k1b*	−0.538	0.015068892
106560428	LOC106560428	Excitatory amino acid transporter 5-like	*slc1a7*	3.492	0.01547044
106612376	LOC106612376	Protein phosphatase 1A-like	*pp1*	2.488	0.017048588
106581568	LOC106581568	Guanylyl cyclase-activating protein 1-like	*guca1a*	3.316	0.018566427
106587958	LOC106587958	Sodium/potassium/calcium exchanger 1-like	*slc24a1*	2.005	0.019726988
106605751	LOC106605751	Neuronal pentraxin-1-like	*nptx1*	2.216	0.021659612
106561698	LOC106561698	Solute carrier organic anion transporter family member 1C1-like	*slco1c1*	3.137	0.022324012
106580796	slc6a4	Solute carrier family 6 member 4	*slc6a4*	2.050	0.022324012
106572384	LOC106572384	Sodium-coupled neutral amino acid transporter 3-like	*slc38a3*	2.164	0.023464354
106574495	LOC106574495	Guanine nucleotide-binding protein subunit alpha-11-like	*gna11*	−0.285	0.025017626
106579173	LOC106579173	Synaptotagmin-2-like	*syt2*	4.003	0.02540081

(Continues)

TABLE 2 (Continued)

ENTREZID	Accession number	Gene name	Putative name	$\log_2$ fold change	FDR
106605091	LOC106605091	Guanine nucleotide-binding protein G(I)/G(S)/G(T) subunit beta-3-like	*gnb3*	2.403	0.026220179
106583542	LOC106583542	Sodium- and chloride-dependent GABA transporter 2-like	*slc6a13*	0.972	0.028452986
106603834	LOC106603834	Solute carrier family 22 member 5-like	*slc22a5*	−1.252	0.029247296
106587942	LOC106587942	Sodium/potassium/calcium exchanger 1-like	*slc24a1*	2.012	0.030142477
106561912	LOC106561912	Cyclic nucleotide-gated cation channel beta-1-like	*cngb1*	3.621	0.032324991
106607984	LOC106607984	Solute carrier family 22 member 16-like	*slc22a16*	1.073	0.03395494
106561031	gpr37	G protein-coupled receptor 37	*gpr37*	1.019	0.035891712
106564793	LOC106564793	Sodium/calcium exchanger 1-like	*slc8a1*	1.535	0.037274497
106597363	LOC106597363	Guanylyl cyclase-activating protein 2-like	*gcap2*	3.478	0.037274497
106566781	LOC106566781	Solute carrier family 26 member 6-like	*slc26a6*	1.458	0.042405183
106594011	LOC106594011	Sodium/potassium/calcium exchanger 1-like	*slc24a1*	2.008	0.045357056
106577267	LOC106577267	Neuronal pentraxin-1-like	*np1*	1.727	0.047487725
106581084	LOC106581084	G protein-activated inward rectifier potassium channel 3-like	*girk3*	3.466	0.048892792
106561886	kcnk5	Potassium two-pore domain channel subfamily K member 5	*kcnk5*	1.098	0.051870554
106591467	LOC106591467	Neuronal pentraxin receptor-like	*nptxr*	−0.435	0.054754969
106570824	LOC106570824	Neuroligin-3-like	*nlgn3*	−0.609	0.068821378
106561537	slc27a4	Solute carrier family 27 member 4	*slc27a4*	−0.341	0.06932593
106610602	slc4a1ap	Solute carrier family 4 member 1 adaptor protein	*slc4a1ap*	−0.254	0.070027446
106572936	LOC106572936	Voltage-dependent L-type calcium channel subunit alpha-1S-like	*cacna1s*	1.622	0.073257288
106600499	LOC106600499	Excitatory amino acid transporter 5-like	*slc1a7*	3.387	0.075511344
106564801	LOC106564801	Potassium voltage-gated channel subfamily H member 1-like	*kcnh1*	1.124	0.076952544
106586510	asmt	Acetylserotonin O-methyltransferase	*asmt*	4.053	0.078732281
106573300	LOC106573300	Guanylyl cyclase inhibitory protein-like	—	4.062	0.079046904
106588065	LOC106588065	Synaptic vesicle glycoprotein 2B-like	*sv2b*	3.356	0.079105596
106585781	slc2a6	Solute carrier family 2 member 6	*slc2a6*	−1.210	0.08829066
106584763	LOC106584763	Potassium voltage-gated channel subfamily C member 1-like	*kcnc1*	−0.601	0.097240875

Notes. Selected based on a FDR <0.1.
FDR: false discovery rate.

that was sufficient to cause behavioral impairments. These results differ from those recently reported for European sea bass (Porteus et al., 2018). The robustness of the EOG responses to altered CO_2 levels may reflect the ability of olfactory sensory neurons to modulate ionic balances while in direct contact with the ambient water because they must be able to detect odorants in the presence of shifting ion concentrations and water chemistries. In contrast, neurons in the olfactory bulb have evolved to function in the tightly controlled fluid chemistry of the central nervous system and may be more sensitive to potential changes in extracellular fluid chemistry (Abbott, Patabendige, Dolman, Yusof, & Begley, 2010; Somjen, 2002). Our EEG recordings support this hypothesis, as elevated CO_2 exposures increased the amplitude, and tended to increase the duration of odorant-induced responses within specific regions of the olfactory bulb. This CO_2-induced increase in excitatory signaling is consistent with the hypothesis that disruption of neuronal signaling in marine fish is associated with disruption of inhibitory GABA signaling (Nilsson et al., 2012; Tresguerres & Hamilton, 2017). Specific odorant-generated signals in the olfactory bulb guide odorant perception and downstream behaviors. Alteration of this odorant specific signal, via dysregulation of the GABA signaling pathway, could lead fish to perceive odorants in an inappropriate way and thus lead to altered behavioral responses.

It has been hypothesized that the main mechanism of behavioral disruption by elevated CO_2 exposure is via alteration of GABA signaling in the central nervous system, driven by a reversal of the Cl^-/HCO_3^+ membrane gradient and a linked disruption of the normal inhibitory action of the $GABA_A$ receptor (Nilsson et al., 2012). The reversal of the Cl^-/HCO_3^+ neuronal membrane gradient results in a reversal of the intended GABA signaling. Therefore, GABA receptor activation results in hyperpolarization of the neuron rather than depolarization. This could potentially lead to inappropriate or overactivation of neurons. CO_2-induced increases in the amplitude of neuronal responses in the mediodorsal olfactory bulb in response to odorants are consistent with this hypothesis. Inhibitory GABAergic neurons in the olfactory bulb play a critical role in synchronization and regulation of neuronal signals required for appropriate odor discrimination (Lizbinski & Dacks, 2017; Tabor, Yaksi, & Friedrich, 2008). The lack of observed effects of CO_2 in the olfactory epithelium and some discrete regions of the olfactory bulb may be due to differential spatial distribution of GABAergic neurons and GABA receptors within these tissues and the role of GABAergic neurons in regulating signaling of specific odorants and mixtures (Cocco et al., 2017; Lizbinski & Dacks, 2017; McGann, 2013; Tabor et al., 2008). For example, while G protein-coupled $GABA_B$ receptors are present in the axonal presynaptic region of the olfactory sensory neurons within the olfactory bulbs, $GABA_A$ receptors are broadly present on mitral/tufted cell secondary neurons within the olfactory bulb (McGann, 2013; Tan, Savigner, Ma, & Luo, 2010).

Consistent with the hypothesis that CO_2 effects on olfactory behaviors involve GABA signaling, our RNA-Seq analysis found that several genes involved in GABA signaling were altered at a CO_2 concentration shown to cause neurobehavioral disruption. These results are largely similar to studies that examined elevated CO_2 effects on mRNA expression of $GABA_A$ receptor genes in other fish species (Lai, Fagernes, Jutfelt, & Nilsson, 2016; Schunter et al., 2017). Interestingly, while we found no change in expression of the $GABA_A$ receptor mRNA in the olfactory bulb under high CO_2 conditions, we did observe a significant increase in *gaba*$_{B2}$ receptor mRNA expression. The metabotropic $GABA_B$ receptor is involved in a distinct inhibitory pathway compared to ionotropic $GABA_A$ receptor and works to modulate neural activity via presynaptic and postsynaptic signaling pathways. However, $GABA_A$ and $GABA_B$ receptors play complementary and distinct roles in modulating olfactory signaling. The $GABA_B$ receptor is a G protein-coupled receptor that, upon activation, inhibits calcium channel function (which can in turn reduce neural excitability and neurotransmitter release) and activates potassium channels to hyperpolarize neurons (Bettler, Kaupmann, Mosbacher, & Gassmann, 2004). Neuronal hyperpolarization via $GABA_A$ receptor modulation of Cl^- influx is quicker than the $GABA_B$ pathway as it does not rely on slower secondary messengers.

To our knowledge, we are the first to report changes in $GABA_B$ gene expression under elevated CO_2, which presents an interesting new component to the list of signaling molecules involved in behavioral alterations under elevated CO_2. Increased expression of the $GABA_B$ receptor could indicate a response by salmon olfactory bulb neurons to compensate for the loss of normal function of the $GABA_A$ receptor pathway. Increased expression of $GABA_A$ receptor mRNA, as a potential compensation for loss of function under elevated CO_2 conditions, is also found in three-spined sticklebacks (Lai et al., 2016). This theory is supported by the fact that several other genes associated with GABA signaling were also significantly altered in coho salmon in the present study. The significant increase in *hcn2*, which plays critical roles in membrane excitability, integration of synaptic inputs, and the generation of membrane potential oscillations within the olfactory bulb, suggests alterations in signal modulation under elevated CO_2 conditions (He, Chen, Li, & Hu, 2014). Two other genes associated with synaptic transmission and modulation of neuronal GABA signaling through Cl^- transport, *snap25* and *kcc1*, also showed significant increases in expression further suggesting altered neuronal signaling within the olfactory bulbs (Abe, Minowa, & Kudo, 2018; Delgado-Martínez, Nehring, & Sørensen, 2007; Delpire, 2000; Wang et al., 2005). The increases in *slc6a13* and *slc38a3*, which can serve roles in taurine/GABA uptake and glutamate uptake needed for GABA synthesis, respectively, potentially indicate increased production or uptake of GABA as a compensatory response by the bulb neurons (Chan et al., 2016; Scimemi, 2014). There was also a significant decrease in *aldh9a1*, which is involved in the production of GABA, and was reported to be overexpressed in fish tolerant of elevated CO_2 exposures (Schunter et al., 2016). Furthermore, the significant changes in expression of the multitude of other genes involved in signal transduction, ion transport (such as *slc26a6* which serves a vital role in transporting HCO_3^+/Cl^-), and machinery related to neurotransmitters such as glutamate, serotonin, and acetylcholine also indicate a potential compensatory response to restore normal neural signaling within the olfactory bulbs.

We found increased expression of major genes involved in melatonin and the circadian rhythm, *asmt* and *aanat*, genes that play key roles in the production of melatonin and its precursor *N*-acetylserotonin. Melatonin production has been linked to modulation of ion regulation in rainbow trout in response to changes in salinity (López-Patiño, Rodríguez-Illamola, Gesto, Soengas, & Míguez, 2011). Schunter et al. (2016) found similar results in damselfish wherein offspring from parents sensitive to elevated CO_2 also had elevated levels of *asmt* mRNA expression, as opposed to offspring from CO_2-tolerant parents. GABA signaling has also been linked to circadian rhythm regulation, and the alteration of expression of genes central to $GABA_B$ function could be driving these changes in genes linked to the circadian rhythm as well (DeWoskin et al., 2015). In total, the RNA-Seq data indicate that olfactory bulb neural signaling pathways experienced major changes on a wide scale in response to the elevated CO_2 exposure, potentially as a mechanism to restore normal function, albeit unsuccessful during the exposure window given our behavioral and neurophysiology results.

The results of our study highlight the fact that salmon, once acclimated to saltwater, are susceptible to neurophysiological changes that can influence behavioral function under shifts in pH similar to those expected with OA. These results are worrisome as the native range of coho salmon in the North East Pacific Ocean is characterized by strong upwelling currents and is predicted to be impacted by elevated CO_2 and low pH projected for the foreseeable future. Indeed, many areas in the Salish Sea (encompassing the Strait of Georgia, Strait of Juan de Fuca, and Puget Sound in Washington State, USA, and British Columbia, CDN) already experience CO_2 and pH levels, at certain times of the year, that are similar to those affecting fish in our study (Feely et al., 2010). Olfaction plays a central role in the salmon life history, and the impairment of normal olfactory-driven behaviors in juvenile salmon can jeopardize their survival. Furthermore, the GABA signaling system hypothesized to be impaired under elevated CO_2 conditions is critical in many other areas of the central nervous system, including vision, mechanoreception, and control of anxiety. However, the effects of elevated CO_2

on these critical neuronal systems, remain to be investigated and are largely unknown in salmon (Ou et al., 2015).

While future real-world exposures to CO_2 concentrations at 2,700 μatm are likely to only occur in a transient scenario similar to our exposure paradigm, longer term exposures would be informative to investigate a potential for salmon to acclimate to the changed chemistry and regain normal neural function. Furthermore, while our study did not investigate recovery of normal behavioral function following cessation of the exposures, there is evidence that such recovery does happen in fish (Chivers et al., 2014; Jarrold, Humphrey, McCormick, & Munday, 2017). The environment that salmon reside in (i.e., open ocean vs. nearshore environment, time of year they reside in each environment, and the water depth they reside at) is important to consider going forward as the degree of neural impairment driven by elevated CO_2 could vary (Jarrold et al., 2017; Pacella, Brown, Waldbusser, Labiosa, & Hales, 2018).

In conclusion, juvenile ocean-phase coho salmon are sensitive to neurobehavioral disruption induced by exposure to elevated CO_2 associated with climate change predictions in the Puget Sound region. Salmon are a keystone species in many aquatic ecosystems in the North Eastern Pacific Ocean and already face substantial pressure from other anthropogenic and nonanthropogenic factors. The potential effects of elevated CO_2 on their mortality will only add to this pressure for long-term survivorship of Pacific salmon.

ACKNOWLEDGEMENTS

We greatly appreciate the EOG and EEG lessons and expertise of Dr. David Baldwin. We appreciate the assistance and advice of Danielle Perez and Frank Sommers with this study. We are also grateful to David Baldwin and Krista Nichols for their comments that greatly improved the manuscript. This work was funded in part by grants from the Washington Ocean Acidification Center, the Washington Sea Grant Program, University of Washington, pursuant to National Oceanic and Atmospheric Administration Award No. NA10OAR4170057, Project R/OCEH-5, and from the University of Washington Superfund Research Program, Grant NIEHS P42ES004696. Additional support was provided by the NOAA Fisheries Northwest Fisheries Science Center and the NOAA Ocean Acidification Program. The views expressed herein are those of the authors and do not necessarily reflect the views of the University of Washington, NOAA, or any of its subagencies.

CONFLICT OF INTEREST

The authors declare no competing interests.

AUTHOR CONTRIBUTIONS

C.W., A.D., E.G., P.M., T.B., and S.B. all participated in the design of the experiment. C.W. and M.M. conducted the study. T.B. and J.M. conducted the bioinformatics. C.W. wrote the paper with editorial input from A.D., E.G., P.M., S.B., T.B., J.M., and M.M.

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SUPPORTING INFORMATION

Additional supporting information may be found online in the Supporting Information section at the end of the article.

How to cite this article: Williams CR, Dittman AH, McElhany P, et al. Elevated CO_2 impairs olfactory-mediated neural and behavioral responses and gene expression in ocean-phase coho salmon (*Oncorhynchus kisutch*). *Glob Change Biol*. 2018;00:1–15. https://doi.org/10.1111/gcb.14532

Exhibit 49

Oregon
John A. Kitzhaber, MD, Governor

DEQ of Environmental Quality
Western Region Eugene Office
165 East 7th Avenue, Suite 100
Eugene, OR 97401
(541) 686-7838
FAX (541) 686-7551
TTY 711

June 25, 2014

Mr. Robert L. Braddock
Vice President-Project Manager
Jordan Cove Energy Project L.P.
125 Central Ave., Suite 380
Coos Bay, OR 97420

Re: Warning Letter with Opportunity to Correct
Jordan Cove-Ingram Yard Contaminated Soils
WLOC-WRE-2014-0033
North Bend, Coos County Proj 6765

Dear Mr. Braddock:

In late April 2014, the Oregon Department of Environmental Quality (DEQ) was informed that contaminated soils had been encountered, excavated and incorporated into onsite berms at the Jordan Cove Ingram Yard site. This activity was part of the site preparation associated with geotechnical tests to be conducted as part of the Jordan Cove Energy Project. On May 8, 2014, I conducted an inspection at the Jordan Cove Ingram Yard site in North Bend, OR.

Based upon the inspection of your facility, and our review of the May 7, 2014 letter report prepared by your consulting engineering firm, SHN documenting the aforementioned site preparation work, DEQ has concluded that Jordan Cove Energy Project L.P. (Jordan Cove) is responsible for the following violations of Oregon environmental law:

VIOLATION #1

OAR 340-093-0040(1) - Prohibited Disposal states the following:

(1) No person shall dispose of or authorize the disposal of solid waste except at a solid waste disposal site permitted by DEQ to receive that waste, or at a class of disposal site specifically exempted by OAR 340-093-0050(3) from the requirement to obtain a solid waste permit.

As described in the SHN letter report, contaminated soils were encountered, excavated, and graded with much of the materials used to construct onsite berms. Investigations conducted at the site in the mid-2000's had identified the presence of these contaminated soils, which are native soils mixed with residual sludge waste. Weyerhaeuser had disposed of sludge waste in the Ingram Yard area when their mill was in operation. Based on results of the earlier site investigations, the contaminated soils contain low levels of potentially bioaccumulating chemicals that must not be placed in the waters of the state.

While it was recognized that contamination level in the soil material are low such that the soils can be left onsite, DEQ stated in a September 15, 2006 No Further Action (NFA) letter that "any residually contaminated soil or sediment excavated during future site activities or development must be properly managed and disposed in accordance with DEQ regulations and policies."

Therefore, the disposal of solid waste (i.e., contaminated soils) that occurred during the site preparation work required a solid waste permit. As the site preparation activities were a short-term operation, DEQ can issue a specific solid waste permit called a "letter authorization."

Disposing of or authorizing the disposal of a solid waste at a location not permitted by DEQ to receive that solid waste is a Class I violation of OAR 340-012-0065(1)(c).

Corrective Action(s) Requested

In order to correct the violation cited above, minimize the impacts of the violation on the environment and employee safety, and to avoid further enforcement action by the DEQ, we request that Jordan Cove take the following action by the date indicated:

Corrective Action – Violation #1:

a) Submit a completed application for a new solid waste disposal site permit. Specifically, the type of permit requested should be a Solid Waste Letter Authorization (SWLA) as this type of permit is applicable for short-term projects. Please submit your application to DEQ **by no later than July 31, 2014**.

Should this violation remain uncorrected or should Jordan Cove repeat this violation, this matter may be referred to the DEQ's Office of Compliance and Enforcement for formal enforcement action, including assessment of civil penalties and/or a DEQ order. Civil penalties can be assessed for each day of violation.

If it is anticipated that future activities at this site will result in the additional excavation and disposal of contaminated soils/materials at the Jordan Cove Energy Project site, these contaminated soils/materials must be managed and/or disposed of in accordance with DEQ rules. If the contaminated soils/materials will be disposed of onsite, Jordan Cove will need to apply for a new solid waste disposal site permit.

If you believe any of the facts in this Warning Letter are in error, you may provide information to me at the office at the address shown at the top of this letter. The DEQ will consider new information you submit and take appropriate action.

The DEQ endeavors to assist you in your compliance efforts. Should you have any questions about the content of this letter or desire additional technical assistance, please feel free to contact me by e-mail at wong.gene@deq.state.or.us or by phone at 541-687-7438.

Sincerely,

Gene Wong

Gene Wong, P.E., Environmental Engineer
Solid Waste Permitting and Compliance
Western Region – Eugene Office

Cc: File

Ec: Fran Holman; DEQ – Salem
Mary Camarata, DEQ - Eugene
Office of Compliance and Enforcement - DEQ Headquarters
J. Mark Denning, SHN Consulting Engineers, 275 Market Avenue, Coos Bay, OR 97420-2228
Kelly McNutt, Kiewit Infrastructure West Co., 2215 E. 1st St., Vancouver, WA 98661

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Oregon
John A. Kitzhaber, MD, Governor

Department of Environmental Quality
Western Region Salem Office
750 Front Street NE, Suite 120
Salem, OR 97301-1039
(503) 378-8240
FAX (503) 373-7944
TTY 711

July 31, 2014

Mr. Robert L. Braddock
Vice-President-Project Manager
Jordan Cove Energy Project L.P.
125 Central Ave., Suite 380
Coos Bay, OR 97420

RE: JCEP LNG Terminal Project L.P. – Ingram Yard
SW Permit No. 1545, SW Project No. 6809
Solid Waste Letter Authorization Permit
Coos County

Dear Mr. Braddock:

The enclosed Solid Waste Letter of Authorization (SWLA) Permit No. 1545 is issued in response to your application received July 21, 2014. This SWLA has been issued to allow the excavation and temporary storage of low-level impacted ash/soil in berms as part of the Test Pile and Ground Improvement Program performed at the Ingram Yard area of the JCEP LNG Terminal Project, as described in your SWLA application. This SWLA also sets forth specific requirements for the maintenance of the berms.

You are urged to carefully read the permit and comply with its conditions.

SWLA Permit No. 1545 is valid until January 31, 2015. For more information on DEQ's Solid Waste Program including rules, statutes and technical assistance visit
http://www.deq.state.or.us/lq/sw/index.htm.

Sincerely,

Brian Fuller, Manager
Western Region Hazardous and Solid Waste
Permitting and Compliance

Encl: SWLA Permit

Cc: File

ec: Gene Wong, DEQ Eugene
Fran Holman, DEQ-Salem
Office of Compliance and Enforcement – DEQ Headquarters
J. Mark Denning, mdenning@shn-engr.com

X:\Solid Waste\SWLA\SWLA2014\1545JordanCove\PermitCvrLtrJul2014

State of Oregon
Department of Environmental Quality

SOLID WASTE DISPOSAL SITE PERMIT: LETTER AUTHORIZATION

Oregon Department of Environmental Quality
165 East 7th Avenue, Suite 100
Eugene, Oregon 97401

Telephone: (541) 686-7838

Issued in accordance with the provisions of ORS Chapter 459 and subject to the land use compatibility statement referenced below.

ISSUED TO:

Jordan Cove Energy Project, L.P.
125 Central Avenue, Suite 380
Coos Bay, OR 97420

(541) 266-7510

FACILITY NAME AND LOCATION:

JCEP LNG Terminal Project, L.P.
Jordan Cove Road
Coos County

PROPERTY OWNER:

Jordan Cove Energy Project, L.P.
125 Central Avenue, Suite 380
Coos Bay, OR 97420

Attn: Robert Braddock

OPERATOR:

Jordan Cove Energy Project, L.P.
125 Central Avenue, Suite 380
Coos Bay, OR 97420

(541) 266-7510

ISSUED IN RESPONSE TO:

- an application for Solid Waste Letter of Authorization (SWLA) received July 21, 2014; and
- a Land Use Compatibility Statement signed by the Coos County Planning Dept. Director, July 11, 2014.

Pursuant to OAR 340-093-0050(5) the determination to issue this permit is based on findings and technical information included in the permit record.

ISSUED BY THE OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY

July 31, 2014

Brian Fuller, Manager
Hazardous and Solid Waste Program
Western Region

Date

PERMITTED ACTIVITIES

In accordance to SWLA No. 1545, which **will expire on January 31, 2015**, the permittee is hereby authorized in conformance with the requirements, limitations and conditions set forth in this document including all attachments.

PERMITTED ACTIVITIES

Description

In response to a Warning Letter issued by DEQ on June 25, 2014 (WLOC-WRE-2014-0033), Jordan Cove Energy Project, L.P. (Jordan Cove) applied for a Solid Waste Letter Authorization Permit (SWLA) to address the short term project that has already been conducted at their site. This project, which was associated with the Test Pile and Ground Improvement Program being performed at the site, involved the grading and temporary stockpiling of low-level impacted ash/soil at the Ingram Yard area of the Jordan Cove Liquefied Natural Gas (LNG) project. The disposal of solid waste (i.e., low-level impacted ash/soil) onsite requires a solid waste permit.

The purpose of the Test Pile and Ground Improvement Program was to investigate various methods for pile driving and ground improvement techniques to determine design parameters and efficient construction techniques for the Jordan Cove Energy Project. In order to perform these geotechnical tests, it was necessary to excavate and temporarily store both clean and low-level impacted ash/soil. Approximately 1,700 cubic yards of soil (both clean and low-level impacted soil) was excavated during the grading activities in the Ingram Yard.

Work on the project began in February 2014 and grading activities in this area for the geotechnical tests were substantially completed in April 2014. Grading operations at the testing site removed the top 12- to 60-inches of sand and top soil. All exposed soil at the finished grade of the test site was clean sand. The low-level impacted ash/soil that had been removed was integrated into larger stockpiles that were subsequently placed into the perimeter berms around the test area. Gravel was used to cover the flat test area surfaces, while the surface of the berms were seeded and mulched.

Activities of the project must be conducted in compliance with following requirement: the structural integrity of the perimeter berms must be maintained to reduce the potential for any materials from the low-level impacted ash/soil to leach out of the berms.

A permanent disposal plan for the ash/soil material temporarily stored as part of the Test Project, as well as ash/soil material not disturbed by the Test Project in the Ingram Yard area, is being developed by Jordan Cove. This plan will need to be submitted to and approved by DEQ prior to any future grading activities where the ash/soil material will be disturbed. This plan should be submitted as part of an application for a new Solid Waste Disposal Permit for this material. It is anticipated that the ash/soil material will be utilized as fill material during planned construction of the LNG terminal and permanently buried.

Disclaimers

The issuance of this permit does not convey property rights in either real or personal property, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights.

DEQ, its officers, agents, or employees do not sustain any liability on account of the issuance of this permit or on account of the construction, maintenance, or operation of facilities pursuant to this permit.

Authority

Conditions of this permit are binding upon the permittee. The permittee is liable for all acts and omissions of the permittee's contractors and agents [ORS 459.376].

The permittee shall allow representatives of DEQ access to the project areas at all reasonable times for the purpose of making inspections, surveys, collecting samples, obtaining data and carrying out other necessary functions related to this permit.

Issuance of this permit does not relieve the permittee from the responsibility to comply with all other applicable federal, state or local laws or regulations. This includes the following solid waste requirements, as well as all updates or additions to these requirements:

1. Solid Waste Letter Authorization Permit Application received July 21, 2014,
2. Oregon Revised Statutes, Chapters 459 and 459A,
3. Oregon Administrative Rules, Chapter 340, and
4. Any other documents submitted by the permittee and approved by DEQ.

Solid Waste Letter of Authorization No.1545 expires on January 31, 2015.

Exhibit 50

http://business.financialpost.com/commodities/energy/pembina-pipelines-new-purpose-get-canadas-oil-and-gas-to-the-rest-of-the-world

Pembina Pipeline's new purpose: Get Canada's oil and gas to the rest of the world

CEO shifts to getting hydrocarbons to the U.S. and Asia, especially in light of Canada's infrastructure problems, which he thinks will only get worse

By Claudia Cattaneo
February 16, 2018
Last Updated
February 20, 2018

Political priorities come and go, especially when it comes to energy these days, and Pembina Pipeline Corp. has been adding value one piece of infrastructure at a time since the days of Louis St. Laurent.

Its most recent growth spurt, much of it through the oil and gas downturn, has boosted its enterprise value to $26.7 billion, from $14.4 billion in 2014 when current chief executive Mick Dilger took over, and from $3 billion 10 years ago.

With that kind of pedigree, you could do worse than pay attention to Dilger, who believes it would be better for governments to help improve the value of existing resources rather than chase new energy sources.

Canada, he points out, sits on some of the world's best and largest deposits of natural gas, which could be the bridge fuel to both help solve the climate change challenge by replacing coal and turn the country into a green superpower.

"How bad does it have to get in Canada before people care?" Dilger said in an interview in the company's Calgary headquarters. "Monies don't come from governments. They come from adding value, and maybe parts of Canada have had it too good and we need some pain before people start to wake up. It's also frustrating to me because I am mindful of the environment."

Pembina is little known outside Western Canada, partly because it rarely seeks publicity, partly because much of its business has been in energy-friendly Alberta.

It grew from a single oil pipeline built in 1954 by Alberta's Mannix dynasty to transport oil from the Pembina oil discovery in Drayton Valley, Alta. The company is now widely held — the Mannix family remains a shareholder — and is now Canada's third-largest pipeline company after Enbridge Inc. and TransCanada Corp.

Pembina has achieved its lofty position by building or buying infrastructure to serve its oil and gas customers in Western Canada, specifically pipelines linked to the oilsands in Alberta and shale discoveries such as the Montney and the Duvernay, storage tanks, fractionation plants that separate light hydrocarbon mixtures into individual substances, and gas-processing facilities.

The next projects in its core geography continue to reflect its time-tested mantra: do the most with the molecules you have.

The projects include a proposed $4-billion petrochemical plant in Sturgeon County in Alberta's Heartland with equal partner Petrochemical Industries Co. of Kuwait, and a $250-million liquefied petroleum gas export terminal in Prince Rupert, B.C.

"We think we have a purpose beyond what we have done, which is to play our part alongside other sector companies to **get our hydrocarbons to the rest of the world**," Dilger said.

But its next game-changing project could be in the United States. Pembina is making progress on reviving the US $10-billion Jordan Cove Energy Project, a liquefied natural gas export terminal on the Oregon coast to process Western Canadian gas, which is in great demand in Asia, but prices have languished because of a lack of export infrastructure.

> "*We think we have a purpose beyond what we have done, which is to play our part alongside other sector companies to get our hydrocarbons to the rest of the world*"
> -Mick Dilger-

Jordan Cove was part of Pembina's acquisition of Veresen Inc. last year, part of a $100-billion U.S. buying spree by Canada's top three pipeline companies over the past three years.

In addition to Pembina's purchase of Veresen, whose assets are half in the U.S., Enbridge bought Spectra Energy Corp. and TransCanada purchased Columbia Pipeline Group Inc.

The U.S. is where Pembina's larger competitors have already spread out to get around Canada's infrastructure gridlock and to take advantage of the more favourable business environment down south.

"That is $100-billion worth of money that could have been spent in Canada," said Dilger, a 54-year-old accountant by trade. "Think about that: the royalties, the jobs. The trend is, as their economy gets more pro business and pro-development, and ours goes the other way, capital will flee Canada. Those are all irrefutable conclusions to the way we are going, versus the way they are going."

The struggling but advanced Jordan Cove LNG project was denied an export permit by the U.S. Federal Energy Regulatory Commission two years ago because of a lack of customers even during a period of weak LNG prices, but Pembina has since filed a new permit application and expects a ruling this November.

An artist's rendering of the Jordan Cove project. Handout/Jordan Cove Energy

"We believe (the project) filed a winning application this time," Dilger said. "They had tremendous local support and federal support. I am not trying to predict what is going to happen in 2023 with commodity prices. But today, the price of gas in Tokyo is US $11. The price of gas in Alberta on a bad day is like $1. It costs you $5 to $6 to get it there. So there is a massive arbitrage today. I don't know what it's going to be in 2023, but there is a lot of interest right now."

Pembina is trying to secure customers and finish pipeline engineering, but if everything works out, the company will be in a position to make a final investment decision as soon as the end of 2018, Dilger said, which might mean the project could be completed in 2023.

"Pembina was smart to keep the project alive because the LNG market is coming to them now," said Dan Tsubouchi, chief market strategist at Stream Asset Financial Management, who believes global LNG demand is recovering a lot faster than previously anticipated.

Buying Veresen also gave Pembina two strategic Canadian gas export assets: a 50 per cent interest in the Alliance natural gas pipeline from Western Canada to Chicago (the rest is owned by Enbridge), and a roughly 43 per cent stake in a natural-gas-processing venture, Aux Sable.

But Dilger worries Canada's energy infrastructure problems will only get worse because of reforms announced by Ottawa last week to modernize the regulatory and environmental reviews of energy projects.

For example, allowing anyone in Canada to have an opinion on whether a major project should go ahead politicizes reviews and puts the country down a "very dangerous" path, he said.

There are three LNG projects making progress on the B.C. coast — LNG Canada led by Royal Dutch Shell PLC with partners PetroChina, Korea Gas Corp. and Mitsubishi Corp. of Japan; Woodfibre LNG, owned by the RGE Group of companies based in Singapore; and Kitimat LNG, a joint venture between Chevron Corp. and Australia's Woodside Petroleum Ltd. — but politics and high costs have been a long-running challenge.

Jordan Cove, meanwhile, would process up to 1.3 billion cubic feet a day of both Western Canadian gas or U.S. Rockies gas into LNG for export to Asia, but it's not the only energy export project that could take Canadian energy in the U.S. to reach Asian markets.

The proposed Eagle Spirit oil pipeline is also moving forward with plans to establish a tanker terminal in Alaska to export Canadian oil and get around the federal Liberal government's tanker ban.

Dilger believes Jordan Cove has a higher chance of success under Pembina than it had under Veresen because it has the money to finance it, the expertise to build both the plant and a 400-kilometre pipeline through tough terrain, and the relationships with Western Canadian producers and Asian customers to make it viable.

Some day, Pembina would like to build an LNG facility on the B.C. coast, too, Dilger said, but Jordan Cove has key advantages: it is cheaper to build a pipeline to receive Western Canadian gas from existing networks than build over the Canadian Rockies; its location near larger population centres means there is labour available to build it; and shorter travel time to Asian markets versus the U.S. Gulf Coast means lower transportation costs for its LNG.

Another priority is the expansion of the Alliance pipeline, one of Canada's large gas export highways into the Chicago hub.

Pembina will move ahead with Veresen's plans to expand the system by up to 500 million cubic feet a day, adding to the current level of 1.8 billion cubic feet a day, by using compression. A binding open season for interested shippers is under way.

"The best market in North America right now is Chicago," Dilger said, "I'd like to see Canadian gas get there and get some higher netbacks."

The Veresen acquisition diversified Pembina's assets into gas and into a new region, he said, but it also fits with the company's integrated business model, which he said is better than having disparate energy businesses geographically.

As for moving into new energy sources such as wind and solar, Dilger doesn't see the value proposition for his company, adding: "How's that working for Ontario so far?"

Financial Post

• Email: ccattaneo@nationalpost.com

Exhibit 51

OILCHANGE INTERNATIONAL

JANUARY 2018

JORDAN COVE LNG AND PACIFIC CONNECTOR PIPELINE GREENHOUSE GAS EMISSIONS BRIEFING

FACTS AT A GLANCE

Total Annual GHG Emissions:	**36.8 million metric tons**
Emissions Equivalent:	**15.4 times the 2016 emissions of Oregon's last remaining coal-fired power plant (the Boardman plant) – or 7.9 million passenger vehicles**
Pipeline Project Name:	Pacific Connector Gas Pipeline
LNG Export Terminal Project Name:	Jordan Cove Energy Project
Ownership:	Pembina Pipeline Corporation
Operator:	TBD
Pipeline Length:	229 miles
Pipeline Diameter:	36 inches
Pipeline Capacity:	1.2 billion cubic feet per day (cf/d)
LNG Export Capacity:	7.8 million metric tons of gas per year (MMT/Y)
Project Cost:	$10 billion
Land Affected:	5,146 acres
States Directly Affected:	Oregon
Counties Affected:	Coos, Douglas, Jackson, and Klamath
Gas Source:	The Rocky Mountain states of Utah, Wyoming, and Colorado and the Montney Basin in British Columbia
Claimed Destination Markets:	Primarily Asia – Japan and China
Intended Permit and Project Schedule (Est.):	Final Environmental Impact Statement (August 2018); FERC order granting authorization and state permits (November 2018); Construction (first half of 2019); In-service date (first half of 2024)

SUMMARY

The proposed Pacific Connector Gas Pipeline and Jordan Cove Energy Project would transport and process into liquefied natural gas (LNG) around 430 billion cubic feet of fossil gas annually.[a] The greenhouse gas (GHG) emissions triggered by the project will be significant, but to date the scope of these emissions has not been well understood.

This paper provides an estimate of the full lifecycle emissions of the project, calculating a reference and high case estimate using the best available information. It finds that the project would add significantly to greenhouse gas emissions both globally and within the state of Oregon.

The emissions estimate includes an estimated range of methane leakage along the supply chain and finds that even a conservative estimate of methane leakage undermines claims that the gas supplied to global markets via the project would lead to a net reduction in GHG emissions. The paper also finds that there is no evidence to support an assumption that gas supplied by the project would replace coal in global markets.

In order to address the global climate crisis, emissions from all sources of fossil fuel must be reduced to zero by mid-century. Building and operating this project will undermine that goal. This paper provides the clear climate rationale against the project going ahead.

a We use the term fossil gas to mean natural gas produced from fossil fuel sources.

Above: LNG Tanker ©Smit Ebro , Grace Dahlia & Fairplay 21

PACIFIC CONNECTOR GAS PIPELINE MAP

PROJECT OVERVIEW

The Pacific Connector Gas Pipeline (PCGP) is a proposed 36-inch fracked gas pipeline that would run 229 miles across southern Oregon to a proposed liquefied natural gas export terminal at Jordan Cove, near Coos Bay, OR. The pipeline would start in southern Klamath County in the farming community of Malin, OR.

The proposed route of the pipeline crosses the Cascade mountains, threatening public and private lands, traditional tribal territories, and more than 2,000 acres of forest. Close to 400 rivers and streams would be crossed, including the Rogue, Klamath, Umpqua, Coos, and Coquille Rivers.

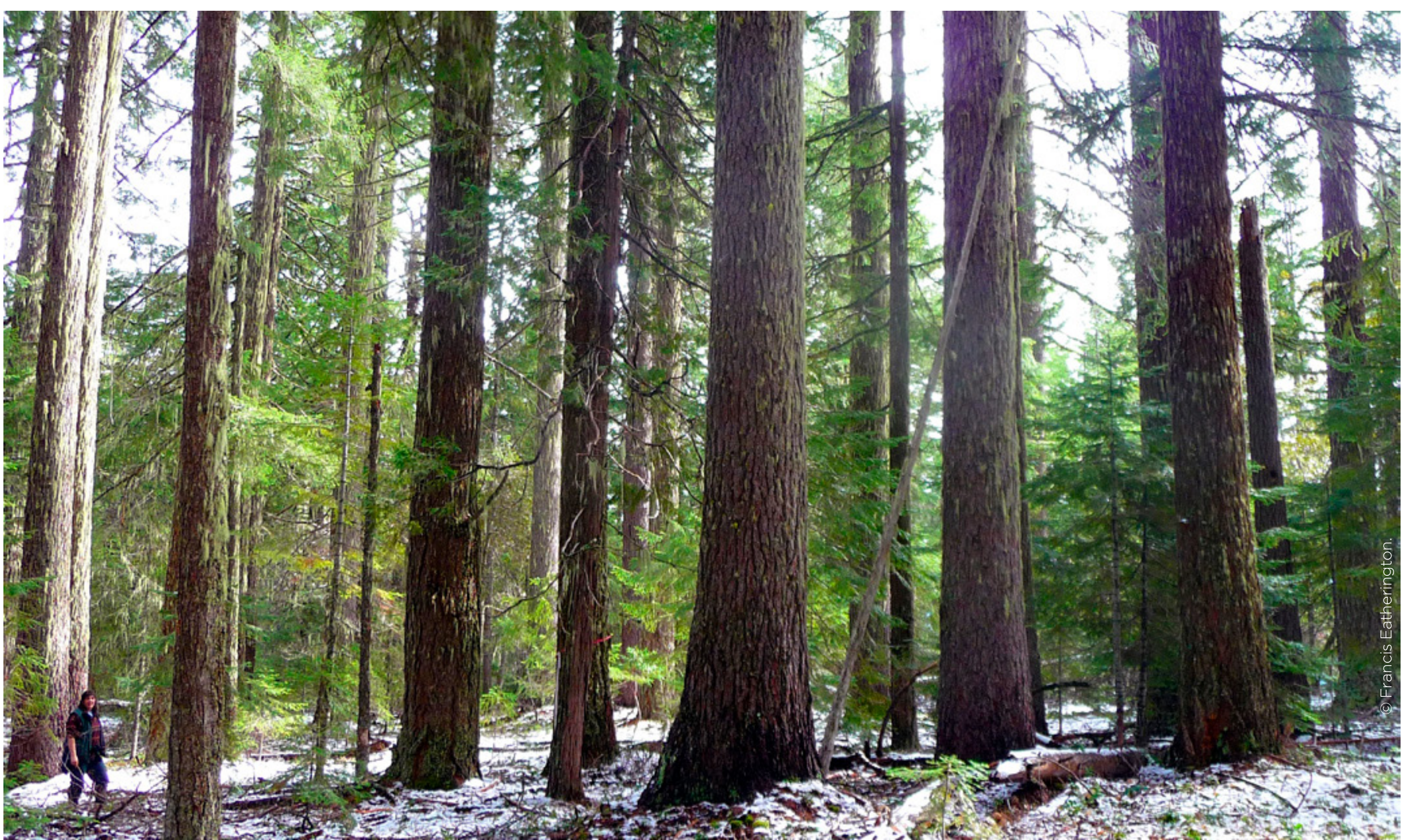
The project is facing significant opposition from indigenous communities along the pipeline route, including the Klamath Tribes, as well as the Yurok and Karuk Tribes along the Klamath River. The construction of the pipeline and the terminal would disturb sacred sites, burial grounds, and cultural resources and could also impact critical runs of salmon and steelhead. The Jordan Cove LNG export terminal would be built on traditional Coos tribal territory. There are also over 500 landowners along the pipeline route that would be impacted by the pipeline, and many will face eminent domain proceedings for the private project if it moves forward. More than 400 landowners, organizations, tribal members, and concerned citizens have filed motions to intervene with the Federal Energy Regulatory Commission (FERC) in opposition to the project, with only five interventions filed in support.[1]

The project backer is the Canadian company Pembina Pipeline Corporation, a fossil fuel giant that recently merged with Veresen, the original proponent of the pipeline proposal. The pipeline would be fed by either of two existing pipelines – the Ruby Pipeline that runs from the Rocky Mountains in Wyoming to Malin, or the Gas Transmission Northwest pipeline that runs from British Columbia. Each pipeline is capable of carrying 100 percent of Pacific Connector's capacity of 1.2 billion cubic feet per day. This creates a unique situation in which Canadian and U.S. fracked gas could compete for export, and opens the possibility that Jordan Cove could provide export service for 100 percent Canadian-sourced fracked gas.

The Pacific Connector Pipeline and the Jordan Cove Energy Project were first proposed in 2005 as a gas import project. The original project was vacated in 2012 and replaced with a LNG export proposal in 2013. In a rare federal decision, FERC denied the project application in 2016, stating that, "because the record does not support a finding that the public benefits of the Pacific Connector Pipeline outweigh the adverse effects on landowners, we deny Pacific Connector's request for certificate authority to construct and operate its project."[2] In early 2017, project backers reapplied under the Trump administration, which has stacked FERC with new appointees.

Pembina plans to complete the federal and state permit process by November 2018. It plans to begin construction in the first half of 2019 and bring the export terminal online by the first half of 2024.

Proposed path of pipeline through Umpqua National Forest, south of Tiller, MP 109.



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FOSSIL GAS AND CLIMATE CHANGE

Climate science clearly indicates the need to reduce consumption of all fossil fuels and make a just transition to a clean energy economy.[3] Building major fossil gas infrastructure today undermines action to protect our climate. Increasing access to fossil gas spurs its use, locking us into releasing more emissions when we must progressively produce and use less of all fossil fuels, including gas.

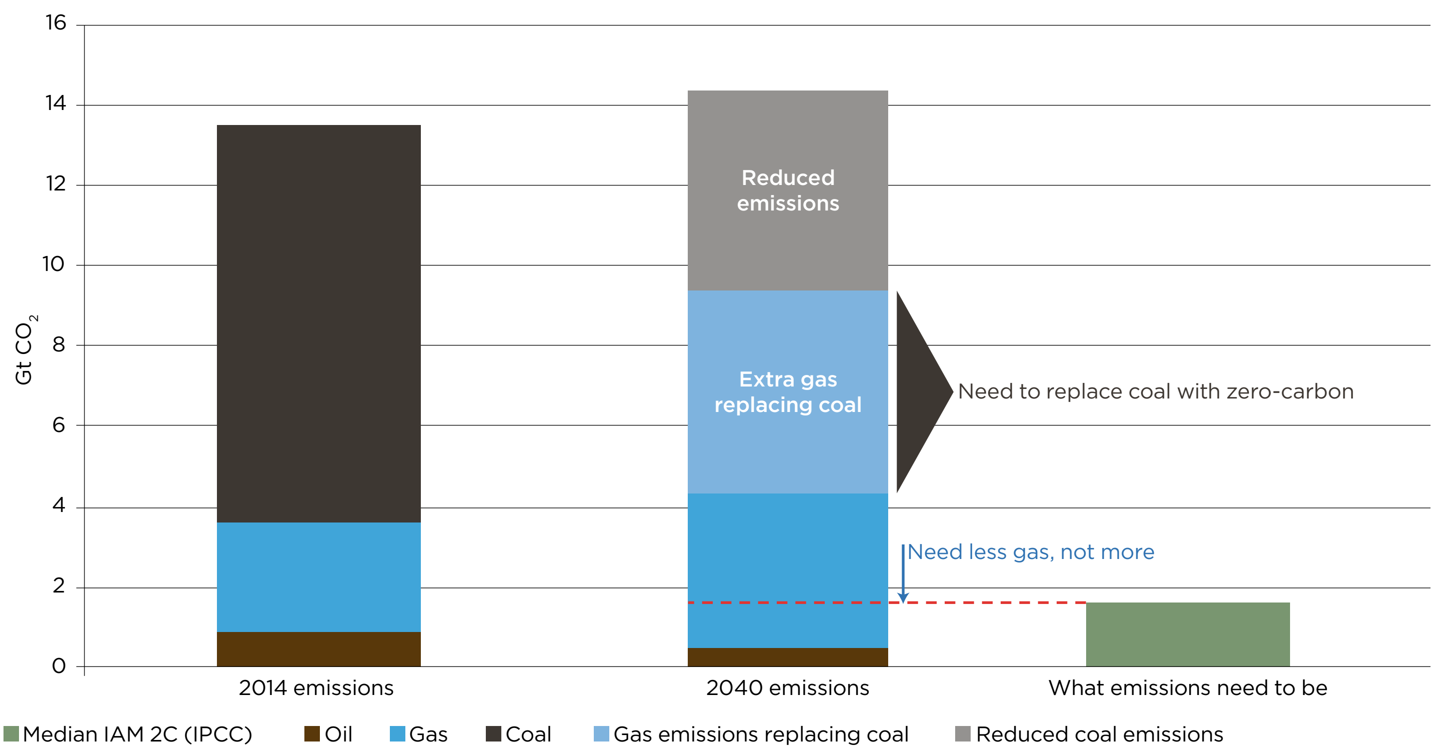
Much of the debate on fossil gas and climate has focused on measuring and reducing the leakage of methane, a potent greenhouse gas, to the atmosphere. But focusing on methane leakage alone distracts from the core issue at hand. To meet climate goals, fossil gas production and consumption must, like that of other fossil fuels, be phased out. Reducing methane leakage, even to zero, does not alter that fact.

Fossil gas proponents also argue that more gas capacity is needed to complement renewable energy sources. Several factors undermine this case, summarized as follows:[4]

1. **No Room for New Fossil Gas:** Climate goals require the power sector to be decarbonized by mid-century. This means gas use must be phased out, not increased (see Figure 1).
2. **New Gas is Holding Back Renewable Energy:** Wind and solar are now cheaper than coal and gas in many regions. This means new gas capacity often displaces new wind and solar rather than old coal.
3. **The Wrong Gas at the Wrong Time:** Claims that gas supports renewable energy development are false. The cheapest gas generation technology, Combined Cycle Gas Turbines (CCGT), is designed for base load operation, not intermittent peaking. In any case, most grids are a long way from renewable energy penetration levels that would require back up. Storage and demand response will be ready to step in by the time they are really required.
4. **New Gas Locks in Emissions for 40+ Years:** Companies building multibillion-dollar gas infrastructure today expect to operate their assets for around 40 years. Emissions goals mean this expectation cannot be met.
5. **Too Much Gas Already:** The coal, oil, and gas in the world's currently producing and under construction projects, if fully extracted and burned, would take the world far beyond safe climate limits. Opening new gas fields is inconsistent with the Paris climate goals.

The fact that methane leakage cannot be reduced to zero, and therefore emissions from fossil gas are in fact higher than is often accounted for, only makes the phasing out of fossil gas more urgent. By enabling an increase in production and consumption of fossil gas, the Jordan Cove LNG terminal and Pacific Connector Gas pipeline will contribute significant amounts of greenhouse gas emissions that will exacerbate climate change.

Figure 1: We Need Less Gas, Not More: Global Emissions from Power Generation (2014 and projected 2040 in IEA New Policies Scenario) Compared to Median IPCC 2040 Power Emissions Consistent With a Likely 2°C Scenario



Source: Oil Change International analysis, see Endnote 4.

PROJECT EMISSIONS ESTIMATED AT 36.8 MILLION METRIC TONS ANNUALLY

The lifecycle greenhouse gas emissions of the project depend on the amount of gas exported through it, and the methane and carbon emissions associated with extracting, piping, processing, transporting, and burning that volume of gas.

The Jordan Cove LNG terminal is expected to export 7.8 million tons of LNG per year.[5] This would require around 85 percent of the 1.2 billion cf/d capacity of the Pacific Connector pipeline.[6] However, the Jordan Cove Energy Project has signed agreements to use 95.8 percent of the pipeline's capacity. This allows for an additional 10 percent of pipeline capacity for seasonal fluctuations and to carry gas to run equipment at the LNG terminal. The greenhouse gas emissions estimate is therefore based on delivering 1.15 billion cf/d to Jordan Cove.

In our reference case, which utilizes a mean methane leakage rate of 1.77 percent across the gas supply chain, we estimate the total lifecycle emissions caused by the project to be over 36.8 million metric tons (MMT) of carbon dioxide equivalent (CO_2e) per year. This is equivalent to over 15.4 times the 2016 emissions from Oregon's only remaining coal plant, the Boardman coal plant, or equivalent to the annual emissions from 7.9 million passenger vehicles. The Boardman plant is scheduled to close in 2020 because of climate and air pollution concerns.[7]

Based on a peer-reviewed study of methane leakage for gas production in three Rocky Mountain states,[8] a high-end estimate brings the overall leakage rate to just over 4 percent. This would raise the annual lifecycle emissions from the project to nearly 52 million metric tons. This would be nearly 22 times the emissions from the Boardman coal plant, or equivalent to the annual emissions from 11.1 million passenger vehicles.

For Oregon's emissions inventory, emissions savings from shutting down Boardman will be cancelled out by this project.

Annual emissions within Oregon would be over 2.2 MMT, which is slightly less than the 2016 emissions from the Boardman plant. For Oregon's emissions inventory, emissions savings from shutting down Boardman will be cancelled out by this project. In fact, in-state emissions could be higher if the project leads to additional gas being transported on the GTN pipeline from Canada. This would increase emissions at GTN compressor stations located in Oregon.

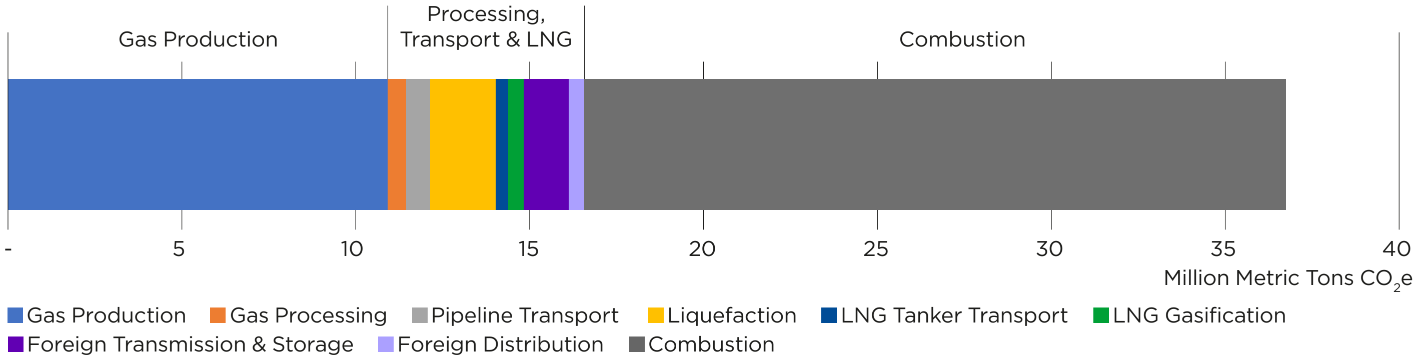
Outside of Oregon, emissions come from fracked gas production and processing, pipeline transport to the state line, tanker transport from Jordan Cove to destinations in Asia, transmission, distribution, and storage between the regasification facility

Table 1: Lifecycle GHG Emissions from Jordan Cove LNG and Pacific Connector Pipeline

Lifecycle Stage	Reference Case (MMT/Y)	High Case (MMT/Y)
Gas Production	10.9	26.0
Gas Processing	0.51	0.52
Pipeline Transport to Jordan Cove	0.78	0.78
Gas Liquefaction	1.8	1.8
Tanker Transport	0.44	0.44
LNG Gasification	0.40	0.40
Foreign Transmission & Storage	1.3	1.3
Foreign Distribution	0.43	0.43
Combustion	20.2	20.2
Total	36.8*	52.0*

*Figures may not add due to rounding.
Source: Oil Change International – See Appendix for details.

Figure 2: Full Lifecycle Emissions from Jordan Cove LNG and Pacific Connector Pipeline - Reference Case



Source: Oil Change International – See Appendix for details.

and points of final use, and finally the combustion of gas.

For methane leakage rates in the production zone, we reference a study published in *Environmental Science & Technology* in June 2017 by researchers from University of Wyoming and Colorado State University. That study quantified atmospheric methane emissions from active natural gas production sites in normal operation in four major U.S. basins/plays: Upper Green River (Wyoming), Denver-Julesburg (Colorado), Uintah (Utah), and Fayetteville (Arkansas).[9] The difference between our reference and high case estimates is primarily based on the difference between the middle and high measurements in the range of figures presented in this paper. However, we did make some downward adjustments to leakage rates in Colorado in both cases, in acknowledgment of new methane regulations in that state (see the Appendix for more details on leakage rates).[10]

For the pipeline and liquefaction emissions of the Jordan Cove and Pacific Connector project, we used emissions data from the latest project application.[11] Elsewhere in the supply chain, we used methane leakage rates based on EPA national averages where we did not have project-specific data. These figures likely underestimate leakage, leading to a conservative estimate of total emissions in our analysis.

We used a 20-year global warming potential factor of 86 to convert methane to carbon dioxide equivalent. For more details on methane assumptions and full details of sources and methods, please see the Appendix.

LNG EXPORTS WOULD HAVE NO EMISSIONS ADVANTAGE OVER COAL

As climate science indicates we must move as quickly as possible toward zero emissions, replacing coal with gas is clearly not a climate solution.[12] Nonetheless, the gas industry and its supporters continue to use this as a talking point, claiming that doing so would lead to a net reduction in emissions. However, even in the hypothetical scenario that every molecule of gas exported from Jordan Cove replaces coal in the destination market, the emissions associated with this project suggest that no net saving in greenhouse gas emissions would occur. In fact, the project could lead to higher net greenhouse gas emissions.

In 2014, the U.S. Department of Energy (DOE) released a "Life Cycle Greenhouse Gas Perspective on Exporting Liquefied Natural Gas from the United States."[13] The report, conducted by the National Energy Technology Laboratory (NETL), found that "compared to domestically produced and combusted gas, there is a significant increase in the lifecycle GHG emissions that are attributed to the LNG supply chain, specifically from liquefaction, tanker transport, and regasification processes."

Domestically, the current climate "break-even" point for lifecycle methane leakage is about 2.7 percent when switching from coal to gas for electricity over a 20-year lifecycle. That means that new gas combined cycle power plants reduce climate impacts compared to coal plants only when leakage remains under 2.7 percent.[14] Other estimates have put the domestic break-even point at 2.8 percent.[15]

When exporting LNG to Asia, the methane leakage rate must be significantly lower to have a "break-even" climate impact. The DOE/NETL report found that when comparing the climate impacts of LNG to coal-fired electricity in China, the lifecycle methane leakage rate would have to stay below 1.4 percent – when exporting LNG from New Orleans to Shanghai – to produce benefits over a 20-year timeframe.

NETL did not model lifecycle greenhouse gas emissions resulting from exporting LNG from the West Coast of the United States to Asian markets. Presumably, the climate break-even point would be slightly higher when exporting LNG from Oregon's Jordan Cove to Asia, given the closer geographic proximity. For comparison, the report found that the break-even point for LNG exports from New Orleans to Europe is 1.9 percent. Therefore, based on the DOE/NETL estimates, the climate break-even point for LNG exported from Jordan Cove to Asia is likely somewhere between 1.4 and 1.9 percent.

Our reference case estimate of methane leakage along the project's entire chain of supply is 1.77 percent. This is likely a conservative estimate as a number of factors could mean the real leakage rate is significantly higher (see Appendix). Even at this relatively low methane leakage rate, claims that greenhouse gas emissions are reduced by replacing coal in Asia with LNG exports from Jordan Cove are unsubstantiated, in part because the methane leakage associated with the project will likely be above the break event point.

FERC'S INADEQUATE CLIMATE ANALYSIS

The Federal Energy Regulatory Commission (FERC) is the primary federal agency that assesses the need for and impacts of interstate gas pipelines and LNG facilities, and it issues permits for construction and operation.[16]

FERC has yet to conduct an updated analysis of the Jordan Cove project, but we know FERC has repeatedly failed to fully assess and analyze the greenhouse gas emissions of the projects it permits. In August 2017, the Sierra Club together with landowners successfully overturned FERC's approval of the Southeast Market Pipelines Project, an interstate fossil gas pipeline project proposed through Alabama, Georgia, and Florida, based on inadequate information on greenhouse gas emissions in the project's environmental impact statement (EIS).[17] Although the project is already completed, the U.S. Court of Appeals vacated and remanded FERC's permits and ordered the agency to issue a supplemental EIS (SEIS) quantifying the project's downstream emissions.

FERC issued a draft of the SEIS in September 2017[18] and the Sierra Club filed detailed and scathing comments on the draft in November.[19] The Sierra Club comments not only call out the continuing inadequacy of FERC's climate emissions analysis, but also add clarity to the case for fully accounting for the entire emissions profile of fossil gas projects.

As in many of FERC's EIS documents, FERC preempts its discussion of greenhouse gas emissions and climate change in the draft SEIS with an assertion that the gas delivered by the project will replace dirtier fossil fuels, namely coal-fired power generation. The Sierra Club raises a number of points regarding this assumption that have salience for Jordan Cove LNG and similar proposed fossil gas infrastructure.

The Sierra Club argues that, to demonstrate that a project is instrumental to the retirement of other fossil fuel capacity, FERC must compare future scenarios with and without the project, rather than simply "juxtapos(ing) past conditions with a future in which the pipeline is built."[20]

A paper published in the international journal *Energy* in November 2017 discussed this issue in detail, specifically examining scenarios in which U.S. LNG is exported to Asia.[21] The paper found that the displacement of coal by LNG exports is far from a given, and that, as a result of U.S. exports of LNG, "emissions are not likely to decrease and may increase significantly due to greater global energy consumption, higher emissions in the US, and methane leakage."[22]

The Sierra Club comments also point out that accelerating projections of renewable energy adoption indicate that retiring coal capacity is not necessarily replaced with gas. Further, much of the coal generation capacity slated for retirement is old and inefficient. It is therefore typically operating far below capacity and likely to be retired whether a new gas pipeline is built or not. In this way, comparisons between retiring installed coal capacity and building new gas-fired capacity are misleading. For power plant emissions to be reduced by retiring coal and adding gas, new gas capacity would have to be run at similarly low utilization rates, which would likely not be economical. With no concrete analysis to back up its assumptions, FERC's attempt to discount gas pipeline emissions based on the offset of dirtier energy sources has no basis in fact.

The Jordan Cove Energy Project makes similar assertions regarding gas replacing coal, claiming that, "(n)atural gas is the cleanest-burning hydrocarbon available, and its transportation to other markets will allow consumers to move away from higher-emission fuels such as coal."[23] The company provides no evidence to support this.

Finally, as the "Climate and Fossil Gas" section explains, the premise that replacing coal with gas leads to positive climate outcomes is flawed. Emissions from fossil fuels need to be close to zero by mid-century to ensure a safe climate. Therefore, any new gas infrastructure built today will need to be replaced with zero emissions energy sources before it reaches the end of its economic life. With Jordan Cove currently scheduled to come online in 2024, investors would expect it to still be operating long after the transition to clean energy should be complete.

There is no evidence that the project would reduce emissions in line with the climate goals established by science - in fact, existing analyses point to the opposite. The 36.8 million tons of annual GHG emissions associated with the project must therefore be viewed as additional pollution that cannot be squared with any greenhouse gas reduction strategy.

There is no evidence that the project would reduce emissions in line with the climate goals established by science - in fact, existing analyses point to the opposite.

OREGON'S CLIMATE GOALS

In 2007, the Oregon legislature adopted goals to reduce climate pollution to 10 percent below 1990 levels in 2020 and at least 75 percent below 1990 levels by 2050.[24] According to these goals, Oregon's greenhouse gas emissions should be below 14.1 MMT in 2050. The state legislature is currently considering the "Clean Energy Jobs Bill," which creates a mechanism to reduce climate pollution in line with state goals.

These goals may fall below the targets set in the UNFCCC's Paris Agreement, which Governor Kate Brown committed to after President Donald Trump withdrew in 2017. The Paris Agreement commits to keeping global temperature rise "well below" 2 degrees Celsius (C) compared to pre-industrial levels and aims for a maximum temperature rise of 1.5°C. The latter goal requires global greenhouse gas emissions to fall to zero by around 2050, while the former (2°C) goal requires emissions to reach zero by about 2065.[25] According to the Oregon Global Warming Commission 2017 Report, Oregon is currently not on track to reach statutorily mandated emission reduction goals in 2020 or 2050.[26]

The total in-state annual emissions of the Jordan Cove Project, which only includes emissions from the LNG terminal, compressor stations, and leakage along the pipeline route, would be over 2.2 MMT, while the total lifecycle emissions of this project are over 36.8 MMT. The LNG terminal alone would emit over 1.8 MMT of greenhouse gas pollution a year, becoming the largest single source of climate pollution in the state of Oregon after 2020. If Oregon reaches its 2050 climate reduction goals, the in-state emissions of Jordan Cove will be equal to 16 percent of Oregon's total emissions, while the lifecycle greenhouse gas emissions will be over 261 percent.

The project's in-state emissions will constitute an increasingly large proportion of remaining allowable emissions, while providing no actual energy supply for the state.

In 2016, the Oregon legislature passed SB-1547, which requires investor-owned utilities to eliminate coal-fired power from Oregon by 2035 because of pollution and climate concerns. Only considering in-state emissions, the Jordan Cove LNG Export Terminal and the Pacific Connector Pipeline would be roughly equivalent to the Boardman coal plant, which is set to close in 2020 in order to meet emissions goals. Considering the total life cycle emissions, this project would be equivalent to over 15.4 Boardman coal plants.

If the state of Oregon's climate policies progress toward alignment with the goals of the Paris Agreement, as Governor Brown has stated she intends,[27] then the project's in-state emissions will constitute an increasingly large proportion of remaining allowable emissions, while providing no actual energy supply for the state. By mid-century, the project will have to be shut down – decades before investors expect the project's economic life to end. Finally, Oregon's commitment to climate leadership would be undermined by hosting a facility that supports unsustainable global emissions and undermines climate action in other regions.

Table 2: GHG Emissions of the Jordan Cove Energy Project as a Percentage of Oregon's GHG Emissions

		Jordan Cove Energy Project		
		LNG Terminal Emissions	Total Project In-State Emissions	Total Project Lifecycle Emissions
	MMT CO_2e per year	1.8	2.2	36.8
Oregon 2015 Emissions	63.4	2.9%	3.5%	58%
Oregon 2050 Goals (75% below 1990)	14.1	13%	16%	261%
Under 2 MOU[b] (2 MT per capita by 2050[c])	11.2	16%	20%	329%

Source: Oil Change International

b The Under 2 MOU, signed by Oregon Gov. Kate Brown in 2015, is a commitment by sub-national governments to reduce GHG emissions towards net-zero by 2050. Central to this is the public commitment by all signatories to reduce GHG emissions by 80-95% below 1990 levels, or to 2 metric tons of carbon dioxide-equivalent per capita, by 2050.
c Based on 5,588,500 Oregon estimated population in 2050. http://www.oregon.gov/das/OEA/Pages/forecastdemographic.aspx

CONCLUSIONS

This briefing provides a calculation and discussion of the greenhouse gas emissions of the Pacific Connector Gas Pipeline and Jordan Cove LNG Export Terminal proposed in the state of Oregon. It clearly shows that the project would add significantly to greenhouse gas emissions both in the state of Oregon and globally.

The analysis shows that methane leakage along the project's supply chain undermines any claim that the project would supply destination markets with cleaner fuel. In addition, the remaining global carbon budget has no room to replace coal with gas, even if methane leakage were zero. In fact, the expansion of fossil gas undermines renewable energy development.

The project would increase the flow of fossil gas to the global market and in doing so would run counter to the goals of the Paris Agreement on climate change. The project would undermine Oregon's potential to play a leadership role in addressing global climate change.

APPENDIX: METHODS AND SOURCES FOR ESTIMATING JORDAN COVE LNG GREENHOUSE GAS EMISSIONS

GENERAL OVERVIEW OF LIFECYCLE EMISSIONS

Lifecycle greenhouse gas emissions include a combination of combustion emissions from burning fossil gas, emissions from producing, processing, and transporting the gas, and methane leakage – the intentional or unintentional leakage of fossil gas into the atmosphere along the full supply chain. In the case of liquefied natural gas export, additional combustion and leakage emissions from liquefaction, tanker transport, regasification, and transport from the import terminal to the ultimate point of consumption must also be included.

Developing any estimate of potential lifecycle greenhouse gas emissions from a proposed project requires using a variety of sources and assumptions. An emissions factor of 117.1 pounds of CO_2 per thousand cubic feet for the combustion of fossil gas is well established and this comprises the largest proportion of total emissions.[28]

Estimates of emissions occurring upstream of the proposed project include the production and processing of fossil gas and are based on available peer-reviewed and government data. For the Pacific Connector pipeline and Jordan Cove terminal, emissions estimates for equipment to be installed, such as compressors and engines, or electricity to be consumed, are supplied in the project applications and environmental impact statement. Emissions occurring downstream or after the defined project's parameters must be determined using other available sources.

The production, processing, and transport of fossil gas requires energy. For example, diesel, gasoline, fossil gas, or electricity are consumed to run drilling rigs, trucks for materials transport, compressors for pipeline pressure, and many other processes that require engines, turbines, and other equipment. Much of the emissions estimates for these stages are derived from expectations of the fuel such equipment is expected to consume based on projected utilization rates and operating times.

In addition to these fuel-based emissions, the production and handling of fossil gas leads to significant quantities of the gas being emitted to the atmosphere uncombusted. Some of this is emitted as part of standard processes such as the blow down of pipelines during maintenance. These intentional emissions of fossil gas are considered 'venting.' Some gas escapes from valves and seals as a result of equipment wear and tear or malfunction and these emissions are considered 'fugitive.'

Fossil gas is primarily made up of methane (CH_4), a hydrocarbon that, pound for pound, is a more powerful heat-trapping gas than carbon dioxide (CO_2), the primary GHG that is causing global temperatures to rise and the climate to change. Because the measurement and analysis of GHGs is based on much more abundant CO_2, the impact of methane on the atmosphere is expressed as a carbon dioxide equivalent (CO_2e) according to its global warming potential (GWP).

CALIBRATING CH_4 WITH CO_2

The study of methane's impact on warming has evolved in the past decade and estimates of the GWP of methane have increased as more has been learned. Methane lasts about 12 years in the atmosphere while CO_2 lasts for centuries. To calibrate methane's impact with that of CO_2, two time horizons have been used: 20 years and 100 years.

We use the 20-year GWP timeframe and 86 GWP for methane from the Intergovernmental Panel on Climate Change's (IPCC) most current *Assessment Report 5* (AR5), because whereas CO_2 accumulates in the atmosphere over the long term, the impact of methane is felt in the short term. Its most important contribution to total warming occurs at the time of peak atmospheric CO_2 concentrations (i.e. net zero CO_2 emissions) – that is, when CO_2 has its greatest warming effect, and methane potentially adds to that maximum amount of warming. According to analyses of IPCC scenarios, net CO_2 emissions need to reach zero around 2050 to have a 50 percent chance of limiting warming to 1.5 degrees Celsius, and around 2065 to have a likely chance of staying below 2 degrees Celsius of warming.[29]

With those scenarios in mind, if the Jordan Cove plant operates from 2024 to 2064, the average molecule of methane will be emitted in 2044 – respectively six years or twenty-six years before peak CO_2 concentrations. As those molecules will have their greatest impact in the period immediately prior to or beyond the point at which CO_2 concentrations should peak, the shorter range GWP is the more relevant measure for the project's methane emissions.[30]

The 100-year GWP is most commonly used by government and industry. It calibrates the GWP of methane at 34 times that of CO_2. However, according to the IPCC: "There is no scientific argument for selecting 100 years compared with other choices. The choice of time horizon is a value judgement because it depends on the relative weight assigned to effects at different times."[31]

The U.S. Environmental Protection Agency (EPA) generally uses the 100-year metric.[32] We strongly urge the EPA and all federal government agencies assessing the impact of fossil gas systems to use the 20-year GWP to properly measure the impact of methane leaked to the atmosphere. This is particularly important at a time when the production of gas is growing so fast, driving increased gas consumption.

STAGES AND SOURCES FOR THE JORDAN COVE GHG ESTIMATE

The estimate of lifecycle emissions begins with fossil gas production and runs the entire journey of the gas through to combustion. In the case of the Jordan Cove LNG terminal, gas would be primarily produced from shale plays in either the Canadian or U.S. Rockies and be transported by pipeline to Malin on the southern Oregon border where the Pacific Connector pipeline would begin.

Project application documents were used for the emissions estimates for the Pacific Connector pipeline and the Jordan Cove LNG plant. The only change we made to these estimates was to convert CH_4 to CO_2e using the 20-year GWP discussed in the previous section.

Methane leakage estimates at the production stage were based on the latest available peer-reviewed science for gas produced in the Rocky Mountain states of Colorado, Utah, and Wyoming.[33] While gas for the project may also be sourced from Canada, data for Canadian production were not available.

The stages, rounded figures, emissions assessed, and data sources for the full lifecycle GHG emissions of the Jordan Cove Energy Project are summarized in Table A1. Calculations are based on producing 7.8 million tons of LNG per year (374.4 Bcf/y), the maximum the project can produce. Fossil gas reaching the project was set to 431.4 Bcf/y, or 95.8% of the maximum 1.2 Bcf/d capacity of the Pacific Connector pipeline, which is how much capacity the company has reserved. The initial volume of gas needed from the wellhead to supply that volume of gas to the project is 437.7 Bcf/y (after factoring in methane leakage). All GHG emissions are shown in million metric tons per year (MMT/Y).

The leakage rates from Table A3 and Table A4 were applied to the Production, Gas Processing, Foreign Transmission and Storage, and Foreign Distribution stages, and resulting emissions are shown as 'Reference Case' and 'High Case' emissions per lifecycle stage in Table A1. Data for combustion and leakage emissions for the Pacific Connector Pipeline and Jordan Cove liquefaction facility were taken from the respective FERC applications. Emissions from the Ruby Pipeline, which would feed gas to the Pacific Connector, were based on 77 percent (1.15 Bcf/d) of the total estimated emissions (0.523 MMT/Y) described in the project's FERC order.[34]

METHANE LEAKAGE RATE ESTIMATE

The gas arriving for liquefaction at Jordan Cove would be delivered by the proposed Pacific Connector Pipeline, which would connect to the Ruby and Gas Transmission Northwest Pipelines. While it is not known at this point exactly where that gas would come from, for purposes of estimating methane leakage, this analysis assumes that 100 percent of the gas will be sourced from the Rocky Mountains region – specifically from Colorado, Wyoming, and Utah, the three most productive Rocky Mountain states for natural gas.[35] This choice was made because, while gas could also come from the Montney Basin in British Columbia, there is a lack of peer-reviewed data sources about fugitive methane emissions from natural gas production in British Columbia.

Table A1: Lifecycle Stages, Emissions, and Sources for the Pacific Connector Pipeline and Jordan Cove Energy Project

Lifecycle Stage	Reference Case (MMT/Y)	High Case (MMT/Y)	Emissions Assessed	Sources
Gas Production	10.9	26.0	Methane emissions resulting from normal operations, routine maintenance, and system upset – mainly from gathering stations, pneumatic controllers, liquids unloading, and offshore platforms; and CO_2 emissions from fuel combustion.	Methane Leakage: Robertson, et al. in *Environmental Science & Technology*, June 2017. http://pubs.acs.org/doi/abs/10.1021/acs.est.7b00571 CO_2: International Institute for Sustainability Analysis and Strategy. http://iinas.org/tl_files/iinas/downloads/GEMIS/2014_Fracking_analysis_comparison.pdf
Gas Processing (dry-wet gas separation)	0.51	0.52	Methane emissions resulting from normal operations, routine maintenance, and system upsets – mainly fugitive emissions from compressors and seals.	Based on national EPA data in "Inventory of U.S. Greenhouse Gas Emissions and Sinks": https://www.epa.gov/sites/production/files/2017-02/documents/2017_complete_report.pdf
Transmission to Jordan Cove	0.78	0.78	CO_2, CH_4, and N_2O emissions from compressor station, pipeline, and meter stations associated with Pacific Connector and Ruby pipelines. Includes fugitive emissions, venting, and combustion-related emissions.	Emissions for PCGP based on project application. http://pacificconnectorgp.com/wp-content/uploads/2017/09/1.1-PCGP-Application-and-Exhibit.pdf For Ruby pipeline, estimate based on FERC certificate order. https://www.ferc.gov/CalendarFiles/20100405150436-CP09-54-000.pdf
LNG Liquefaction	1.8	1.8	CO_2, CH_4, and N_2O emissions from liquefaction operations, fugitive emissions, and on-site vessel fuel combustion.	Figures from Jordan Cove application. http://pacificconnectorgp.com/wp-content/uploads/2017/09/1.1-PCGP-Application-and-Exhibit.pdf
Tanker Transport	0.44	0.44	CO_2 emissions from fuel combustion.	Based on distance to Tokyo and Shanghai, and Jaramillo et al. http://www.ce.cmu.edu/~gdrg/readings/2005/10/12/Jaramillo_LifeCycleCarbonEmissionsFromLNG.pdf
LNG Gasification	0.40	0.40	CO_2 emissions from fuel combustion.	Based on: Jaramillo et al http://www.ce.cmu.edu/~gdrg/readings/2005/10/12/Jaramillo_LifeCycleCarbonEmissionsFromLNG.pdf
Foreign Transmission & Storage	1.3	1.3	Methane emissions resulting from normal operations, routine maintenance, and system upsets – fugitive emissions from compressor stations and venting from pneumatic controllers account for most of the emissions from this stage.	Based on EPA estimates in U.S. "Inventory of U.S. Greenhouse Gas Emissions and Sinks": https://www.epa.gov/sites/production/files/2017-02/documents/2017_complete_report.pdf
Foreign Distribution	0.43	0.43	Methane emissions resulting from normal operations, routine maintenance, and system upsets – mainly from fugitive emissions from pipelines and stations.	Based on EPA estimates in U.S. "Inventory of U.S. Greenhouse Gas Emissions and Sinks": https://www.epa.gov/sites/production/files/2017-02/documents/2017_complete_report.pdf
Combustion	20.2	20.2	CO_2 emissions from fuel combustion.	EPA Fuel Emissions Factors Assumptions https://www.epa.gov/sites/production/files/2015-08/documents/chapter_11_other_fuels_and_fuel_emission_factors.pdf
Total	36.8*	52.0*		

*Figures may not add due to rounding

Table A2: EPA Methane Leakage Rate Estimates from 2017 U.S. GHG Inventory

Lifecycle Stage	Leakage Rate
Field Production leakage	0.79%
Processing leakage	0.08%
Transmission and Storage leakage	0.25%
Distribution leakage	0.08%
Total leakage	1.20%

Source: Oil Change International

Table A3: Reference Methane Leakage Rate for Jordan Cove GHG Lifecycle Analysis

Lifecycle Stage	Leakage Rate
Field Production leakage	1.36%
Processing leakage	0.08%
Transmission and Storage leakage	0.25%
Distribution leakage	0.08%
Total leakage	1.77%

Source: Oil Change International

Table A4: High-End Methane Leakage Rate for Jordan Cove GHG Lifecycle Analysis

Lifecycle Stage	Leakage Rate
Field Production leakage	3.66%
Processing leakage	0.08%
Transmission and Storage leakage	0.25%
Distribution leakage	0.08%
Total leakage	4.08%

Source: Oil Change International

For stages of the process for which we did not have access to project-specific estimates for leakage – Processing, Foreign Transportation and Storage, and Foreign Distribution (see Table A1) – we used national level data from the U.S. EPA. Data from the EPA's latest GHG inventory would indicate that the U.S. national methane leakage rate is 1.2%.[36] That figure is a blended composite of all fossil gas production nationally, and does not account for regional variation. Table A2 shows the breakdown of EPA's methane emission estimates from all stages of the domestic fossil gas lifecycle.

For U.S. Rocky Mountain-specific methane leakage figures, this analysis looked to a recent peer-reviewed study published in *Environmental Science & Technology* in June 2017. The study was conducted by researchers from University of Wyoming and Colorado State University and quantified atmospheric methane emissions from active gas production sites in normal operation in four major U.S. basins/plays: Upper Green River (Wyoming), Denver-Julesburg (Colorado), Uintah (Utah), and Fayetteville (Arkansas) (Robertson et al. 2017).[37]

The emissions were measured within the basins on randomly chosen days in 2014 and 2015 from the University of Wyoming Mobile Laboratory utilizing the EPA's Other Test Method (OTM) 33a. The median methane leakage rates measured from the three Rocky Mountain basins during the field production stage were 0.18 percent (0.12–0.29%) in Wyoming, 2.1 percent (1.1–3.9%) in Colorado, and 2.8 percent (1.0–8.6%) in Utah.

The mean average of those field production leakage rates is 1.69 percent, with a high-end average of 4.26 percent, but it was determined for this study to make an adaptation. Since 2014, Colorado has implemented rules to reduce oil and gas methane emissions through air pollution control practices and technologies, including leak detection and repair (LDAR) requirements.[38] Therefore, the low-end of the range measured by the study in Colorado may be a fairer assessment of expected methane emissions for fossil gas production in the Denver-Julesburg basin than the median rate used for the other two states. Using the low end of the methane leakage range for Colorado, the average field production leakage rate in the Rocky Mountain states, as reported in Robertson et al., would be 1.36 percent, with a high-end average of 3.66 percent. The high end for Colorado was assumed to be the median leakage rate in the study (2.1 percent).

Based on national EPA data, but regionalized to account for field production methane emissions measured in the Rocky Mountains, the reference methane leakage rate for gas exported from Jordan Cove is 1.77 percent. The high-end methane leakage rate for gas exported from Jordan Cove is 4.08 percent.

CONSERVATIVE ASSUMPTIONS BAKED INTO LEAKAGE ESTIMATE

The leakage rate estimates presented in the preceding section are conservative in at least two ways. First, several studies have found that EPA emissions factors for leakage from existing fossil gas systems are too low. For example, a July 2015 study published in *Environmental Science & Technology* by researchers from University of Arkansas – Fayetteville, University of Houston, Purdue University, Aerodyne Research, Inc., Colorado State University, Carnegie Mellon University, and Environmental Defense Fund found that anthropogenic methane emissions from the oil and gas industry were 50 percent higher than estimates derived from the EPA inventory.[39]

More recent studies have measured leakage rates of between 4.2 and 8.4 percent in the Bakken shale region.[40] If domestic fossil gas processing and transmission emissions are higher than EPA estimates, the lifecycle leakage rate for Jordan Cove's LNG would be higher than this paper presents.

Second, this analysis used EPA's relatively low domestic leakage rate estimates for the transmission and storage and distribution stages, rather than rates in Asia, where those two stages of the fossil gas lifecycle would take place in the case of the Jordan Cove project. If the pipelines in Asian countries importing Jordan Cove's gas leak at higher rates than the EPA estimates for U.S. pipelines, the actual lifecycle leakage rate for Jordan Cove's LNG would be higher than our estimate.

Tanker emissions estimates were based on a paper from the Civil and Environmental Engineering Faculty at Carnegie Mellon University and amended based on the shipping distance between Jordan Cove and Shanghai and Tokyo. We assumed a 50/50 split of shipments between these two ports.

ENDNOTES

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The full calculations can be found in the spreadsheet available at http://bit.ly/JCLNG-GHGs.

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Exhibit 52

INTERNATIONAL GAS UNION
UNION INTERNATIONALE DU GAZ

2018 World LNG Report

27th World Gas Conference Edition

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Photo courtesy of Chevron

2. State of the LNG Industry[1]

293.1 MT
Global trade in 2017

Global Trade: For the third consecutive year, global LNG trade set a record, reaching 293.1 million tonnes (MT). This marks an increase of 35.2 MT (+12%) from 2016; the second largest ever, only behind the 40 MT increase of 2010. The increase in trade was supported by a corresponding increase in LNG supply, driven by Australian and US projects. With additional trains at Australia Pacific LNG, Gorgon LNG, and higher production from existing trains, Australia added 11.9 MT of production in 2017. United States production gains of 10.2 MT were driven entirely by Sabine Pass LNG, which added two new trains in 2017. Asia continued to be the driver of global demand, with China growing by 12.7 MT – the largest annual growth by a single country ever. This was driven by the strong environmental policy designed to promote coal-to-gas switching. The other key countries driving global LNG growth include South Korea, Pakistan, Spain, and Turkey for a combined 11.9 MT. The Pacific Basin continues to be the key driver of trade growth, with intra-Pacific trade flows reaching a record 125 MT, shaped by Australian production and Chinese demand.

88 MT
Non long-term trade, 2017

Short and Medium Term LNG Market (as defined in Chapter 8): Non long-term LNG trade reached 88.3 MT in 2017, an increase of 16 MT year-on-year (YOY) and accounted for 30% of total gross LNG trade. The substantial increase in short-term trade in 2017 can be attributed to growing LNG supply and demand elasticity.

New short-term supply largely came from ramp-ups in the Atlantic Basin, where new liquefaction capacity added during the year was contracted mostly to short-term traders and aggregators. Nearly 70% of exports from Sabine Pass LNG were traded on the non long-term market in 2017, and 100% of exports from the newly-restarted Angola LNG were sold under either spot or short-term contracts. Although China continues to receive volumes under new long-term contracts, the scale of its growth in 2017 meant that the country also had a substantial increase in short-term imports as well; the market's non long-term growth of 4.7 MT in 2017 was the largest of any importer.

\$6.85/MMBtu
Average Northeast Asian spot price, 2017

Global Prices: Average Asian LNG prices (both spot and contracted) increased by \$1.33 per million British thermal units (MMBtu) over 2016 owing to rising oil prices and stronger Pacific Basin demand, but most price markers experienced significant variation during the year. As new supply came online and slightly overwhelmed demand, LNG prices fell across the globe into the summer season, only to rise steadily in the second half of the year. After falling to \$5.28/MMBtu in August 2017, landed Northeast Asian spot prices reached an average \$9.88/MMBtu by January 2018 owing to the effects of a cold winter and strong demand from Chinese environmental regulation. The United Kingdom National Balancing Point (NBP) also experienced significant variation during the year, climbing from a low of \$4.46/MMBtu in June to a high of \$7.76/MMBtu in December. As prices rose globally, differentials between basins were similar to their level in 2016, with Asian spot prices spending a few notable months in the middle of the year at a discount to NBP again. However, by January 2018, Asian spot prices had climbed back to a \$2.91/MMBtu premium to NBP.

[1] The scope of this report is limited only to international LNG trade, excluding small-scale projects, unless explicitly stated. Small-scale projects are defined as anything less than 0.5 MTPA for liquefaction, 1.0 MTPA for regasification, and 60,000 cm for LNG vessels. Domestic trade between terminals is also not included.

369 MTPA
Global nominal liquefaction capacity, March 2018

Liquefaction Plants: Global liquefaction capacity remains in the extended phase of build-out that began in 2016, driven largely by capacity in Australia and the United States. Between January 2017 and March 2018, 32.2 MTPA of liquefaction capacity was added. In engineering progress, the first floating liquefaction (FLNG) project came online in Malaysia, with additional FLNG projects set to come online during 2018 and beyond. Although no new liquefaction capacity had been added in Russia since Sakhalin 2 LNG T2 in 2010, the first train of Yamal LNG achieved commercial operations in March 2018 and is expected to ultimately add 17.4 MTPA of liquefaction capacity. Looking forward, Australia and the United States will continue to represent the majority of liquefaction capacity additions in the short term; including Wheatstone LNG, Prelude FLNG, and Ichthys LNG in the former; and Cove Point LNG, Freeport LNG, and Elba Island LNG in the latter. As of March 2018, 92.0 MTPA of liquefaction capacity was under construction. Only one project reached a final investment decision (FID) during 2017, Coral South FLNG (3.4 MTPA) – the first project to be sanctioned in Mozambique. While progress was made on other proposals, FID activity globally remains low in comparison to previous years.

875 MTPA
Proposed liquefaction capacity, March 2018

New Liquefaction Proposals: Although reaching FID has become a challenging prospect over the past few years, continued resource discovery and strong reserves have underpinned a growing list of proposed projects. As of March 2018, the total liquefaction capacity of proposed projects reached 875.5 MTPA, with the majority in the United States and Canada. Despite the large amount of proposed capacity in those two countries, the announcement in early 2017 by Qatar that it would lift the moratorium on production of its North Field to underpin new liquefaction trains, provides further potential supply. With many under-construction projects expected to contribute to strong global supply over the next few years, many developers have moved on to the early-2020s as the next available window in which to bring a new liquefaction project online.

851 MTPA
Global nominal regasification capacity, March 2018

Regasification Terminals: Global regasification capacity has continued to increase, rising to 851 MTPA by March 2018, out-pacing increases in liquefaction capacity. A total of 45 MTPA of regasification capacity was added during 2017, most of it during January 2017, as terminals that had been completed during 2016 began commercial operations. The key additions made during the second half of 2017 were all in Asia, including Pakistan, Thailand, and Malaysia. No new markets added large-scale regasification capacity during the year, for the first time in ten years[2]. Along with the rapid increase in liquefaction capacity expected through the end of the decade, additional regasification capacity is expected to be constructed. Additions will be in both mature markets which are experiencing increased gas demand, as well as in new markets where governments have made developing gas demand a priority. There remains an additional 87.7 MTPA of regasification capacity under construction as of March 2018. This includes capacity across several new markets, such as Bahrain, Bangladesh, Panama, the Philippines, and Russia. Of under-construction capacity, 37.7 MTPA of capacity is anticipated online during 2018, much of it in China.

84 MTPA[3]
FSRU capacity, March 2018

Floating Regasification: Three FSRU projects came online during 2017, boosting total regasification capacity of floating projects to 84 MTPA. A terminal at Pakistan's Port Qasim added 5.7 MTPA, and Turkey's first floating project, the Etki terminal, began operations in January 2017. As of March 2018, seven FSRUs were under construction. Many of these projects are in new markets, including Bahrain, Bangladesh, and Panama, showing the continued use of floating technologies to access new sources of demand. Other projects, such as those in India and Turkey, highlight the use of FSRUs in quickly addressing growing demand. As of January 2018, nine FSRUs were on the order book of shipbuilding yards. Furthermore, several FSRUs were open for charter, with some being used as conventional LNG carriers, indicating no immediate shortage of vessels for floating terminals.

478 Vessels
LNG fleet, end-2017

Shipping Fleet: The global LNG shipping fleet consisted of 478 vessels at the end of 2017, including conventional vessels and ships acting as FSRUs and floating storage units. In 2017, a total of 27 newbuilds (including three FSRUs) were delivered from shipyards. Relative to the previous year, this was a much more balanced addition relative to liquefaction capacity, but the accumulation of the tonnage buildout from the previous years kept short-term charter rates low for most of 2017. However, toward the end of the year, an increase in Asian spot purchases led short-term charter rates to rise; by December 2017, rates for dual-fuel diesel electric/tri-fuel diesel electric (DFDE/TFDE) tankers reached an average $81,700/day.

9.8% of Supply
Share of LNG in global gas supply in 2016[4]

LNG in the Global Gas Market: Natural gas accounts for just under a quarter of global energy demand, of which 9.8% is supplied as LNG. Although LNG supply previously grew faster than any other natural gas supply source – averaging 6.0% per annum from 2000 to 2016 – its market share growth has stalled since 2010 as indigenous production and pipeline supply have competed well for growing global gas markets. Despite the lack of market share growth in recent years, the large additions of LNG supply through 2020 mean LNG is poised to resume expansion.

[2] While Malta began LNG imports in 2017, its regasification terminal is small-scale at 0.4 MTPA of capacity, and thus is not included in regasification capacity totals, but is included in the trade balance.
[3] This 84 MTPA is included in the global regasification capacity total of 851 MTPA quoted above.
[4] Data for pipeline trade and indigenous gas production comes from the BP Statistical Review. Data for 2017 is not yet available.

Exhibit 53

Current Applications

Coos County

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Applications Available for Comment:

Applicant (Click name for details & Full Application)	Application Number	Status	Waterbody	Location	Activity Type (Click for descriptions)	Comments
Coquille Watershed Association	APP0061819	Technical Review	Coquille R	28S13W18	R/F (Culv,RemFill,Tidegate)	View | Add
Coquille Watershed Association	APP0061820	Technical Review	Baker Cr	31S12W03	R/F (FishHabit,RemFill)	View | Add
Robinson Concrete Pumping	APP0061288	Technical Review	Tenmile Lk	23S12W20CD	R/F (Dock,OverWater,Piling)	View | Add

Applications Not Yet Available for Comment:

Applicant (Click name for details & Full Application)	Application Number	Status	Waterbody	Location	Activity Type (Click for descriptions)
AT&T Corp.	APP0061818	Application Review	Pacific O	27S14W08	R/F (Cbl,Removal)
Southport Forest Products LLC	APP0061629	Application Review	Coos Bay	25S13W07DD	R/F (Piling,RemFill)
Sugarman Stan	APP0060181	App. - Awaiting App/Notif Revision	Fishtrap Cr	28S13W33	R/F (ErosionCon,Fill,Road)
Tenmile Lakes Basin Partnership	APP0061806	App. - Awaiting App/Notif Revision	Shutter Cr	23S12W29BC	GP ()

Applications No Longer Available for Comment:

Applicant (Click name for details & Full Application)	Application Number	Status	Waterbody	Location	Activity Type (Click for descriptions)	Comm
Coos Bay City of	APP0061778	Technical Review	Coal Bank Sl	25S13W34DD	R/F (ErosionCon,Pipeline,RemFill,Util)	Vie
Jordan Cove Energy Project LP	APP0060697	App. - Extension	Wetland/Coos R/Rogue R/Klamath R	25S13W04	R/F (Pipeline,RemFill)	Vie
Lyon Construction LLC	APP0061291	App. - Extension	Tenmile Lk	23S12W21CB	R/F (Dock,OverWater,Piling,RemFill)	Vie

Recent GA Notifications:

Applicant (Click name for details & Full Application)	Application Number	Status	Waterbody	Location	Activity Type (Click for descriptions)

Recent NSP (Voluntary Restoration) Notifications:

Applicant (Click name for details & Full Application)	Application Number	Status	Waterbody	Location	Activity Type (Click for descriptions)

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Current Applications

Coos County

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Applications Available for Comment:

Applicant (Click name for details & Full Application)	Application Number	Status	Waterbody	Location	Activity Type (Click for descriptions)	Comments
Jordan Cove Energy Project LP	APP0060697	Technical Review	Wetland/Coos R/Rogue R/Klamath R	25S13W04	R/F (Pipeline,RemFill)	View | Add

Applications Not Yet Available for Comment:

Applicant (Click name for details & Full Application)	Application Number	Status	Waterbody	Location	Activity Type (Click for descriptions)
Ballard Shellfish Co.	APP0061387	App. - Awaiting App/Notif Revision	Coos Bay	25S13W08	R/F (Fill,FloatStruc,Other ,OverWater)
Robinson Concrete Pumping	APP0061288	App. - Awaiting App/Notif Revision	Tenmile Lk	23S12W20CD	R/F (Dock,OverWater,Piling)
Southport Forest Products LLC	APP0061629	App. - Awaiting App/Notif Revision	Coos Bay	25S13W07	R/F (Piling,RemFill)
Sugarman Stan	APP0060181	App. - Awaiting App/Notif Revision	Fishtrap Cr	28S13W33	R/F (ErosionCon,Fill,Road)

Applications No Longer Available for Comment:

Applicant (Click name for details & Full Application)	Application Number	Status	Waterbody	Location	Activity Type (Click for descriptions)	Comments
Bandon Port of	APP0061566	Technical Review	Coquille R	28S14W30	R/F (Fill,OverWater)	View
Georgia Pacific West LLC	APP0061457	App. - Extension	Isthmus Sl	25S13W35	R/F (Piling,RemFill)	View
Lyon Construction LLC	APP0061291	Technical Review	Tenmile Lk	23S12W21CB	R/F (Dock,OverWater,Piling)	View
North Bend City of	APP0061371	Technical Review	Wetland/Coos Bay	25S13W15AA	R/F (BoatRamp,Dock,Piling,PublicUse,RemFill)	View

Recent GA Notifications:

Applicant (Click name for details & Full Application)	Application Number	Status	Waterbody	Location	Activity Type (Click for descriptions)
Lyon Construction LLC	APP0061725	Application Review	Tenmile Lk	23S12W09BA	GA (OverWater)
Lyon Construction LLC	APP0061746	Application Review	Tenmile Lk	23S12W10BB	GA (OverWater)

Recent NSP (Voluntary Restoration) Notifications:

Applicant (Click name for details & Full Application)	Application Number	Status	Waterbody	Location	Activity Type (Click for descriptions)

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Exhibit 54

CP13-483

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue, Suite 900
Seattle, WA 98101-3140

OFFICE OF ECOSYSTEMS, TRIBAL AND PUBLIC AFFAIRS

ORIGINAL

August 18, 2015

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, DC 20426

Dear Ms Bose:

The U.S. Environmental Protection Agency (EPA) is providing comments about the Jordan Cove Liquefaction and Pacific Connector Pipeline Project (EPA Project Number 12-0042-FRC), which specifically pertain to the management of dredged material excavated during maintenance of the proposed facility (FERC Docket: CP13-483-000).

The purpose of this letter is to provide detail and clarity on expectations for analysis and management of Coos Bay Dredged Material Disposal Sites. These comments support and expand EPA's previous comments as they have pertained to EPA's responsibilities under Section 102 and Section 103 of the Marine Protection, Research, and Sanctuaries Act (MPRSA). The EPA provided comments to the Federal Energy Regulatory Commission (FERC) and the U.S. Army Corps of Engineers (USACE) on this topic on October 29, 2012 (National Environmental Protection Act scoping letter), January 12, 2015 (USACE Public Notice), and February 11, 2015 (Draft Environmental Impact Statement).

Jordan Cove's Dredged Material Management Plan (May 2013) provides a cursory analysis of volume, grain size, and disposal options for the maintenance dredged material. Although the Dredged Material Management Plan discusses these three variables, there will continue to be uncertainty about whether material would be suited for Coos Bay Ocean Dredged Material Disposal Site F (Site F), Coos Bay Ocean Dredged Material Disposal Site H (Site H), or both. Also, there will be uncertainty about the volume of dredged material that would need to be disposed during each maintenance event, and when the first maintenance dredging event would occur. Given these uncertainties, EPA has not been provided sufficient information to state that Site H and/or Site F is a suitable disposal site for the duration of the FERC license. The analysis and assumptions provided in the Dredged Material Management Plan are potentially sufficient for the first maintenance dredging event as long as the assumptions, i.e., grain size and volumes, do not change.

When considering the disposal options for dredged material beyond the first maintenance event, the project proponent should understand that Site F and Site H do not have unlimited capacity. Capacity of these two sites depends upon several factors, all of which change through time (most notably, the volume of material dumped at the sites and winter storm events which move the material offsite). Thus, it is imperative that the project proponent conduct a thorough analysis of the ability of these two disposal sites to accept the volumes of maintenance dredged material, the consequences of disposal on the physical conditions of the site(s), and the consequences for those entities that currently use the sites for disposal of dredged material. The primary user of Site F and Site H is the USACE for their maintenance of the Federal Navigation channels in Coos Bay. The Oregon International Port of Coos Bay also has requested and received a permit from USACE, with EPA concurrence, to dispose of dredged material at both Site F and H, as appropriate.

Prior to formally initiating a request for a MPRSA Section 103 permit from the USACE, the project proponent must complete site capacity assessments for both Site F and Site H. The project proponent must include the EPA and the USACE Ocean Dumping Coordinators in the development of the assessments. A site capacity assessment includes, at a minimum: 1) a timeframe upon which to conduct an analysis. This would range between 10-20 years; 2) an analysis of how the proposed disposal changes the bathymetry and sediment dynamics at the ODMDSs; 3) an analysis as to how the proposed disposal affects the longevity of the ODMDS; and 4) an analysis of the how the proposed disposal alters the availability of the ODMDSs for the current users.

This analysis would determine whether Site F and/or Site H is appropriate for disposal of Jordan Cove's maintenance dredged material. Should the analysis conclude that Site F and/or Site H could not accommodate the maintenance dredged material, the project proponent would need to coordinate with EPA to designate a new ODMDS. The EPA's designation process for an ocean disposal site (40 CFR Part 228) is an approximately 5 year process. Thus, the project proponent would need to begin discussions with EPA and the USACE at least 7 years prior to the anticipated second maintenance dredging event.

Please feel free to contact me at (206) 553-1601 or by email at reichgott.christine@epa.gov, or you may contact Bridgette Lohrman of my staff at (503) 326-4006 or by email lohrman.bridgette@epa.gov if you have any questions about the content of this letter.

Sincerely,

Christine B. Reichgott

Christine B. Reichgott, Manager
Environmental Review and Sediment Management Unit

cc: Paul Friedman, FERC
Wendy Briner, USACE
Kate Groth, USACE
Tyler Krug, USACE

Exhibit 55

Continental Shelf Research 95 (2015) 1–14

Contents lists available at ScienceDirect

Continental Shelf Research

journal homepage: www.elsevier.com/locate/csr

Research paper

The impact of channel deepening and dredging on estuarine sediment concentration

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ARTICLE INFO

Article history:
Received 2 July 2014
Received in revised form
24 November 2014
Accepted 29 December 2014
Available online 3 January 2015

Keywords:
Dredging
Turbidity
Channel deepening
Estuarine circulation

ABSTRACT

Many estuaries worldwide are becoming more urbanised with heavier traffic in the waterways, requiring continuous channel deepening and larger ports, and increasing suspended sediment concentration (SSC). An example of a heavily impacted estuary where SSC levels are rising is the Ems Estuary, located between the Netherlands and Germany. In order to provide larger and larger ships access to three ports and a shipyard, the tidal channels in the Ems Estuary have been substantially deepened by dredging over the past decades. This has led to tidal amplification and hyper concentrated sediment conditions in the upstream tidal river. In the middle and outer reaches of the Ems Estuary, the tidal amplification is limited, and mechanisms responsible for increasing SSC are poorly understood. Most likely, channel and port deepening lead to larger SSC levels because of resulting enhanced siltation rates and therefore an increase in maintenance dredging. Additionally, channel deepening may increase up-estuary suspended sediment transport due to enhanced salinity-induced estuarine circulation.

The effect of channel deepening and port construction on SSC levels is investigated using a numerical model of suspended sediment transport forced by tides, waves and salinity. The model satisfactorily reproduces observed water levels, velocity, sediment concentration and port deposition in the estuary, and therefore is subsequently applied to test the impact of channel deepening, historical dredging strategy and port construction on SSCs in the Estuary. These model scenarios suggest that: (1) channel deepening appears to be a main factor for enhancing the transport of sediments up-estuary, due to increased salinity-driven estuarine circulation; (2) sediment extraction strategies from the ports have a large impact on estuarine SSC; and (3) maintenance dredging and disposal influences the spatial distribution of SSC but has a limited effect on average SSC levels.

1. Introduction

Many estuaries worldwide have been modified in the past decades to centuries, in order to reclaim land and to allow ever larger ship access to inland waterways. These interventions include channel deepening and straightening as well as reclamation of the intertidal area, frequently leading to a combination of tidal amplification, increasing estuarine circulation, and increasing flood-dominance of tidal asymmetry (Winterwerp and Wang, 2013; Winterwerp et al., 2013). All of these mechanisms lead to increased residual transport. Tidal amplification strengthens the ebb and the flood tide transports, and consequently also the difference between ebb and flood (in case of an asymmetric tide). For example, a flood-dominant estuary will then become more flood-dominant. An increase in the flood dominance of the tides strengthens the flood flow velocities and weakens ebb flow velocity. Sediment transport increases non-linearly with the flow, leading to larger flood tide transport. Estuarine circulation leads to up-estuary transport; any increase herein therefore enlarges the up-estuary sediment transport. Which of these mechanisms is more important is site-specific, depending on the tidal regime, fresh water supply and sediment type. As a result of larger up-estuary sediment transport, in most (if not all) estuarine systems, the suspended sediment concentration has strongly increased. Some examples are the Ems River (Winterwerp et al., 2013; de Jonge et al., 2014), the Elbe (Kerner, 2007; Winterwerp et al., 2013), the Weser (Schrottke et al., 2006), and the Loire (Walther et al., 2012; Winterwerp et al., 2013).

The response of estuarine suspended sediment concentrations caused by anthropogenic influences is still poorly known. Decadal time-series documenting long-term changes in suspended sediment concentrations are rare (Fabricius et al., 2013). Additionally, many of these anthropogenic measures took place gradually and

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http://dx.doi.org/10.1016/j.csr.2014.12.010

concurrently, and the response of estuarine suspended sediment dynamics to these changes may be slow (Winterwerp et al., 2013) and difficult to separate. Lastly, estuarine suspended sediment dynamics are complex, with up-estuary transport usually dominated by a combination of different physical mechanisms. Up-estuary decreasing salinity gradients generate an up-estuary directed near-bed flow velocity and down-estuary directed surface flow (estuarine circulation: Hansen and Rattray, 1965) which, combined with typical higher near-bed sediment concentrations, generates up-estuary sediment transport. This type of vertical circulation is relevant for fine sediment transport when this mechanism maintains (partial) stratification; in well-mixed estuaries horizontal circulation tends to develop at the expense of vertical circulations (Dyer, 1994). Estuarine circulation may be strengthened by tidal straining (differential advection of salinity by a vertical velocity shear; Simpson et al., 1990), demonstrated by Burchard and Baumert (1998) to enhance up-estuary transport, as well as by tidal asymmetry in internal mixing (Jay and Musiak, 1994). An asymmetry in the tidal velocity field may also lead to up-estuary sediment transport when the duration of High Water (HW) slack exceeds the period of Low Water (LW) slack or when the duration of the flood is shorter than that of the ebb (Friedrichs and Aubrey, 1988). Spatial variations further contribute, with settling lag generating landward sediment transport in response to landward decreasing flow velocities (Postma, 1961) or water depth (van Straaten and Kuenen, 1957). A time-variation in sediment properties (mainly due to flocculation and consolidation) further adds to the complexity (Scully and Friedrichs, 2007; Winterwerp, 2011). The relative contribution of these mechanisms differs per estuary, but may also change in time as a response to human interventions (Winterwerp, 2011).

In addition to influencing hydrodynamics and thereby long-term sediment transport processes, deepening (and port construction) in turbid estuaries will also increase siltation rates and, as a result, maintenance dredging needs and disposal. On the short term, maintenance dredging leads to increasing concentration levels in the direct vicinity of the dredging vessel (e.g. Collins, 1995; Pennekamp et al., 1996; Mikkelsen and Pejrup, 2000; Smith and Friedrichs, 2011). In the long-term, the effects of dredging on SSC is dominated by more complex mechanisms related to the water–bed interaction such as buffering of fines in the sandy seabed (van Kessel et al., 2011a), which is more difficult to quantify (van Kessel and van Maren, 2013). Most studies related to the effect of dredging originate from coral reef and seagrass environments, where their impact is most detrimental; see reviews by Erftemeijer and Lewis, 2006 (seagrass) and Erftemeijer et al., 2012 (corals). However, the question remains, to what extent dredging influences a long-term increase in suspended sediment concentrations (apart from its short-term impact), for the Ems Estuary and other systems. Finally, deepening allows larger ship access and often also to more intense ship traffic. Therefore resuspension by ships is likely to enhance suspended sediment concentrations further (van Houtan and Pauly, 2007; Aarninkhof, 2008).

Given the scarcity of available data over sufficiently long timescales, the wide range of human impacts, and the non-linear behaviour associated with sediment transport processes, a quantitative assessment of changes in suspended sediment concentration in an estuary caused by human activities is challenging. In this paper we use a numerical model to systematically investigate the individual contributions of deepening and dredging on suspended sediment dynamics in a heavily influenced estuary (the Ems Estuary) for which a reasonably large amount of data (recent and historical) exists. Existing process studies focussed on the tidal river draining into the larger estuary (the lower Ems River), in which changes in tidal dynamics are dominant and the suspended sediment concentrations increased several orders of magnitude in the past 3 decades. The conclusions of these studies are based on (semi-) analytical idealised models, revealing the role of sediment-induced density currents (Talke et al., 2009) settling lag (Chernetsky et al., 2010), deepening and hydraulic roughness (Winterwerp et al., 2013) and the potential role of the length (Schuttelaars et al., 2013) and depth (de Jonge et al., 2014) of the tidal river. Observations by de Jonge (1983) in the Ems Estuary suggest an increase in SSC as a result of dredging activities, but available data is limited, and collected in a period when construction work simultaneously took place. Despite large amounts of dredging, knowledge on the effect of deepening in the outer estuary as well as the effect of dredging and subsequent release on long-term SSC remains limited. A model approach to simulate long-term sediment dynamics, recently developed by van Kessel et al. (2011a), provides a tool to obtain better insight in the relative importance of dredging and subsequent disposal (van Kessel and van Maren, 2013), in the short term as well as the long-term.

This paper aims to better understanding the relative role of deepening and dredging on the sediment dynamics in the Ems Estuary in quantitative terms. We will first introduce the Ems Estuary, and describe the historical changes in suspended sediment concentration during dredging and deepening of the estuary. In the following section, the model is introduced and calibrated (Section 3) with which the effect of dredging and deepening is further quantified and analysed (Section 4).

2. The EMS estuary

The Ems estuary, situated on the Dutch–German border (Fig. 1), is an estuary which has undergone large anthropogenic changes in the past decades to centuries. Land reclamations carried out in the past 500 years have greatly reduced the intertidal area. Since 1650, the size of the Ems Estuary (the subtidal, intertidal and intratidal area) up to Eemshaven (between km 35 and 70; see Fig. 1 for location) decreased by 40% from 435 to 258 km^2 (Herrling and Niemeyer, 2007). The combined intertidal and supratidal area decreased by 45% from 285 to 156 km^2. Infilling is mostly of marine origin (the Wadden Sea and/or North Sea); the sediment load carried by the Ems River or smaller local rivers is very small. Human interferences in the estuary have accelerated in the past 50 years, with the construction/extension of three ports (Eemshaven, Delfzijl and Emden) and a large shipyard (Papenburg). The present-day approximate maintenance depths of the approach channels to the ports are 12 m (Eemshaven), 10 m (Delfzijl) and 11 m (Emden), requiring regular maintenance dredging. The tidal channels in the Ems Estuary were historically organised as distinct ebb- and flood-channels (van Veen, 1950). Some of these channels have degenerated as a result of channel deepening, effectively transforming parts of the estuary (especially its middle reaches; see Fig. 1 for location) into a single-channel system. Channel deepening affects tidal propagation, typically increasing the tidal range; which in turn leads to higher turbidity levels (Uncles et al., 2002). Deepening, but especially port construction, leads to more maintenance dredging and subsequent sediment dispersal; de Jonge (1983, 2000) suggests that this has significantly influenced the average turbidity levels. In this section, we will illustrate changes in bathymetry, sediment concentrations, and dredging in more detail.

The impact of human activities is most pronounced in the lower Ems River, a tidal river draining into the Ems estuary (see Fig. 1). The water depth increased from 4 m below MHW (circa 1960) up to 7.5 m below MHW (present day), leading to a strong tidal amplification and increasing suspended sediment concentrations. While suspended sediment concentrations were typically 10s to 100s of mg/l in the 1950's (Postma, 1961) and 1970s

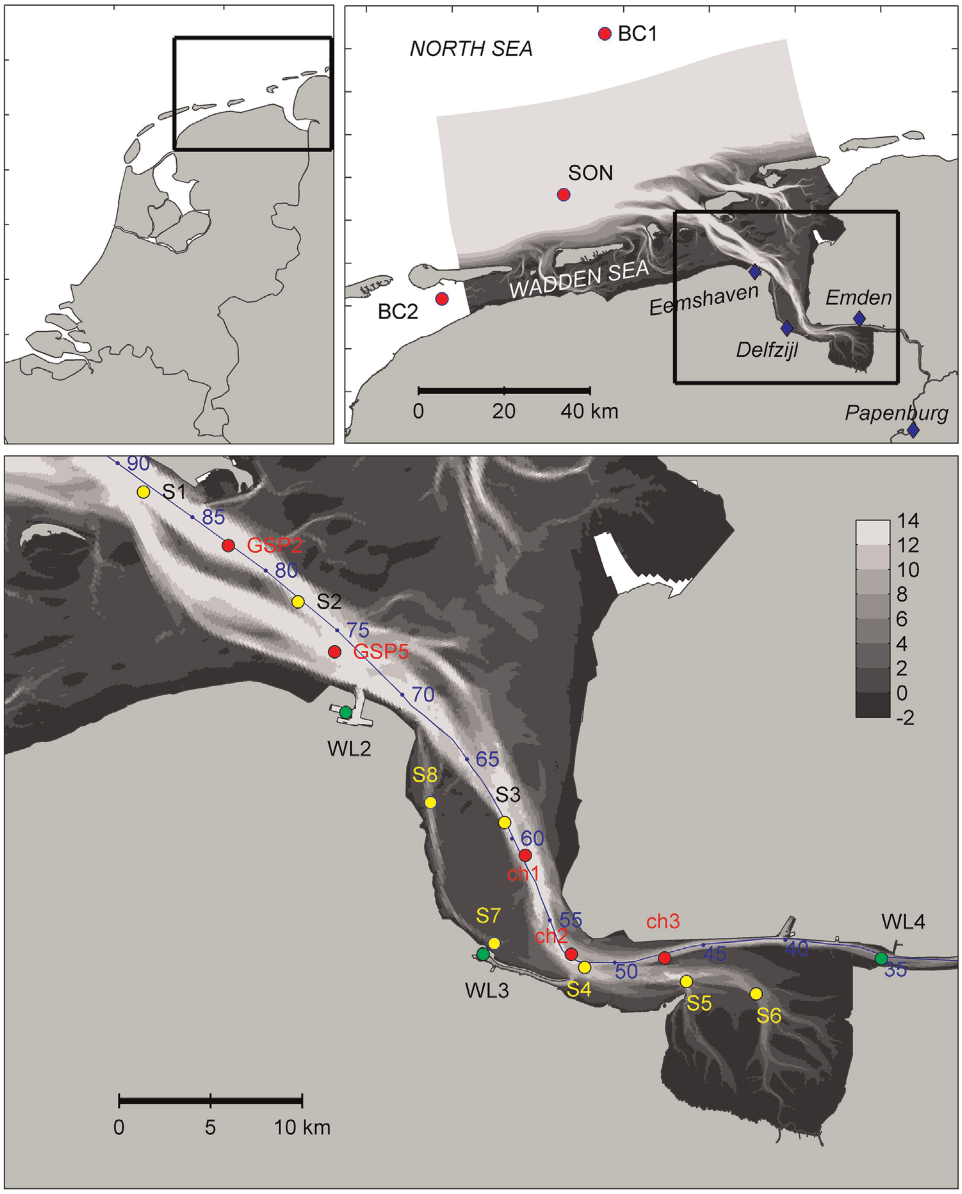

Fig. 1. Top right: map of the Ems estuary and model domain with the ports of Emden, Delfzijl, and Eemshavenand observation stations for waves (SON) and salinity (BC1 and BC2). Lower panel: more detailed map with observation stations Yellow dots stations indicate suspended sediment concentration observation points, green dots are water level observation points, and red dots represent flow velocity observations and model output. The blue markers and numbers are Ems kilometres, a standard reference in the estuary. Only the bed level between −2 and 14 m is shown to highlight the difference in tidal flats and channels, but the channels and offshore sea may be up to 30 m deep. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

(de Jonge et al., 2014), the present-day lower Ems River is characterized by thick fluid mud deposits with concentrations in the order of 10s to 100s of g/l (Talke et al., 2009; Wang, 2010; Papenmeier et al., 2013). Large quantities of fine sediment are transported from the Ems estuary into the lower Ems River by a combination of density-driven flow (Talke et al., 2009, Donker and de Swart, 2013), lag effects (Chernetsky et al., 2010) and various types of tidal asymmetry (Winterwerp, 2011), possibly strengthened by tidal resonance after construction of an up-estuary weir (Schuttelaars et al., 2013). However, it remains unclear to what extent changes in the lower Ems River affect the Ems estuary. The high turbidity zone of the lower Ems River may be partly flushed into the Ems estuary during large winter discharge events (Postma, 1981, de Jonge et al., 2014). On the other hand over 1 million tons of fine sediment are extracted annually from the lower Ems River (Krebs and Weilbeer, 2008) potentially reducing the suspended sediment concentration in the Ems estuary.

Four standardized measurement locations exist in the Ems estuary, which are regularly sampled as part of the standard Dutch Monitoring Programme (hereafter called MWTL, see locations in Fig. 1). Measurements started in the early 1970s, but before 1990 the sampling strategies and methods regularly changed. Since 1990, the suspended matter is clearly increasing (Fig. 2) – statistical analyses reveal that this increase is statistically significant at the 95% confidence level (Vroom et al., 2012).

The most dramatic changes that took place in the estuary itself (excluding the lower Ems River) were deepening of the tidal channels and changes in dredging volumes and strategy. North of km 610 (Fig. 3), the morphological change is mainly reflected in laterally migrating channels. However, in the narrow section (between km 595 and 605), the main navigation channel became consistently deeper, whereas a degenerated tidal channel west of the main channel continually filled up with sediment (both with several metres).

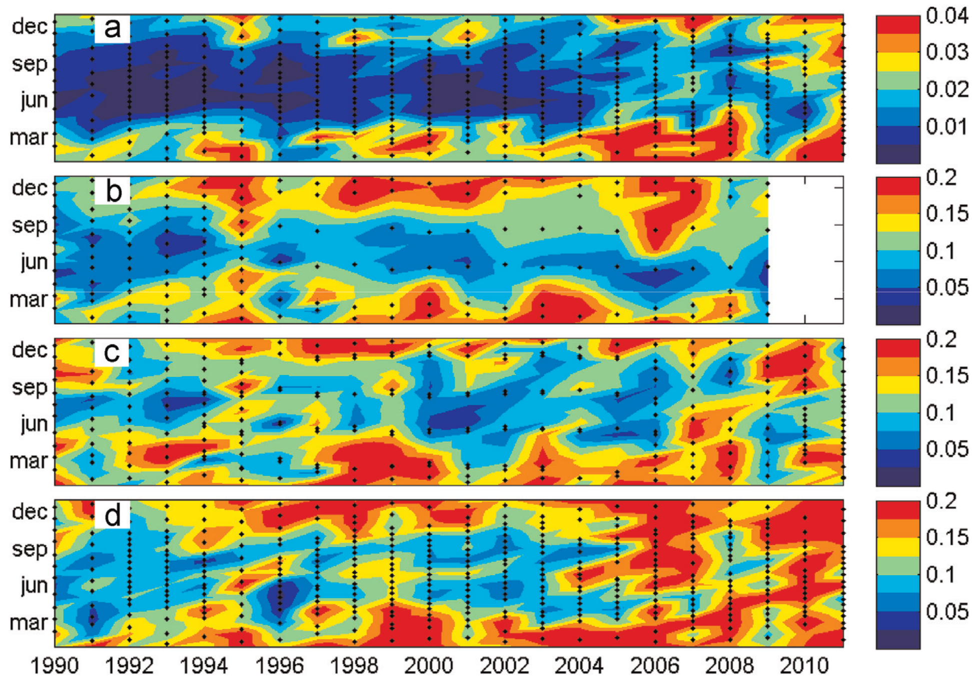

Fig. 2. Timestack plot of suspended sediment concentration in kg/m^3 in S1 (a; most seaward station), S8 (b), S7 (c), and S6 (d; most landward station); see Fig. 1 for locations. Observations at S8 were discontinued in 2010.

Since the 1960s the dredging activities in the Ems estuary have increased significantly (Fig. 4). The dredging volume is the amount of sediment that is removed from the seabed. This sediment can be extracted (when sediment is brought on land) or dispersed (when the sediment is disposed on dumping grounds elsewhere in the estuary). Sediment can be extracted for navigational purposes or for sand mining; the latter by definition meaning extraction. There have also been several changes in dredging strategies over the past decades. Most of the dredged sediment is muddy (Mulder, 2013).

An important observation is that the total dredging volume was at its peak in the 1970s and 1980s ($\sim$18 million m^3), but has decreased since then to $\sim$10 million m^3. Surprisingly, the amount of dispersed sediment has remained fairly constant (at $\sim$8 million m^3). The main change is related to sediment extraction. Between 1960 and 1994, 5.1 million m^3/year on average was extracted from the port of Emden (1.5 million m^3/year) and fairway (3.6 million m^3/year). Since 1994, sediment is no longer dredged from the port of Emden, but instead regularly re-aerated, thereby preventing consolidation. The resulting poorly consolidated bed remains navigable, and consequently the port no longer requires maintenance dredging (Wurpts and Torn, 2005). Sediment is still extracted from the lower Ems River. Since the early 1980s, the yearly dredged volume in the lower Ems River is disposed on land and has been steadily increasing from around 200,000 m^3/yr (Krebs and Weilbeer, 2008) to 1.5–2 million m^3/yr since 1993 (Weilbeer and Uliczka, 2012). Initially, the dredged sediment was sandy but is now predominantly muddy (Krebs and Weilbeer, 2008).

Sediment originating from the Emden fairway and the ports of Delfzijl and Eemshaven are dispersed in the Ems Estuary. Six million m^3/yr is dredged from the Emden fairway (Ems-km 40–53), and disposed seaward of Ems-km 64 (see Fig. 1 for the Ems km, but Section 4 for the location of the disposal grounds). An additional 2.8 million m^3/yr is dredged from the ports of Delfzijl and Eemshaven (Mulder, 2013), half of which is locally re-suspended through water injection dredging (Port of Delfzijl). About 1 million m^3/yr is dredged from the Eemshaven and disposed locally, whereas 0.3 million m^3/yr is dredged from the port of Delfzijl and disposed in the Dollard basin.

The rapid rise in required dredging volumes in the lower Ems River (around 1993) coincided with deepening of the lower Ems River from 5.7 to 7.3 m (1991–1994). However, in the same period the port of Emden ended its annual extraction of $\sim$5 million m^3/yr, increasing the amount of sediment available for transport into the lower Ems River. The increase in dredging requirements may therefore be the result of deepening, but also of the changing dredging strategies.

The main human interventions can be summarised as follows. Over centuries, the size of the intertidal areas has been gradually reduced, resulting in increasingly less natural sediment sinks. In the past decades, several ports have been constructed and extended, requiring deepening of the approach channels and dredging and disposal of sediment. In the port of Emden, sediment was not disposed of, but $\sim$5 million m^3 of sediment was annually extracted. This extraction strategy ended in 1994, simultaneously with a substantial deepening of the lower Ems River. The effect of tidal channel deepening in the Ems Estuary and sediment extraction from the port of Emden will be investigated in more detail in the next section.

3. Numerical model setup and calibration

3.1. Hydrodynamics

In order to quantify the individual impacts of dredging and deepening on the suspended sediment dynamics, a 3D numerical model was setup using the Delft3D software. The 8 vertical σ-layers increase logarithmically in thickness from the bed to the surface (2, 3, 5, 8, 13, 19, 25 and 25% respectively). The model bathymetry is based on surveys by the Dutch Ministry of Public Works in 2005 (Fig. 1). The model is forced at the seaward boundaries by water levels, salinity and temperature. The water level time series were derived from a larger operational model available online (http://opendap-matroos.deltares.nl/thredds/catalog/maps/normal/hmcn_kustfijn/catalog.html), in which tidal and storm-induced water level variations are modelled. The salinity is

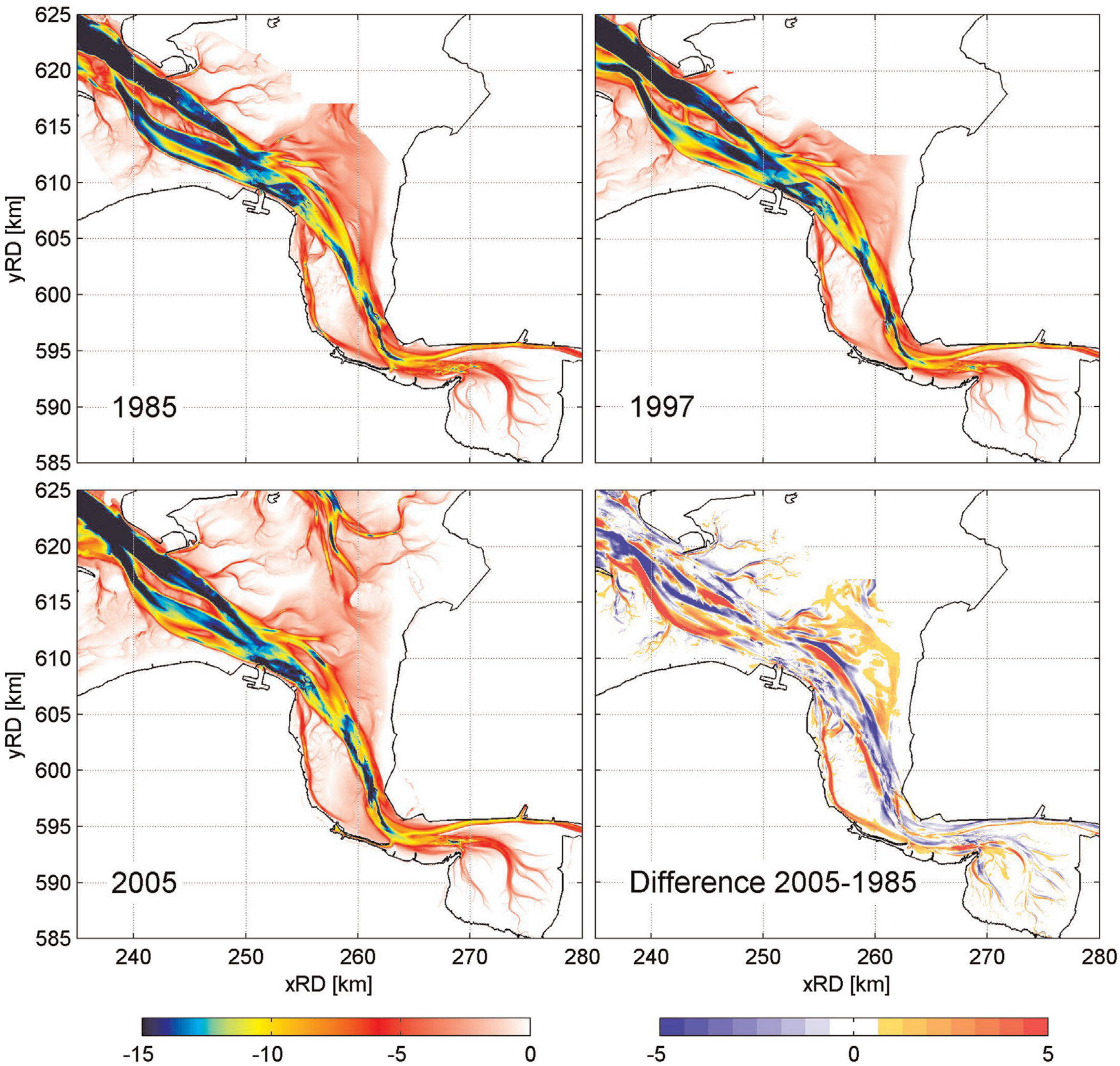

Fig. 3. Bathymetry in the Ems estuary in 1985, 1997, and 2005 (in metres relative to Dutch ordnance datum, based on soundings by the Dutch ministry of public works), and the difference between 1985 and 2005 (in metres).

derived from a nearby observation station measured every 4 weeks (live.waterbase.nl). Six rivers drain into the model of which the discharge of the largest (the Ems River) varies between 30 and 300 m^3/s (Fig. 5). The other rivers are typically an order of magnitude smaller, but also prescribed in the model. The effect of waves is computed with a SWAN wave model (Booij et al., 1999) run in online mode to include wave–current interaction. The wave model is forced by wave parameters (significant wave height, direction and the representative wave period) observed at an offshore wave buoy (Fig. 5) assuming a JONSWAP-spectrum (Hasselmann et al., 1973), and a spatially varying wind field (HIRLAM).

The computed water levels are compared with one-year observations in the frequency domain (using harmonic analysis; Pawlowicz et al., 2002) at 4 selected water level stations covering the estuary (Table 1). Typically, the error in computed water level amplitudes A_h and phases ϕ_h of the individual constituents is less than 5%, with even higher accuracy in the outer reaches of the estuary. From the most seaward station (S1) to the most up-estuary station shown here (WL3) the tides (observed as well as computed) are amplified by ~50%. Flow velocity has been observed for a period of 5 months at two stations (GSP2 and GSP 5) located in the estuary mouth. The amplitudes and phases of the modelled flow velocity (Table 2) are within 20% of observations at the most seaward station (GSP2) and in slightly better agreement deeper into the estuary (GSP5).

The type of asymmetry is determined by the flow velocity phase inclination θ_u of M_4 with M_2, given by $\theta_u = 2\phi_{u,M2} - \phi_{u,M4}$. The modelled and observed θ_u is 279 and 298° respectively using results from Table 2 at station GSP 5 (GSP 2 is not used to compute θ_u because of the small flow velocity amplitude $A_{u,M4}$). Tides with θ_u between 225° and 315° have equal ebb and flood flow velocities, but a longer duration of high water (HW) slack than low water (LW) slack. Such a slack tide asymmetry generates landward sediment transport by the settling lag (Postma, 1961); especially fine sediment is sensitive to local asymmetries in the duration of slack tide (Friedrichs, 2011). For short tidal basins, a phaselag θ_u of 270° corresponds to a phaselag in water levels θ_h of 180° (Friedrichs and Aubrey, 1988). The phaselag θ_h (with $\theta_h = 2\phi_{h,M2} - \phi_{h,M4}$) is typically between 160 and 180° in the four selected water level stations (Table 1, for both observations and model results), therefore in line with the velocity asymmetry. Both the water levels and the velocity data therefore show that the duration of HW slack exceeds the duration of LW slack (promoting tide-driven up-estuary sediment transport) which is reproduced by the model.

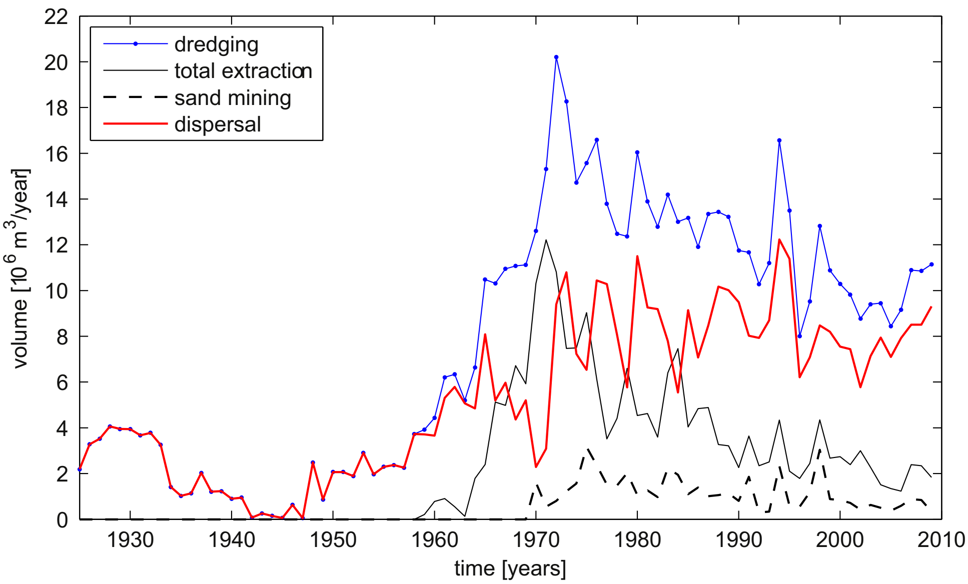

Fig. 4. Dredging volumes for the Ems estuary since 1925. Dredging volumes before 1960 are from de Jonge (1983) and exclude sand mining. Dredging volumes after 1960 is from Mulder (2013) for the Ems estuary (including sand mining) and from Krebs (2006) in the lower Ems River (until 2006; after 2006 a constant value of 1.5 million m^3 is assumed). Total extraction includes sand mining and dredge spill. Before 1994, this sediment was mainly from the port of Emden and approach channel (Mulder, 2013), averaging 5 million m^3/yr. After 1994, mostly sediment dredged in the lower Ems River is brought on land (~1.5 million m^3; Weilbeer and Uliczka, 2012). Sediment dispersal is the difference between dredging and total extraction.

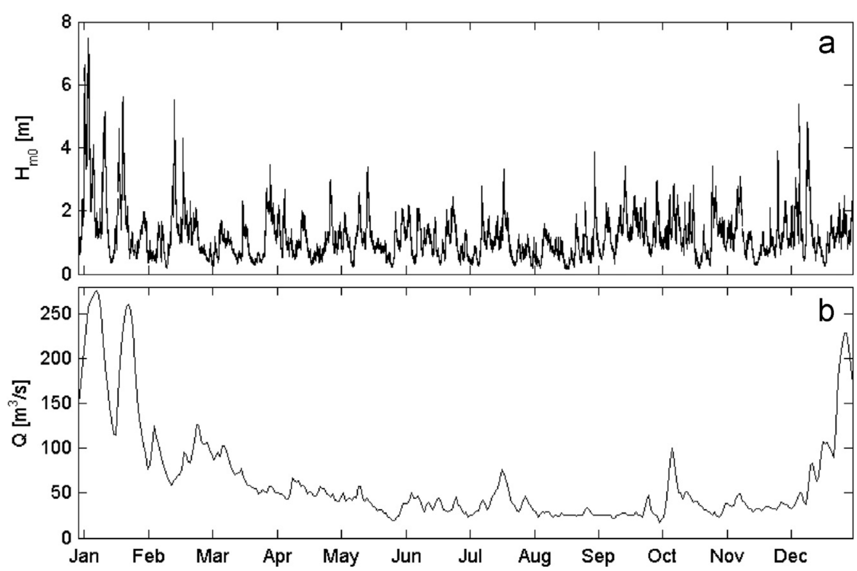

Fig. 5. Wave height (a) observed in an offshore wave station (SON, see Fig. 1 for location), and daily discharge (b) of the main river draining into the Ems Estuary (the Ems river at Herbrum), in 2012.

Table 1
Observed/modelled water level amplitudes (A_h) and phases (ϕ_h) of the 4 largest tidal constituents at stations S1 and WL1 – WL3. See Fig. 1 for the location of stations.

Constituent	Parameter	Station			
		S1	WL2	WL3	WL4
M_2	A_h [cm]	104/102	124/122	141/138	156/147
	ϕ_h [°]	248/247	281/275	300/295	313/313
S_2	A_h [cm]	31/30	35/35	40/39	42/44
	ϕ_h [°]	327/325	5/359	234/272	43/45
N_2	A_h [cm]	13/13	17/16	20/18	23/20
	ϕ_h [°]	236/235	275/269	298/294	312/314
M_4	A_h [cm]	9/9	10/10	18/17	18/13
	ϕ_h [°]	336/334	39/34	70/74	114/96

Table 2
Observed/modeled major flow velocity amplitudes (A_u) and phases (ϕ_u) of the 4 largest tidal constituents at stations GSP2 and GSP5. See Fig. 1 for the location of stations. Observed flow velocity amplitudes of 5 cm/s or less are shaded grey.

Constituent	Parameter	Station	
		GSP2	GSP5
M_2	A_u [cm/s]	80/96	87/99
	ϕ_u [°]	13/23	32/32
S_2	A_u [cm/s]	22/26	22/26
	ϕ_u [°]	85/96	103/103
N_2	A_u [cm/s]	17/17	17/18
	ϕ_u [°]	351/6	10/14
M_4	A_u [cm/s]	2/6	11/13
	ϕ_u [°]	325/327	126/145

3.2. Sediment transport

Next, a sediment transport model has been setup incorporating the effect of the buffering of fine sediments in the seabed (applying the algorithms developed by van Kessel et al., 2011a) and accounting for deposition in, and dredging and dispersal of sediments from the three estuarine ports. These algorithms are coupled offline with the hydrodynamics, and have been applied previously in the North Sea (van Kessel et al., 2011a), the Western Scheldt (van Kessel et al., 2011b), and Singapore (van Maren et al., 2014). This model distinguishes two bed layers: an upper layer (S_1) which rapidly accumulates and erodes, and a deeper layer (S_2) in which sediment accumulates gradually and from which it is only eroded during energetic conditions (spring tides or storms). This S_2 layer represents a sandy layer in which fine sediment accumulates during calm conditions. When the bed shear stress exceeds a critical value the sandy layer becomes mobile, and fine sediment that infiltrated earlier into this layer is slowly released. However, the transport of the sand layer itself is not modelled, but prescribed as a layer of a constant, and user-defined, thickness. Most sediment is stored (buffered) in this S_2 layer; S_1 represents the typically thin fluff layer consisting of mud, which rapidly erodes.

The erosion rate E_1 of S_1 depends linearly on the amount of available sediment below a user-defined threshold M_0/M_1:

$$E_1 = mM_1\left(\frac{\tau}{\tau_{cr,1}} - 1\right), \quad m < \frac{M_0}{M_1}$$

$$E_1 = M_0\left(\frac{\tau}{\tau_{cr,1}} - 1\right), \quad m > \frac{M_0}{M_1}$$

Here m is the mass of sediment in layer S_1 (in kg/m^2). This has the important consequence that also in dynamic environments the equilibrium sediment mass on the bed is non-zero, contrary to standard Krone-Partheniades (KP) models. Typically, this results in smoother and more realistic model behaviour in mixed sand–mud environments ($m < M_0/M_1$). For completely muddy areas ($m > M_0/M_1$), the buffer model switches to standard KP formulations for erosion of bed layer S_1. Hence, M_0 is the standard zero-order erosion parameter (kg/m^2/s) whereas M_1 (1/s) is the erosion parameter for limited sediment availability.

The erosion E_2 of S_2 scales with the excess shear stress to the power 1.5, in line with empirical sand transport pick up functions, assuming that fines trapped within the sandy bed are released when sand is mobilised:

$$E_2 = p_2M_2\left(\frac{\tau}{\tau_{cr,2}} - 1\right)^{1.5}$$

Here, p_2 is the fines fraction in S_2 (computed by the model) and M_2 is the resuspension parameter for S_2 (kg/m^2/s).

The deposition flux D is the settling velocity w_s times the near-bed sediment concentration C:

$$D = w_sC$$

The deposition flux D is divided between layers S_1 and S_2 with a burial parameter α:

$$D_1 = (1 - \alpha)w_sC$$

$$D_2 = \alpha w_sC$$

The value for α is based on calibration (van Kessel and van Maren, 2013), and is typically 0.05–0.2. A low value for α implies a slow exchange with buffer layer S_2. In combination with settings for M_2 and $\tau_{cr,2}$ it also determines the residence time of fines in the buffer layer.

We use two sediment fractions, IM1 with a large settling velocity (1.2 mm/s) and IM2 with a small (0.25 mm/s) settling velocity. The settling velocity of IM1, representing fairly large and rapidly settling flocs, is based on observed settling velocities of flocs in the Ems estuary typically between 1 and 2 mm/s (van Leussen and Cornelisse, 1996). The IM2 settling velocity corresponds to the minimum settling velocity observed by van Leussen and Cornelisse (1996). The spatial distribution of IM1 and IM2 is determined by the model: all sediment in the model domain entered through the open boundaries, where IM1 and IM2 were prescribed at equal sediment concentrations.

Spatially uniform values for the critical shear stress for erosion τ_{cr} are prescribed for the S_1 layer and the S_2 layer. Sediment which does not or only marginally consolidates has a critical shear stress for erosion τ_{cr} of several 0.01 to ~0.1 Pa (e.g. Widdows et al., 2007). Therefore the critical shear stress for the fluff layer is very low ($\tau_{cr,1}$ = 0.05 Pa), implying that sediment in the top layer is easily resuspended. Sediment in S_2 is assumed to erode during more energetic conditions only, when a substantial amount of sand is brought in suspension and the mud trapped in the sand layer is released. This occurs at larger shear stresses than the initiation of motion of sand particles; earlier studies (van Kessel et al., 2011a) suggested a value around 1 Pa. In this study, $\tau_{cr,2}$ is set to 0.9 Pa. The thickness of the sand bed (layer S_2) is set to 10 cm, representing the zone where active mixing by biological activity and (bedform-related) sediment transport takes place. The erosion parameters M_0, M_1, and M_2 (see Table 3) are obtained through calibration (van Kessel and van Maren, 2013). Flocculation and consolidation are not modelled. The use of 2 bed layers represents model behaviour similar to consolidation: during low energy conditions sediment is progressively buried in layer 2 (and is therefore no longer regularly resuspended). Also the effect of biology (influencing the erodibility of the intertidal mud deposits) is not accounted for in the model.

The boundary conditions at the North Sea and Wadden Sea are set at 10 mg/l and 100 mg/l for IM1 and IM2 respectively, based on long-term observation stations (similar to the observations in Fig. 2). A sediment concentration of 10 mg/l is also prescribed to all fresh water sources. An equilibrium bed condition (the amount of sediment in S_1, S_2, and in suspension) is obtained by: running the model with a thin S_2 bed layer (for faster adaptation time) for a number of years; then increasing the thickness of the S_2 layer to 10 cm (a typical active layer depth); and finally running the model repetitively with cyclic hydrodynamic forcing until dynamic equilibrium is achieved (where the suspended sediment concentration and sediment availability vary with tidal and seasonal timescales, but not over the years). Depending on the settings of the model, a dynamic equilibrium for both the distribution of mud on the bed and suspended in the water column is achieved within several years (Five years using the settings in Table 3). The bed level in the sediment transport model is kept constant, so it is not a morphological model: erosion and deposition influences the available mass of sediment below a bed level which is constant in time.

Nine areas are defined from which sediment is dredged once

Table 3
Sediment transport model settings.

Parameter	Description	IM1	IM2
$w_{s,0}$ [mm/s]	Settling velocity	1.2	0.25
M_0 [kg/m^2/s]	Erosion parameter	2.5×10^{-3}	2.5×10^{-3}
M_1 [/s]	Erosion parameter	1.2×10^{-4}	1.2×10^{-4}
M_2 [kg/m^2/s]	Erosion parameter	1.2×10^{-3}	1.2×10^{-3}
$\tau_{cr,1}$ [Pa]	Critical bed shear stress	0.05	0.05
$\tau_{cr,2}$ [Pa]	Critical bed shear stress	0.9	0.9
α [−]	Burial rate	0.1	0.1
Thickness S_2 [m]	Thickness of sand bed	0.1	

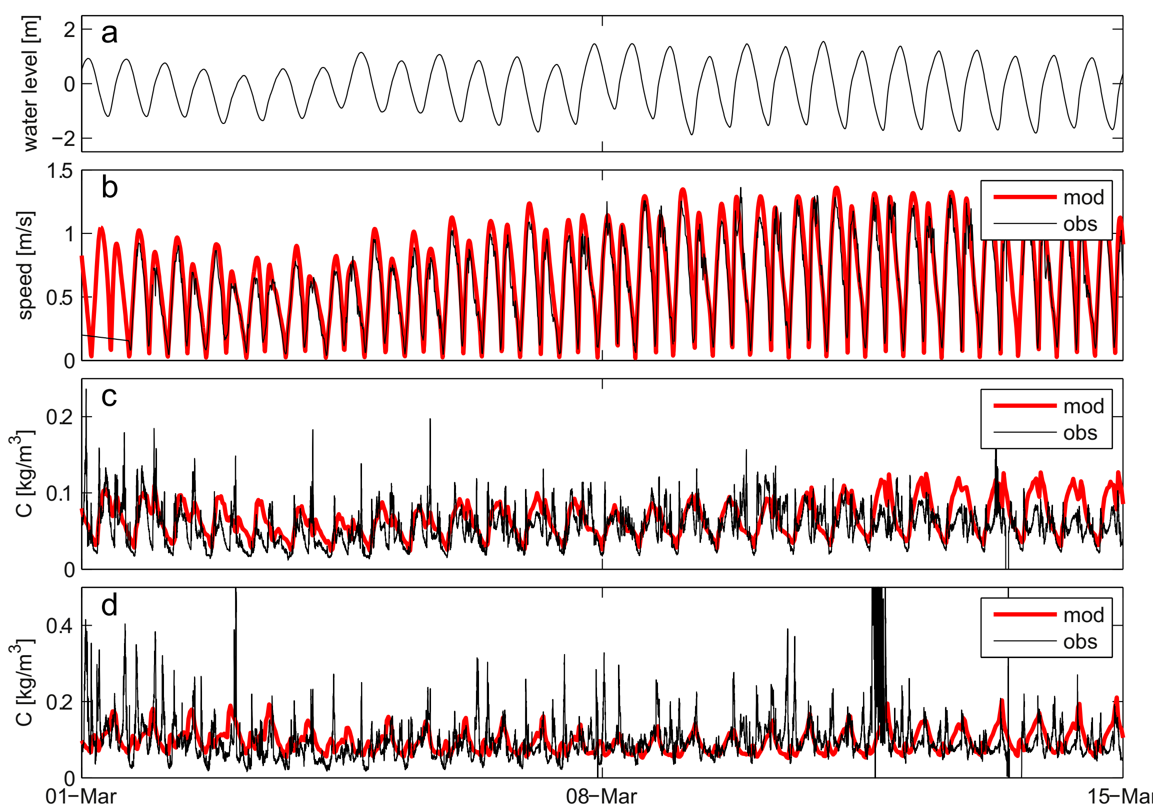

Fig. 6. Computed water level (a); observed (black) and computed (red) depth-averaged flow velocity (b); near-surface sediment concentration 4 m below the water surface, (c); and near-bed sediment concentration (d) at location GSP5, from 1 to 15 March 2012. See Fig. 1for the location. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

every week (from layer S_1 and layer S_2), and disposed in the dumping locations designated to the dredging sites. Dredging is instantaneous, but disposal is distributed over 3 days to avoid unrealistic peaks in the suspended sediment concentrations. Given the large dredging volumes in the area, discretization of dredging and dumping in different areas provides a more realistic description of sediment transport in the estuary. Additionally, the computed deposition rates in the ports can be compared with observed dredging volumes, providing validation of the sediment transport model. An added value of such a dredging module is that it allows for a quantitative insight in the long-term effects on dredge spoil dispersal.

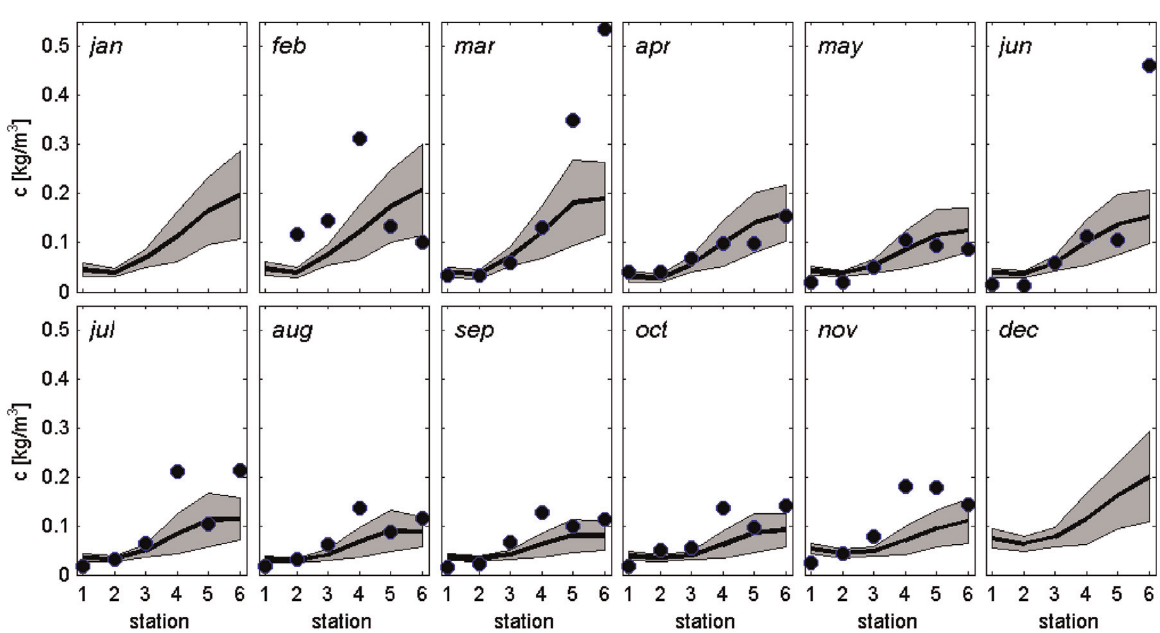

Fig. 7. Monthly averaged computed surface sediment concentration (black line, with grey shading indicating the standard deviation) and observed surface sediment concentration (black dots, February through November) in 2012 at stations S1–S6 (in kg/m^3). See Fig. 1 for the location of stations.

A time-series comparison of the computed and observed suspended sediment concentration at station GSP5 (Fig. 6) reveals that the intra tidal and spring neap variation in SSC are well reproduced. The computed near-bed sediment concentration is typically two times larger than the near-surface sediment concentration, which is in line with field observations, suggesting that the vertical sediment concentration gradients are reproduced. The along-estuary gradient in SSC is evaluated by comparing the model against snapshot surface samples collected every 2–4 weeks at 6 stations (S1–S6, see Fig. 1 for location). The model reproduces the observed up-estuary increase in the surface sediment concentration, and the seasonal variation of the sediment concentration with larger sediment concentrations during the winter months (Fig. 7). The largest deviations between observations and model results occur in February and November. An explanation for this could be that sediment flushed from the lower Ems River is underestimated by the model: the largest deviations occur at stations halfway the estuary. This flushing is underestimated because the sediment transport processes in the Ems River are very complex – see the end of this section. Nevertheless, even though two-weekly snapshot measurements only provide an indicative value for comparison with a sediment transport model, the reasonable correspondence suggests the model reproduces the actual estuarine suspended sediment concentration gradient.

The model also reproduces the pronounced up-estuary increase in mud content in the bed (Fig. 8). The highest mud content is observed and computed in the Dollard bay and the approaches to the port of Delfzijl. In line with observations, the computed mud content increases in the landward direction of the Wadden Sea (the coastal lagoon adjacent to the Ems Estuary) as well. The computed siltation in the three ports in the estuary is typically around 0.5–0.8 million tons/yr. The computed deposition in the ports of Eemshaven and Delfzijl are within 10% of the long-term observed deposition rates (Table 4). However, deposition in the port of Emden and its approach channel is strongly underestimated. This is probably related to the hyper turbid conditions in the lower Ems River, which drains into the Ems estuary close to the port of Emden.

The sedimentary conditions in this reach of the river require a different modelling approach with more complex formulations to account for flocculation, sediment-induced density effects, and consolidation. These processes demand for more detailed and short time scale simulations which conflict with the multi-year objectives of this study. Therefore a more accurate description of the sediment dynamics in the lower Ems River is beyond the scope of this paper.

Table 4
Estimated and computed deposition rates.

Port/area	Estimated deposition (million tons/yr)	Computed deposition (million tons/yr)
Eemshaven	0.5	0.44
Delfzijl	0.8	0.76
Emden port and fairway	1.6	0.55

4. Effect of sediment extraction sediment disposal and deepening

The developed model is subsequently used to experiment with historic scenarios. This reference model reflects the present-day conditions (i.e. the 2005 bathymetry and no extraction of sediment). It was hypothesised earlier in this paper that discontinuing sediment extraction (dredging the ports and bringing sediment on land) has led to a pronounced increase in SSC. Therefore the reference model with dredging is re-run with extraction (instead of dredging and dumping) of all sediment depositing in the port of Emden and its approach channel. With respect to this scenario with extraction, the reference model (with dredging from Emden) leads to an increase of 0–50 mg/l in SSC in the outer reaches, but up to 100 mg/l within the estuary (Fig. 9a). The typical concentrations in these up-estuary sections are 100–300 mg/l (Fig. 7), implying the impact of dredging strategy is substantial. However, it was also concluded that the model strongly underestimates deposition rates in the port of Emden and its approach channel (Table 4). Therefore, although historically as much as 2.5 million tons were extracted on an annual basis, only 0.5 million tons/yr is extracted in the model. To better approximate the effect of extracting such a large sediment mass, the model is also run with extraction from all ports (totalling a mass of 1.75 million tons, see Table 4). This leads to a two-fold larger suspended sediment concentration change (Fig. 9b).

The most realistic way to evaluate the effect of the presence of ports (excluding their approach channels) is by comparing the model including ports and subsequent dredging and disposal activities (the reference model), with a scenario without ports (and therefore also without deposition in ports nor related dredging and disposal activities). Including ports raises the suspended sediment concentration in the vicinity of disposal sites, but decreases the sediment concentration further away from the disposal sites (Fig. 9c). This follows from the large sediment accumulation rates in the ports, extracting sediment from the estuary and hence lowering the ambient suspended sediment concentration.

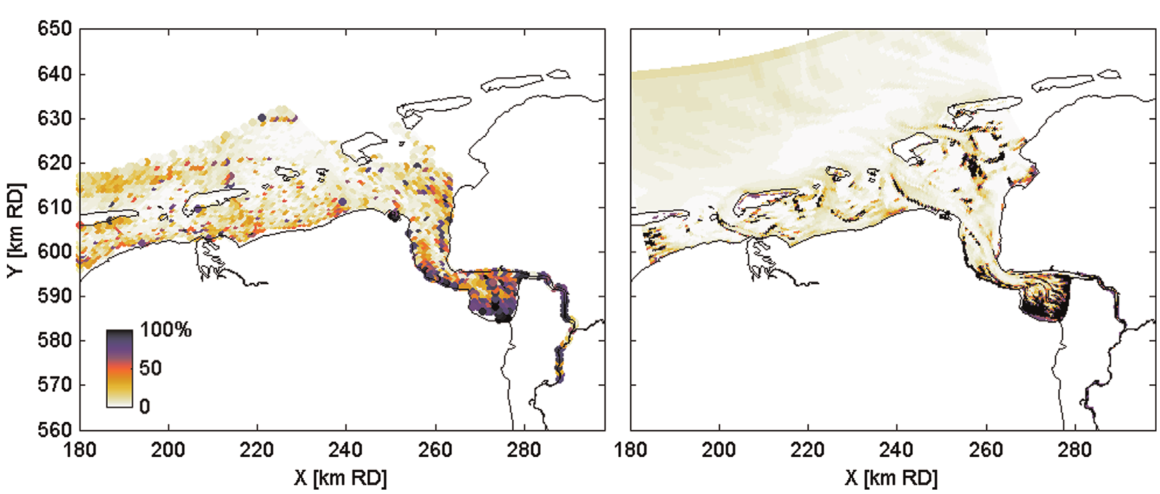

Fig. 8. Observed (left, based on surveys from 1989) and computed (right, S1 and S2) mud content in the bed (in %).

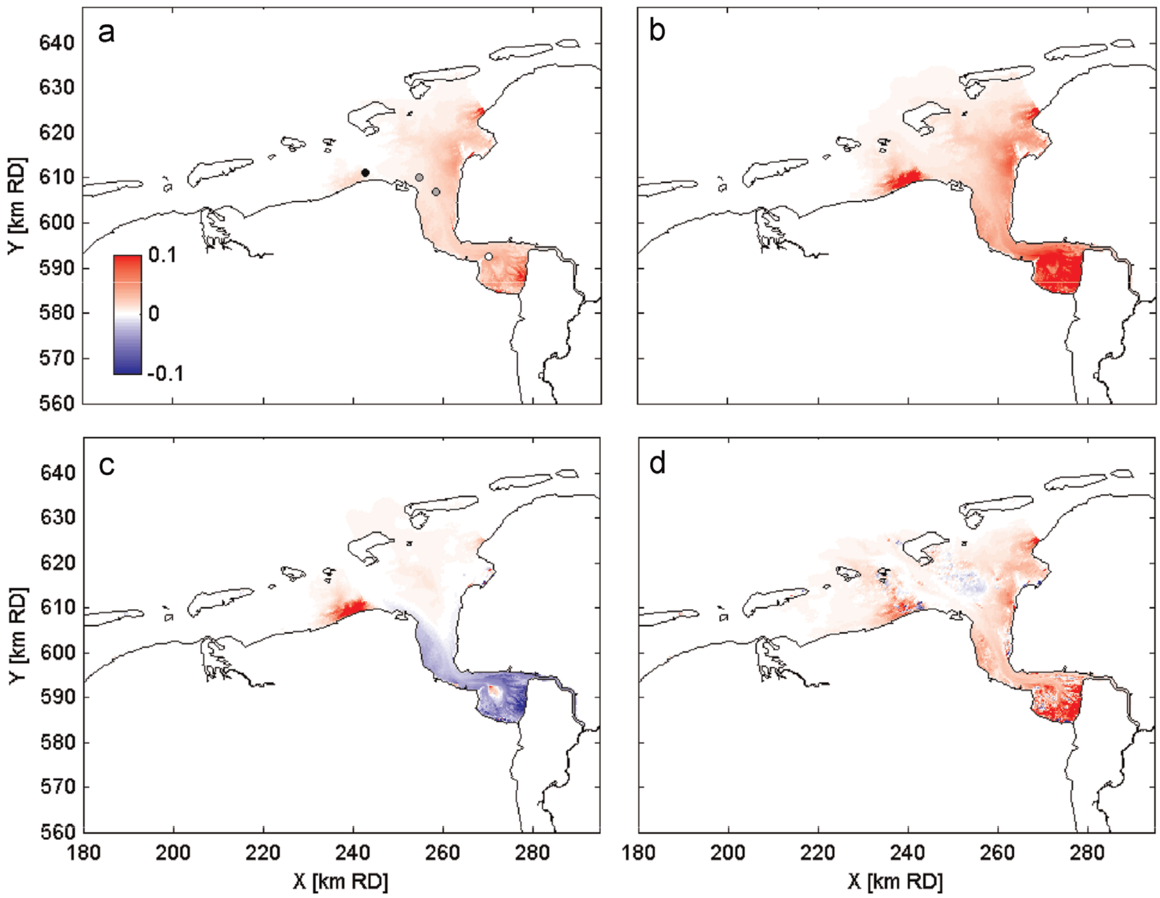

Fig. 9. Computed increase of yearly averaged surface suspended sediment concentration (in kg/m^3) for 4 scenarios. The increase is defined as the difference of the annual means, computed for Scenario (a): dredging and dumping of all ports, compared with extracting from Emden; Scenario (b): dredging and dumping from all ports, compared with extraction from all ports; Scenario (c) construction of ports and resulting dredging and disposal of sediment, compared with no ports nor dredging activities; Scenarios (d) extraction from Emden with the 1985 bathymetry compared to dumping from Emden and 2005 bathymetry. The disposal grounds are visualised in panel (a) with circles, with a colour depending on the origin of the disposed sediment (black for Eemshaven, grey for Emden, and white for Delfzijl).

In order to allow ships to enter the ports, tidal channels are frequently deepened. The tidal channels in the Ems estuary have been deepened with several metres (Fig. 3). As a consequence, a model with the 1985 bathymetry was setup. The closest approximation of the change from the 1980s to the 2000s is by comparing the reference model with a scenario including the 1985 bathymetry model and extraction from the port of Emden (Fig. 9d). Compared to extraction only (Fig. 9a), the increase in suspended sediment concentration is larger. Therefore the impact of deepening alone is evaluated in more detail.

The model is run with the 1985 and 2005 bathymetry (with all other settings equal). The year 2005 is simulated with a baroclinic model (including density-induced effects due salinity) and a barotropic model (without density effects) in order to separate the change in SSC due to estuarine circulation. Deepening of the estuarine channels alone leads to an increase of more than 50 mg/l

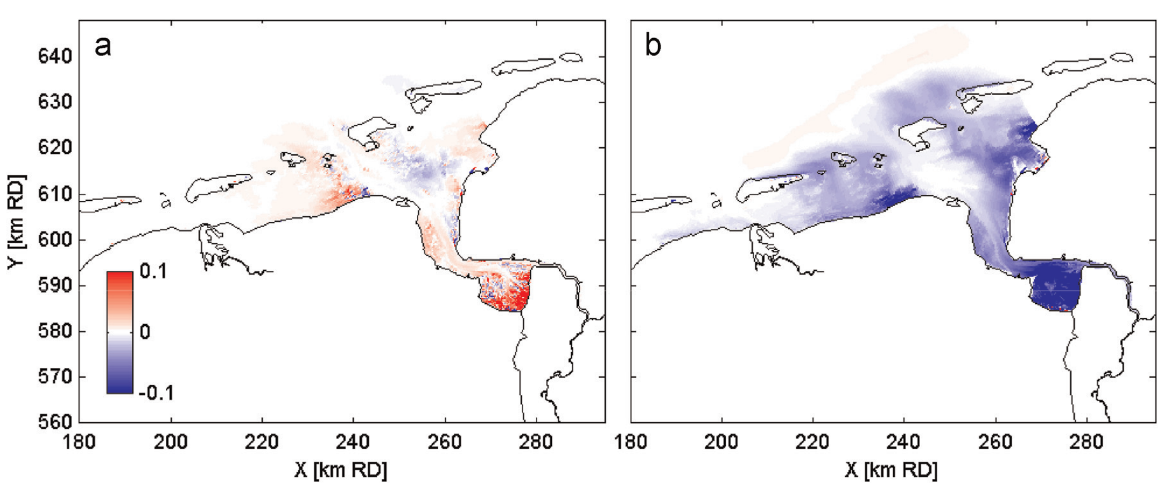

Fig. 10. Computed increase in surface sediment concentration (in kg/m^3) due to deepening from 1985 to 2005 (a) and a reduction in surface sediment concentration by running the model without density effects (b).

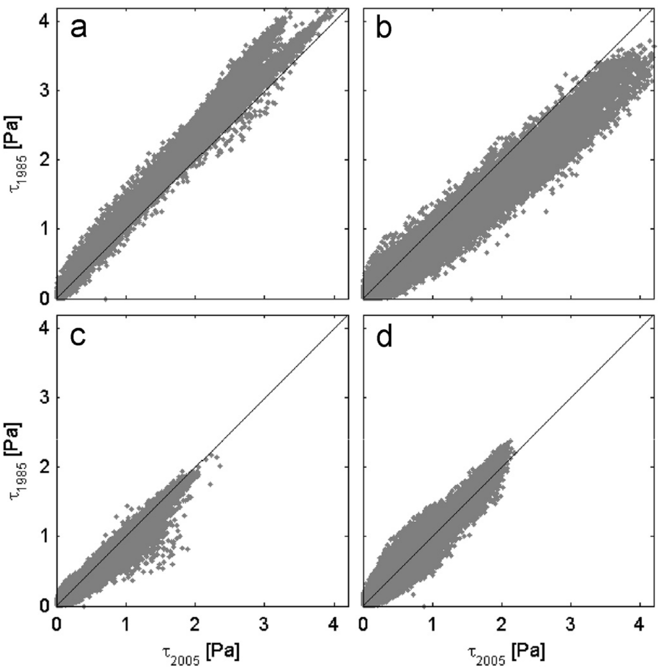

Fig. 11. Bed shear stress computed every 10 minutes at GSP2 (a), ch1 (b), ch2 (c), and ch3 (d) for 2005 (*x*-axis) and 1985 (*y*-axis): plotted values cover the full year. See Fig. 1 for the location of stations.

in the up-estuary parts (Fig. 10a). The tide-induced bed shear stresses differ slightly between 1985 and 2005 (Fig. 11) because of small phase shifts in the propagation of the tides, but there is no overall trend. At station GSP2, the bed shear stress was slightly larger in 1985 whereas the bed shear stress at ch1 was slightly larger in 2005. Such relatively small changes do not have an effect on turbidity as large as in Fig. 10a.

A more realistic mechanism for this change therefore is estuarine circulation. Estuarine circulation is a residual flow component (superimposed on the oscillating tidal currents) which develops in the presence of a horizontal salinity gradient, and increases in strength with larger water depth. The surface flow velocity is directed towards the area of higher salinity, the near-bed velocity is directed towards the freshwater source. Since the near-bed sediment concentration is higher than the near-surface sediment concentration (see also Fig. 6), estuarine circulation generates up-estuary sediment transport. For the 2005 bathymetry, estuarine circulation is a key mechanism for up-estuary transport, which is demonstrated with a model excluding density effects. The suspended sediment concentration in this barotropic model is much lower than the reference model (Fig. 10b), demonstrating the importance of estuarine circulation.

The effect of salinity is therefore further explored with residual flow velocity profiles at 4 stations throughout the main channel of the Ems estuary (Fig. 12, see Fig. 1 for the location). Without density effects, the residual flow velocity is low and displays a logarithmic vertical profile. In contrast, for both 1985 and 2005 (with density effects) the residual near-bed flow velocity is typically directed up-estuary. However, the magnitude of the near-bed flow velocity is typically two times larger in 2005, compared to 1985. It is therefore concluded that the deepening of the tidal channels in the estuary in the period 1985 to 2005 has strengthened density-induced estuarine circulation patterns, which subsequently substantially raised the suspended sediment concentration.

5. Discussion

5.1. Long-term effects of dredging on SSC

With a few exceptions such as de Jonge (1983), the long-term impact of dredging on suspended sediment concentrations has received fairly limited attention in scientific literature. The long-term morphological effects of dredging are fairly well known due to the relatively large amount of (historic) topographic data in heavily modified estuaries (e.g. Jeuken and Wang, 2010; Monge-Ganuzas et al., 2013). Most commonly, studies related to dredging-induced turbidity focus on the sediment dynamics in the direct vicinity of the dredger (Pennekamp et al., 1996; Mikkelsen and Pejrup, 2000; Spearman et al., 2011; Smith and Friedrichs, 2011), on the fate or deposition of dredged sediment (e.g. Bai et al., 2003; Van den Eynde, 2004; Cronin et al., 2011; Hayter et al., 2012; Alba et al., 2014), or on the impact on sensitive ecosystems (Erftemeijer

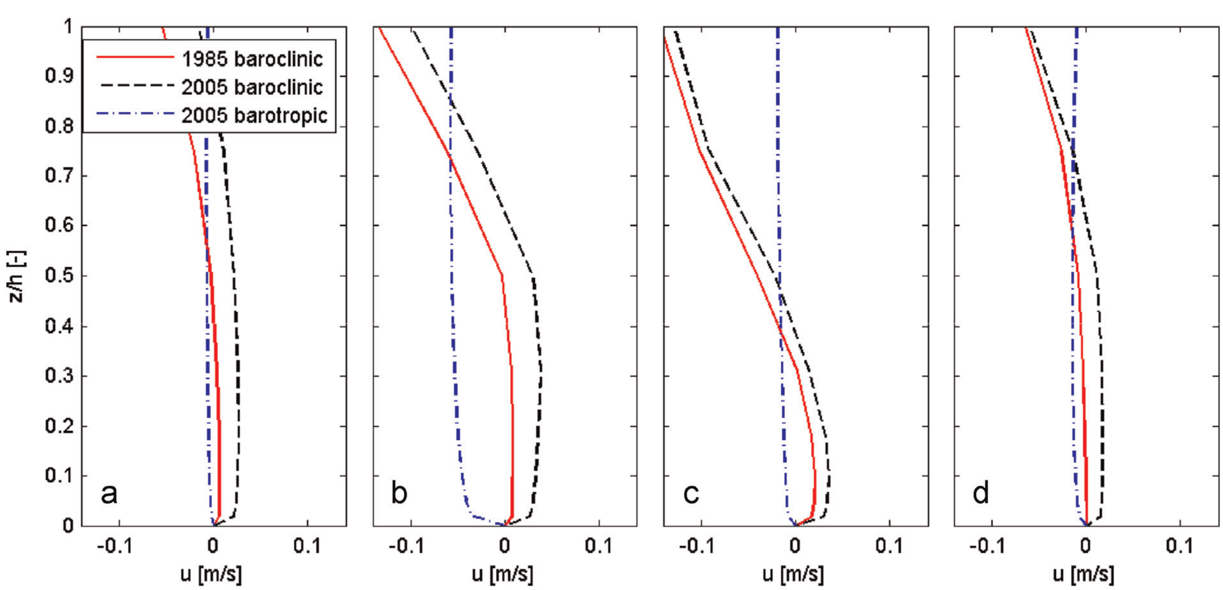

Fig. 12. Residual flow velocity profiles, with positive values directed up-estuary, computed at GSP2 (a), ch1 (b), ch2 (c), and ch3 (d) for 1985 and 2005 (baroclinic mode) and 2005 (barotropic mode, i.e. no density effects). The averaging period is January through March, the period during which the fresh water discharge is largest. See Fig. 1 for the location of stations.

and Lewis, 2006; Erftemeijer et al., 2012). When carefully executed, the impact of dredged sediment disposal on turbidity may be limited to the short-term and near-field (Fredette and French, 2004). Often the dispersion of individual plumes is considered, whereas it is the long term cumulative effect of a large number of individual plumes that determines the impact. Over longer timescales resuspension of dredged material from the seabed may become the dominant factor contributing to turbidity (van Kessel and van Maren, 2013). Fettweis et al. (2011) observed a long-term increase in the suspended sediment concentration and formation of fluid mud. Fluid mud formation is not included in our model, even though fluid mud forms in the entrance of the Emden navigation channel. Regular resuspension of this fluid mud layer contributes to elevated sediment concentration levels. As indicated earlier, the underestimated sediment concentrations in February and November are possibly related to the complex suspended sediment dynamics in the navigation channel, which are not captured by the model. If any long-term increase in SSC is related to fluid mud formation, this will not be properly accounted for in the model applied here.

In our simulations, the effect of dredging and disposal is large when comparing the present-day situation (a scenario in which dredged sediment is disposed) to a scenario in which sediment is not disposed but sediment is still allowed to settle in ports (equivalent to extraction, see Fig. 9b). However, a more appropriate scenario to estimate the effect of dredging and disposal is to compare the present-day situation to a scenario without ports (and hence no dredging and disposal). This reveals a much more limited effect of dredging and disposal: the sediment concentration increases near the disposal sites but slightly decreases elsewhere (Fig. 10c). Our results are difficult to compare with de Jonge (1983), who concluded that the suspended sediment concentrations in the Ems Estuary in a specific year depended on the distance dredged during that year. This relationship was strongly influenced by capital dredging for construction of the Eemshaven, and it remains unclear how much of the dredged sediment in the analyses is extracted or disposed. Moreover, although the distance dredged and sediment concentration is correlated in de Jonge's data, both also increase in time: hence the increase may also be the result of channel deepening.

5.2. Effects of deepening on SSC

It is well known that salinity-induced density currents lead to up-estuary transport of sediment (e.g. Meade, 1969; Uncles et al., 1985). In our model, this effect of salinity-induced residual currents is demonstrated by the pronounced difference between the computed sediment concentration in barotropic (excluding salinity-induced residual currents) and baroclinic (including salinity-induced residual currents) simulations (Fig. 11b). The magnitude of the residual flow velocity u in the tidal channel scales with the cubed water depth h as in Hansen and Rattray (1965):

$$u_z \equiv h^3\left(1 - 9\left(\frac{z}{h}\right)^2 + 8\left(\frac{z}{h}\right)^3\right)$$

As a result of this strong depth-dependence, deepening of tidal channels leads to strengthening of the residual current. For a 10 m deep channel, deepening by 2–4 m leads to a 1.7–2.7-fold increase in salinity-induced residual flow (assuming the horizontal salinity gradient is unaffected by deepening). In very few (if any) estuaries worldwide, observational evidence exists for the impact of deepening on estuarine circulation. The reason for this is that the residual flow velocity is very sensitive to the observational technique and exact location. Channel deepening is often accomplished over many years or even decades. Identical data collection programs before and after channel deepening are therefore few or non-existent. A reliable alternative to assess the impact of deepening on residual currents is a scenario analysis using a well-calibrated process-based numerical model.

Our model strongly suggests that baroclinic processes influence the estuarine suspended sediment dynamics, and that the magnitude of estuarine circulation increased as a result of deepening. As a result, the modelled response to channel deepening is an up-estuary increase in SSC. It should be realised that the computed effect of different scenarios (dumping/extraction, 1985/2005, barotropic/baroclinic) is influenced by the parameter settings and process formulations of the numerical sediment transport model. Therefore, while the trends remain valid, the absolute values or details in the spatial patterns of changes in suspended sediment concentration computed with process-based numerical models as used here should be interpreted carefully.

5.3. Other impacts

The change in dredging strategy and deepening is likely not the only contributor to increased suspended sediment concentration. In the Ems Estuary, and the lower Ems River, the loss of tidal flats may influence long-term changes in the suspended sediment dynamics. Deepening of the lower Ems River (the main river draining into the Ems Estuary) has strongly amplified the tides and increased the suspended sediment concentrations within the tidal river (e.g. de Jonge et al., 2014). One million tons of sediment is annually extracted from the lower Ems River (Krebs and Weilbeer, 2008), and on the long term the tidal river may therefore reduce the sediment concentration in the estuary. However, regular flushing of the tidal river during high discharge events (Spingat and Oumeraci, 2000) transports sediments from the river into the estuary, and the long-term effect of the tidal river on the estuary remains poorly known. Additionally, many of the intertidal areas that existed in the Ems estuary have been reclaimed in the past centuries. These intertidal areas provided a natural sink for sediment to accumulate.

Since 1650, the size of the Ems Estuary has decreased by 40% (177 km,see Section 2) due to infilling with fine sediments. Most of this accumulation took place in the Dollard, which used to be much larger: the present-day intertidal area used to be tidal channels. In some areas, deposition must therefore have been many metres. These sediment deposits are well consolidated, and therefore have a dry density of $\sim$1500 kg/m^3. Assuming an average thickness in deposition of 3 m yields an average annual accumulation rate of 2.3 million tons (partly consisting of sand), between 1650 and present. This number is a very crude estimate for the yearly siltation rates, and more research is needed to further quantify it. Nevertheless, the long-term loss of sediments by deposition is probably comparable to the extraction rates from the port of Emden ($\sim$2.5 million tons/yr). With a constant supply of sediments, removal of this natural sink inevitably leads to a rise in suspended sediment concentrations. It therefore seems likely that apart from deepening and port construction, the suspended sediment concentration has already been slowly increasing for centuries. Compared to the large dredging volumes, and especially the impact of extraction, the impact of changing ship traffic (hypothesized in Section 1) is probably a minor effect

This leads to the following hypothesis for the increasing suspended sediment concentrations in the Ems Estuary:

1. The potential sediment supply to the Ems estuary by the North Sea and Wadden Sea has always been large.
2. The large-scale reclamation of intertidal areas increased the suspended sediment concentrations in the past centuries.

3. Large-scale port construction but especially deepening of the tidal channels in the 1960s increased the up-estuary sediment transport; however.
4. The increase in suspended sediment concentration remained limited because of large-scale sediment extraction (on average ~2.5 million tons/yr) in and near the port of Emden until the early 1990s.
5. After 1990, sediment was no longer extracted, and as a result the suspended sediment concentrations increased substantially.

5.4. Relevance for other estuaries

Many estuaries worldwide are heavily modified. Channels are deepened to accommodate larger ships, and intertidal areas are reclaimed to for need of land. These changes have led to tidal amplification and to increasing suspended sediment concentrations (Winterwerp and Wang, 2013; Winterwerp et al., 2013). The role of dredging on the suspended sediment concentration and the impact of deepening on turbidity through enhanced estuarine circulation (both addressed in this paper), have so far received little scientific attention. This is probably because (1) many of these human interventions occur concurrently, and therefore it is difficult to distinguish individual contributions, and (2) long-term data documenting changes in suspended sediment concentration are rare (Fabricius et al., 2013). Although the impact of dredging is often monitored and modelled on short timescales (especially during capital dredging works), long-term effects have so far only been established to a limited degree (van Kessel and van Maren, 2013).

Some aspects of the results presented here on the Ems Estuary are very site-specific, such as the sediment extraction. However, most other aspects are probably typical for estuaries in populated areas: (1) intertidal areas are reclaimed, leading to a loss of sediment sinks, (2) channels are deepened, resulting in more up-estuary transport of sediment. We therefore believe that the results presented here apply to a wide range of turbid estuaries in which tidal channels have been deepened for port construction, and tidal flats reclaimed for land use.

6. Conclusions

A calibrated suspended sediment transport model has been setup to simulate suspended sediment dynamics in the Ems Estuary. This model suggests that the observed increase in the suspended sediment concentration can be mainly related to the increase in up-estuary transport of sediment due to estuarine circulation caused by deepening of tidal channels. It is also possible that the large-scale reclamation of intertidal areas increased the suspended sediment concentrations in the past centuries. Discontinuing the large-scale sediment extraction from the port of Emden produced an additional pronounced increase in SSC because the imported sediment was not further removed from the system. The effect of the ports themselves, including dredging and dumping, is lower than deepening and consequent extraction. Compared to an estuary without ports, the sediment concentration in the present-day estuary is higher near disposal sites, but lower elsewhere in the estuary (because the ports act as sinks). The Ems estuary provides an example of a heavily impacted estuary for which a relatively large amount of data is available, but may be representative for many estuaries worldwide.

Acknowledgements

This work is part of the project ‘Mud dynamics in the Ems-Dollard’, funded by the Dutch Ministry of Public Works in fulfilments of the requirements for the Water Framework Directives. Writing of this manuscript was supported by The Waddenacademie. We gratefully acknowledge The Dutch ministry of public works, Groningen Sea Ports, and IMARES for the use of their data. Suggestions by two anonymous reviewers greatly improved the manuscript.

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Exhibit 56

Marine Pollution Bulletin

Volume 32, Issues 8–9, August–September 1996, Pages 615-622

Report

The effects of marine gravel extraction on the macrobenthos: Results 2 years post-dredging

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Available online 25 February 1999.

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https://doi.org/10.1016/0025-326X(96)00024-0

Abstract

An offshore experimental dredging study was initiated off North Norfolk (UK) in 1992 to investigate the impacts of marine gravel extraction on the macrofauna. A dredged ‘treatment’ and a non-dredged ‘reference’ site were selected to evaluate the initial impacts and subsequent processes of recolonization. A survey of the benthos was conducted prior to the removal of 50 000 t of marine aggregate from the treatment site. Thereafter annual monitoring surveys were conducted commencing immediately after the dredging episode. Results indicated that whilst the dominant species recolonized quickly following dredging many rarer species did not. Evidence from sidescan sonar records and underwater cameras indicated a considerable amount of sediment transport during the first two winters following dredging and the once well-defined dredge tracks have now become infilled with sand and gravel. The substantially reduced biomass at the treatment site some 24 months after dredging is thought to be due to a local increase in sediment disturbance caused by tide and wave action over the winter period. Finally, the biological findings of this study are discussed in relation to their wider environmental significance.

Exhibit 57

Estuarine, Coastal and Shelf Science

Volume 39, Issue 1, July 1994, Pages 75-91

Regular Article

Seagrasses, Dredging and Light in Laguna Madre, Texas, U.S.A.

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Available online 25 May 2002.

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https://doi.org/10.1006/ecss.1994.1050

Abstract

Light reduction resulting from maintenance dredging was the suspected cause of large-scale loss of seagrass cover in deep parts of Laguna Madre between surveys conducted in 1965 and 1974. Additional changes to 1988, together with an analysis of dredging frequency and intensity for different parts of the laguna, were consistent with this interpretation. Intensive monitoring of the underwater light regime and compilation of detailed environmental data for 3 months before and 15 months after a dredging project in 1988 revealed reduced light attributable to dredging in four of eight subdivisions of the study area, including the most extensive seagrass meadow in the study area. Dredging effects were strongest close to disposal areas used during this project but still were detectable on transects >1·2 km from the nearest dredge disposal area. In the subdivision of the study area where most of the dredge disposal occurred, light attenuation was increased throughout the 15 months of observation after dredging. In the seagrass meadow and the transition zone at the outer edge of the meadow, effects were evident up to 10 months after dredging. Resuspension and dispersion events caused by wind-generated waves are responsible for the propagation of dredge-related turbidity over space and time in this system.

Keywords

light attenuation; dredging; seagrasses; coastal lagoon; Texas coast

Exhibit 58

Marine Pollution Bulletin

Volume 58, Issue 6, June 2009, Pages 832-840

Dredging related metal bioaccumulation in oysters

L.H. Hedge, N.A. Knott, E.L. Johnston

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Available online 3 March 2009.

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https://doi.org/10.1016/j.marpolbul.2009.01.020 Get rights and content

Abstract

Bivalves are regularly used as biomonitors of contaminants in coastal and estuarine waters. We used oysters to assess short term changes in metal availability caused by the resuspension of contaminated sediments. Sydney Rock Oysters, *Saccostrea glomerata*, were deployed at multiple sites in Port Kembla Harbour and two reference estuaries for 11 weeks before dredging and for two equivalent periods during dredging. *Saccostrea* experienced large increases in accumulation of zinc, copper and tin during dredging in the Port relative to oysters deployed in reference estuaries. Lead and tin were found to be permanently elevated within Port Kembla. We present a clear and un-confounded demonstration of the potential for dredging activities to cause large scale increases in water column contamination. Our results also demonstrate the usefulness of external reference locations in overcoming temporal confounding in bioaccumulation studies.

Keywords

Saccostrea; Sediments; Bioavailability; Resuspension; BACI

Recommended articles Citing articles (58)

Exhibit 59

http://theworldlink.com/news/local/shell-shock/article_389a9be8-77dc-11df-9127-001cc4c03286.html

Shell shock

June 14, 2010
By Nate Traylor, Staff Writer - The World

Images of the oil slick devastating the Gulf of Mexico's seafood industry bring back nightmarish memories for Max and Lilli Clausen.

In 1999, Clausen Oysters in North Bend was the victim of a fuel spill that ruined millions of dollars of product.

That spill, caused by a grounded freighter, was an ink blot compared with the massive eruption of crude spewing off the coast of Louisiana. The local disaster wreaked similar havoc, though on a much smaller scale.

The Clausens, both well past retirement age, sympathize with their Gulf Coast colleagues, some of whom they know from lobbying functions and industry events.

Authorities are failing to take quick, effective action to mop up BP's mess, just as they underperformed here 11 years ago, Lilli Clausen said.

"What upsets me is the politics," she said. "They're doing too much talking and not taking enough action."

In February 1999, a freighter carrying 400,000 gallons of diesel fuel and bunker oil ran aground a mile north of the North Spit. Its name, New Carissa, soon would become famous.

Tug boats were unavailable to tow the ship out to sea. Meanwhile, inclement weather continued to drive the vessel toward shore.

Eventually the hull cracked. Oil leaked. The ship was declared a total loss. Officials blew it up.

"After that ship broke apart, that oil just came in," Lilli Clausen recalls.

Oil from the New Carissa killed more than 200 birds and did immeasurable damage to local sea organisms.

The Coast Guard set out booms to prevent oil from reaching the South Slough National Estuarine Reserve. But little was done to protect private oyster beds. Fuel touched all 600 acres of the Clausens' farm, wiping out about $2 million to $3 million in product.

"We lost 70 to 75 percent of our oysters," Max Clausen said.

"We asked for booms," Lilli Clausen said. "They promised us."

The booms didn't come. Oil spread into the bay. Tar balls and sheen on the water prompted state health officials to shut down all commercial oyster operations. The Clausens laid off half of their crew.

Likewise, Louisiana health officials have closed some oyster production and canceled shrimp season on the central coast. Even those that are still operating are battling the misconception that their product is unsafe for consumption.

"They're losing their markets," Lilli Clausen said. "We did, too."

Lilli Clausen recalled an embarrassing article published in a trade magazine, reporting Coos Bay was serving oily oysters.

"People quit buying," she said.

The Clausens fought a nearly 5-year legal battle with their insurer. The company was reluctant to pay, arguing rain, not oil, had killed their crop.

After an appeal, the Clausens won a $1.2 million settlement, but recovering from the disaster took nearly a decade. They would have retired years ago had it not occurred.

Similarly, some Louisiana oyster farmers can expect a long, uphill battle before they see financial reparations, Lilli Clausen said.

Exhibit 60

ELLEN F. ROSENBLUM
Attorney General

FREDERICK M. BOSS
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

December 1, 2017

Ms. Kimberly D. Bose, Secretary
888 First Street, N.E., Room 1A
Washington, DC 20426

Re: *Jordan Cove LP Pacific Connector Gas Pipeline LP*
Docket Nos. PF17-4-000, CP17-494-000, and CP17-495-000

Dear Ms. Bose:

Please find the attached comments, submitted by the Oregon Department of Energy on behalf of the Oregon Department of Geology and Mineral Industries, in the above-referenced matters.

Sincerely,

/s/ Jesse D. Ratcliffe

Jesse D. Ratcliffe
Assistant Attorney General
Natural Resources Section

JDR:pjn/8643729

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Oregon
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November 6, 2017

Sean Mole
Jordan Cove Analyst
Oregon Department of Energy
550 Capitol St NE, 1st floor
Salem, OR 97301

Re: DOGAMI Comments Related to Geologic Hazards and the Proposed Jordan Cove LNG Terminal and Pacific Gas Connection Pipeline

Dear Mr. Mole:

The Oregon Department of Geology and Mineral Industries (DOGAMI) reviewed the materials relating to geologic hazards in:

- Resource Report 6 – Geological Resources Jordan Cove Energy Project, dated April 2017
- Resource Report 6 – Pacific Connector Gas Pipeline Project, dated May 2017
- Draft Resource Report 13 – Engineering and Design Material, Chapter 13.3 Natural Hazards and Conditions, Jordan Cove Energy Project, dated May 2017, which includes:
    - Appendix I.13 Natural Hazard Design Investigations and Forces, and
    - Appendix J.13 Site Investigation and Conditions, and Foundation Design

DOGAMI finds the information in the Resource Reports submitted by the Applicant to be incomplete, has comments about possible deficiencies in the scientific and engineering analyses related to geologic hazards; and at this point is not satisfied that geologic hazards will be adequately addressed to ensure public safety. Please see attached: 1) General Review comments, and 2) comments on the Resource Reports.

While DOGAMI has regulatory and statutory authority on mining operations and building in the tsunami regulatory zone, this letter is not intended to address those specific requirements. The Applicant must meet Oregon building code requirements and Oregon laws, including Section 1803.2.1 Tsunami Inundation Zone of the Oregon Structural Specialty Code (Oregon Revised Statutes [ORS] 455.446 and 455.447).

Thank you for the opportunity to assist with this project. If you have any questions, please contact me at 971-673-1555 (brad.avy@oregon.gov) or Yumei Wang at 971-673-1551 (yumei.wang@oregon.gov).

Sincerely,

Brad J. Avy
Director and State Geologist

cc: Jon Allan, Tsunami Lead
Bill Burns, Natural Hazards Section Supervisor
Laura Gabel, Geologist
Ian Madin, Deputy Director and Chief Scientist
Jed Roberts, Geological Survey and Services Program Manager
Yumei Wang, Engineer

General Review Comments

This proposed project is in a high seismic hazard area due to the Cascadia Subduction Zone, which can produce a magnitude 9 earthquake, and the proposed Liquefied Natural Gas (LNG) Terminal facility is located in the Cascadia tsunami inundation zone. Some specific concerns related to the performance of the proposed facilities and public safety include:

1. The long duration of shaking expected with a magnitude 9 earthquake and how it might impact the proposed facilities and safety of people;
2. Ground failure of the softer and looser soils in the nearby area and how it may impact the proposed facilities and safety of people;
3. How the proposed facilities may negatively impact the tsunami hazards in the surrounding areas and safety of people;
4. Tsunami scour in the nearby area and how the Maximum Considered Tsunami (MCT), that is, the design tsunami, may impact the local landforms, including the dunes, and proposed facilities and safety of people;
5. Dynamic erosion of the North Spit dunes in response to the design tsunami and how it may impact tsunami runup at the proposed facilities and safety of people;
6. Tsunami debris impacting the nearby area and how it may impact the local landforms, including the dunes, proposed facilities and safety of people;
7. Dependencies on existing infrastructure that may fail, such as roads and levees; and
8. Lack of discussion of instrument monitoring safety programs related to potential ground failures, including ground settlement of soft soils and movement of landslides.

DOGAMI encourages designing and building for disaster resilience and future climate using science, data and community wisdom to protect against and adapt to risks. This will allow people, communities and systems to be better prepared to withstand catastrophic events and future climate—both natural and human-caused—and be able to bounce back more quickly and emerge stronger from shocks and stresses.

Applicant should follow existing regulations (e.g., State of Oregon's Oregon Revised Statutes, Oregon Administrative Rules, Oregon building codes, federal laws, and local regulations):

- Use best practices supporting public safety;
- Use a long-term view to protect citizens, property, environment, and standard of living;
- Integrate resilience, where possible, by avoiding high risk areas or embracing higher performance standards than may be required by building codes and regulations. This will lessen damage and speed recovery after disasters, and improve continuity of operations.

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DOGAMI Comments on Resource Reports

DOGAMI's comments pertain to the specific resource reports as presented by the Applicant. It is possible that some of the comments on Resource Report 6 are addressed in Resource Report 13; however, the Applicant has not explained nor organized the information in a manner that can be readily reviewed.

Resource Report 6 – Jordan Cove Energy Project

9. The Resource Report 6 Jordan Cove Energy Project is incomplete. For example, none of the Appendices for have been provided in Resource Report 6, including:
    - Appendix A.6 – Geotechnical Data Report, Jordan Cove LNG Project
    - Appendix B.6 – Seismic Ground Motion Hazard Study, Jordan Cove LNG Project
    - Appendix C.6 – Geotechnical Report, Jordan Cove LNG Project
    - Appendix D.6 – Estuary Flood Risk and Hazard Study, Jordan Cove LNG Project
    - Appendix E.6 – Tsunami Hydrodynamic Modelling, Jordan Cove LNG Project
    - Appendix F.6 – Tsunami Maximum Run-up Modelling, Jordan Cove LNG Project
    - Appendix G.6 – Tsunami Wave Amplitude Analysis, Jordan Cove LNG Project
    - Appendix H.6 – Design Wind Speed Assessment, Jordan Cove LNG Project

10. Section 6.4.1.1 Earthquakes of the Resource Report 6 – Jordan Cove Energy Project provides seismic ground motions that are both incomplete and unclear. For example, the Applicant states that there is a "comparison in Table 6.4.1 includes values for soft rock site conditions as well as the anticipated site soil conditions after construction." Please provide this information in a clear manner that includes informative labels for the reviewer.

11. Section 6.4.1.1 Earthquakes of the Resource Report 6 – Jordan Cove Energy Project provides seismic ground motions that have not used new building code reference documents, namely American Society of Civil Engineers (ASCE) 7-16. Please discuss why ASCE 7-16 has not been used, or provide and discuss design values using ASCE 7-16.

12. Section 6.4.1.3 Soil Liquefaction of the Resource Report 6 – Jordan Cove Energy Project refers to Appendix C.6, however, this appendix was not provided. As requested earlier, please provide information that is referenced.

13. Section 6.4.1.3 Soil Liquefaction of the Resource Report 6 – Jordan Cove Energy Project does not include information on the method used for the liquefaction triggering analyses. DOGAMI recommends that the Applicant conduct analyses consistent with the National

Academies Liquefaction Study Report (2016), available at https://www.nap.edu/catalog/23474/state-of-the-art-and-practice-in-the-assessment-of-earthquake-induced-soil-liquefaction-and-its-consequences.

For all of the liquefaction analyses, the assumptions, methods used, and uncertainties associated with them should be explicitly stated and presented for each step of the analysis. This includes the uncertainties associated with field investigations, lab testing, triggering analyses, settlement analyses, lateral spreading analyses, and proposed mitigation. This should also be a part of any future analyses including soil-structure interaction and other modeling of the structural responses to the hazards and for proposed mitigation. Results should be summarized so that it is clear which resulting values are being used for design purposes.

14. Section 6.4.1.4 Tsunamis of the Resource Report 6 – Jordan Cove Energy Project states: "The modeled rupture scenario XL1 has an estimated period longer than the 10,000-year event discussed in Volume 2, Section 13.I.2.4 of FERC's Guidance Manual for Environmental Report Preparation (February 2017)." DOGAMI's XL1 is a deterministic scenario. The DOGAMI XL1 scenario is not associated with a period longer than the 10,000-year event.

    Since 2016, there has been a national standard for tsunami resilient design in the American Society of Civil Engineers (ASCE) 7-16 Chapter 6 Tsunami Loads and Effects. This is the consensus-based engineering standard that is a referenced requirement in the latest (2018) International Building Code (IBC). The IBC is a model code that is widely adopted throughout the country including by the State of Oregon. ASCE 7-16 was extensively vetted by the American Society of Civil Engineers using an accredited and audited consensus process.

    DOGAMI recommends the Applicant comply with ASCE 7-16. DOGAMI recommends that the Applicant meet or exceed the inundation limit and other design parameters in the ASCE 7 Tsunami Design Geodatabase and select design procedures and parameters, such as design inundation depths and flow velocities, which would result in a proposed facility that will protect human safety. Any modeling procedure for determining site-specific tsunami design inundation and velocities should follow Section 6.7 of ASCE 7-16 and demonstrate that the tsunami input meets the Probabilistic Tsunami Hazard Analysis Offshore Tsunami Amplitude of the ASCE Tsunami Design Geodatabase. Maps and criteria in the ASCE 7-16 design standard are based on engineering risk analysis and reliability targets. The ASCE 7-16 Maximum Considered Tsunami (MCT) has a 2% probability of being exceeded in a 50-year period, or a 2,475 year average return period. The ASCE 7-16 MCT is a design basis event, characterized by the inundation depths and flow velocities at the stages of inflow and outflow most critical to the structure(s).

The Applicant should clearly present each step of the multiple tsunami analyses in a manner suitable for peer review by qualified professionals. All analyses, methods, assumptions and final values used for the structural design procedures for tsunami effects should be clearly documented so that results are reproducible. This includes, but is not limited to, identifying debris impact loads, foundation design factors, uplift forces, scour forces, and loads for all Tsunami Risk Category III and IV Nonbuilding Structures and designated nonstructural components.

15. Section 6.4.1.4 Tsunamis of the Resource Report 6 – Jordan Cove Energy Project refers to the existing Trans Pacific Parkway/US- 101 Intersection as being in the tsunami inundation zone. The Applicant states "To maintain grades, improvements to the intersection will not remove the intersection from the tsunami inundation zone." There appears to be only one access road for the proposed Jordan Cove LNG facility. This access road is in the tsunami inundation zone. In order for the access road to be reliably useable for safety purposes after a future tsunami disaster, it would need to incorporate both earthquake and tsunami resistant designs. These designs would need to factor in potential cyclic strain, liquefaction and lateral spreading from ground shaking. In addition, the designs would need to account for tsunami forces, including flooding, velocities, scour, buoyancy and debris impact. Has this roadway and access to the proposed facilities been evaluated for possible damage due to tsunami forces, such as tsunami scour and tsunami debris impact? Please provide analyses, results and, if needed, proposed mitigation that addresses both post-earthquake and post-tsunami safety for proposed berms, roadways and elevated ground. Related documents should be complete, clearly organized and presented to allow for peer review by qualified specialists.

<u>Resource Report 6 – Pacific Connector Gas Pipeline Project</u>

16. The Resource Report 6 – Pacific Connector Gas Pipeline Project is incomplete. For example, some of the Appendices for have not been provided, including:
    - APPENDIX C – Site-Specific Landslide Evaluation
    - APPENDIX H – Geotechnical Boring Logs
    - APPENDIX I – Laboratory Testing
    - APPENDIX J – Seismic Reflection Survey – Stukel Mt. Fault

17. The Applicant states (on page 7): "With the exception of those in the Klamath Falls area, these mapped surface faults are not considered active and are not believed to be capable of renewed movement or earthquake generation (USGS, 2002 interactive fault website)". DOGAMI considers Quaternary active faults as capable of generating potentially damaging earthquakes. DOGAMI has mapped late Quaternary faults in Coos Bay, which could impact the proposed project. Please refer to this publication: www.oregongeology.org/pubs/gms/GMS-094.pdf. DOGAMI recommends that a thorough literature review be conducted for known Quaternary active faults, as well as a site specific investigation that covers the proposed project area to evaluate if unknown Quaternary faults exist that may negatively impact the proposed facilities. Analysis of recently acquired lidar data throughout Oregon has identified numerous previously unidentified late Quaternary or Holocene fault scarps including in the Klamath Falls area. The entire pipeline right-of-way (ROW) should be evaluated thoroughly with lidar coverage of a broad area around the ROW to identify potentially hazardous faults.

18. The Applicant states (on page 8): "The PCGP Project is located in relatively sheltered areas of Coos Bay, where the effects of a tsunami on the pipeline are expected to be relatively minor". DOGAMI requests the tsunami analyses that supports this statement. What tsunami modeling was conducted for the proposed pipeline alignment? What are the tsunami flow depths used to estimate scour potential? Were tsunami scouring forces evaluated for both the incoming (inflow) and outgoing (outflow) tsunami waves?

19. The Applicant states (on page 9): "The recurrence interval between Cascadia events has been irregular and ranges from about 100 to 1,000 years (Atwater and Hemphill-Haley, 1997). Typical recurrence intervals are thought to be on the order of 400 to 600 years (Clague et al., 2000)." DOGAMI requests that the Applicant consider the most recent scientifically peer reviewed data on recurrence intervals for the Cascadia Subduction Zone (e.g., Goldfinger, et al, 2016). DOGAMI recommends that the Applicant consider the continually evolving scientific information on the Cascadia Subduction Zone and related seismic hazards.

20. The Applicant states (on page 10): " PGAs for the PCGP Project are listed in Table 2, based on USGS (2008) data compilation." DOGAMI requests that the Applicant consider the most recent USGS data, including the 2014 USGS seismic hazard maps.

21. The Applicant states (on page 10) "Higher PGAs are possible where soft soil overlies bedrock, such as in the vicinity of North Slough and Haynes Inlet MP 1.47H to 5.3H. We estimate Site Class D conditions are appropriate for the MP 1.47H to 5.3H areas." It is

common in estuaries to have soils that are softer than Site Class D conditions due to the presence of estuarine muds and river sediments, and these soils may amplify earthquake shaking. Rather than the Applicant estimating the Site Class type as D, DOGAMI recommends that both a literature review and site specific analyses are conducted to determine actual Site Class types and use those to determine PGAs and other relevant seismic ground motions and response. Downhole shear wave velocity measurements of Coos Bay estuarine sediments are available in the DOGAMI O-13-06 database.

22. The Applicant states (on page 11): " ...there is a low risk of pipeline damage from ground shaking in the absence of other deformation adversely affecting the pipeline. Based on these studies, the potential damage to buried pipelines from ground shaking intensity at the site is considered to be low." DOGAMI requests the Applicant to provide information on the vulnerability of buried pipelines in sloped areas without ground deformation during seismic shaking, such as along portions of the proposed corridor that crosses the Coast, Klamath and Cascade Ranges.

23. The Applicant states (on page 11): "ancient, inactive faults have no potential for rupture." DOGAMI finds this statement to be misleading. Weak planes or zones, such as ancient faults and bedding planes, can be displaced from earthquake shaking. DOGAMI recommends that the Applicant evaluate weak planes and zones for potential displacement that could impact the proposed pipeline.

24. The Applicant reviews faults that cross the proposed pipeline on pages 11 - 13 and includes "TABLE 3. MAPPED QUATERNARY AND HOLOCENE FAULTS CROSSING THE PCGP PROJECT". DOGAMI recommends that Applicant evaluate all faults that can impact the pipeline, including nearby active faults in Coos Bay. As stated in an earlier comment, DOGAMI has mapped late Quaternary faults in Coos Bay, which could impact the proposed project. Please refer to this publication: www.oregongeology.org/pubs/gms/GMS-094.pdf. DOGAMI recommends that a thorough literature review be conducted for known Quaternary active faults, as well as a site specific investigation that covers the proposed project area to evaluate if unknown Quaternary faults exist that may negatively impact the proposed facilities.

25. The Applicant states (on page 13): "As mentioned in the previous section, published maps are adequate for identifying the presence or absence of active faults, but are generally not detailed enough for pipeline design." DOGAMI disagrees with this statement—many areas have not been carefully mapped by geologists and it is highly likely that many active faults have not yet been identified. Furthermore, newer technologies that allow for identification

of active faults are now readily available whereas in the past they were not. As stated in an earlier comment, DOGAMI recommends that a thorough literature review be conducted for known Quaternary active faults, as well as a site specific investigation that covers the proposed project area to evaluate if unknown Quaternary faults exist that may negatively impact the proposed facilities.

26. The Applicant discusses a three phase liquefaction analysis approach and states (on page 15): "This second phase liquefaction analysis was completed using simplified methods (Seed et al., 2003; Idriss and Boulanger, 2008; and Boulanger and Idriss 2014)". DOGAMI recommends that the Applicant conduct analyses consistent with the National Academies Liquefaction Study Report (2016), available at https://www.nap.edu/catalog/23474/state-of-the-art-and-practice-in-the-assessment-of-earthquake-induced-soil-liquefaction-and-its-consequences. For the Applicant's second phase, conducting analyses using additional methods to estimate liquefaction triggering would be considered as standard-of-practice. As DOGAMI stated in earlier comments, for all of the liquefaction analyses, the assumptions, methods used, and uncertainties associated with them need to be explicitly stated and presented for each step in the analysis. This includes the uncertainties associated with field investigations, lab testing, triggering analyses, settlement analyses, lateral spreading analyses, and proposed mitigation. This should also be a part of any future analyses including soil-structure interaction and other modeling of the structural responses to the hazards and for proposed mitigation. Results should be summarized so that it is clear which results are being used for design purposes.

27. The Applicant states (on page 15): "If liquefaction will be triggered at previously identified susceptible pipeline segments under the maximum considered earthquake (MCE) per ASCE 7-10 code". As DOGAMI stated in an earlier comment, the Applicant has developed seismic ground motions that have not used newer building code reference documents, namely ASCE 7-16, which was published in 2016 as opposed to 2010. Ground motion values using ASCE 7-16 should be presented and used in the liquefaction analyses.

28. The Applicant states (on page 16): "the liquefaction and lateral spreading potential at Indian Creek (MP 128.58 – 128.62) remains unknown and access to the site remains restricted". DOGAMI requests that the Applicant keep DOGAMI informed on the status of this situation and data gap, and explain their next steps. For example, will the Applicant select another proposed route?

29. The Applicant states (on page 16): "The third phase analysis for the rerouted pipeline segment extending from MP 1.5H to 5.5H is in process and the results will be available for

the final submittal of this report." DOGAMI requests that the Applicant keep DOGAMI informed on the status of these analyses.

30. The Applicant states (on page 17): "Higher PGAs are possible where soft soil overlies bedrock, such as in the vicinity of North Slough at MP 1.47 to 3.2H and Haynes Inlet MP 4.7H to 5.5. We estimate Site Class D conditions are appropriate for the North Slough and Haynes Inlet areas." As DOGAMI stated earlier, it is common in estuaries to have soils that are softer than Site Class D conditions due to the presence of estuarine muds and river sediments, and these soils may amplify earthquake shaking. Rather than the Applicant estimating the Site Class type as D, DOGAMI recommends that site specific analyses are conducted to determine actual Site Class types and use those to determine PGAs and other relevant seismic ground motions and response.

31. The Applicant states (on page 20): "At the Coos River site, stresses exceed 100 percent SMYS but are estimated to be below the combined stress limit as shown in Figure 4.3.1 above. However, the analyses were based on elastic modulus and when the yield stress is exceeded, as in the case of the Coos River site, a fully plastic analysis is required to accurately assess the pipe stresses and strains. A fully plastic analysis requires modeling the stress-strain behavior of the pipeline under cyclic conditions in such a way as to capture strain-hardening effects, which requires a full-scale cyclic pipe load test to develop accurate model parameters. It also requires that the operational hoop, thermal, and internal pressures are accounted for during cyclic conditions. This type of analysis is beyond the scope and expertise of GeoEngineers." DOGAMI recommends that appropriate pipeline analyses are conducted by qualified specialists for the Coos Bay site, and potential impacts associated with liquefaction, lateral spreading, cyclic strain, and buoyancy forces be addressed to ensure public safety.

32. The Applicant states (on page 20): "with the potential for very large, long recurrence interval, Cascadia events". DOGAMI finds this statement as misleading. Seismologists and earthquake geoscientists, as professionals, would not generally consider earthquake recurrence intervals on the order of a few hundred years to be "very large, long". DOGAMI requests the Applicant to clarify, substantiate or change their statement.

33. The Applicant states (on page 20): "a fully plastic analysis of pipe strain will be completed to verify that the liquefaction and lateral spreading induced plastic deformation of the pipe at the Coos River crossing is tolerable." As stated earlier, DOGAMI recommends that appropriate pipeline analyses are conducted by qualified specialists for the Coos Bay site,

and potential impacts associated with liquefaction, lateral spreading, cyclic strain, and buoyancy forces are addressed to ensure public safety.

34. The Applicant states in their Conclusion sector (on page 21): "One Holocene (active) fault crossing and three Quaternary fault crossings were identified along the proposed pipeline alignment as listed in Table 3." As DOGAMI stated earlier, DOGAMI recommends that a thorough literature review be conducted for known Quaternary active faults, as well as a site specific investigation that covers the proposed project area to evaluate if unknown Quaternary faults exist that may negatively impact the proposed facilities. The faults should not be limited to locations of the proposed pipeline crossings.

35. The Applicant states (on page 25): "some of the later reroute alignments are currently outside the area of LiDAR and aerial photograph coverage". DOGAMI recommends the Applicant obtain high resolution lidar for all areas that may impact the proposed facilities along the proposed route. Lidar coverage should be collected with enough buffer distance to characterize potential seismic and landslide hazards. For example, for landslide hazards, the lidar should include from the valley bottom to the top of the ridge. Also, there is publicly available statewide aerial photography. Please evaluate the potential large landslides keeping in mind that landslides may extend from the tops of ridges and may move downslope to block rivers. In addition, lidar should be used to evaluate seismic sources.

36. The Applicant states (on page 27): "The DOGAMI study provides a broad-scale assessment and mapping of slopes potentially susceptible to RMLs along the portion of the pipeline within Coos, Douglas and Jackson counties (MPs 1.5H - 166). The potential for RMLs to occur east of MP 166 generally is considered to be relatively low based on geologic conditions, relatively little rainfall and statistically fewer past historical RML occurrences. However, the slopes east of MP 166 were reviewed for this hazards report to identify high-risk sites based on general guidelines provided in Forest Practices (FP) Technical Note 2 of the Oregon Department of Forestry (ODF, 2000). The ODF guidelines recommend screening for high-risk sites by identifying slopes that exceed 65 percent gradient on existing topographic maps, then performing surface reconnaissance to identify high risk site features." Both the DOGAMI RML and ODF RML methods are outdated. DOGAMI recommends that the Applicant use current state of practice methods that include lidar as a base map.

37. The Applicant states (on page 27): "Based on available topographic mapping, no slopes along the pipeline alignment east of MP 166 exceed 65 percent or appear to be at high

potential for RML occurrence." DOGAMI does not agree with the conclusion based on the fact that state-of-practice methods were not used to develop this conclusion. DOGAMI recommends that the Applicant use current state of practice methods that include lidar as a base map.

38. The Applicant states (on page 46): "As currently planned the portions of the pipeline that are crossing waterbodies that have the potential to be impacted by tsunami scour, will be installed using trenchless methods at depths well below the potential scour depths. Therefore, tsunami scour is not considered a hazard to the pipeline project." The Applicant further states "The modeling analysis showed that some temporary scour may occur in Coos Bay along the pipeline during inundation of the tsunami (approximately 1 to 2 hours)." The Applicant indicates that scour from tidal currents and river flows are approximately 3 feet at the pipeline crossing, and "it is recommended to use a 3-foot depth of scour resulting from tsunami impact". DOGAMI requests the Applicant provide information on maximum potential scour depth from a Cascadia tsunami. Also, DOGAMI requests information on the minimum factor of safety the Applicant applied to address the maximum potential scour depth from Cascadia tsunamis along the proposed alignment in greater Coos Bay area.

Draft Resource Report 13 Engineering and Design Material, Chapter 13.3 Natural Hazards and Conditions, Jordan Cove Energy Project, dated May 2017, which includes:

- Appendix I.13 Natural Hazard Design Investigations and Forces, and
- Appendix J.13 Site Investigation and Conditions, and Foundation Design

Based on the review of tsunami-related documents in Resource Report 13, DOGAMI requests additional supporting information that discusses and clarifies the following:

39. The Applicant, in general, found that their MIKE21 modeling matched the DOGAMI L1 first wave arrival (which reflects the largest wave), although wave amplitudes and phase differences were observed for later wave arrivals. No explanation is provided to account for the latter differences. DOGAMI requests further discussion of differences in the modeling results after the initial wave arrival to account for phase and amplitude differences observed in the modeling results.

40. DOGAMI requests that the Applicant provide peer reviewed documentation that describes the MIKE21 FM model and its ability to model tsunami inundation. Many issues are unclear, for example, does MIKE21 adequately account for the (vertical) wave runup on the wall and/or composite structure?

41. DOGAMI requests that the Applicant provide further explanation of the approach used to define the digital elevation model (DEM) that is recommended. In particular, how does the developed grid differ from the tsunami grids generated by NOAA's National Center for Environmental Information (NCEI). These data may be obtained here: https://www.ngdc.noaa.gov/mgg/inundation/tsunami/.

42. DOGAMI requests that the Applicant explain to what extent has the model been tuned to match the DOGAMI L1 scenario and inundation results.

43. DOGAMI requests that the Applicant provide a better depiction of the three cases used to define the design crests. It is unclear whether the design reflects a berm, wall, or a composite structure around the perimeter of the entire complex, or portions of the complex. Please provide figures that characterize the proposed design.

44. DOGAMI requests that the Applicant explain why mean high water (MHW) was used as opposed to MHHW (as used by DOGAMI).

45. Values of future sea level rise (SLR) presented by the Applicant are based on existing (historical) trends derived for the Charleston tide gauge. Based on its current rate, estimates were made out into the future (i.e. 30 years). This is an overly simplistic approach that assumes the past is the key to the future and hence discounts possible acceleration of SLR in the future. A more effective approach would be to base future estimates on the National Research Council (2012) SLR study that was completed for the US West Coast. National Research Council estimates account for expected local tectonic changes as well eustatic and steric responses and are a more reasonable (and current) estimates for the future. Please address SLR using current scientific data and methods.

46. Provide analysis of the potential role of sediment erosion of the North Spit dunes caused by the design tsunami. Research on the US East Coast suggests that sediment erosion during a tsunami may be significant and could impact inundation extents and runup (Tehranirad et al., 2015, 2016; Tehranirad, 2016). This notion is also supported by field studies following the March 11, 2011 Tohoku, Japan tsunami (Goto et al., 2012; Tanaka et al., 2012).

47. Provide analyses of the potential role of tsunami wave reflection/focusing/defocusing as the tsunami impacts the proposed LNG facilities and its possible public safety implications for the surrounding Coos Bay environment. Tsunami waves that impact against proposed protective structures (e.g., berm, wall or composite structure) and the subsequent transfer of that energy to other areas within the bay is a public safety concern. DOGAMI requests

additional modeling for the purposes of addressing public safety. All documents should be complete, clearly organized and presented to allow for peer review by qualified specialists.

48. DOGAMI requests that the Applicant provide analysis of maritime vessels and their potential to become ballistics within the bay. Maritime evacuation planning in response to the tsunami should be conducted and provided.

49. DOGAMI requests that the Applicant provide analysis on the potential for off-site debris impacting the facilities and the potential ramifications with respect to public safety.

50. DOGAMI requests that the Applicant provide information on each of the DEMs used for the tsunami model. For example, were three different DEMs used that reflect the three different case studies: berm, wall and composite structure? Please provide the DEMs.

51. Elevated structures, including elevated berms, used for assembly areas in the tsunami inundation zone are subject to ASCE 7-16 chapter 6 requirements. To ensure public safety, DOGAMI strongly recommends that the Applicant design all elevated structures to be used as assembly areas in the ASCE tsunami design zone in accordance with ASCE 7-16 chapter 6. Design documents should be complete, clearly organized and presented to allow for peer review by qualified specialists.

Document Content(s)

Exhibit 61

PUBLIC COMMENT

Provided by Barbara Gimlin, P.O. Box 1527, North Bend, OR 97459

Intertidal Flats Mitigation Proposed for Kentuck Slough

Jordan Cove Energy Project Joint Permit Applications

U.S. Army Corps of Engineers/Oregon Department of State Lands

January 11, 2015

INTRODUCTION

This public comment document presents concerns and credibility issues regarding the Compensatory Wetland Mitigation (CWM) plans submitted or referred to in current U.S. Army Corps of Engineers (Corps) and Oregon Department of State Lands (DSL) Joint Permit Applications (JPAs) for the Jordan Cove Energy Project (JCEP) in North Bend, Oregon. Of the CWM versions presented for the overall JCEP project, this document focuses on only one portion of each— the estuarine mitigation proposed for the Intertidal Flats Mitigation Site at Kentuck Slough.

The estuarine mitigation proposed for Kentuck by the JCEP has not undergone the serious environmental and hydrologic evaluation needed to ensure the mitigation will not result in contamination of the Coos Bay estuary, flooding of adjacent and upstream property owners, and a potential mosquito infestation that would affect area residents. Much more input is needed from hydrologists, engineers, natural resources scientists, and planners to fully understand and design a plan for the site that will address current and future site-specific conditions on the ground, including upstream of the site. The inconsistencies in the plans brought forward, together with the lack of appropriate studies and documentation, is alarming. As it stands, there is a significant potential for substantial adverse effects from the mitigation proposed at Kentuck.

Coos Bay is my playground and I enjoy boating, fishing, clamming, and crabbing in the bay. Kentuck is part of the neighborhood I live in. If toxins are released into the bay from the existing plans for the project, be it from the extensive soil contamination at the main facility site or former golf course toxins released by opening up Kentuck, it will likely have a devastating effect to marine life and the humans who consume shellfish if the issues presented are not fully addressed. In addition, my neighbors who live up Kentuck Way Lane already have increased annual flooding problems, and that will likely increase even more by the current plans for Kentuck.

There are various CWM plans floating around in the regulatory system for the mitigation proposed for the overall project, and all include various versions of the mitigation proposed for Kentuck. The lack of consistency is an indicator that the project warrants close and interactive scrutiny by the local, state and federal agencies that are authorized to review and approve the project.

BACKGROUND

The comments included in this document are based on my personal observations living one mile from Kentuck since 2008, along with firsthand knowledge of the JCEP while working on the project as environmental consultant while employed by SHN Consulting Engineers & Geologists, Inc. (SHN) in Coos Bay from March 2013 to April 2014.

The existing bridge over the Kentuck Slough channel is located on East Bay Road and includes four large tidegates that regulate the flow between the channel and the Coos Bay estuary. The structure was rebuilt in 2007 and Coos County received $2,321,000 through Oregon Transportation Investment Act funds in 2003 to construct the project. Now the JCEP wants to remove the bridge and tidegates and open up the estuary along East Bay Road by building a bridge and allowing tide waters into both the former Kentuck golf course and the historical inlet that at one time extended approximately five miles inland prior to being filled over 60 years ago.

Figure 1. Existing tidegates (4) at the East Bay Road bridge over the Kentuck Slough channel. The tidegates and bridge were rebuilt in 2007 at the cost of over $2 million. (1-8-15).

The most recent JCEP JPA on record for the DSL was submitted in March 2014. The most recent version of the JPA submitted to the Corps was in October 2014. There are four CWM plans included and referred to in project documentation. They were all prepared by David Evans and Associates, Inc. (DEA) and look very similar. Of note, two different (but similar) CWM plans are included in the full JPA document submitted to the Corps for the current JCEP permit application, and both are dated October 2014. It is unclear which CWM plan is the final product, even from the narrative, but it appears the CWM plan attached first in the document is the one that is moving forward. In addition, two other

CWM plans were submitted to the DSL and are associated with their project documentation (December 2011, March 2014).

My concerns about the lack of proper study and analysis for the Kentuck mitigation portion of the project repeatedly fell on deaf ears while I worked on the project under SHN. I sat in on weekly conference calls with DEA, the consulting company hired by the project to (among many things) write the CWP plan. It was like they didn't want to hear anything that would interfere with what they had in place. This was despite the fact that the plan(s) in place did not take into account the issues brought forth in this public comment. I went as far as to send site photos during flooding stages and documentation of ongoing fill being conducted upstream that could affect the site hydrology. To my knowledge, it was ignored. The issues certainly were not included or addressed in the resultant CWM plans proposed by DEA, or in any other part of the JPAs prepared by DEA that were submitted to the Corps and DSL.

The CWM plans used in the current JPA for the Corps frequently refer to the DSL Removal-Fill (RF) Permit No. 37712-RF (issued by the DSL in December 2011 and expiring December 21, 2016) as providing approval for the mitigation proposed for estuarine resources at Kentuck for the current JCEP project. DSL Permit 37712-RF is based on a JPA submitted to the DSL in 2011 by the International Port of Coos Bay (Port) for the Port's previously proposed Oregon Gateway Marine Terminal project.

The current JCEP DSL permit recorded online at the DSL's website (as of January 8, 2015), Permit 54908-RF, is dated March 20, 2014, and includes a CWM plan dated March 2014. The March 2014 CWM plan has significant changes from the CWM plan approved by the DSL in December 2011, and is different from the two October 2014 CWM plans included in the Corps JPA. There is no documentation provided in any of the JCEP documents to demonstrate the previous CWM plan approved for the Port DSL permit issued in 2011 has been subsequently approved (as revised) for the current DSL permit for the JCEP. The 2011 approval was based on a different applicant and a different overall project. If the Corps and/or DSL have approved the subsequent changes, that process of approval should be documented as part of the administrative record included in the most current JPAs.

There is a lack of consistency in the information presented for review in the JPAs and associated CWM plans. It can be difficult at times to tell what is actually planned for the site. Even the most current CWM plan presented has not been updated and lists the construction of the project and associated mitigation as anticipated to begin in the 3rd and 4th quarters of 2014.

Despite the above inconsistencies, the comments and questions presented in this document are valid for all CWM plans associated with the JCEP.

EXISTING EAST BAY ROAD BRIDGE AND ASSOCIATED TIDEGATES

The narratives for the various CWM plans for Kentuck do not clearly present information on the existing tidegate structure installed under the current East Bay Road bridge that connects Kentuck Slough to Coos Bay. It is a substantial structure with four large tidegates and was rebuilt in 2007.

Prior to the recent replacement, the previous bridge did not meet current design standards and needed to be replaced. Attached to the downstream side of the existing bridge was a set of three 7.5-ft wide by 10-ft high top-hinged tide gates. One of the tide gates was wedged in the gate slot and completely inoperable. The other two gates functioned, but leaked significantly during flood tides. Additionally, the gates were frequently overtopped during high tides.

The leaky gates allowed for saltwater intrusion into the slough and also resulted in an increase in the amount of saltwater that intruded into adjacent land via groundwater flow. This negatively affected the quality of the soil during the summer months when there is little freshwater inflow to the slough to help dilute the salt concentrations from the bay water. The local landowners indicated at the time that the volume of saltwater influx to the slough was tolerable, but any increase would not be acceptable.

WEST Consultants, Inc., was hired to conduct an HEC-RAS unsteady flow hydraulic model of the tidegate designs for the new bridge to accommodate and improve upon conditions that encourage the estuarine habitat, while at the same time would not increase the volume of saltwater influx to the slough over the existing conditions. Kentuck Slough is considered an important salmonid habitat. Therefore, the hydraulic parameters for the replacement tidegates installed in 2007 were developed in close consultation with the National Marine Fisheries Service (NMFS), U.S. Fish and Wildlife Service (USFWS), and the Oregon Department of Fish and Wildlife.

After over $2 million being spent to create an efficient bridge with tidegates at Kentuck in 2007, the JCEP now wants to undo it. For the complicated mitigation proposed at Kentuck for the JCEP, more complex hydraulic analysis to identify the impacts is needed to support the determination of appropriate mitigation. Removal of the existing bridge and tidegates needs full evaluation of existing hydrology, hydraulics, sediment transport, fluvial geomorphology and water quality, and the supporting documentation needs to be presented for evaluation.

INTERTIDAL FLATS MITIGATION PROPOSED — KENTUCK SITE

The Kentuck Slough site is referred to as “primarily unvegtated mudflat and tide channels, and some salt marsh.” The following appears to be the scope of work for the JCEP CWM plan related to the site, from the JPA submitted to the Corps:

> *Jordan Cove Energy Project Compensatory Wetland Mitigation Plan – Part B*
>
> **1.2.2 Intertidal Flats Mitigation Site (Kentuck Slough Site)**
>
> **Mitigation Goal 2:** Reestablish tidal flow to approximately 45.01 acres of historical intertidal habitats adjacent to Kentuck Slough. (Actual area as currently designed will be 46.59 acres, which results in additional contingency credits. Mitigation Goal 2 and associated Objectives are based on the minimum acreage needed to meet standard DSL mitigation ratios). To achieve this goal, the following objectives will be carried out:
> • **Objective 2.1:** Construct a new bridge in East Bay Drive to allow tidal exchange between Kentuck Inlet and the “back nine” of Kentuck Golf Course.
> • **Objective 2.2:** Construct a new cross dike between the front and back nine of Kentuck Golf Course, with a standard tidegate to drain the front nine to the back nine, and construct a fish friendly tidegate array through the Kentuck Slough dike, allowing the majority of flow from Kentuck Slough to enter the back nine.
> • **Objective 2.3:** Remove the culvert and tidegate located adjacent to the east side of East Bay Road near the southeast corner of the golf course site.

• **Objective 2.4:** Restore tidal connection to the irrigation pond creek system through installation of a fish passable culvert that meets ODFW fish passage criteria.
• **Objective 2.5:** Construct and/or enhance approximately 6,000 linear feet of tide channels.
• **Objective 2.6**: Establish an approximately 1.73 acre wetland bench along Kentuck Slough by relocating the existing levee southward.
• **Objective 2.7:** Establish an emergent to scrub-shrub, brackish to freshwater transitional plant community along the Kentuck Slough bench described in Objective 2.6.
• **Objective 2.8:** Establish a minimum of 0.18 acres of salt marsh habitat within the internal portion of the Kentuck Slough site, with the remainder of the internal portion (43.10 acres) being mudflat and/or tide channel. A greater amount of salt marsh, with subsequent reduction in mudflat is acceptable.

Below is the general study area used by DEA for Kentuck.

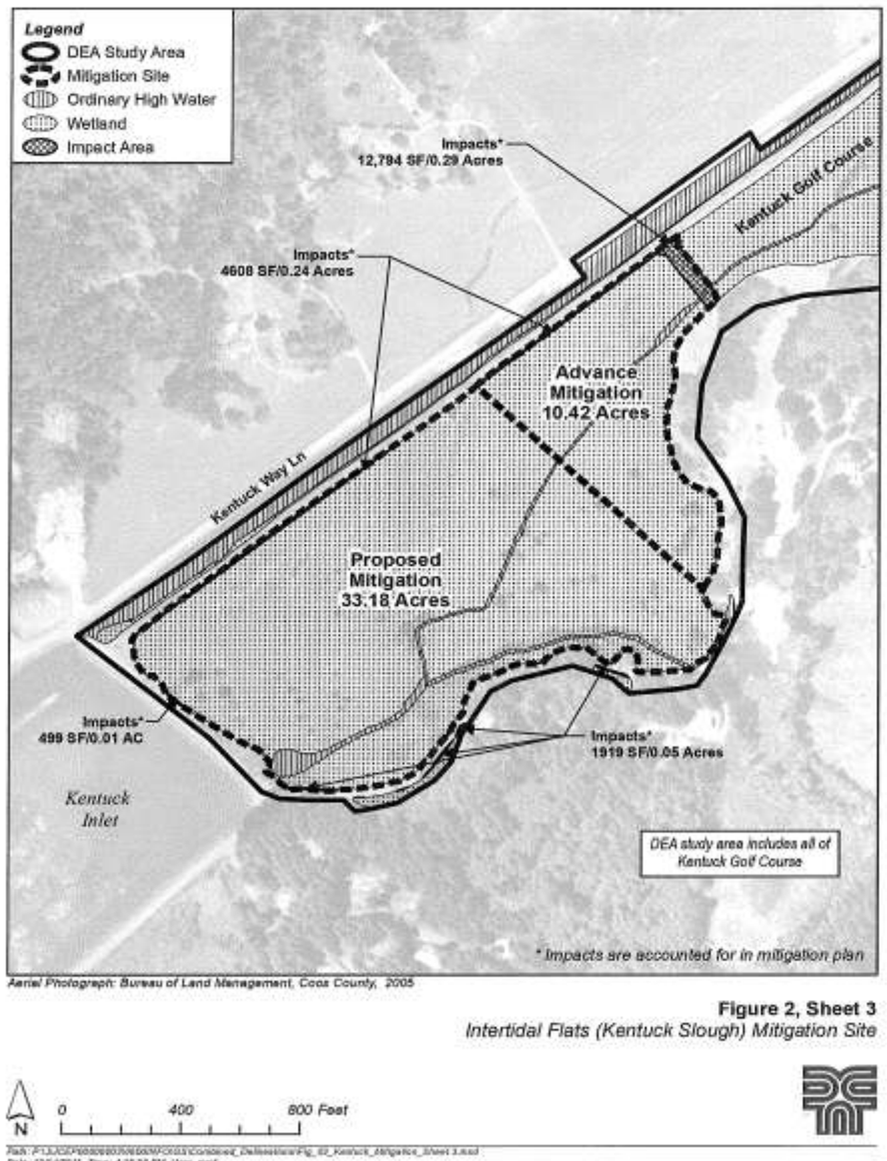

Figure 2. Study area used by DEA to development mitigation at the Kentuck Slough site.

Changes to the JCEP CWM Plan in the October 2014 Corps Permit Application

One of the CWM plans for Kentuck submitted in the October 2014 JPA to the Corps states mitigation for the site has been refined based on agency comments since the issuance of DSL Permit 37712-RF in 2011. What agency comments were considered and why aren't they referenced and documented? For the current CWM plan, the following are fairly significant changes to the mitigation proposed from what was previously approved in DSL Permit 37712-RF in 2011:

- The October 2014 CWM plan includes the establishment of 12.49 additional acres of tidally influenced habitats at the site and adjacent areas that were not included in 2011.
- Mitigation improvements such as levee relocation, cross-dike placement, roadway upgrades, etc., wil now result in 3.11 acres of permanent incidental wetland impacts, of which 0.59 acres was previously included.
- An additional 0.59 acres of incidental emergent wetlands impacts wil result from improvements needed at the site, in addition to the 10.47 acres of mudflat impacts presented in 2011.
- Current designs include raising elevations within the site to better support establishment of salt marsh, provided there is suitable material to import to raise grades. (*This seems a bit vague.*)
- The current design proposes rebuilding the existing Kentuck Slough levee roughly adjacent to the south side of the existing levee and restoring the area under the old levee back to wetland, creating a wetland bench along the slough channel.

Inconsistencies in Elevation Data

The October 2014 CWM plan states the following:

- *The primary salt marsh surface at the reference site (immediately downstream of East Bay Road) occurs between approximately elevations 5.5 and 8.5 feet NAVD88 (North American Vertical Datum of 1988). However, typical elevations within the former golf course range between 2.0 and 4.0 feet NAVD88. These lower elevations in the former golf course preclude vegetation establishment, and therefore mudflat would be the predominant habitat type without intervention. … Current design includes raising elevations within the site to better support establishment of salt marsh; however this is reliant on having suitable material to import to raise grades.*

However, in a November 4, 2010, letter to Chuck Wheeler at the National Marine Fisheries Service, DEA states the following:

- *The proposed mitigation would reestablish tidal flow to approximately 33 acres of historic intertidal mudflat/low marsh habitat adjacent to Kentuck Slough. Survey information confirms that elevations within the golf course are appropriate for establishing mudflat habitat. The primary salt marsh surface at the reference site (immediately downstream of East Bay Drive) occurs between elevations 7.0 and 9.0 feet mean low low water (MLLW). However, typical elevations within the golf course range between 4.0 and 6.0 feet MLLW. These lower elevations in the golf course preclude vegetation establishment and therefore mudflat will be the predominant habitat type (DEA 2010).*

Why would the elevation at MLLW immediately downstream of East Bay Road (7.0-9.0 feet) be higher than the NAVD88 elevation data at the same site presented by DEA in 2014 (5.5-8.5 feet)? In turn, the MLLW listed for the golf course in 2010 (4.0-6.0 feet) is higher than the NAVD88 elevation data in 2014 (2.0-4.0 feet). No supporting documents from site visits, field studies, and surveys conducted are provided for any of the assertions. And it sure seems like much more elevation data is needed overall.

PRIMARY CONCERNS ABOUT THE PROPOSED MITIGATION AT KENTUCK

Potential Site Contaminants

The former golf course at Kentuck operated over four decades before closing in 2009. The CWM plans do not demonstrate that any studies on contaminants have been conducted at the site, particularly for contaminants that may be harmful to marine life. While fertilizers, pesticides and herbicides have improved in recent years, who knows what was previously used at the site and the residual contamination risk the previous use as a golf course may pose.

Attachment A for the October 2014 Corps JPA lists the following regarding potential hazardous materials that may be encountered by the overall project:

13. **Hazardous, Toxic, and Waste Material Handling:** Petroleum products, chemicals, fresh cement, sandblasted material and chipped paint, wood treated with leachable preservatives or other deleterious waste materials shall not be allowed to enter waters of this state. Machinery refueling is to occur at least 150 feet from waters of this state and confined in a designated area to prevent spillage into waters of this state. Barges shall have containment system to effectively prevent petroleum products or other deleterious material from entering waters of this state. Project-related spills into waters of this state or onto land with a potential to enter waters of this state shall be reported to the Oregon Emergency Response System (OERS) at 1-800-452-0311.

This short section does not begin to address the issue of potential contaminants at the Kentuck mitigation site, which is part of the overall JCEP. In addition to concerns over the prior use as a golf course, other concerns were brought up during a Coos County Commissioners meeting on September 22, 2009. The commissioners approved a zone change for the Kentuck Golf Course to exclusive farm use to allow the Port to use the land. Commissioner Bob Main voted no, in light of concerns he said he had about pollutants washing into Coos Bay. Commissioners Nikki Whitty and Kevin Stufflebean voted yes.

A story carried in *The* World newspaper on September 23, 2009, said developers had devised a plan that would flood the back nine holes of the course to satisfy government wetland replacement requirements for the JCEP, and that they would remove part of the dike west of the course and build a bridge for East Bay Road. It also included the following:

> *Main said he was concerned that a former methamphetamine lab in a house in the area had contaminated the course and would leach into the bay if the mitigation plans proceeded. Oregon's Department of Health Services has a house on Golf Course Lane listed as unfit for use.*

Main's fellow commissioners and the Port's lawyer tried to reassure Main, noting that state and federal agencies would check into those issues through a biological assessment and U.S. Army Corps of Engineers review. Main remained opposed.

"I'm not comfortable that they will check that potential problem," he said.

Mark Whitlow, a Portland attorney representing the Port, said it was premature to discuss the runoff issue, because the primary purpose of the meeting was the zone change.

"Until the Port's project goes forward, there is no project proposal for the site," he said.

There is no mention in any of the CMP plans that the potential contamination from the former meth house has been investigated. This is not for lack of knowledge. I brought up the article during the summer of 2013 twice during weekly conference calls with DEA and also provided DEA staff with a copy of the article. And it's clear the JCEP's attorney, Mark Whitlow, was aware of the potential issue. At a minimum, it should be brought up and addressed in all project documents related to the proposed mitigation.

Site Hydrology

There is a serious lack of documentation of existing hydrological studies that have been conducted for the proposed Kentuck mitigation, including upstream of the site. The area floods frequently and even when the golf course was open, the locals referred to it as the "yacht club" during the rainy season. Farms and homes to the north of the Kentuck Slough channel, along with to the west (upstream) for approximately three miles, are frequently flooded during heavy rains.

Figure 3. Former Kentuck Golf Course taken from East Bay Road (looking west) following heavy rain. The channel is on the other side of the levy shown on the left. (12-24-14)

The October 2014 CMP plan states that groundwater at the site was typically observed in soil pits from 10 inches depth to within an inch or two of the surface. It further states that saturation typically occurred 2 inches above this depth and that these conditions are "typical of wintertime conditions." The plan, however, does not present any data, dates, or locations to substantiate this claim. From driving past the site on an almost daily basis for the past 6-1/2 years, I can tell you the ground saturation is frequent and much deeper during rainy periods. Heavy rains can occur in the fall, winter, and spring, and further monitoring and analysis is needed to accurately depict the current hydrology.

Figure 4. Kentuck Slough channel west of East Bay Road bridge and tidegates (north of the former Kentuck golf course) following heavy rain. (12-24-14)

Section 4.3.2.1 of the October 2014 CWM plan for existing hydrology states the following:

> *Shallow ponding was observed in many locations throughout the former golf course, but was most pronounced in the western half. Ground topography throughout the former golf course varies slightly, with roughly 2 to 3 feet of difference in relief from location to location. Drift lines were observed along the edges of the higher areas, which suggest that ponding was substantially greater before the site visit occurred. This ponding is likely the result of direct precipitation, which had not occurred for more than a week before the site visit.*

My first question would be, "What site visit?" And just one site visit was conducted to determine the existing hydrology? It's far from adequate. Where's the documentation? When was it conducted? One site visit vaguely referred to in the plan is listed as having occurred in January 2009. Is that the one they're referring to? The short Existing Hydrology section refers to shallow inundation occurring during "high tide," but what high tide?   Tides vary many feet with the lunar cycle. Where is the data, are there photos, and how can they possibly claim the four paragraphs in Existing Hydrology represent the existing hydrology? The science is missing.

There is limited space for water to go at Kentuck and opening up the estuary will likely increase the flooding potential far upstream and to the north if this factor is not carefully studied and analyzed in the development of a project design. In addition, the annual rise of the world's oceans, thought to be approximately 1 cm a year, also needs to be calculated in.

Figure 5. Farm north of Kentuck Way Lane at Mile Post 1 following heavy rain. (12-24-14)

The above photo of a farm north of Kentuck Way Lane shows typical flooding during heavy rains. The site is west (upstream) of the new tidegate and dike proposed in the mitigation, despite the substantial reinforcement at the existing bridge and tidegates one mile downstream. The flooding extends to the south and west of Kentuck Way Lane, as shown in the next photo.

Figure 6. Farm south of Kentuck Way Lane at Milepost 1.5. Photo taken from Kentuck Lane at Milepost 1 and is looking west beyond the proposed tidegate and berm for the JCEP Kentuck mitigation. (12-24-14)

The October 2014 CWM plan refers to potential site constraints identified in the CWM plan authorized under DSL Permit 37712-RF, including the following:

> *Opening the site to tidal influence creates the risk of increased flooding potential and saltwater intrusion to adjacent and upstream landowners. New cross dike construction and repair and/or enhancement of the existing dike are therefore required to ameliorate this risk.*

That all sounds well and good, but where are the studies and data to address how the new tidegate and dike will address the increased tidal flow and the substantial flooding that occurs well upstream of the site they propose to block off?

Flood impacts (stage, velocity, duration) need to be addressed regarding current alterations that have been taking place upstream. In particular, Main Rock Products, Inc. (Main Rock) between Mile Post (MP) 3 and 4 has been progressively filling a 47.41 acre parcel located at 95688 Kentuck Way Lane (Parcel No. 1100, Coos County Tax ID: 25400, Map No. 25S12W04). The area is listed by the USFWS Wetlands Mapper as being Palustrine, emergent and temporarily flooded (PEMA) wetlands. As the fill amount has increased, portions of the wetlands have been excavated out to define the next boundary for the fill extension.

Figure 7. Coos County tax map showing the location of the Main Rock Products, Inc. parcel being filled.

Currently the western 1/3 of the parcel is being filled. However, further east along Kentuck Way Lane, the remaining 2/3 of the tax lot has also been progressively filled since 2003.

On January 8, 2014, I submitted an alleged violation report regarding the fill to Anita Andazola, Corps Compliance & Enforcement specialist, at the Corps North Bend Field Office. The alleged violation was provided to DEA at the time and followed up with discussion during a conference call with DEA on January 13, 2014, while I still worked for SHN. During the conference call, after expressing my extensive concerns about the Kentuck mitigation proposed, Sean Sullivan, DEA JCEP project lead, said unless there was a malfunction of the tidegate proposed for mitigation, problems were not anticipated. I reiterated that I felt it was quite likely the extensive amount of fill that has been occurring upstream of the mitigation site will affect the overall hydrology of the area and we left it at that.

On July 9, 2014, I followed up with Anita Andazola at the Corps on the alleged violation report submitted in January. Her response was that the information had previously been provided by the Corps to the EPA and she recommended I contact Yvonne Vallette of the EPA's Portland office. I spoke with Yvonne the same day and found out that another alleged violation report had been turned in by one of the adjacent property owners in October of 2013. Yvonne had visited the Corps' office in North Bend and met with Anita about various projects. She said she had expected to do a site visit and conduct further review of the Kentuck situation at that time, but they were not able to get to it. The Oregon Department of Environmental Quality National Pollution Discharge Elimination Systems (NPDES) permit was reissued for Main Rock on November 18, 2013 (Facility No. 52575), without modifications. Main Rock continues to operate under a permit under the Oregon Department of Geology and Mineral Industries (DOGAMI), which allegedly has approved the fill. A copy of the correspondence with the Corps and EPA is attached.

Figure 8. Ongoing fill activities along Kentuck Way Lane. View is at MP 3.2 looking east. (1-11-15)

A site visit on January 11, 2015, confirmed that extensive fill of the western portion of the Main Rock parcel has been continuing and now extends much further towards Kentuck Creek to the south since January 2014, filling a very wet area. The fill that is being placed appears to be spoils extracted from marketable rock/gravel and appears to be have a high silt/clay component. There are no sediment and erosion control measures in place for the extensive fill piles placed at the site. Instead, there are visible bulldozer tracks where the fill is systematically being pushed into the wetlands. Over the years, there has likely been a significant rise in elevation at the site(s) for the fill that has placed. It has created a platform-like over-sized berm for the surrounding wetlands and creek.

Figure 9. Ongoing fill activities along Kentuck Way Lane. View is at MP 3.2 looking west. (1-11-15)

Historical photos help to show the amount of fill that has been progressively been placed by Main Rock in recent years south of MP 3 and 4 of Kentuck Way Lane. For the parcel being filled, Kentuck Creek weaves back and forth along the long lot, occurring south of the site for the western 1/3 and eastern 1/3 but crossing over to the northern side adjacent to the road (Kentuck Way Lane) for the middle portion.

In Google Earth imagery from August 27, 2007, you can see where fill has been placed to the east at approximately MP 3.4. The images from November 16, 2011, show that Main Rock also began to fill the wetlands to the west from approximately MP 3.1-3.3, with the fill measuring approximately 445' long by 60' wide. By July 22, 2012, it was approximately 665' long and 120' wide. Although the length didn't change much by the next Google Earth photo taken on May 3, 2013 (approximately 690' long), the width of the fill from Kentuck Way Lane toward Kentuck Creek increased to approximately 190 feet. Since the last imagery, the length and particularly the width has increased much more. Not easily seen from Kentuck Way Lane is the extensive excavating and bulldozing of fill that is occurring at the current site along the southern boundary of the fill.

Figure 10. Fill placed south of Kentuck Way Lane between MP 3 and 4 (top right) as of August 27, 2007.

Figure 11. Fill placed south of Kentuck Way Lane between MP 3.1 and 3.3 as of July 22, 2012.

Figure 12. Fill placed between MP 3 and 4 as of May 3, 2013.

When the Kentuck mitigation site is newly re-opened to Coos Bay to increase the size of the estuary, complex and dynamic flow patterns are likely to occur. It is essential that the plan design takes into account the increased flows, tidal channels, and how flooding of adjacent properties to the north and west will be prevented. A hydrodynamic model that clearly researches and addresses the capacity and flow dynamics likely to occur needs to be developed and submitted for approval prior to issuance of Corps and DSL permits associated with the project. This should include monitoring that extends upstream of the proposed mitigation site and be based, at a minimum, on tides, storm surge, stream velocity, flow capacity, projected long-term sea level rise and, most importantly, current conditions. In addition, the current monitoring proposed in the CWM plans is far from adequate (once a year) and needs to be revised to ensure all seasons and scenarios are monitored and addressed.

Nautical charts displayed at the Coos Bay Boat Building Center show that from 1865 to 1937 Kentuck Slough extended approximately 5 miles inland from its current site and was an inlet. By 1947 approximately ½ of the inlet was filled in to the east, and by 1953 the inlet was primarily filled in west of East Bay Road. Today, the Kentuck Slough channel that remains is regulated by four large tidegates under East Bay Road, with a levy separating the channel east of the bridge/tidegates from the former Kentuck Golf Course site (closed in September 2009). The proposed JCEP Kentuck mitigation site extends from river mile 0.0 to 0.9 of the Kentuck Slough channel. In addition, there is a 5' diameter culvert and tidegate near the southeast corner of the former golf course along East Bay Road (approximately 1/10 mile from the four existing tidegates and associated bridge) that will be revised.

Figure 13. Nautical chart from 1937 shows Kentuck Inlet extending approximately 5 miles inland.

Figure 14. Nautical chart from 1947 shows Kentuck Inlet as filled to the west, reducing its size approximately in half.

Figure 15. By 1953, the nautical chart shows Kentuck Inlet filled to its approximate location today, with a channel now in its place.

The CWM plan (page 10) states the Kentuck mitigation site is a “100-acre historic flood terrace” that historically “would have been classified as an estuarine wetland.” **Historically it was an inlet.**

AND WHAT ABOUT THE MOSQUITOES?

In the summer of 2012, an expansion project undertaken by the USFWS was completed for the Bandon Marsh south of Coos Bay. The purpose of the project was to allow tidal flats to resume their natural state after being diked and used for grazing land by farmers for decades. The expansion resulted in a huge mosquito infestation the following summer that was referred to as a biological disaster. It wreaked havoc on all surrounding property owners and made ventures outside a chore to escape the mosquitoes. The increase of mosquitoes was determined to be caused by removing tidegates, digging ditches, and increasing hydrology for the expansion. The original price tag for the 1000-acre restoration project was $4 million dollars. It inflated to $10 million plus and could have grown upwards of $100 million dollars if it were not for the temporary suspension of the marsh expansion in September 2013, until the situation could be contained.

While the Kentuck Slough mitigation proposed is smaller in size, it is very similar in terms of expansion of tidal flats. The potential for a similar mosquito infestation at Kentuck needs to be thoroughly evaluated and brought forward in discussions.

CONCLUSION

The estuarine mitigation proposed for Kentuck by the JCEP has a significant potential to result in contamination of the Coos Bay estuary, flooding of adjacent and upstream property owners, and a potential mosquito infestation that would affect area residents. During my time working on the JCEP under SHN, I encountered serious transparency and integrity issues with the management of both SHN and DEA. From inaccurate site plans submitted with permits to failing to address issues as they arose, the standard operating procedures of "let's wait and see if it comes out in public comment" is not the proper response to issues. Hence my public comment.

Before the project starts moving dirt around (or mud and sand), it needs to conduct a full analysis on every aspect of the mitigation proposed at Kentuck and demonstrate it understands the implications to the environment it will be affecting. The issues ranges far beyond the CWM comments presented in this document for the Kentuck. There is a pattern being set for the JCEP, and another major issue is the ongoing neglect by the project to properly address soil contamination issues at the facility site on the North Spit of Coos Bay. As with the soil contamination issues, additional studies are needed to ensure the designs and plans in place prior to ground disturbing activities fully address the potential adverse effects of the project.

It is my assertion that inadequate environmental and hydrologic studies have been conducted to warrant the Kentuck Slough mitigation to proceed as planned. It is imperative the Corps and DSL make sure the proper process is followed to ensure the natural and human environment will be protected to the maximum extent possible. That is not being done by the current CWM proposed and the residents who call Coos Bay and North Bend home deserve better. Both agencies need to ask tough questions, to coordinate with other respective agencies to ensure they are approving the same actions, and to expect complete investigation and analysis before approving any action.

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John Souder, Executive Director, Coos Watershed Association
Warren Brainard, Chief, Confederated Tribes of Coos Lower Umpqua and Siuslaw Indians (CTCLUSI)
Howard Crombie, Director, Department of Natural Resources, CTCLUSI
Bob Garcia, Chairman, CTCLUSI
Don Ivy, Chief, Coquille Indian Tribe
Brenda Meade, Chairperson, Coquille Indian Tribe

ATTACHMENT
July 2014 Correspondence with the Corps and EPA

From: "Vallette, Yvonne" <Vallette.Yvonne@epa.gov>
To: "Andazola, Anita M NWP" <Anita.M.Andazola@usace.army.mil>, bgimlin@charter.net
Date: 07/09/2014 08:05:51 EDT
Subject: RE: [EXTERNAL] Checking in and update on alleged violation submitted for Kentuck on 1-8-14 (UNCLASSIFIED)

Anita: I chatted w/ Barb this afternoon to assure her that we have taken a look at this situation. I think next steps is to talk w/ DOGAMI and get a better sense of what their permit allows (or not). Looking at the aerial photos, there definitely seems to be some fill creep happening. That overburden pile is just getting wider and wider (and probably taller), so a line needs to be drawn somewhere to stop it from spreading. Let's talk tomorrow if you have time.

Yvonne Vallette, PWS
Aquatic Ecologist
U.S. Environmental Protection Agency
Region 10, Oregon Ops Office
805 SW Broadway, Ste. 500
Portland, OR 97205
Phone: (503) 326-2716
Cell: (503) 545-4962

-----Original Message-----

Sent: Wednesday, July 09, 2014 4:18 PM
From: Andazola, Anita M NWP To: bgimlin@charter.net
Cc: Vallette, Yvonne
Subject: RE: [EXTERNAL] Checking in and update on alleged violation submitted for Kentuck on 1-8-14 (UNCLASSIFIED)
Classification: UNCLASSIFIED
Caveats: NONE

Barb - This information has been previously provided by the Corps to EPA. You may be interested in contacting EPA directly. Yvonne Vallette is likely your best option at 503-326-2716.

Sincerely,
Anita Andazola, Biologist
Corps of Engineers Regulatory
Eugene Section
Compliance & Enforcement
2201 Broadway, Ste. C
North Bend, Oregon 97459
541-756-5316 office
541-751-1624 Fax
http://www.nwp.usace.army.mil/Missions/Regulatory.aspx

-----Original Message-----

Sent: Wednesday, July 09, 2014 3:51 PM
From: bgimlin@charter.net
To: Andazola, Anita M NWP
Subject: [EXTERNAL] Checking in and update on alleged violation submitted for Kentuck on 1-8-14

Hi Anita,

I wanted to touch base with you about the report of an alleged violation I submitted to you on January 8 for the fill of wetlands at 95688 Kentuck Way Lane in North Bend (attached). The fill continues and last week they were going gangbusters with trucks back and forth to the site, repeatedly dumping fill. I went for a bicycle ride past the site and was very disheartened to see what was occurring. They have completely filled in the two large rectangular ponded areas along the road (shown in the previous photos) and they continue to fill the site to the south with all the ponded areas from those photos also filled in now.

The continued and large expanse of fill in USFWS-designated wetlands is bound to increase the flooding downstream of their neighbors. Should I contact the USFWS and/or the EPA about this? I would like to know something is being done and that corrective actions will be required.

I'd be happy to take some additional photos if that would help. I am cc'ing my friend Carri Baker who lives approximately 1 mile west of the site and who will undoubtedly continue to be affected more and more by the fill that is occurring. As previously mentioned, I would like to keep this report confidential.

Thank you for your assistance in this matter and I'll look forward to hearing from you. Something needs to be done, and sooner rather than later.

Barb

Barbara J. Gimlin
P.O. Box 1527
North Bend, OR 97459

Exhibit 62

DICKSTEINSHAPIRO LLP

1825 Eye Street NW | Washington, DC 20006-5403
TEL (202) 420-2200 | FAX (202) 420-2201 | dicksteinshapiro.com

February 6, 2014

Via Electronic Filing

Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, DC 20426

Re: Supplemental Information
Supplement to Technical Memorandum – Tsunami Hydrodynamic Modeling
Jordan Cove Energy Project, L.P., Docket No. CP13-483-000

Dear Ms. Bose:

Jordan Cove Energy Project, L.P. (JCEP) hereby submits for filing in the above referenced docket supplemental information described below that is related to JCEP's application, filed May 21, 2013, for authorization to site, construct and operate a natural gas liquefaction and liquefied natural gas export facility on the North Spit of Coos Bay in unincorporated Coos County, Oregon. Specifically, Coast & Harbor Engineering, Inc. (CHE) has prepared a Supplement to CHE's Technical Memorandum on Tsunami Hydrodynamic Modeling dated September 26, 2013 (CHE 2013b) and filed in this docket on October 1, 2013 as Attachment 6.16-1 to the Second Supplemental Response to Environmental Information Request. The Supplement to Technical Memorandum addresses the differences between the most recent report (CHE 2013b) and the previously submitted report (Zhang 2012).

All information included in this filing is Public. This filing is being made electronically. All persons on the Official Service List will be served by email with a copy of this filing. Three courtesy paper copies and three CDs of this filing are being provided for the Office of Energy Projects (OEP), to the attention of Paul Friedman, Steven Busch and James Glaze, respectively, and one courtesy paper copy and one CD are being provided to each of John Scott at Tetra Tech, the third party environmental contractor for JCEP's project, and Bob Bachman, also a FERC contractor. Finally, all other persons listed below will be served by email with a copy of this filing.

If you have any questions about this filing, please contact me at webbb@dicksteinshapiro.com or 202-420-4782 or my colleague Joan Darby at darbyj@dicksteinshapiro.com or 202-420-2745.

Respectfully submitted,

/s/ *Beth L. Webb*

Attorney for
Jordan Cove Energy Project, L.P.

cc: Service List
Paul Friedman, OEP, FERC
Steven Busch, OEP, FERC
James Glaze, OEP FERC
John Scott, Tetra Tech
Joe Iozzi, Tetra Tech
Bob Bachman
Paul Uncapher, North State Resources
Lorraine Salas, BLM
Leslie Frewing, BLM
Wes Yamamoto, FS
Kristen Hiatt, BOR
Heidi Firstencel, COE
Russ Berg, USCG
Marc Talbert, DOE
Teresa Kubo, EPA
Doug Young, FWS
Thomas Finch, DOT

Enclosure

COAST & HARBOR
ENGINEERING

Supplement to Technical Memorandum
Jordan Cove LNG Facility Tsunami Hydrodynamic Modeling

This document supplements the Technical Memorandum on Tsunami Hydrodynamic Modeling prepared by Coast & Harbor Engineering, Inc. (CHE) dated September 26, 2013, CHE (2013b). The supplement addresses the differences between the most recent report (CHE 2013b) and previously submitted report (Zhang 2012).

The most recent tsunami hydrodynamic modeling study conducted by CHE (2013b) was initiated to update the previous work performed by Zhang (2012) to implement the most recent guidelines and requirements of the Federal Energy Regulatory Commission (FERC). The following updates were implemented in the 2013 study:

- Model bathymetry and topography at the project site were updated from the previous study of Zhang (2012) to reflect the most recent design elevations in the tsunami hydrodynamic modeling. The previous study of Zhang (2012) did not include some recent modifications of design bathymetry and topography elevations of the project.
- Tsunami hydrodynamic modeling was conducted using the Mean High Water (MHW) tidal elevation, in coordination with the Oregon Department of Geology and Mineral Industries (DOGAMI) and FERC. The previous study of Zhang (2012) had used Mean Higher High Water (MHHW).
- To account for uncertainties in prediction of tsunami wave runup on the protection berm around the LNG facility, a safety factor of 1.3 was applied to the results of tsunami hydrodynamic modeling, as required by FERC and in anticipation of an update to the American Society of Civil Engineers Minimum Design Loads for Buildings and Other Structures (ASCE/SEI 7-10) to be released in 2016. The detailed methodology for implementation of this safety factor is explained in CHE (2013a). The previous study of Zhang (2012) had not used this safety factor.
- The most recent tsunami hydrodynamic modeling study by CHE (2013b) uses the L1 rupture scenario ("Large" splay fault Cascadia source), which represents 3 of 19 full-margin Cascadia events over the last 10,000 years, following Priest *et al.* (2009, 2010) and Witter *et al.* (2011). DOGAMI estimated that this scenario is probably the closest scenario to the FERC required 2,475-year return period design earthquake event. The previous study of Zhang (2012) had used XL and XXL rupture scenarios in addition to the L1 event. Upon further discussion and coordination with DOGAMI and FERC, it was agreed that the L1 rupture scenario is the appropriate design scenario to meet FERC requirements.

It was expected that implementation of the above items in the tsunami hydrodynamic modeling study of CHE (2013b) will lead to results different from that of Zhang (2012) in terms of water surface elevation and depth-averaged velocity. In order to ensure consistency between recent (CHE 2013b) and previous (Zhang 2012) tsunami modeling studies, first, a repeat of modeling effort conducted by Zhang (2012) using exactly the same modeling grid, input files, and source code was conducted and results of Zhang (2012) were reproduced. Second, a comparison between modeling results of CHE (2013b) and Zhang (2012) for the modified landscape was conducted (for the L1 rupture scenario).

Figures 1 through 3 demonstrate and compare the extent of maximum inundation from the two studies of CHE (2013b) (shown in red), and Zhang (2012) (shown in yellow) for the L1 event for the modified landscape. Figure 1 compares the modeling results on the large scale, for the entire Coos Bay. The figure shows a reasonable overall agreement in terms of extent of tsunami inundation (and hence, water surface elevation) between results obtained in CHE (2013b) and Zhang (2012).

Figure 2 shows a zoomed-in view of the modeling at the project site. The shown differences between modeling results are expected and mainly due to implementation of the most recent design elevations in constructing the model bathymetry and topography by CHE (2013).

Figure 3 presents a zoomed-in view of the modeling results in Coos Bay further inland from the project site. The figure shows a larger extent of inundation, mostly at embayment areas, predicted by Zhang (2012) tsunami modeling compared to that of CHE (2013b). The difference in the inundation extents can be explained as follows:

- The landscape in the area between yellow and red lines is relatively flat, with typical elevations of 6 to 8 ft above NAVD88, and mainly at the end of embayment areas. This means that even small changes in water surface elevation correspond to rather large changes in extent of inundation (runup) on these flat landscapes.

- A safety factor of 1.3 is not applicable in the areas with elevations less than MHW (6.46 NAVD88). Therefore this factor cannot be used to increase the water surface elevation in this modeling domain.

- Therefore, it is expected that inundation extent due to tsunami that was modeled at MHHW elevation exceed inundation extent due to tsunami that was modeled at MHW elevation in these areas.

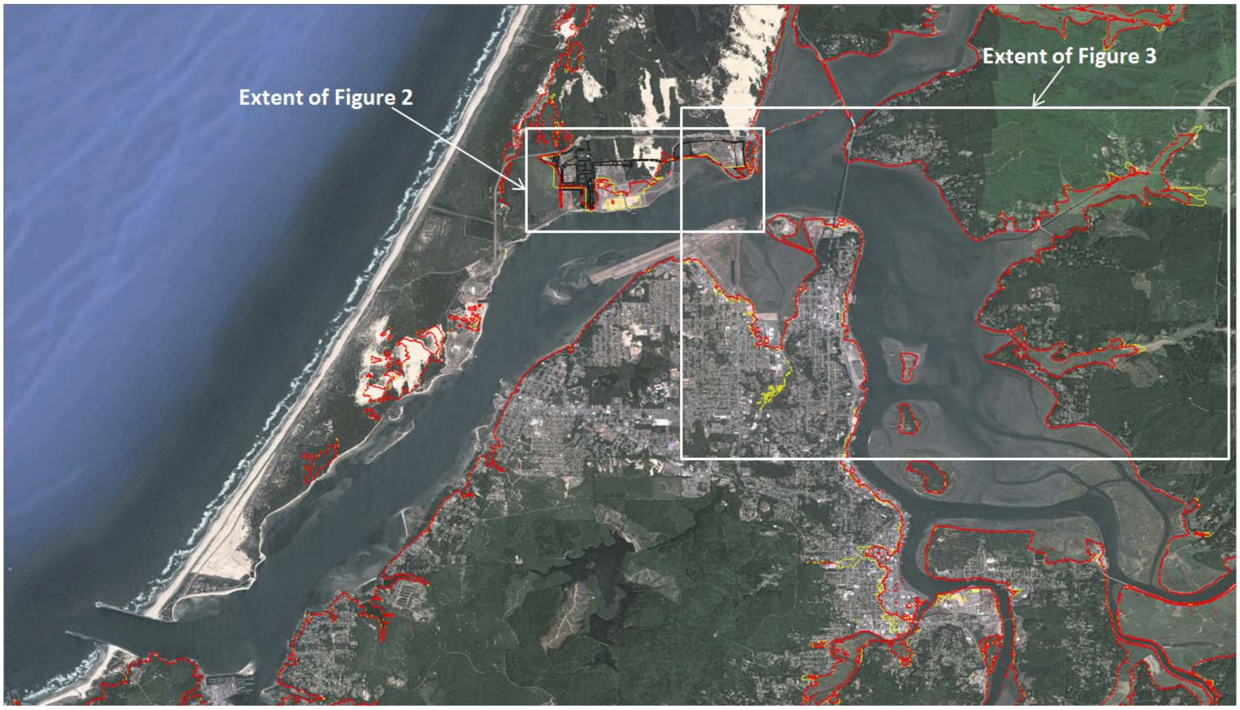


Figure 1. Extent of tsunami wave inundation for L1 Scenario for Coos Bay for modified landscape obtained from Zhang (2012) study, shown in yellow and CHE (2013b) study, shown in red

Figure 2. Extent of tsunami wave inundation for L1 Scenario at project site for modified landscape obtained from Zhang (2012) study, shown in yellow and CHE (2013b) study, shown in red

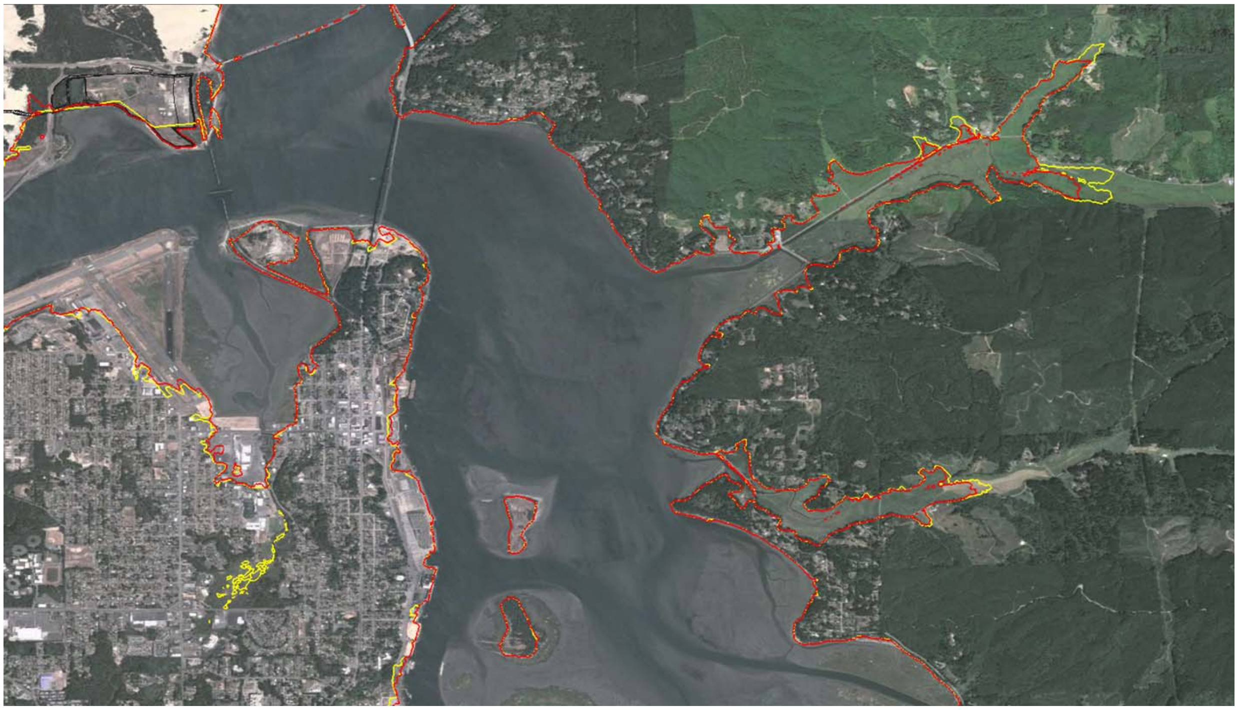


Figure 3. Extent of tsunami wave inundation for L1 Scenario further east of project site for modified landscape obtained from Zhang (2012) study, shown in yellow and CHE (2013b) study, shown in red

1. References

CHE. 2013a. Jordan Cove Energy Project, Tsunami Hydrodynamic Modeling Input and Methodology. Coast & Harbor Engineering. Edmonds, WA.

CHE. 2013b. Technical Memorandum: Jordan Cove LNG Facility Tsunami Hydrodynamic Modeling. Prepared for Jordan Cove Energy Project. Coast & Harbor Engineering. Edmonds, WA.

Priest, G.R., Goldfinger, C., Wang, K., Witter, R., Zhang, Y., Baptista, A.M. 2009. Tsunami hazard assessment of the Northern Oregon coast: a multi-deterministic approach tested at Cannon Beach, Clatsop County, Oregon: Oregon Department of Geology and Mineral Industries Special Paper 41.

Priest, G.R., Goldfinger, C., Wang, K., Witter, R., Zhang, Y., Baptista, A.M. 2010. Confidence levels for tsunami-inundation limits in northern Oregon inferred from a 10,000-year history of great earthquakes at the Cascadia subduction zone: Natural Hazards, doi10.1007/s11069-009-9453-5.

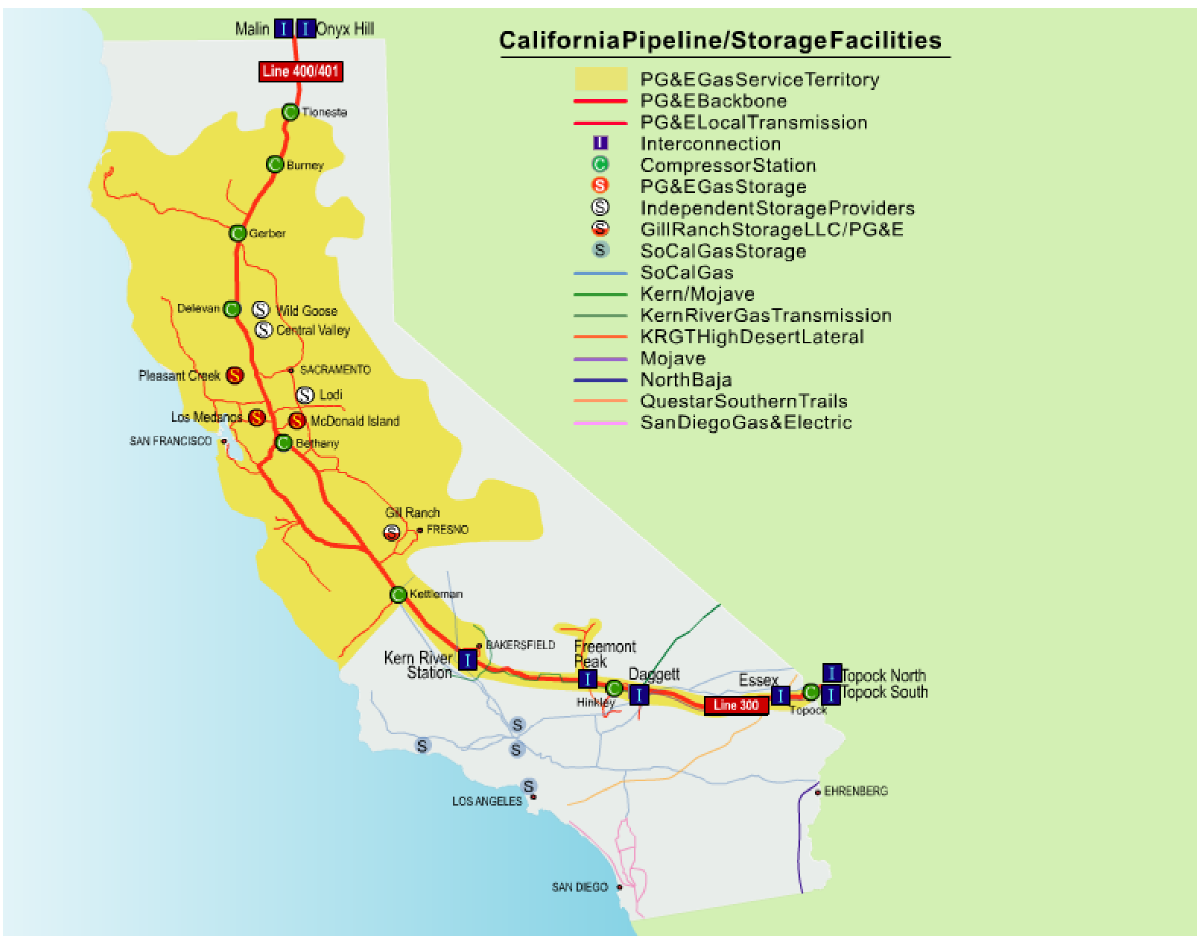
Witter, R. C., Y. Zhang, K. Wang, G. R. Priest, C. Goldfinger, L. L. Stimely, J. T. English, and P. A. Ferro. Special Paper 43, Simulating tsunami inundation at Bandon, Coos County, Oregon, using hypothetical Cascadia and Alaska earthquake scenarios.

Zhang, Y.J. 2012. Final Report, Site-Specific Tsunami Modeling at the Jordan Cove LNG Facility Coos County, Using New Cascadia Sources. Center for Coastal Margin Observation & Prediction (CMOP), Oregon Health & Science University.

Exhibit 63

Alternative Jordan Cove Facility Siting / Pacific Connector Pipeline Route #1

A variety of Natural Gas pipeline infrastructure to West Coast Ports already exists. A detailed explanation as to why the Jordan Cove Energy Project did not look at utilizing these already existing pipelines and Ports in order to develop their LNG Export terminal should be analyzed in the EIS. A detailed explanation as to why PG & E is no longer a partner in this project should also be included.



Alternative Jordan Cove LNG Export Terminal Siting Locations (#2)

An explanation as to why other siting locations such as the Jerden Cove just north of Winchester Bay and/or the Industrial Site in Gardner, Oregon, were not analyzed as siting locations for the Jordan Cove LNG terminal, should be included in the EIS review.

Example #3
Pipeline Transportation and Terminal Location

Example #4

Pacific Trail Pipeline Project

PACIFIC TRAIL PIPELINES

MOVING NATURAL GAS FROM WESTERN CANADA TO ASIAN **MARKETS**

Pacific Trail Pipelines will provide a direct connection between the Spectra Energy Transmission pipeline system and the Kitimat LNG terminal for the transportation of natural gas from Western Canada to Asian markets.

Click to enlarge

Quick Facts:

- Pipeline location: Summit Lake to Kitimat, British Columbia
- Pipeline length: Approximately 463 km
- Pipeline capacity: Up to approximately 1,000 MMcf/d
- Compressor station: 1
- Diametre of pipe: 42 inches

Latest News

25/Feb/2013

Pacific Trail Pipelines Limited Partnership sign $200 million commercial agreement with 15 First Nations regarding the pipeline component of the Kitimat LNG Project

Read More »

11/Feb/2013

Apache, Chevron complete Chevron Canada's entry into Kitimat LNG

Read More »

NAVIGANT

Overview of Proposed Energy Operations of Jordan Cove Export Project

The proposed Jordan Cove Energy Project is located at Coos Bay in southern Oregon. JCEP received FERC approval in Docket No. CP07-444 to construct an LNG import facility. FERC also approved the construction of the Pacific Connector Pipeline. JCEP has received authorization from the Department of Energy in Docket No. 11-127-LNG to export LNG from the site to FTA countries. It intends to file applications in 2012 to export to non-FTA countries and to amend its FERC authorization to include authority to construct a dual-use import-export facility.

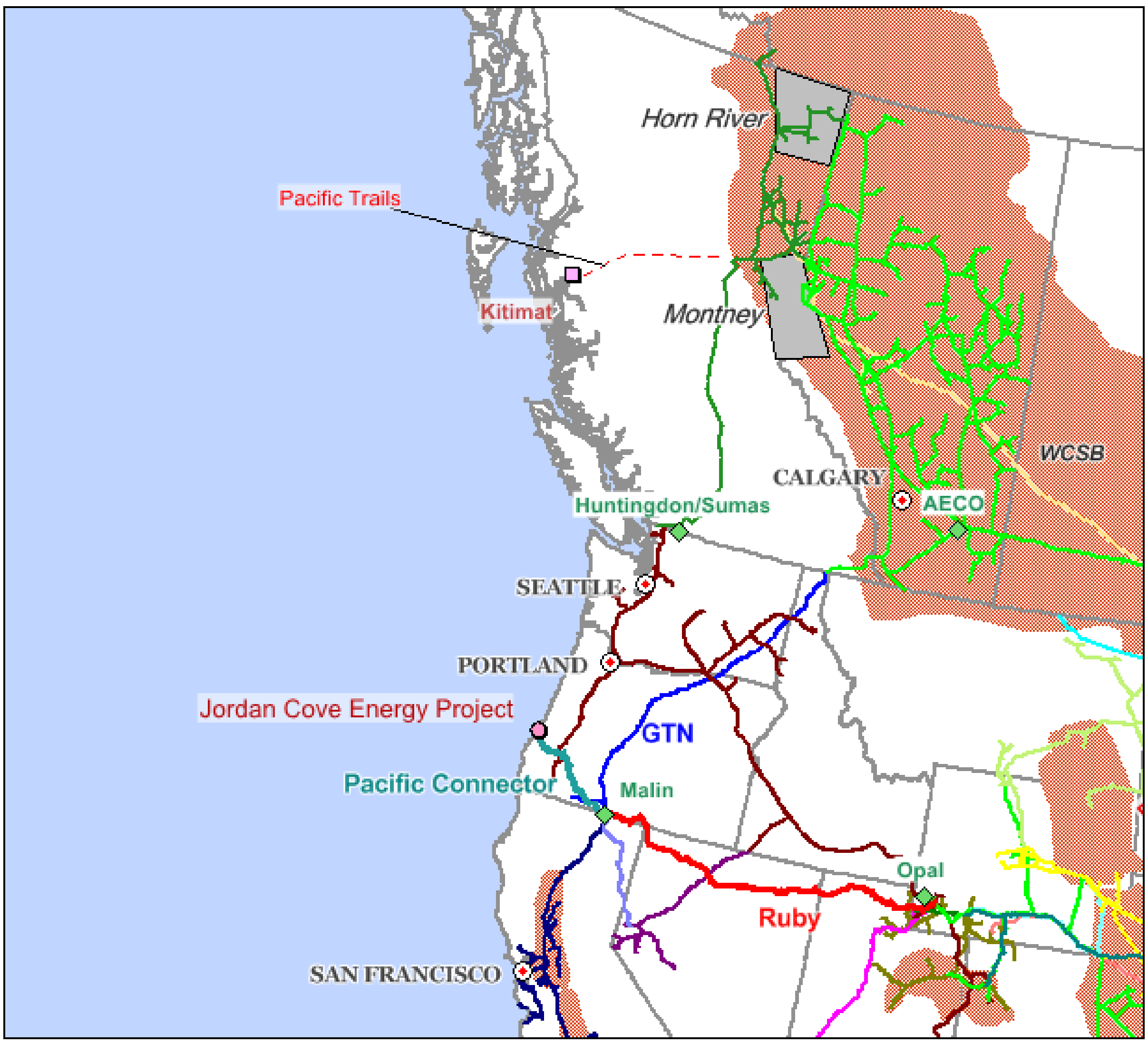


Figure 15: Jordan Cove Energy Project Location Map

Exhibit 64

BROOKINGS

BROOKINGS ENERGY SECURITY AND CLIMATE INITIATIVE
NATURAL GAS TASK FORCE

NATURAL GAS ISSUE BRIEF #4:

An Assessment of U.S. Natural Gas Exports

JULY 2015

Tim Boersma
Charles K. Ebinger
Heather L. Greenley

ACKNOWLEDGMENTS

The authors would like to thank Ben Schlesinger, Lex Huurdeman, Jim Jensen, and Geert Greving for their careful reviews and/or helpful suggestions. The authors would also like to acknowledge the members of the Brookings Natural Gas Task Force for their time and helpful contributions during the October 2014 session upon which this issue brief is based. They are also grateful to Jennifer Potvin, Shams Haidari, and the Brookings Foreign Policy communications team for their editorial assistance and work on the production of this brief.

ABOUT THE BROOKINGS ENERGY SECURITY AND CLIMATE INTITIATIVE

The Energy Security and Climate Initiative (ESCI) at Brookings is designed to encourage the development, discussion, and dissemination of high-caliber energy security and climate research. ESCI, through its research and convening efforts, seeks to examine three key substantive aspects of energy security: the geopolitics of energy; the economics of energy; and the growing environmental imperative of balancing increasing global economic prosperity in a carbon-constrained context.

Contact for ESCI:
Jennifer Potvin
Project Coordinator
(202) 797-4389
jpotvin@brookings.edu

PREFACE

In May 2011, the Brookings Institution Energy Security and Climate Initiative (ESCI) assembled a Task Force of independent natural gas experts, whose expertise and insights inform its research on various issues regarding the U.S. natural gas sector. After the first series of meetings, Brookings released a report in May 2012 analyzing the case and prospects for exports of liquefied natural gas (LNG) from the United States. The Task Force now continues to meet periodically to discuss important issues facing the gas sector more broadly. With input from the Task Force, Brookings will continue to release periodic issue briefs for policymakers.

The conclusions and recommendations of this report are those of the authors and do not necessarily reflect the views of the members of the Task Force.

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An Assessment of U.S. Natural Gas Exports

Tim Boersma
Charles K. Ebinger
Heather L. Greenley[1]

Introduction

Increased natural gas production in the United States has fueled a lively debate on the future of natural gas exports. This debate has focused so far predominantly on exports of liquefied natural gas (LNG). At the same time, the debate is clouded with many confusing statements about the regulatory regime related to natural gas exports with many foreign nations and even some domestic observers having the erroneous belief that the United States has severe restrictions on exports, when in fact no project has to date ever been rejected. In addition, estimates about the amount of U.S. natural gas that will be competitive in global markets vary widely, in part because a number of new supply sources are expected to enter the market in the coming years. There are also many uncertainties regarding global demand for LNG going forward. Finally, declining natural gas sales to the United States have incentivized Canada's provincial and federal authorities to search for opportunities to market its product elsewhere in the world, though unconventional gas development in Canada trails U.S. production, and in some parts of the country gas infrastructure is less developed than in most parts of the United States.

This policy brief provides an assessment of U.S. natural gas exports in the coming years, as well as its competitive position vis-à-vis other suppliers that are emerging worldwide. It does so by briefly outlining the existing regulatory framework related to LNG exports from the United States. It then proceeds with a timeline for LNG export projects that are being developed.[2] The policy brief then turns to what are currently considered major (potential) rivals of U.S. LNG, before it concludes with some final observations regarding the competitive position of U.S. LNG as of June of 2015.

This paper builds on extensive discussions within the Brookings Institution's Natural Gas Task Force (NGTF), along with our analysis of available literature on existing natural gas production trends, price formation, and legal and infrastructural limitations. We are grateful for the rich debates that have occurred in our NGTF. Despite the generosity and valuable contributions of all our speakers and participants, this policy brief reflects solely our views, and any errors remain our own.

[1] The authors are all members of the Energy Security and Climate Initiative at the Brookings Institution. Tim Boersma is a fellow and acting director; Charles K. Ebinger is a senior fellow; and Heather L. Greenley is a senior research assistant.
[2] We have used data that were available in early June 2015, or before.

The global LNG market

For many years, the outlook for natural gas has been very positive, and the outlook for LNG was similarly optimistic. A golden age for natural gas was near, according to the International Energy Agency in 2011. Today, that same agency reports that the outlook may still be bright, but is not set in stone.[3] Falling oil prices have knock-on effects on gas production worldwide, and, perhaps more importantly, demand for natural gas in 2014, particularly in Asia, proved to be substantially more moderate than anticipated.

Recent high regional prices, in both Europe and Asia, have incentivized the construction of significant additional LNG capacity additions. By 2020 additional LNG capacity additions totaling 164 billion cubic meters (bcm) will have come into the market, of which 90 percent will come from Australia and the United States. This, combined with slowing demand, has led to a situation of oversupply, which is expected to last until at least 2017.[4] It is against this background that we write our report. **Table 1** shows some key characteristics of global LNG markets, before we turn to the U.S. regulatory framework.

United States regulatory framework

The evolution of the U.S. LNG export licensing process

All U.S. LNG export projects must receive approvals from both the Department of Energy's Office of Fossil Energy as well as the Federal Energy Regulatory Commission (FERC) per the statutory provisions of the 1938 Natural Gas Act (NGA) Section 3(15 USC§717b).[5] Prior to 2014, this process required an initial application to the Department of Energy (DOE) and a national interest determination finding that LNG exports were within the public interest. This process was then followed by a FERC review after which if the project met all regulatory considerations an approval for the construction of an export facility followed.

Exports to countries holding free trade agreements (FTA) with the U.S. are automatically deemed in the public interest, and therefore licensable by the DOE. For exports to countries without an FTA with the United States, the Office of Fossil Energy was still required to issue an export permit unless, after publishing the application in the Federal Register, seeking public comments, and receiving protests against the sale or notices of intervention by parties opposed to the sale, such exports could be detrimental to the public interest. However, a major shortcoming of this process was the very vague grounds used to determine what was meant by the "public interest." Additionally, under the regulatory process, DOE had the ability to issue permits up to a certain cumulative volume of LNG exports and then to deny subsequent applications if it perceived that tight market conditions made such additional exports in contravention of the public interest. Finally, the DOE's low-cost, undemanding application process soon became bogged down with dozens of export applications.

Following DOE's approval, authorization by FERC was (and still is) also necessary for any LNG export facilities requiring the siting, construction, or operation of those facilities, or to amend an existing FERC authorization. Certain additional regulatory

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[3] International Energy Agency (IEA), Gas: Medium-Term Market Report 2015, by Costanza Jacazio et al. Paris: OECD/IEA, 2015.
[4] Ibid., 94.
[5] For a more in-depth assessment of the process for approval for LNG exports prior to 2014, see: Charles Ebinger et al., "Liquid Markets: Assessing the Case for U.S. Exports of Liquefied Natural Gas," Brookings Institution, May 2012, http://www.brookings.edu/~/media/research/files/reports/2012/5/02%20lng%20exports%20ebinger/0502_lng_exports_ebinger.pdf.

TABLE 1. THE GLOBAL LNG MARKET[6]

KEY CHARACTERISTICS OF THE GLOBAL LNG MARKET

LNG has been the fastest growing source of gas supply, averaging 7 percent annual growth since 2000. However, over the last three years, LNG trade has been stable at just below the peak of 241.5 million metric tons per annum (mtpa) reached in 2011. LNG in 2013 met 10 percent of global gas demand.

In 2013, the Middle East supplied 42 percent of global LNG supplies, while the Asia Pacific supplied 30 percent. Around 65 percent of the world's liquefaction capacity is held in just five countries: Qatar, Indonesia, Australia, Malaysia, and Nigeria.

Most LNG demand growth has been in the Asia Pacific region, particularly due to increased consumption in China and South Korea. Japan remains the world's dominant importer, utilizing 37 percent of global imports.

Though interregional trade patterns have intensified in recent years, a single price structure for global LNG does not exist. In fact, current investments in the sector are based largely on the premise that these price differentials will remain in place (and incentivize arbitrage).

Historically, LNG trade was based on long-term contracts and oil-indexation, in order to manage risks associated with high upfront costs of liquefaction, transport in specialized tankers, and regasification. However, in 2013, 33 percent of global trade was not long-term (referring to cargoes that are not supported by 5+ years Sales and Purchase Agreements, cargoes diverted from their original/planned destination, and cargoes above take-or-pay commitments). Several factors have contributed to this trend, including the growth of contracts with destination flexibility, and the lack of domestic production or pipeline imports in Japan, Korea, and Taiwan (as a result, sudden changes in demand following for instance a phase out of nuclear capacity have to be covered in the spot market). In addition, the continued price differentials between various regions, and the fact that LNG volumes have been freed up due to a loss of competitiveness vis-à-vis coal (Europe) and shale gas (United States) has facilitated shorter-term trade.

Re-exports of LNG likely remain an important feature of global LNG markets, as described above. In 2013, re-exports grew for the fourth year in a row, to 4.6 megatons (MT) and continues to grow today. Another market development has been the introduction of new pricing formulas by U.S. firms (based on North American spot market prices, instead of oil-indexation). Even though U.S. pricing formulas are currently unique, and low oil prices may take away the immediate incentive for more widespread change, it seems likely that in due time hub-based pricing will become more common. Next to these developments, a number of technological innovations may drive further changes in global LNG markets going forward, such as floating LNG, small scale LNG, high-efficiency liquefaction plants, and LNG ice breakers which would facilitate Arctic transportation.

approvals for offshore facilities involving the export of LNG are on occasion also needed from the Coast Guard as well as the Department of Transportation. If a favorable verdict was made by these agencies, then applications were issued a Certificate of Public Convenience and Necessity allowing the project to proceed to construction and operation.

Environmental review and assessment

The approval of the Office of Fossil Energy and of FERC additionally required an Environmental Impact Statement (EIS) under the National Environmental Policy Act (NEPA of 1970). All projects were to have an EIS for every proposed major federal action that

[6] Based on International Gas Union, *World LNG Report – 2014 Edition* (Fornebu, Norway: International Gas Union, 2014), 23, http://igu.org/sites/default/files/node-page-field_file/IGU%20-%20World%20LNG%20Report%20-%202014%20Edition.pdf.

was thought to have a significant impact on the environment, in accordance with NEPA's requirements. Even projects with less significant impacts still required documentation. For example, even if the environmental impacts were indeterminable, an EIS would have to be done in order to conclude if an EIS was necessary. If the ensuing EIS determined that the proposed project had no significant environmental impacts, then a Finding of No Significant Impact (FONSI) report was provided. Finally, projects perceived to have no significant impacts on the environment could be processed as Categorical Exclusions alleviating any requirement to provide either an EIS or a less robust Environmental Assessment (EA). In preparing all the documentation required by NEPA, both the Department of Energy and the FERC were also charged with identifying any other compliance requirements pertinent to the project such as the Clean Air Act, the Clean Water Act, the Endangered Species Act, and the National Historic Preservation Act, as well as any approvals under these or state-related requirements that fell under these federal statutes. In addition to the environmental requirements, LNG export projects can be subject to the oversight requirements of other agencies such as the Department of Transportation's Office of Pipeline Safety, the National Fire Protection Association, and the Federal Emergency Management Agency.

This seemingly simple, but realistically complex regulatory approval process was made more convoluted by the uncertainty of how long it would take, particularly for those applying to export to non-FTA countries. Again, prior to 2014, the DOE reviewed applications to export LNG to countries without a free trade agreement in the order in which they were received, resulting in a cumbersome and painstakingly time-consuming process. This provided industry with little or no certainty that their projects would be approved if they were way down the applicant list, even if they had excellent technical partners, sound balance sheets, committed customers, and strong prospects for certain financing. While the DOE, per its legal mandate, intended to process these applications in a timely manner (at an average of one every eight weeks), by March 2014 the escalating number of applications had prolonged the approval process by nearly four years, regardless of the project's environmental complexities or lack thereof. "The result was that projects which might make it through the environmental review, led by the Federal Energy Regulatory Commission (FERC) or the U.S. Maritime Administration (MARAD) depending on jurisdiction, might not be considered until they came up in the queue, possibly years later, or might be rejected altogether because they exceeded the soft cap of 12 billion cubic feet per day (Bcf/d)."[7]

On May 29, 2014, the DOE announced a modification of the application process for LNG exports to countries without a U.S. free trade agreement. First, the DOE effectively terminated conditional verdicts to export to non-FTA countries without a NEPA review. "DOE typically issued these conditional authorizations after completion of the notice and

[7] David L. Goldwyn, "DOE's New Procedure for Approving LNG Export Permits: A More Sensible Approach," Brookings Institution, June 10, 2014, www.brookings.edu/research/articles/2014/06/10-doe-approving-lng-export-goldwyn-hendrix. The existence of the so-called soft cap grew out of a study commissioned in 2012 by the DOE with the goal of determining how much LNG could be exported from the United States within the public interest. Finally issued in 2014, the DOE's study, authored by NERA, found inter alia that the more LNG the United States exports, the greater the public interest, thus in effect depriving the DOE of any stopping point, based on its own required criteria and its own study. Because the highest volume scenario NERA examined was 12 Bcf/d of exports, this justified a "soft cap" of 12 Bcf/d in the eyes of some observers. The cap was, indeed, soft because NERA soon privately updated its study, finding public interest in a 19 Bcf/d scenario.

comment process, but before completion of NEPA review."[8] As discussed earlier, prior to this time many projects had to wait in queue in the order in which they were received; some of these were still undergoing environmental review because this assessment could be highly complex, while other projects that had no environmental impact still waited in line. Following the change in policy, the DOE only issues public interest approval for projects that have secured their NEPA requirement, streamlining the DOE approval process. Furthermore, the DOE eliminated the queue system and now approves applications based on when an application "has completed the pertinent NEPA review process and when DOE has sufficient information on which to base a public interest determination."[9]

Despite this attempt to clarify and streamline the approval process, industry still remains a bit concerned over how the changes will work in actuality. Moreover, the issue of what criteria DOE uses and what weight each criterion is given in determining what constitutes the "public interest" is not fully guaranteed by the issuing of an export permit. The United States government still reserves the full right to withdraw export permits determined not to be in the public interest.[10] Unfortunately, this determination is outside the DOE's jurisdiction and can only be changed or clarified by an act of Congress. Nonetheless, with the change in policy, DOE has made a vast improvement in the approval process providing industry with noticeably more confidence in the approval timeline, once they have undergone their NEPA review.

Current trade flows and North American export projects under construction

Since 2007, Canadian gas pipeline exports to the United States have been in a sluggish decline as new U.S. domestic supplies, largely from unconventional gas, and the construction of new pipelines to distribute them are quickly obviating the need for Canadian gas imports. In 2013, virtually all U.S. imports of natural gas came from Canada, totaling 2,785 Bcf.[11] Given these market trends and the absence of new export markets, Canadian gas production likely will remain stagnant, serving only the domestic economy and some select niche U.S. regional markets. It is worth noting however, that those niche markets also may evaporate for two reasons. First, U.S. domestic infrastructure investments continue to expand, bringing previously stranded gas supplies to market. To give an example, in 2013 Canadian imports into the northeastern United States dropped by almost 12 percent, due to the increase in production from the Marcellus shale and expanded pipeline capacity.[12] Second, gas market growth in California, a highly important niche market for Canadian gas, is in decline as large renewable energy projects increasingly dominate electricity generation capacity, gradually pushing out gas.

In response to this Canadian "existential" gas market crisis and the perception that the United States is a "low cost" gas producer, the Canadian gas industry has embarked on ambitious schemes

[8] Procedures for Liquefied Natural Gas Export Decisions, 79 Fed. Reg. 32262 (proposed June 4, 2014), https://federalregister.gov/a/2014-12932.
[9] Ibid.
[10] The right to withdraw export permits due to the determination of not being in the public interest is unlikely to be exercised. This issue becomes moot once natural gas export prices reach the point of no longer being in the public interest, the price of exporting U.S. natural gas becomes too expensive and therefore uneconomic.
[11] U.S. Energy Information Administration, "U.S. Natural Gas Imports & Exports 2013," May 28, 2014, http://www.eia.gov/naturalgas/importsexports/annual/.
[12] Ibid.

to ship Canadian gas to Asian markets where gas prices have historically been high. Currently, there are no fewer than 19 proposed LNG projects along the coast of British Columbia.[13] There are also two more in Oregon that, if built, would be supplied by gas from Western Canada, and several liquefaction plants have been proposed in Canada's Maritime Provinces on its Atlantic coast.

To date, however, no final decision has been made for any Canadian LNG export project and none have been built. Malaysia's Petronas has decided to continue to move forward with its project in British Colombia, yet final investments are still waiting for federal and provincial approval.[14] Much of the delay in Canada relates to the relatively long distances over which wholly new gas pipelines have to be constructed to enable LNG exportation. These long pipeline routes (e.g., over 600 miles in British Columbia) have drawn significant environmental backlash, complicated by protracted negotiations with the First Nations and recent revisions to the tax regime in British Columbia. Recently, several First Nations, including the Lax Kw'alaams, have voted against LNG plans in British Columbia as it interferes with traditional territories, leaving significant environmental and ecological concerns which need to be addressed.[15] With these delays possibly curbing potential investment, Ottawa has announced a federal tax break for proposed LNG terminals in British Columbia, which intends to spur investment by making British Columbian LNG more competitive and to alleviate some economic uncertainty.[16]

In the United States, the euphoria brought on by the unconventional gas revolution has been astounding as estimates of technically recoverable natural gas resources have ascended to over 2,200 trillion cubic feet (Tcf), an amount in excess of 87 years supply at current consumption levels.[17] The magnitude of these resources has led to FERC's approval of several LNG export terminals, five of which are under construction (**Figure 1**).[18] Furthermore, there are 21 additional proposed projects in the continental United States and one in Alaska pending review by U.S. regulatory authorities, including several existing import terminals that are requesting to be converted into export facilities, i.e., for which substantial gas infrastructure components are already in place. In addition, it is estimated that there could be 11 more potential facilities in terms of available sites.[19]

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13 For a list of British Columbian projects see: "Explore B.C.'s LNG Projects," Government of British Columbia, http://engage.gov.bc.ca/lnginbc/lng-projects/. For a list of Canadian projects applying for an LNG export terminal license with the Government of Canada, see: "Canadian LNG Projects," Natural Resources Canada, last modified September 23, 2014, http://www.nrcan.gc.ca/energy/natural-gas/5683.

14 Chester Dawson, "Shell-Led Natural Gas Export Project in Canada Clears Environmental Hurdles," *The Wall Street Journal*, June 17, 2015, http://www.wsj.com/articles/shell-led-natural-gas-export-project-in-canada-clears-environmental-hurdles-1434584827.

15 Justine Hunter, "Lacklustre Support from B.C. First Nations Signals Trouble for LNG Facility," *The Globe and Mail*, May 10, 2015, http://www.theglobeandmail.com/news/british-columbia/lacklustre-support-from-bc-first-nations-signals-trouble-for-lng-facility/article24361708/.

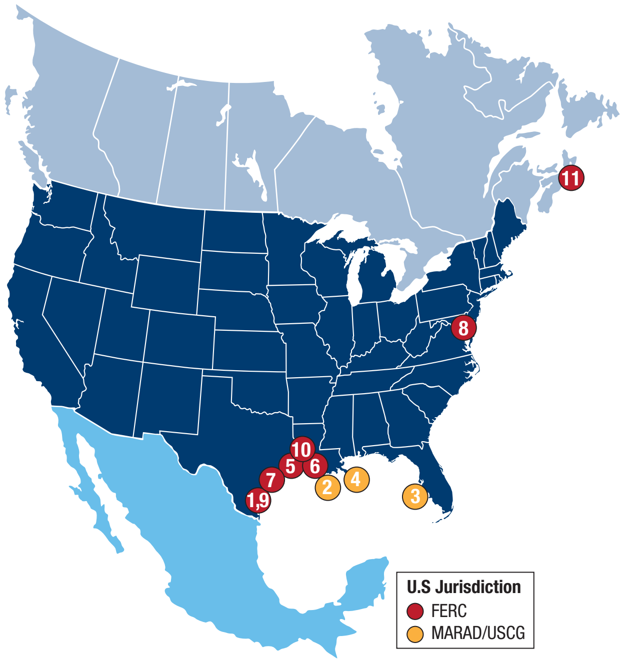
16 Brent Jang and Ian Bailey, "Ottawa Grants Tax Breaks for LNG Sector in BC," *The Globe and Mail*, February 19, 2015, http://www.theglobeandmail.com/news/british-columbia/harper-announces-tax-breaks-for-lng-industry-in-bc-to-spur-job-growth/article23106853/.

17 "Frequently Asked Questions: 'How much natural gas does the United States have and how long will it last?,'" U.S. Energy Information Administration, last modified December 3, 2014, http://www.eia.gov/tools/faqs/faq.cfm?id=58&t=8.

18 Likewise, proved U.S. gas reserves have reached record levels of 354 trillion cubic feet as of year-end 2013: U.S. Energy Information Administration, "U.S. Crude Oil and Natural Gas Proved Reserves," December 19, 2014, http://www.eia.gov/naturalgas/crudeoilreserves/.

19 "LNG," Federal Energy Regulatory Commission, last modified June 18, 2015, http://www.ferc.gov/industries/gas/indus-act/lng.asp.

FIGURE 1. NORTH AMERICAN LNG IMPORT/EXPORT TERMINALS APPROVED



As of June 18, 2015

Import Terminal

APPROVED - UNDER CONSTRUCTION
U.S. – FERC
1. **Corpus Christi, TX:** 0.4 Bcfd (Cheniere – Corpus Christi LNG) (CP12-507)

APPROVED – NOT UNDER CONSTRUCTION
U.S. – MARAD/Coast Guard
2. **Gulf of Mexico:** 1.0 Bcfd (Main Pass McMoRan Exp.)
3. **Offshore Florida:** 1.2 Bcfd (Hoëgh LNG – Port Dolphin Energy)
4. **Gulf of Mexico:** 1.4 Bcfd (TORP Technology–Bienville LNG)

Export Terminal

APPROVED – UNDER CONSTRUCTION
U.S. – FERC
5. **Sabine, LA:** 2.76 Bcfd (Cheniere/Sabine Pass LNG) (CP11-72 & CP14-12)
6. **Hackberry, LA:** 1.7 Bcfd (Sempra – Cameron LNG) (CP13-25)
7. **Freeport, TX:** 1.8 Bcfd (Freeport LNG Dev/Freeport LNG Expansion/FLNG Liquefaction) (CP12-509)
8. **Cove Point, MD:** 0?82 Bcfd (Dominion – Cove Point LNG) (CP13-113)
9. **Corpus Christi, TX:** 2.14 Bcfd (Cheniere – Corpus Christi LNG) (CP12-507)

APPROVED – NOT UNDER CONSTRUCTION
U.S. – FERC
10. **Sabine Pass, LA:** 1.40 Bcfd (Sabine Pass Liquefaction) (CP13-552)

APPROVED – NOT UNDER CONSTRUCTION
Canadian
11. **Port Hawkesbury, NS:** 0.5 Bcfd (Bear Head LNG)
12. **Kitimat, BC:** 3.23 Bcfd (LNG Canada)

Source: Federal Energy Regulation Commission, U.S. Department of Energy

While the projected number of North American LNG export facilities is massive, closer examination of the projects' financial realities offer a more nuanced story. Almost all of the existing analysis and forecasts have been based on three central tenants. First, that spot market prices at Henry Hub will continue to be at record low levels. However, in reality, Henry Hub prices, while remaining relatively low, are projected in most forecasts to rise steadily in the coming years, albeit gradually. Unless the costs of the liquefaction process, transportation, and regasification of natural gas can be reduced, and there are currently few indications that they can, those marginal differences in hub prices may become more significant in determining how attractive U.S. LNG exports will be.[20] The second supposition is that prices in Asia and Europe will remain high, creating ample room for arbitrage. Currently, Henry Hub prices have remained low at around $3/Mcf. Meanwhile, spot prices in Asia (roughly $6-7/mmBtu for 2015-2016)[21] and Europe have tumbled over the course of 2014 (because they have been tied to world oil prices, which declined precipitously, because of a slowdown in economic growth, and because natural gas faces stiff competition from other fuel sources, negatively impacting demand) to levels where it would be increasingly difficult for North American LNG to be considered profitable. The third supposition is the continued

[20] International Gas Union, *World LNG Report - 2014 Edition*.
[21] Osamu Tsukimori, "Japan Feb LNG Spot Price Falls a Quarter to $7.60/mmBtu," Reuters, March 10, 2015, http://www.reuters.com/article/2015/03/10/lng-japan-spot-idUSL4N0WC1JL20150310.

practice outside the United States of indexing the price of LNG to the oil price, coupled with the general assumption that oil prices will remain high. Consequently, when oil prices fell by 50 percent after October 2014, many LNG projects' fiscal solvency were called into question. Even with prices having slightly rebounded, investors remain increasingly cautious about new projects. U.S. projects that are currently under construction are unique in that their pricing formulas are based on spot-market prices at Henry Hub, unlike other LNG projects around the world which are in some form indexed to oil or oil-related products. With the fall in oil prices, rivals to U.S. LNG projects, in particular those in Australia (which are discussed in more detail later in this brief) have become more competitive than they were just one year ago, but it is uncertain how the oil price will develop going forward.

In addition, there are many other uncertainties worth considering:

1. The pace at which China ramps up pipeline imports, particularly from Russia;
2. The rate at which many countries with large shale gas resources (China, Argentina, South Africa, and Algeria, to name a few) successfully develop them;
3. Inter-fuel competition from other sources such as coal and renewables with LNG, especially in the Asian power market;
4. Whether or not Russia will also initiate large scale pipeline exports to Japan and the Koreas, owing partially to the pace and scale of Russian LNG exports from its Arctic regions, as well as how much Russian LNG from Yamal and Sakhalin will continue to flow;
5. The speed and degree to which Japan determines whether or not to bring its nuclear reactors back online, and to what extent nuclear outages in South Korea continue to spur LNG imports;
6. To what extent Japan will continue its support schemes for renewable electricity and significantly expand in particular its solar capacity;
7. The ability to utilize LNG as a transportation fuel, particularly in the Chinese and Indian markets where pollution and health concerns are growing;
8. Whether the United Nations Framework Convention on Climate Change meeting in Paris in late 2015 reaches a global agreement on reducing CO_2 emissions and the nature of that agreement; and,
9. To what extent the major economies in Asia, in particular China and India, decide to reduce the share of coal in their electricity generation, especially if there is no serious agreement to reduce CO_2 at the Conference of the Parties meeting. In such a scenario coal will remain very competitive with LNG.[22]

Faced with the foregoing uncertainties, U.S. LNG export projects are actually poised to compete favorably with new LNG projects coming to the world market from other locations. U.S. construction costs are comparatively low, especially for brown-field liquefaction projects, i.e., that will convert existing import terminals that have already secured environmental approvals for existing facilities. Additionally, low U.S. energy prices provide a construction cost edge, and the United States offers significant skilled labor at a reasonable cost.[23] Finally, depending on global oil prices, the U.S. LNG pricing structure,

[22] Brian Songhurst, "LNG Plant Cost Escalation," The Oxford Institute for Energy Studies, February 2014, http://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/02/NG-83.pdf.

[23] Leonardo Maugeri, "Falling Short: A Reality Check for Global LNG Exports," Harvard Kennedy School, December 2014, 21, http://belfercenter.ksg.harvard.edu/files/Falling%20Short-LNG%202014.pdf.

based on Henry Hub spot market prices, may give U.S. projects a competitive advantage going forward by providing buyers with lower cost LNG and price index diversity.

Yet the success of U.S. projects is not guaranteed. First, capacity costs are not fixed and can rise with an increased demand for material and skilled labor, as the overall economy improves.[24] Second, the oil price level plays an important role. Leonardo Maugeri of Harvard's Kennedy School makes a compelling case that U.S. LNG projects are likely less competitive at an oil price (Brent) level of $80/bbl compared to $100/bbl. With other LNG projects indexed to the price of crude, the current price level would make LNG from Australia more competitive vis-à-vis U.S. LNG in Asia.[25] It is worth noting that Australian projects that are competitive are not per definition profitable. Some estimates suggest that Australian LNG projects break even at around $85/bbl, though of course every case is unique.[26] Third, with respect to Europe in general, LNG producers have to wonder what will be the absorptive capacity of the market. In Europe, LNG competes with cheap coal, support mechanisms for renewables, and very competitive pipeline gas from Russia, Norway, and Algeria (notwithstanding declining domestic production from the Netherlands, for example). It is not unlikely that, even if large amounts of U.S. LNG make it to the European market, traditional suppliers would start a price war rather than give up market share.[27] There is some empirical evidence that U.S. LNG could be very competitive in the more liquid parts of the European market, in particular the UK and Netherlands. Fourth, given all these uncertainties, possible constraints, and the fact that a significant amount of projects are permeating the market in the coming years, it may be increasingly difficult to finance additional projects going forward.

For all proposed LNG projects worldwide, timing is crucial. According to M.C. Moore et al., of the University of Calgary, "delays beyond 2024 risk complete competitive loss of market entry for Canadian companies. Already British Columbia is behind schedule on the government's goal of having at least one terminal in operation by 2015."[28] Moore et al. argue that if Canadian facilities lag behind the projected entry of U.S. LNG facilities, they are at considerable risk for losing out on market share competitiveness by 2024 because of their relatively high delivered-product costs. Thus, it is still highly uncertain what amount of North American LNG will actually make it to the market. We observe that at this point in time, the number of firm export projects in the United States can be counted on one hand, while in Canada there are currently no projects under construction. We also note that even full regulatory approval from FERC and DOE does not guarantee that a project will eventually be built. In addition to regulatory approval, a project requires financing, and at current price levels with more LNG (particularly from Australia and the U.S.) coming on stream, we believe that it is increasingly unlikely that new projects other than fully licensed and financed ones will make it to the market before the early 2020s. Even for the five U.S. projects that have received all green lights over the course of 2014, it is important to keep in mind that

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[24] Ibid., 23.
[25] Ibid., 33.
[26] Bob Lamont, "Falling Oil Prices Set to Hit Future LNG Price," *The Observer*, November 4, 2014, http://m.gladstoneobserver.com.au/news/cheap-oil-to-hit-lng-price/2441170/.
[27] Tim Boersma et al., "Business as Usual: European Gas Market Functioning in Times of Turmoil and Increasing Import Dependence," The Brookings Institution, October 2014, 22, http://www.brookings.edu/~/media/Research/Files/Papers/2014/10/european-gas-market-import-dependence/business_as_usual_final_3.pdf?la=en.
[28] M.C. Moore et al., "Risky Business: The Issue of Timing, Entry and Performance in the Asia-Pacific LNG Market," *The School of Public Policy SPP Research Papers* 7, no. 18, July 2014, http://policyschool.ucalgary.ca/sites/default/files/research/moore-lng-onl.pdf.

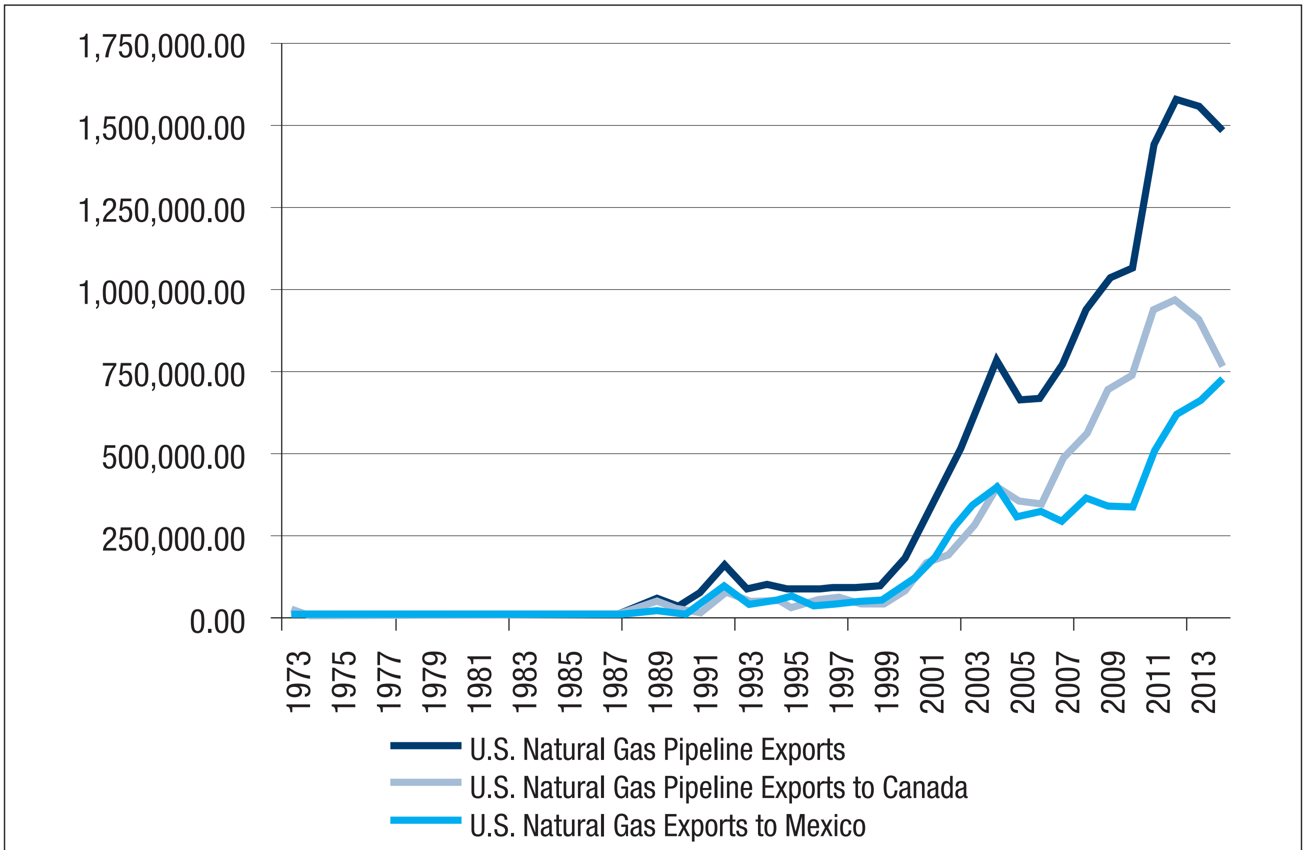
with an estimated brownfield construction time of four years, the earliest achievable start dates will be in late 2018/early 2019,[29] other than the initial four trains (2.2 Bcf/d) of the Sabine Pass LNG export project, which are nearing completion and expected to enter service beginning November 2015. We believe that the trend of increased regional pipeline gas exports will continue however, resulting in particular in vastly increased pipeline exports from the United States to Mexico (**Figure 2**), and a further erosion of Canadian–U.S. gas trade. This leaves an open question where Canadian producers can market their gas going forward.

Competition for U.S. LNG: The cases of Australia and East Africa

Australia

Australia has moved fast to break into the LNG market. With three major facilities already in operation and seven more prepared to go online in the next couple of years, Australia is poised to exceed Qatar as the world's largest LNG exporter in terms of export volumes. However, the Australian projects face significant cost increases, amongst others because production costs turned out higher than anticipated,

FIGURE 2. U.S. NATURAL GAS EXPORTS AND RE-EXPORTS BY COUNTRY



Source: U.S. Energy Information Administration

[29] Ibid.; International Gas Union, *World LNG Report – 2014 Edition, 23.*

and labor costs rose significantly. Because of that, combined with the fact that Australian LNG prices have been linked to oil, it remains to be seen how competitive Australian LNG will be. Regardless of their competitiveness, with huge sunk costs, the Australian projects are still expected to compete in the global market space.

Australia has approximately 43 Tcf of proven natural gas reserves with an additional 437 Tcf of technically recoverable shale gas reserves.[30] Much of the domestic need for natural gas was previously provided by Eastern Australia, but recently there has been a shift and the eastern market has begun exporting LNG. This increase in exports has had an upward effect on domestic prices. As a result, populist voices have emerged, calling to keep natural gas in the country in order to keep domestic prices low. However, the Australian government does not support this policy, arguing that reserving natural gas for domestic use will inhibit innovation, limit diversity of supply, and discourage new investment opportunities.[31] Furthermore, the domestic Australian natural gas market is small, with coal currently dominating the electricity sector at about 64 percent of generation capacity.[32] In addition, foreign investment in the development of the Australian natural gas export market has been beneficial to the Australian economy. The new LNG export facility in Queensland alone has provided the country with 30,000 construction jobs and 12,000 permanent positions through at least 2020.[33] The Queensland Curtis LNG plant is the world's first large scale plant to convert coal-bed methane to LNG. In January 2015, it sent its first tanker carrying LNG to Singapore, Chile, China, and Japan.

Notwithstanding the economic benefits, the Australian projects have generated public concern. A shortage of skilled labor has resulted in delays and cost increases. The projects require skilled labor and Australia's labor pool is limited. However, labor unions in Australia and governmental restrictions over temporary work visas have made it difficult to bring in foreign workers. The labor unions in Australia are powerful and have been able to interrupt the construction of a project under the "right-of-entry" provision.[34] Additionally, labor unions have negotiated for higher wages, on top of already high salaries due to a strong Australian dollar. That strong currency also contributed to skyrocketing prices for construction materials, such as steel, in the early stages of the development of some of these projects. All of these issues contributed to delays in expected completion times as well as significant cost overruns. For example, the Gorgon project, with a capacity of 15.6 mtpa, has been delayed from an original completion date of 2014 to late 2015, while its costs have increased by 40 percent.[35]

Australian LNG projects target Asian markets. They have a major advantage vis-à-vis North American exports in terms of proximity, as transportation costs are lower. Conversely, Australian projects have

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30 "Australia Overview," U.S. Energy Information Administration, last modified August 28, 2014, http://www.eia.gov/beta/international/analysis.cfm?iso=AUS.

31 Australian Government Department of Industry and Science, *2015 Energy White Paper*, (Canberra, Australia Capital Territory: Canberra ACT Department of Industry and Science, April 2015), http://ewp.industry.gov.au/sites/test.ewp.industry.gov.au/files/EnergyWhitePaper.pdf.

32 Ibid.

33 Ibid.

34 David Ledesma et al., "The Future of Australian LNG Exports: Will Domestic Challenges Limit the Development of Future LNG Export Capacity?" Oxford Institute for Energy Studies, Oxford University, September 2014, http://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/09/NG-90.pdf.

35 Ledesma et al., "The Future of Australian LNG Exports: Will Domestic Challenges Limit the Development of Future LNG Export Capacity?"

negotiated contracts based on the price of oil, a formula that may lose its competitive edge in comparison to U.S. projects if oil prices start to rise again. In addition, low Henry Hub prices have sparked a debate amongst Asian buyers whether oil-indexation should still be the preferred pricing method for LNG. There have also been discussions about the development of an Asian benchmark, a stance that is actively supported by the U.S. Department of State. The drop in oil prices has eroded some of the urgent needs of Asian buyers to address the oil-indexation of LNG cargoes, though we do not expect that desire for changes in pricing formulas to disappear. At the same time, it is too early to claim that non-oil based contracting practices marks a widespread disruption of the current system.[36]

Australian LNG faces uncertainties regarding Asian demand. Japan is currently determining how many nuclear power plants it can bring back online since the shutdown of its nuclear fleet after the disaster in Fukushima. In 2013, 80 percent of Australian LNG exports went to Japan, and in 2012 Australia was the largest source of LNG for Japan.[37] Next to the more mature markets in Japan and South Korea, most growth in LNG demand is expected in China and India. However, growth in China in 2014 was weaker than anticipated due to the overall economic slowdown.[38]

Nevertheless, Australia is still on schedule to take-over Qatar to become the world's primary LNG supplier before 2020. One major contributing factor has been that Australia secured contracts before the U.S. shale gas revolution took off in full. Australia's potential for exports is enormous: "LNG exports rose in 2013 to 22.3 mtpa (30.5 Bcm), up by 9% from 2012 and by 2018 the proportion of Australian produced gas exported for LNG is projected to rise to 81%."[39] However, new investments have become uncertain, with other projects coming on stream and global demand in the nearby future possibly being weaker than expected.

East Africa

Over the past decade, both Tanzania and Mozambique have made significant offshore natural gas discoveries. With reports indicating discovered gas at over 140 Tcf in Mozambique and another 46 Tcf in Tanzania, East Africa can become a major competitor in the world LNG market. Although these two countries can produce LNG at relatively competitive rates due to largely conventional deposits and East Africa's close proximity to Asian markets, both Tanzania and Mozambique have substantial barriers to overcome concerning domestic regulations and political stability as well as the lack of available infrastructure to get this natural gas to market.

Both Tanzania and Mozambique must develop infrastructure in order to secure financial investment. The governments of Tanzania and Mozambique have worked with LNG project developers to design a "unitization initiative" in order to cut costs by sharing LNG production facilitates while also effectively curbing construction time.[40] The infrastructure issue becomes even more compounded with the remote

[36] Ibid.; International Gas Union, *World LNG Report – 2014 Edition*, 14.
[37] "Australia Overview," U.S. Energy Information Administration.
[38] BG Group, "Global LNG Market Outlook 2014-15," BG Group, http://www.bg-group.com/480/about-us/lng/global-lng-market-overview-2013-14/.
[39] Ledesma et al., "The Future of Australian LNG Exports: Will Domestic Challenges Limit the Development of Future LNG Export Capacity?"
[40] International Energy Agency, The Asian Quest for LNG in a Globalising Market, by Anne-Sophie Corbeau et al. Paris: OECD/IEA, 2014, http://www.iea.org/publications/freepublications/publication/PartnerCountrySeriesTheAsianQuestforLNGinaGlobalisingMarket.pdf.

location of many of these LNG facilities. In Tanzania, LNG project completion is currently estimated anywhere from 2021 to 2023 with expected international investments of $20 to 30 billion. While Mozambique LNG is officially still estimated to come to the market by around 2018 to 2019, there is a growing consensus that delays could move the completion date back to the mid-2020s. Companies working in the area, such as Eni and BG, have expressed their concerns over the infrastructure challenge being resolved in time to meet the 2018 target.[41]

Additionally, both countries are struggling to attract an adequate, skilled labor force to develop this infrastructure, with the local median age hovering around 17 years. Mozambique has attempted to quell this issue by instituting the Decree Law of December 2014, which outlines specific qualifications for bringing in skilled foreign workers. This decree, among other things, eases restrictions on hiring foreign workers, yet stresses the need to give job priority first to qualified Mozambicans. Additionally, the decree suggests that foreign workers should not be hired for unskilled jobs or those that are not technically complex as these should be reserved for the local population.

Tanzania and Mozambique have also considered using these natural gas resources to meet their domestic needs. The Tanzanian government has made it clear that it will prioritize the domestic market over exports. According to the Natural Gas Policy of Tanzania 2013, "Tanzania aims to have a reasonable share of the resource for domestic applications as a necessary measure to ensure diversification of the gas economy before [development of an] export market."[42] While the Tanzanian domestic market for natural gas is relatively small in comparison to its reserves, this policy could pose a significant barrier to investment. In Mozambique, the new Petroleum Law introduced by Parliament established a 25 percent domestic supply obligation.[43] The national market of Mozambique will not be able to absorb this amount in the long term; therefore, an open question is whether to allow South Africa to be part of this "national market."

East Africa faces the stigma of historic political instability, which could influence both future investments as well as physically impact production. While Tanzania has been a peaceful nation for over 50 years, Mozambique ended a nearly 20-year civil war in 1992 with the signing of a peace agreement. Despite the formal peace, there have been new periods of unrest. Starting in October 2012 and continuing throughout 2013, new skirmishes warranted a second peace deal, which has been in place since September 2014. Still, there continues to be concerns over the ability of the government to maintain political stability and protect against uprisings that could impact future investment in Mozambique.

Despite this uncertainty, at this point Mozambique is comparatively better positioned to export LNG than Tanzania. Mozambique has developed a much more specific regulatory framework and does not have any qualms with exporting the majority of its natural gas. The government recognizes the need for strong regulation and control over how energy resources are managed within the country in order to guarantee domestic revenues. Responsible planning and the reorganization of tax and regulatory poli-

[41] International Energy Agency, *Medium-Term Gas Market Report: Market Analysis and Forecasts to 2019*, Paris: OECD/IEA, 2014.
[42] The United Republic of Tanzania, *The Natural Gas Policy of Tanzania – 2013*, Dar es Salaam: October 2013, 14, http://www.tanzania.go.tz/egov_uploads/documents/Natural_Gas_Policy_-_Approved_sw.pdf.
[43] William Felimao, "Mozambique Passes Petroleum Law and Tax Break for Eni, Anadarko," *Bloomberg Business*, August 15, 2014, http://www.bloomberg.com/news/articles/2014-08-15/mozambique-passes-petroleum-law-and-tax-break-for-eni-anadarko.

cies are necessary in order for Mozambique's natural gas resources to be developed. The government recognizes that Mozambique has the ability to come out of poverty through the development of its energy resources. Standard Bank estimates that LNG could add 15,000 direct jobs and $39 billion in gross domestic product per annum to the Mozambique economy by 2035.[44] The government of Mozambique has issued documentation considering issues such as transparency, regulatory clarity, revenue usage, infrastructure, education, and environmental protection to be priorities when determining the future development of their local natural gas resources.[45] While these are indeed noble intentions, there is still much work to be done in order to overcome rampant corruption, such as rent seeking, which could undermine development.[46]

Even amidst these challenges, there still remains significant interest from Asian investors in developing this LNG. Together both Tanzania and Mozambique make East Africa an attractive investment opportunity. Their location makes their export potential to India and South Asia viable. Companies that operate in Mozambique, such as Eni and Anadarko, plan to have LNG projects online around 2018 with an estimated capacity of 27.2 bcm/year.[47] Even though completion of these projects before the end of the decade may be optimistic, if these plans are implemented and successful, in due time they could result in making Mozambique and Tanzania significant LNG exporters.

Final observations

From this brief overview, we reach the following conclusions:

Though the U.S. regulatory processes for LNG exports to countries with which the United States does not have a free trade agreement are convoluted, lengthy, expensive, and could be further streamlined, there is no outright ban to sell natural gas to any country. To date, no project has been rejected by either DOE or FERC. Thus, it is essentially up to the market to figure out how much room there is for exports of natural gas from the U.S.

We believe that the U.S. LNG projects that are currently under construction, totaling close to 10 Bcf/d in capacity, will make it to the market by 2020, but additional projects are at this point increasingly uncertain. As noted, factors that are important to consider are alternative suppliers of LNG about to enter the market, as well as competition from existing suppliers, such as Qatar, and pipeline supplies from Russia, Norway, and Algeria, and perhaps by the mid-2020s, Iran. Demand in Asia will be affected by the success or failure of additional intercontinental pipeline projects. Russia continues to expand to new markets in Asia, particularly in China, the Koreas, and Japan. Additionally, Central Asian countries continue to add new production and pipelines to the Asian power and industrial markets. Demand will also be affected by the likelihood of at least some

[44] Standard Bank and Conningarth Economists, *Mozambique LNG: Macroeconomic Study*, (Johannesburg, South Africa: Standard Bank, 2014), http://www.mzlng.com/content/documents/MZLNG/LNG/Development/2014-MozambiqueLNGReport-ENG.pdf.
[45] ICF International, *The Future of Natural Gas in Mozambique: Towards a Gas Master Plan* (Washington, DC: Public-Private Infrastructure Advisory Facility, December 20, 2012): ES-17, 18, http://www.ppiaf.org/sites/ppiaf.org/files/publication/Mozambique-Gas-Master-Plan-executive-summary.pdf.
[46] Anne Frühauf, "Mozambique's LNG Revolution: A Political Risk Outlook for the Rovuma LNG Ventures," The Oxford Institute for Energy Studies, April 2014, http://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/04/NG-86.pdf.
[47] International Energy Agency, *Medium-Term Gas Market Report: Market Analysis and Forecasts to 2019*.

countries tapping into their own unconventional gas reserves in the coming years. If a country like China is successful in this endeavor, this will likely have a downward effect on LNG demand. Prices would also be affected. If, for example, a country like Argentina or Algeria is successful with new quantities of gas beyond their domestic requirements, then more supplies will reach at least regional markets putting a downward pressure on prices. Furthermore, the degree to which Japan (and to a lesser extent, South Korea) utilizes its nuclear capacity, can have a dramatic impact on LNG demand and the availability of supplies in the next couple of years. Finally, it remains to be seen whether there will be a global agreement to curb carbon emissions, as many energy forecasts seem to assume, and if so, what kind of agreement emerges, e.g., carbon pricing and GHG restrictions tend to favor natural gas and LNG, although outright requirements for or subsidies to renewables may have the opposite effect. Absent such an agreement, coal remains very competitive against LNG, especially in Asia's burgeoning electricity market. And then there are uncertainties in the LNG market itself, most prominently to what extent arbitrage between the different pricing regions in the market remains attractive, and whether promising technological advances like floating LNG facilities, small scale LNG, and usage of LNG in marine and transportation sectors become more widely dispersed.

Owing to strong environmental opposition by First Nations groups, leading local and international environmental organizations, and fishing interests, less rapid unconventional gas extraction, and less developed infrastructure, it is unlikely that Canada will have a LNG terminal up and running before the end of the decade. Canadian projects are opposed on a number of grounds (siting, impact on fisheries, adding to CO_2 emissions, pipelines serving the projects crossing wilderness areas in British Columbia), and in the current market constellation we believe it will be increasingly difficult to finance new projects, because demand in the coming years can likely be met by existing capacity in combination with those plants that are currently under construction.

In terms of foreign competition, Australia with early market entrance will be paving the way for the future shape of LNG exports. Despite budgetary and project setbacks, Australia's LNG exports are coming online before most of the North American projects. In the coming years we expect to see fierce competition between different LNG suppliers, as supplies outgrow demand, turning the LNG market into a buyers' market. In addition, in areas such as electricity generation, LNG competes with pipeline gas and other fuel sources. As described, there are many different factors that will determine the amount of the future growth of LNG demand, and we would be cautious to take the unprecedented growth figures that we have seen until 2011 for granted.

The jury is out on whether or not Tanzania and in particular Mozambique can become significant producers of natural gas, though there is enormous potential. With many investors interested in developing this region, the lack of infrastructure, rent-seeking, and the ability to complete construction are among the greatest risks to East African LNG market development in the short term. It is worth noting that in the current market environment, and keeping in mind the local challenges in East Africa, constructing greenfields may be increasingly challenging. At the same time, it has been done before, recently, for instance, in Papua New Guinea. LNG coming out of East Africa in due time may well have the ability to compete cost-effectively against North American LNG exports.

The U.S. projects that are currently under construction are unique in their price setting. Even though in the current modest oil price environment the immediate imperative for a more widespread adoption of this pricing formula may have faded, we believe that in the longer run it is likely that more gas producers will abandon the traditional model of oil-indexation. In northwestern Europe in 2008 and 2009 we saw a shift away from oil-indexation, incentivized by oversupply, and the supply glut that is anticipated in the coming years may well have similar effects. For major buyers of natural gas it is important to keep in mind though that spot-price indexation does not equal guaranteed lower prices, and more volatility is certainly one possible outcome.

In sum, the United States is poised to become a major global supplier of LNG, but its operators will face significant competition from a variety of suppliers, in terms of alternative LNG, pipeline gas, domestic production, and alternative energy sources. A number of Australian and U.S. projects are ahead of the curve and will come to the market in the coming years. In combination with slowing demand for LNG these developments will lead to a situation of oversupply, which is expected to last at least until 2017. Therefore, going forward, despite the presence of abundant resources worldwide, we believe it will be increasingly difficult to finance new LNG projects, due to high upfront costs in combination with a substantial number of uncertainties which influence supply and demand. That does not prohibit some of the aforementioned projects in for instance Canada or Mozambique to come to the market, as in due time surely we expect a new investment cycle that results in new liquefaction and regasification capacity coming on-stream.

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Dr. Tim Boersma is a fellow and acting director in the Energy Security and Climate Initiative, part of the Foreign Policy Program at Brookings. His research focuses on energy policy coordination, energy security, gas infrastructure and regulation, and unconventional natural gas extraction.

From 2011 to 2012, he was a Transatlantic Academy fellow in Washington, D.C. Before starting his career in research, Tim spent five years in the private sector, working as a corporate counsel to the electricity production sector in the Netherlands. In November 2014 Tim published a Routledge monograph with Philip Andrews-Speed, Raimund Bleischwitz, Corey Johnson, Geoffrey Kemp, and Stacy D. VanDeveer called "Want, Waste, or War? The Global Resource Nexus and the Struggle for Land, Energy, Food, Water, and Minerals." In addition, his manuscript entitled "Energy Security and Natural Gas Markets in Europe: Lessons from the EU and the United States," is scheduled to be published in the series Routledge Studies in Energy Policy in September 2015. Boersma holds a Ph.D. in international relations from the University of Groningen.

Charles Ebinger

Dr. Charles K. Ebinger has nearly forty years' experience dealing with international and domestic natural gas issues. In 1977, Dr. Ebinger conducted a pioneering study for the American Gas Association (AGA) on the prospects for LNG imports into the United States. In 1983, he conducted another pioneering study for AGA examining the prospects for Natural Gas Vehicles in the U.S. market. During the early to mid-1980s Dr. Ebinger, as Director of the Georgetown University energy program at CSIS, was deeply involved in the policy debate on the pros/cons of Europe becoming more dependent on exports of natural gas from the Soviet Union for the NATO alliance, an issue he has continued to be involved on to this day. Dr. Ebinger has been involved in numerous studies focused on natural gas issues for the World Bank, the Asian Development Bank and USAID. Dr. Ebinger has served as a member of the Board of Directors for the Kokomo Gas and Fuel Company, an Indiana based natural gas distribution utility and North Coast Energy, an oil and gas production company.

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Heather L. Greenley is a senior research assistant with the Energy Security and Climate Initiative. While at Brookings, she has written pieces on the U.S. crude oil export ban, global coal markets, and Arctic development. Her research on international policy issues includes global electricity markets, cybersecurity, and various aspects of energy security with regional focuses in the Arctic and China. She has a M.S. in Global Affairs from New York University where she served as president of the Energy Policy International Club and was awarded the 2014 AFCEA Intelligence Graduate Scholarship for her work on cybersecurity and the North American electricity grid. She has a B.A. in East Asian Language & Literature (Mandarin Chinese) from the University of Florida.

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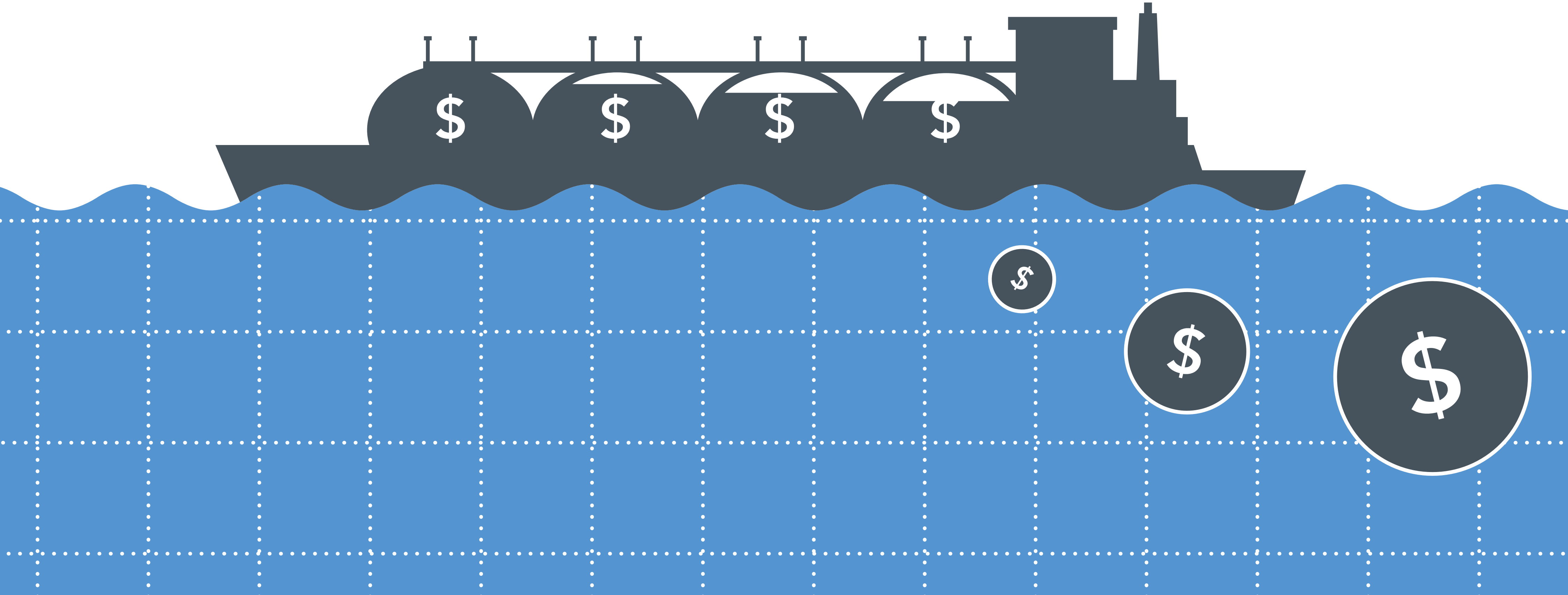
Exhibit 65

Carbon supply cost curves:
Evaluating financial risk to gas capital expenditures



About Carbon Tracker

The Carbon Tracker Initiative (CTI) is a financial not for profit financial think-tank. Its goal is to align the capital markets with the risks of climate change. Since its inception in 2009 Carbon Tracker has played a pioneering role in popularising the concepts of the carbon bubble, unburnable carbon and stranded assets. These concepts have entered the financial lexicon and are being taken increasingly seriously by a range of financial institutions including investment banks, ratings agencies, pension funds and asset managers.

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More detailed papers on gas supply and demand are available at:
www.carbontracker.org/report/gascostcurve

Acknowledgements

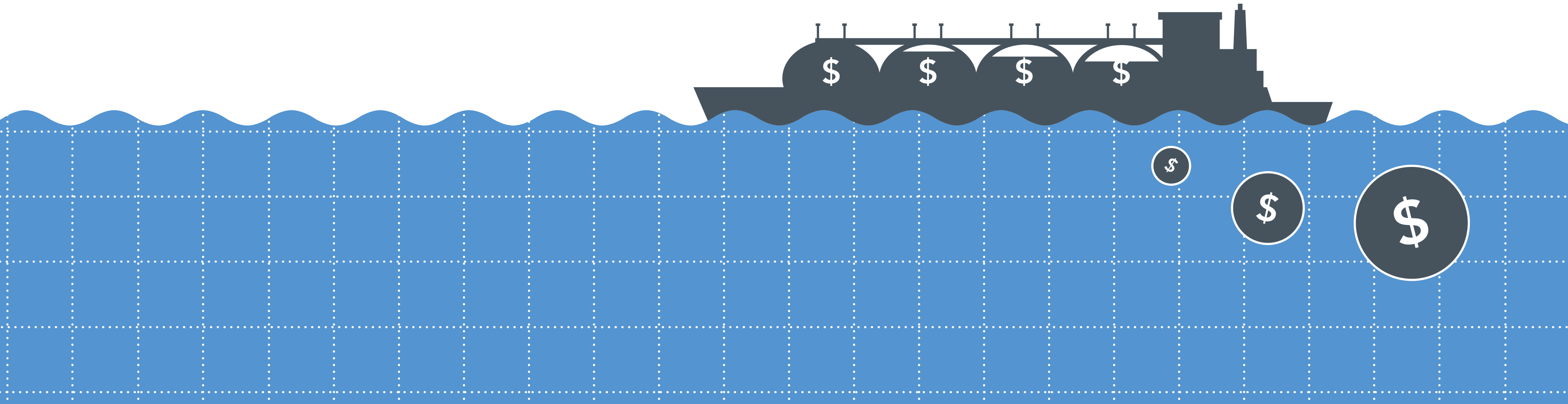
Authored by James Leaton, Andrew Grant, Matt Gray, Luke Sussams, with communications advice from Stefano Ambrogi and Margherita Gagliardi at Carbon Tracker. This paper is a summary which draws on research conducted in partnership with Energy Transition Advisors, ETA, led by Mark Fulton, with Paul Spedding.

The underlying analysis in this report prepared by Carbon Tracker and ETA is based on supply cost data licensed from Wood Mackenzie Limited. Wood Mackenzie is a global leader in commercial intelligence for the energy, metals and mining industries. They provide objective analysis on assets, companies and markets, giving clients the insights the need to make better strategic decisions. The analysis presented and the opinions expressed in this report are solely those of Carbon Tracker & ETA.

Carbon Tracker would like to acknowledge the input of those who reviewed draft papers: Anthony Hobley, Mark Campanale, Jeremy Leggett, Reid Capalino, Mark Lewis, Nick Robins, Shanna Cleveland.

Designed and typeset by Soapbox,
www.soapbox.co.uk

Contents



Executive summary

Perfect storm

2015 has only confirmed the direction of travel away from fossil fuels. The G7 has agreed to aim to reduce emissions by up to 70% below 2010 levels by 2050. Efforts to keep global warming below 2 degrees are ratcheting up, which is tightening the carbon budget remaining for fossil fuels. There are many combinations of coal, oil and gas which could make up the future fossil fuel portion of the world's energy supply. This will vary across power, heat and transport uses, and between regions. This direction of travel to a low carbon future is not just about getting a global deal on climate change. Even as the negotiations have continued, there has been a perfect storm of factors at work. These include concerns over health and air quality, technological advances like domestic energy storage products, the decoupling of economic growth and energy demand, and the continued fall in the cost of renewables.

Demand and price

Analysing the world's gas supply brings you very quickly back to demand. Until LNG became commercially viable, many gas deposits were literally stranded, as they had no access to potential markets. The advent of LNG technology has connected supply and demand bringing gas to new countries, and competition to existing markets. The need for capital intensive infrastructure means that new LNG supply is unlikely to progress far without the gas being contracted in advance. This doesn't mean you can't have too much gas though – if utilities overestimate the demand for their gas power generation, oversupply can weaken prices. The drop in oil prices over the last year has also put pressure on contract prices linked to the oil benchmarks.

Gas connoisseurs

Low carbon scenarios do include the potential for gas demand to grow over the next decade. But if we are to stay within a carbon budget the world needs to be selective in developing gas supply, in order to ensure we use the remaining budget most efficiently. This will also be driven by the relative costs of different power sources in each region. The golden age of gas once mooted by energy commentators has not arrived in most regions. With the costs of renewables falling, gas is already struggling to compete in some markets, or could be priced out soon in others. The shale gas revolution in the US has been the exception, but this has not been replicated in Europe where the swing has been from coal to renewables.

Fugitives on the run

The issue of fugitive emissions has raised questions over the climate benefits of unconventional gas. There is no consensus on the extent of the problem, but there is agreement action is needed. The development of shale gas has prompted proposals from regulators and industry in North America. These need to be delivered fast if gas is to demonstrate it can help meet carbon pollution targets. At the gas prices in our scenarios, capturing this lost product should more than pay for itself, so there is little excuse for not dealing with the problem. The solutions need to be applied to all gas and coal developments and infrastructure, including conventional gas, as there is no room in the carbon budgets for fugitive emissions exacerbating the situation.

LNG left on the shelf?

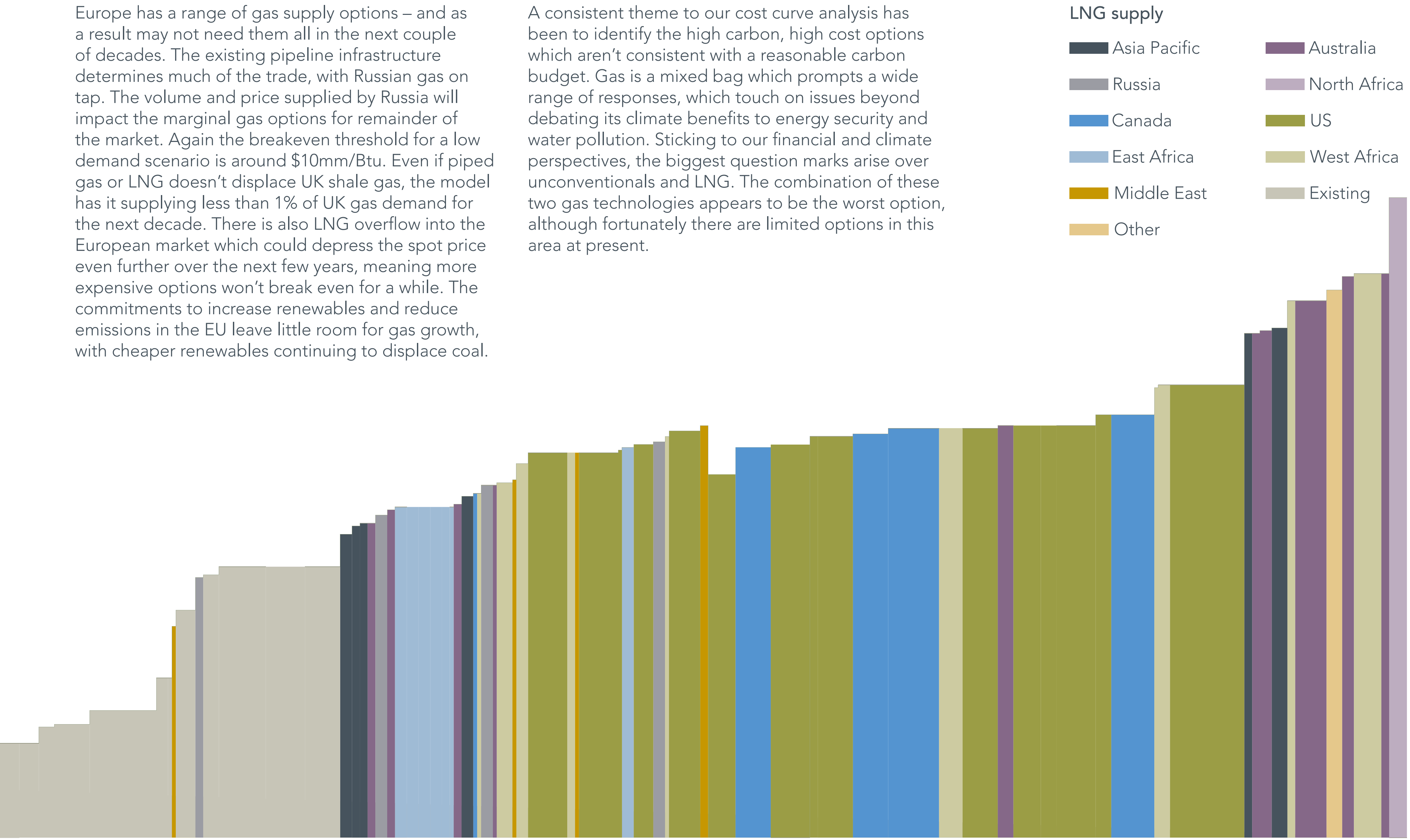
Partly due to the long lead time, LNG supply is covered for a low demand scenario for the next decade. Beyond this LNG with supply costs below around $10/mmBtu delivered to Japan will be needed. But there are $283bn of high cost, energy intensive LNG projects that would continue to be deferred if demand disappoints. In particular the number of LNG plants in the US, Canada and Australia could disappoint those expecting large LNG industries to develop.

European diversity

Europe has a range of gas supply options – and as a result may not need them all in the next couple of decades. The existing pipeline infrastructure determines much of the trade, with Russian gas on tap. The volume and price supplied by Russia will impact the marginal gas options for remainder of the market. Again the breakeven threshold for a low demand scenario is around $10mm/Btu. Even if piped gas or LNG doesn't displace UK shale gas, the model has it supplying less than 1% of UK gas demand for the next decade. There is also LNG overflow into the European market which could depress the spot price even further over the next few years, meaning more expensive options won't break even for a while. The commitments to increase renewables and reduce emissions in the EU leave little room for gas growth, with cheaper renewables continuing to displace coal.

High carbon high cost

A consistent theme to our cost curve analysis has been to identify the high carbon, high cost options which aren't consistent with a reasonable carbon budget. Gas is a mixed bag which prompts a wide range of responses, which touch on issues beyond debating its climate benefits to energy security and water pollution. Sticking to our financial and climate perspectives, the biggest question marks arise over unconventionals and LNG. The combination of these two gas technologies appears to be the worst option, although fortunately there are limited options in this area at present.



Foreword

Carbon Tracker's financial research has created a new debate around climate change and investment literally reframing the debate – "the climate swerve".

Carbon Tracker started this journey by considering the stocks of carbon in coal, oil and gas in the ground and comparing them to the carbon budget necessary to keep average global temperature increase below 2°C thereby achieving a high probability of avoiding, what the international community considers to be dangerous levels of warming.

This gas analysis completes the series of carbon supply cost curve reports looking in turn at oil, coal and now gas. Carbon Tracker's focus is translating a key aspect of the climate science, the carbon budget, into the language of our audience, the financial markets in a way that tells them they have a financial risk issue now.

This report is, so far as we are aware, the first time anyone has sought to look at key gas markets in both a holistic and granular way. So in that sense alone it is a unique and important milestone. As a reference scenario we have assumed that gas would have a 24% share of a global carbon budget. This does of course raise interesting questions around other scenarios, where oil or coal might have a smaller share of the budget. This report clearly demonstrates that global gas industry presents a much more complicated picture then either oil or coal. It is a mixed bag. For the gas industry there is some good news as unlike oil and coal there is still some limited room for growth even within the 2°C budget. Unfortunately for the industry this is not anywhere near as much as it projects and certainly does not suggest a golden age of gas.

Major players in the gas industry are taking positive steps to quantify and address the fugitive emissions issue. If they are successful in achieving the commitment to limit fugitive emissions at 1% across the industry this will go a long way to positioning gas as a carbon 'lite' option. But they are not there yet and more companies and regions need to come onboard to ensure there is clear blue sky between unconventional gas and coal.

Alongside policy measures we are seeing the potential for disruptive advances in energy technology that can outcompete centralised power generation whether from coal or gas and provide cheap access to renewable energy for all. This is even more pronounced for gas in emerging markets without indigenous gas supply, where expensive infrastructure is needed for any coal to gas switch. With the cost of renewables falling all the time, time is running out for gas in some markets.

There is a realisation that ignoring climate risk and hoping it will go away is no longer an acceptable risk management strategy for investment institutions. Pension funds are under increasing pressure to articulate how they are addressing the need to both mitigate emissions and adapt to changing climates and markets. Since our coal report in September 2014 many investors now see coal as not only the most visible target of all, and so most at risk of regulatory intervention, but as a poor investment. Gas by contrast is still seen as the clean alternative by many investors. This report shows that the reality is a much more complex and nuanced picture, if it is assumed there is not unlimited demand for gas.

Carbon Tracker is not an advocate of a pure divestment approach to fossil fuels. Rather we advocate engagement, correctly pricing the risk premium associated with fossil fuels, transparency and the closure of high cost, high carbon projects – project level divestment. We look to identify the most economically rational path for the fossil fuel industry to fit within the carbon budget. This is clear cut with oil where many high cost high carbon projects do not make financial sense such as arctic, oil sands and ultra deep sea projects; or coal given that much of the US coal mining industry has already shrunk in value, many investors will have limited exposure already. See our report, 'The US Coal Crash – Evidence for Structural Change', which provides strong evidence for the structural decline of coal.

The story for gas is more complicated, very much a mixed bag. This does not need to be a negative issue for investors or diversified resource companies. As active stewards of capital they can, using tools such as the carbon supply cost curve, ensure that value is maximised, either through redeployment of capital within companies, or by returning the capital to shareholders. There is clear alignment between high cost and excess carbon through the cost curve. This analysis serves as a reminder to investors to ensure company strategy is aligned with their best long-term interests.

Anthony Hobley

CEO, The Carbon Tracker Initiative
July 2015

1. Introduction

Competition between fossil fuels

Having produced global cost curve analyses for oil and coal in 2014, this set of gas cost curves completes the set of fossil fuels. It comes at a timely moment with fierce competition between coal and gas as a power source going forward. This is encapsulated in the renewed calls by the European oil and gas sector for measures such as a global carbon price, which will favour its gas production over coal for large power plants.

Climate benefits

Gas is often billed as a cleaner fossil fuel compared to coal, but this is not guaranteed (New Climate Economy 2015). As with all greenhouse gas accounting the devil is in the detail. The potential for extra methane emissions from unconventional gas and the energy requirements of producing liquefied natural gas (LNG) need to be addressed. There is growing industry and investor attention on these matters, as research continues to improve understanding and reduce emissions.

Complex regional markets

The gas analysis is undoubtedly the most complex of the three fuels, with competing supplies and the global trade in LNG to analyse. There is significant regionality, as exemplified by the growth of US shale gas production, the uncertainty around EU carbon markets, and Asian LNG demand projections.

New trading dynamics

The interaction between these markets is also critical. The majority of the LNG market is contracted in advance to justify the huge capital investment. Some flexible production is retained for sales on the spot markets. This has created a new dynamic with LNG oversupply offering some diversification from Russian piped gas in Europe. North American LNG exports are a new option being considered, with the potential to take spot prices linked to Henry Hub, rather than being linked to oil prices as is the case in much of the rest of the market.

Golden age or gold rush?

The talk of a golden age of gas has been around for a while. This has seen huge investment pour into new gas supplies. As with any commodity there is a risk that this leads to cost inflation, oversupply, and weakening prices. Growth in demand for gas is expected in most scenarios – the question is how much? The current glut of LNG supply demonstrates that the gas value chain is still capable of misreading future demand levels. The initial rush for US shale is now over, with questions being raised about its financial stability in a low oil price environment.

Operating within a carbon budget

Creating an energy system that fits within a carbon budget still imposes limits on all fossil fuels, including gas. This means that in low carbon scenarios less gas will be required over the next few decades than in business as usual, where consumption grows at a faster rate. Some scenarios may have faster growth of gas use earlier on, but this would displace the available carbon budget elsewhere. This could be reducing the share of coal or oil, or lowering unmitigated combustion of gas later on.

Paris and beyond

The UNFCCC COP in Paris at the end of 2015 is only the next step in the global negotiations. It will confirm the current country level objectives which can be further ratcheted down. Alongside this are the announcements from the G7 to aim for up to 70% decarbonisation by 2050, and the raft of regional, city, corporate and investor commitments to reduce emissions and increase renewables. These all represent a downside for fossil fuels at the high end of the cost curves.

Further investment

There will undoubtedly be more investment in developing gas supplies. However there will be a limit to how much is needed, especially given how much capital has already piled into new LNG supply for example. This study aims to inform how much investment may be required in a low carbon scenario.

2. Allocating the carbon budget

Continuing from our previous carbon supply cost curves analyses of coal, and oil, the remaining carbon dioxide budget for gas in the reference scenario is 216 $GtCO_2$ (with 324 $GtCO_2$ for coal and 360 $GtCO_2$ for oil). This allocation is based on the proportions of emissions from coal, oil and gas projected in the International Energy Agency's (IEA) 450 scenario. It represents 24% of the total budget to 2050 of 900 $GtCO_2$ which is estimated by the Grantham Research Institute on Climate Change at LSE to give an 80% probability of limiting anthropogenic warming to 2°C.

Based on the distribution of emissions through the decades, just over 50% of the carbon budget for gas is apportioned up to 2035. The analysis only runs to 2035 to match the availability of the gas supply and economics data. This provides a carbon budget of around 125 $GtCO_2$ for this period. This is apportioned as follows:

Figure 1: Breakdown of gas carbon budget

	$GtCO_2$ emissions to 2035	
Gas Type	**450 scenario**	**LDS**
Conventional	77.5	82.0
LNG	16.8	16.9
Unconventional	30.9	33.3
Total	125.2	132.2

Gas consumption before delivery

The gas supply data displayed in this analysis is the volume delivered under contract to the customer. We have therefore had to factor in the consumption of gas in the extraction phase (6%) for all gas. For LNG there is further usage of gas prior to delivery in the liquefaction and regasification processes (12%), as well as in boil-off during ship transfer (2.5%). These percentages are based on analysis of 2012 IEA demand data compared to the 'marketed' data analysed in the model.

Fugitive methane emissions

The carbon budgets used in our analysis refer only to carbon dioxide emissions. There is an inherent assumption regarding efforts to tackle other greenhouse gases in modelling these carbon dioxide budgets. These budgets do not factor in any significant uplift in methane emissions due to the growth in unconventional gas.

Both conventional and unconventional gas operations have fugitive emissions. For each 1% of leakage, the leaked methane amounts to around 12% of the CO_2 emissions from the combustion of the remaining gas, on a CO_2-equivalent (CO_2e) basis (WRI, 2015). Using WRI and IEA analysis as a guide, gas needs fugitive emissions of less than 3% to provide a climate benefit over a typical coal plant (noting there is variation in performance at a plant level for both coal and gas) (WRI 2013, IEA 2012).

Both industry and government bodies are developing a number of initiatives to tackle fugitive emissions (CCAC Oil & Gas Methane Partnership; One Future US). This is still an emerging area of research, with a wide range of results. We surveyed a number of recent studies which had fugitive emissions levels ranging from 0.42% to a 10% midpoint, giving a median of 2.9% fugitive emissions for unconventional gas. This compares to median of 1.4% for studies analysing fugitive emissions from conventional gas.

Only time will tell if the unconventional gas industry can deliver significant reductions in fugitive emissions across the board. If a higher percentage of fugitive methane emissions for unconventional gas needs to be factored in, it would further squeeze the carbon dioxide budget. Further information on fugitive emissions is available in the accompanying detailed supply methodology paper.

Geographic split

We have broken down gas demand into three main markets which drive supply for producing cost curves. These are North America, Europe and LNG, which together represent around half of the global market. These markets are not entirely independent, as for example, oversupply of LNG may impact the indigenous demand levels in Europe depending on relative prices, and the competitiveness of North American LNG exports will be influenced by the domestic gas price. Much of gas supply in the rest of the world is produced and consumed domestically rather than being traded on a fully functioning market, so there is less value in showing this on a cost curve.

3. Demand scenarios

Of the fossil fuels, only gas demand is higher in 2040 compared to 2012 under IEA New Policies Scenario (NPS) and 450 scenarios, (IEA 2014). The NPS and 450 show an overall CAGR of 1.6% and 0.7%, respectively, from 2012 to 2040. The biggest contrast between the NPS and 450 scenarios – and the biggest enabler of lower fossil fuel demand – is a decrease in overall energy demand, because of energy efficiency and conservation.

The level of gas demand has grown 22% less in 450 than NPS by 2040. Within this decline, the majority of the reduction occurs between 2030 and 2040, as government policies aimed at curbing energy consumption reduce demand for all fuels. The power sector currently accounts for around 40% of gas demand, with industry and heat each making up around 20%. There is hardly any increase in gas demand for power from 2012 in the 450 scenario. There is still growth in heat and industry usage, although it is tempered by efficiency gains compared to the NPS.

The OECD remains the largest absolute source of gas demand by 2040. However, over 40% of demand growth between 2012 and 2040 comes from non-OECD Asia. In addition, the Middle East, Africa and Latin America represent one-third of total growth between 2012 and 2040. OECD demand declines by 13% by 2040 in the 450 scenario, whereas non-OECD demand increases by 49% in the same period. The regional variation in demand in IEA scenarios is reflected in how we have projected demand for the EU, North America and LNG in our analysis. More information on demand scenarios and potential drivers for change is available in the separate more detailed demand paper.

Industry outlooks

The scenarios provided by the oil majors have CAGRs between the IEA NPS and CPS of 1.6% or higher to 2035. The percentage change is shown as the different scenarios are not directly comparable. The Low Demand Scenario (LDS) presented here is essentially an updated NPS which has a global CAGR of 1.4%, to reflect the direction of travel we already see below the NPS.

There is very limited potential for difference in gas demand early on, due to the amount of supply already contracted in the model. Within the markets covered, the biggest difference to industry forecasts is probably a lower level of production long term (post 2020) in North America.

Direction of travel

The reasons for Carbon Tracker already seeing fossil fuel power demand lower than IEA NPS include:

- The slowing of economic growth rates, and the decoupling of GDP growth and power demand in major economies
- The restructuring of energy markets, reducing dependence on base load, and increasing off-grid generation
- Onshore wind already cheaper than fossil fuels in some markets with solar set to follow in a growing number of major markets
- The potential for disruptive new technology advancements, e.g. energy storage
- Improved efficiency of use for heating buildings

These factors create a perfect storm whereby rapid changes in the energy system can emerge. It is important to note that these areas are not dependent on a global deal on climate change – many are already happening as the negotiations continue (BNEF 2015).

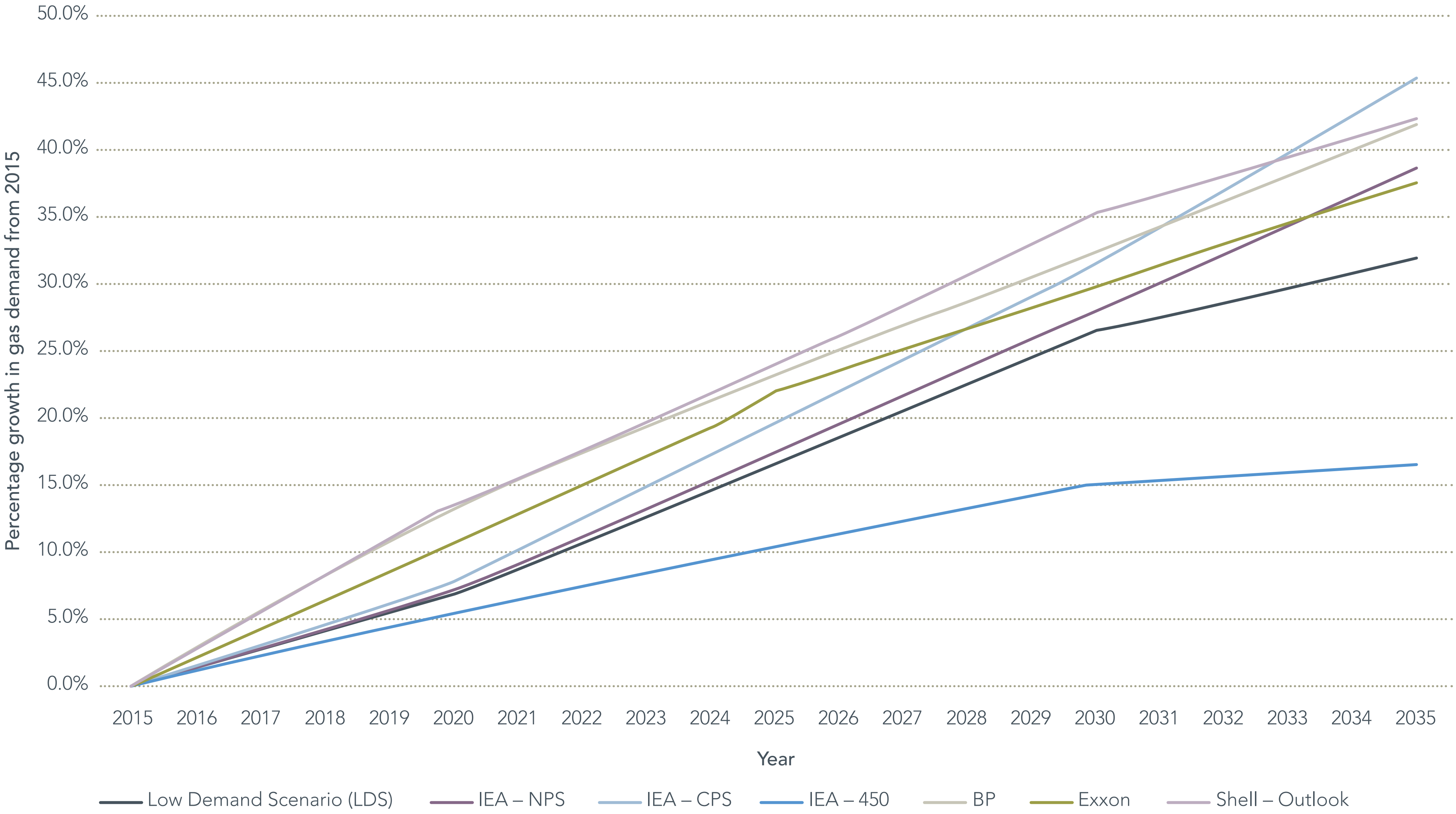
Coal to gas switching

It has long been expected that carbon pricing mechanisms such as the EU Emissions Trading Scheme would prompt a switch from coal to gas. In order for such market mechanisms to deliver this kind of change the right balance between carbon prices and commodity prices needs to result. Carbon pricing still increases costs of gas plants, however, and this also enhances the competitiveness of renewables. Over the last decade there has been no significant increase in EU gas consumption as some may have anticipated.

In the US, the swing away from coal generation has been split two-thirds gas and one-third renewables (Carbon Tracker 2015). This has been achieved through both cheap gas prices, and increasing costs for coal plants resulting from EPA measures to reduce pollution. There has already been an 8% increase in the share of gas power generation.

Thermal coal is already in structural decline in a number of markets, and official figures indicate a peak in demand in 2014 in China. The window for switching to gas may be closing however. Gas can bring some incremental benefits in terms of greenhouse emissions, but there is a limit to how many more decades of unmitigated emissions from new gas plants we can be locked into. Some regions are already leapfrogging straight to renewables as costs become competitive.

Figure 2: Comparison of demand scenarios



Sources: Company reports, IEA World Energy Outlook, Carbon Tracker analysis

450 vs low demand scenario

The analysis did model the IEA 450 scenario well as a low demand scenario closer to the IEA NPS scenario. The gap between the scenarios varies across the markets analysed for the following reasons:

- Variability of changes in demand to 2035 in the IEA scenarios across regions
- The way the model allocates LNG supply demand across an increasing number of regions
- The relative prices assumptions of the model outputs across the regions

Looking out to 2025, the differences are smaller – with the most change experienced in the decade to 2035. This reflects the more similar demand trajectories between the LDS and 450 scenarios in the short term, and the fact that most LNG supply is already contracted to 2025.

Overall production is down 5% in the 450 scenario vs the LDS over the period for the regions covered here. There is very little difference in the LNG picture between 450 and LDS.

In Europe there is a 6% reduction in demand to 2035 in the 450 scenario compared to the LDS. North America has the biggest difference with a 7% drop in production over the period to 2035.

We have displayed indicative 450 demand intersects on the cost curves for information, although the precise order of supply points along the cost curve may be slightly different in the model due to its dynamic nature, and the different regional balance between the two scenarios.

Overall capex is down 6% between the scenarios with the 450 needing $172bn less than the LDS. Half of this reduction relates to the US, with 30% relating to Europe and 20% LNG.

Price trends

Gas prices have seen increasing divergence over the last decade. Recent price trends reflect some key developments and events. In North America, the continuing development of shale gas technology has kept prices at lower levels. In Asian LNG, the Fukushima incident in 2011 stimulated elevated prices.

The picture is changing again in 2015. The recent oil price drop in the second half of 2014 has fed through into contracted gas prices which are indexed to oil prices. The oversupply of LNG is also depressing Asian LNG spot prices, which have just converged with European benchmarks, and are below the contract import prices.

Price risk

It is important to distinguish between contract prices and spot prices. The majority of LNG in Asia and Europe is supplied under contracts which are are indexed to oil prices. This has given stable high prices over the last few years; but the drop in oil prices has fed through over the last year. LNG producers may retain a proportion of production (say 10–20%) for the spot market to give flexibility to exploit higher prices. New LNG projects in North America are different in that the pricing structure is related to fixed costs plus Henry Hub.

Where gas is supplied by pipe this is also typically contracted (e.g. from Russia). The cost of new infrastructure needs to be factored into the development of fields requiring new pipeline capacity. Gas production such as that in the North Sea or from US shale is sold using spot prices or spot futures prices. Both gas suppliers and major consumers can choose to hedge gas prices to limit impacts of price movements on either revenues or costs.

If there is a period of lower gas prices for LNG and Europe over the next few years this could stimulate further investment in gas power generation and increase the proportion of gas generation capacity.

Figure 3: Comparison of gas production and capex in the regions and scenarios (2015–2035)

	Production (bcm)				Capex ($bn)			
	450		LDS		450		LDS	
	Needed	Unneeded	Needed	Unneeded	Needed	Unneeded	Needed	Unneeded
Global LNG	10,274	3,534	10,430	3,446	553	414	588	379
North America	19,910	4,513	21,358	3,064	1,063	284	1,148	199
Europe	8,279	1,172	8,829	1,018	964	347	1,015	296
Total	38,463	9,220	40,617	7,528	2,580	1,046	2,751	874

Figure 4: Trends in contract and spot gas prices across regional markets over the last decade

Source: Bloomberg data

4. Supply cost curves

The approach of using a cost curve provides an indication of the relative costs of supplying volumes of product. The basic economic theory is that the market will select the cheapest production to meet the demand level, all other things being equal. In reality other factors such as political risk, public sentiment on unconventional gas, and market regulation may override the pure economic logic, and operators will also be working to try and reduce the costs of projects where possible.

The model incorporates the geography (location of supply and demand centres) and infrastructure of global gas trade. The 'earliest start date' and breakeven cost of a project or supply source that is made available in the model is determined by Wood Mackenzie analysts to reflect project development status and its global context. As a result there are a small number of projects not needed in a demand scenario which appear cheaper on the cost curve than those that are included. For example in North America this reflects that some nodes of production will be supplying localised markets, rather than competing on a national basis.

Supply and demand

The cost curves indicate which projects are needed to meet the demand level specified – those to the left of the demand line. Beyond this potential production which is not needed in this demand scenario is to the right of the demand line. Fully unconstrained supply data was not available, especially for North America – this relates to the demand-led nature of the industry. In theory supply should be tailored to demand, however the lagtime of 5 years or more to deliver LNG infrastructure allows some mismatch to occur, resulting in periods of oversupply.

The capital-intensive nature of LNG means that most operators will secure contracts to sell the gas before they invest the capital. There will still be some price risk for the producer, depending on how the contract is structured (e.g. linked to the oil price).

Project types

For LNG and Europe the data indicates the project stage so we can identify existing projects which have already started construction or production. Beyond this we can also differentiate between conventional and unconventional projects. This enables the reader to differentiate between the different types of extraction techniques, project economics, and environmental aspects of the two types of gas.

The majority of unconventional production to date has taken place in the United States. Some other countries are seeking to apply hydraulic fracturing technology (e.g. UK, China), whilst others have banned its use (e.g. France, Germany, Netherlands). The model reflects some of these restrictions in adjusting the 'earliest start dates'. Beyond shale gas, other types of unconventional gas include coal bed methane and tight gas.

Capex and production

The three demand markets covered in this paper are the largest and most liquid globally, and represent around half of the global gas demand. Much of the rest of the world has domestic gas production which does not currently interact with the traded gas markets. As with our oil and coal studies, we concentrate on capex over the next decade (2015–2025) and production over the longer term (in this case 2015–2035).

Breakeven prices

A project's Break Even Gas Price (BEGP) is the price that – considering all future cash flows (i.e. costs, revenues, government take) – is needed to deliver an asset-level net present value (NPV) of zero assuming a given discount rate (15% for upstream (ex-US/Canada), 10% for North America upstream, 12% for integrated LNG projects, 10% for stand-alone LNG plants).

Where infrastructure has already been built, cash costs are used in place of breakeven costs to reflect the sunk nature of this capital and the move to operational economics. The boom in investment in gas infrastructure over the last few years means that there is significant capacity due to come onstream which has already invested the upfront capital, and contracted to supply gas.

Delivered cost basis

The gas costs displayed on the cost curves are the delivered costs, including transport by pipeline or LNG tanker as appropriate. This indicates the likely costs to the potential buyer.

In Europe and North America, gas transport costs are calculated based on the "most likely point of delivery" (as determined by the model), taking into account geographic and logistical constraints. In our global LNG market analysis, cargoes are indexed to Japan delivery (as a proxy for Asia generally, which accounts for the large majority of global LNG demand).

The model assumes a Brent oil price of $85 for oil indexed contract prices and when calculating the cost of gas production. Real prices are used subject to inflation of 2% post 2015 and foreign exchange rates are set as at the time of the model run.

5. LNG carbon supply cost curve

97% of the LNG required in our low demand scenario to 2025 can be met by projects already committed to. This partly reflects the long lead times for capital intensive LNG projects. New (pre-final investment decision) supply is only needed from 2024 onwards, and due to the large number of competing projects only the most cost effective likely go ahead, notably:

- Brownfield projects in the Pacific
- A limited amount of US projects
- Mozambique – supported by economies of scale and proximity to demand (India)
- Other more speculative, but likely to be competitive projects – Iran, Iraq and West Africa

Even looking out to 2035, 82% of LNG requirements for the low demand scenario already have supply identified. The marginal tranche of supply between the 450 and LDS scenario is likely to be a US LNG project.

Strategy rethink

Some companies are betting on big growth in LNG capacity. However this is based on energy demand growth, and gas' share of this larger pie. If new supply is not needed for another decade, this could leave companies seeing much lower levels of activity for the next few years. There is a further $283bn of new LNG projects over the next decade that would not go ahead if LNG capex matches our demand scenario.

Lowering expectations

It is clear that the US, Canada and Australia would have to temper their ambitions for new LNG over the next decade in a low demand scenario, with the distribution of unneeded capital expenditure as follows:

- $82bn in Canada
- $71bn in the US
- $68bn in Australia

Price assumptions

LNG pricing remains weak compared to post-Fukushima / pre-oil price crash levels in the scenario, with spot prices in the range $8–11/mmBtu for most of the period. This translates to a long term breakeven test of around $10/mmBtu. The model selects which projects go ahead based on spot prices for LNG. It is important to note that LNG projects can require 15–20 years to pay back the capital costs, so long-term pricing is important. There is market commentary asking whether LNG markets will link more to spot prices, and see greater convergence with regional markets, e.g. Henry Hub prices.

After the Fukushima disaster in 2011, Asian LNG spot prices were in the $14-20/mmBtu range. The current oversupply could see further weakening in the short-term. LNG spot prices are now more closely mapping European gas prices, becoming the flexible supply option.

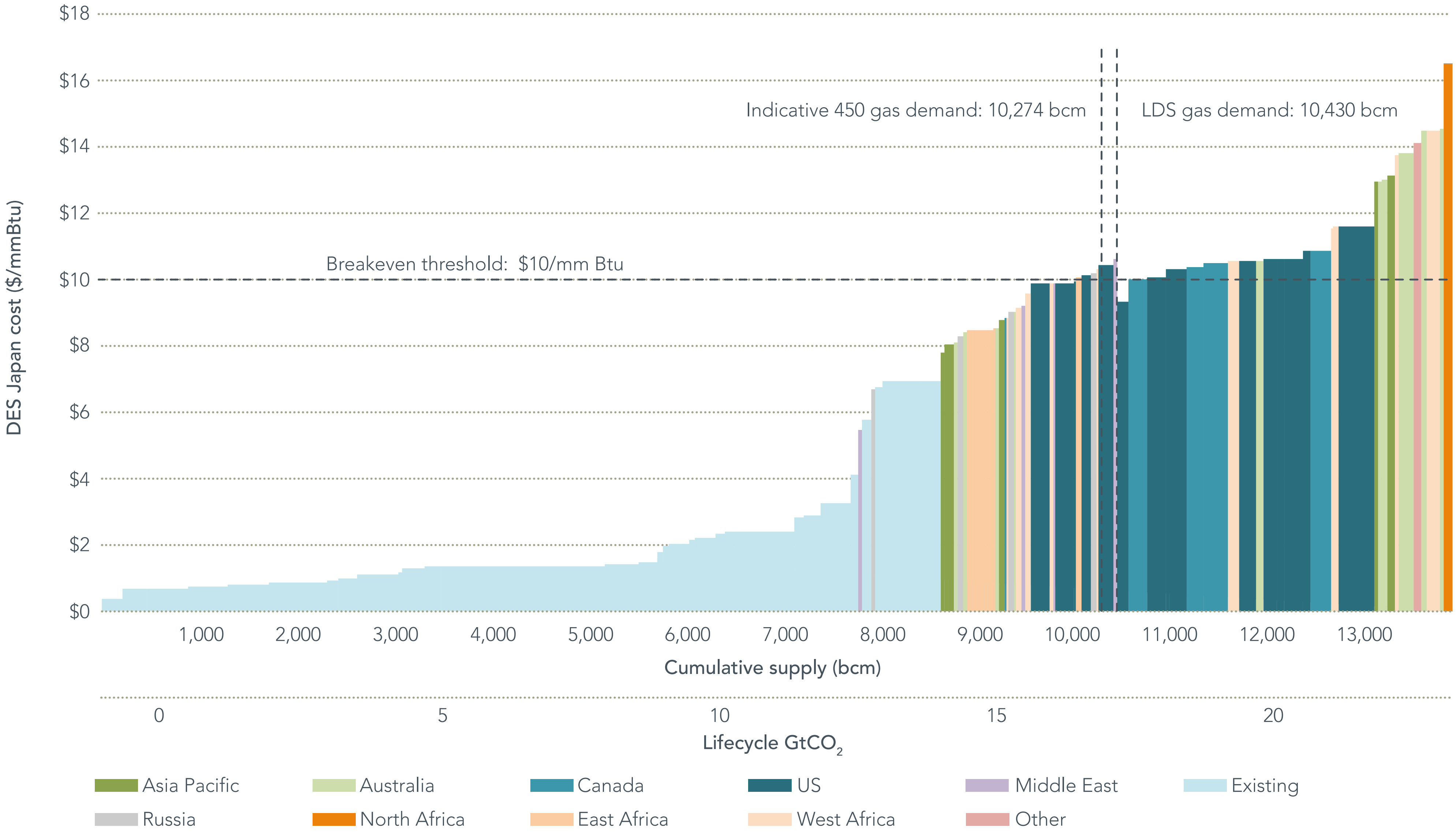
Carbon intensive

Increasing the proportion of gas supply from LNG makes it more difficult to achieve emissions reductions. This is because around one fifth of the delivered gas can be consumed in extraction, liquefaction, shipping and regasification.The change of state from gas to liquid is particularly energy intensive.This puts LNG at a disadvantage in carbon efficiency terms.

The most GHG intensive option is a combination of unconventional gas supplied via LNG infrastructure. Fortunately there is only around 17% that is LNG fed by US shale gas or Australian coal bed methane which breaks even under $10/mmBtu. Over half of the unneeded LNG capex relates to unconventional sources of gas supply, in the US and Canada. Removing this from the gas supply scenario is helpful in terms of limiting future greenhouse gas emissions.

This translates to a long term breakeven test of around $10/mmBtu

Figure 5: Global LNG cost supply cost curve, 2015–2035



Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

6. European carbon supply cost curve

The European market covered here includes piped domestic supply and piped imports from North Africa, Middle East, the Caspian and Russia.

Russian influence

Against this picture of fairly flat demand and well-supplied LNG markets, material new supply and uncontracted Russian gas is only needed from 2026 onwards in order to satisfy demand (although some is needed before this point in order to satisfy local demand). Based on the Brent price scenario of a flat $85/bbl throughout the period, oil-indexed imports from Russia remain competitive in the long term.

For Russian supply, a target price has been assumed in the model which would reflect a fair competitive position of Russian gas into Europe i.e. one that is competitive but not undercutting all the other new supply simply to gain political points and market share. This "target price" setting means Russia targets profitability above market share. This has the further effect of providing a balance of LNG and Russian piped gas in Europe, as states may wish to pursue given the perceived political risk of being too reliant on Russia for gas supplies.

This suggests that UK unconventionals will supply less than 1% of UK gas demand over the next decade

450 Scenario

There are a few tranches of supply that sit in the marginal cost band between the 450 and LDS scenarios. This includes the UK shale gas that is included in the supply in both scenarios. This is a function of the model limiting Russian supply. There is cheaper Russian supply that could displace UK unconventional gas production.

Unconventional impact on UK supply

If unconventionals are included by the model, only 3 bcm in the 450 scenario and 6 bcm in the LDS of unconventional production in the UK is included in total over the decade to 2025. This could increase post 2025, with the model estimates of volume and price indicating a further 80 bcm if Russian gas volumes are limited.

This compares to UK gas consumption of over 70 bcm per annum in recent years. This suggests that UK unconventionals will supply less than 1% of UK gas demand over the next decade (assuming demand stays at the same level). In practice this could easily be replaced by importing slightly more LNG to the UK.

LNG overflow

Oversupply in LNG markets over the next decade weighs on European hub prices as Europe acts as a "sink" for excess LNG supply. The prices show a similar trend to Asian LNG throughout, often in the $8–11/mmBtu range on an annual basis. This again translates to a long term breakeven threshold of around $10/mmBtu.

Indigenous gas uncompetitive

The model indicates that new indigenous gas above $10/mmBtu fails to make the cut in the low demand scenario. Some Russian production also is excess to requirements, but a large amount still clearly makes the cut.

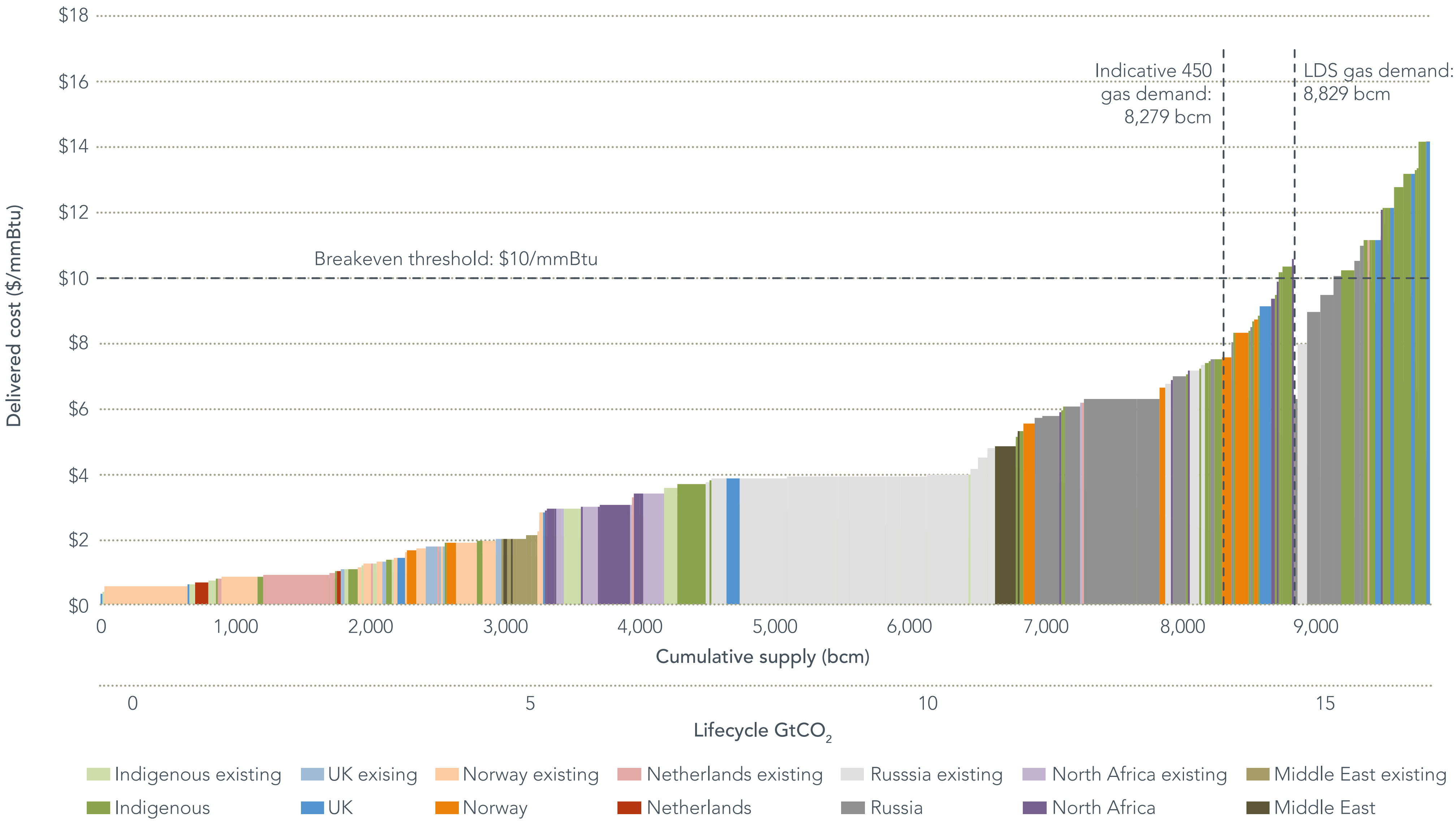
EU unconventionals

The model indicates that up to 5% of Europe's gas production could come from European unconventional sources over the next couple of decades in either scenario. This may end up being lower depending on which jurisdictions allow hydraulic fracturing to take place. Higher rates of unconventionals come through post 2025 than in the first decade, in the model.

Coal to gas switch

Gas has not seen its share of European power generation increase over the last decade. The weak EU carbon market and availability of cheap coal has not incentivised a new order in fossil fuel power generation. Over this period the previous EU utility business model has expired with the growth of decentralised renewables, as seen in Germany's 'Energiewende' (Agora, 2015, Carbon Tracker, 2015). Gas use can only grow at the expense of coal generation, given Europe's trajectory for emissions to 2050. Europe has objectives to cut emissions by 40% by 2030 and 80–95% by 2050 compared to 1990 levels. This does not leave much room for new large fossil-fuel based power plants that could run for decades.

Figure 6: Europe carbon supply cost curve, 2015–2035



Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

7. North America carbon supply cost curve

The approach for North America reflects the different gas industry operations and available dataset for the region. Most large new gas interests are amalgamated into production tranches (to reflect different drilling costs) rather than being at the project level. The sheer number of wells and plays makes it impossible to show the detail on this cost curve. This curve does not show unconstrained supply as this approach is not possible with the data due to the significant resources and short-term nature of shale gas plays. The chart shows the breakeven cost to the expected point of delivery. Prices will vary regionally, so it is not valid to compare to a single reference price such as Henry Hub.

Shale gas

The shale gas boom in the United States has altered the US energy picture, making gas cost competitive with coal in many states, especially where new air pollution requirements are coming in (Bloomberg, 2015). Even in a low demand scenario the model projects that shale gas will form nearly three-quarters of the US supply. The marginal supply is unconventional and the demand level will therefore determine the level of shale production required for the domestic market.

450 scenario

The difference between the scenarios is a 1,448 bcm tranche of US shale gas which does not get produced. The bulk of the fall-off in production (84%) occurs post-2025.

Financially sustainable?

The shorter term, less capital intensive, nature of shale gas in the United States means it is easier to adjust supply compared to an LNG plant. There is further capacity which companies are expecting to bring onstream; but companies could adjust their plans to respond to changes in demand and price. The resulting drop in revenues may place a financial strain on the smaller producers who have high levels of debt to service.

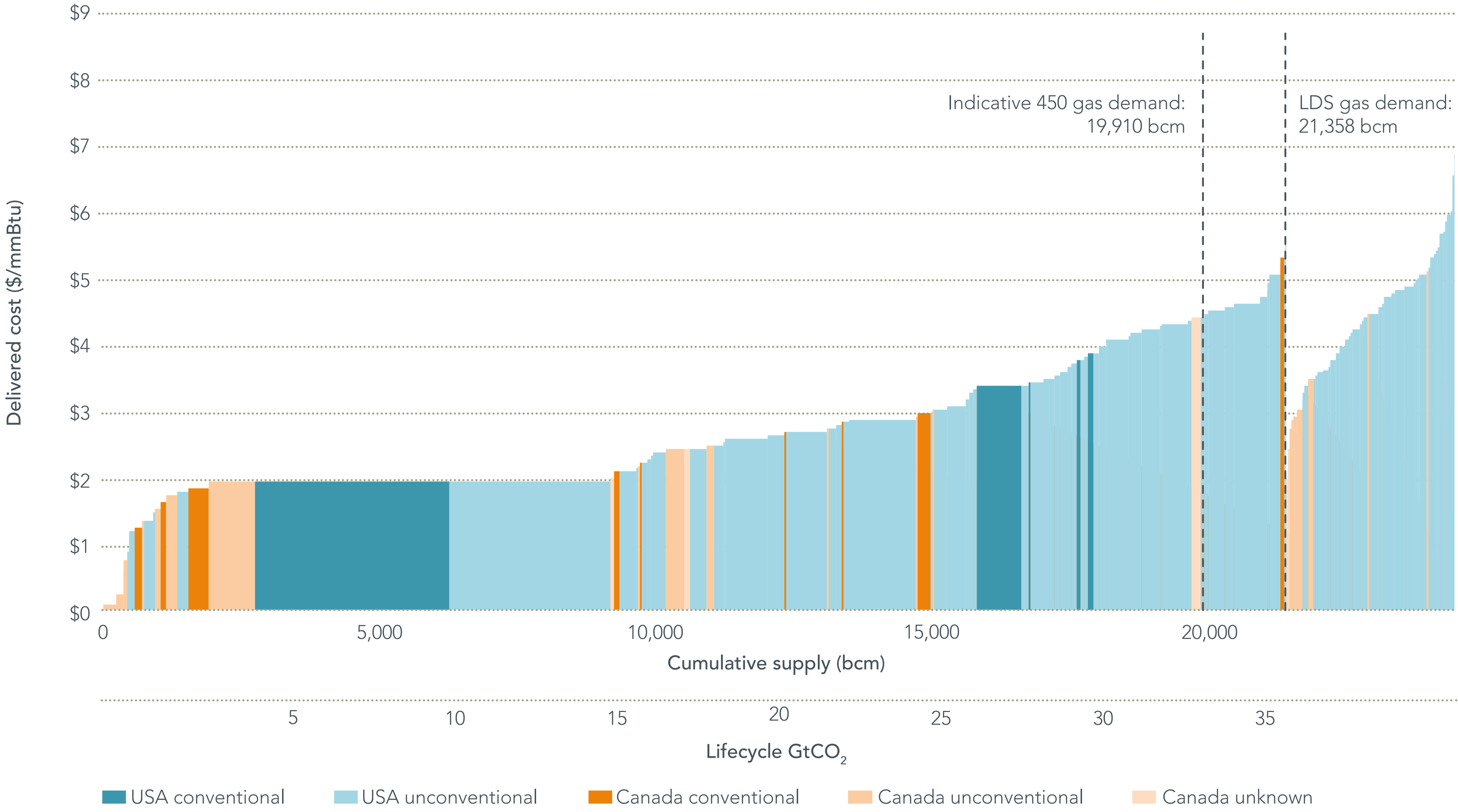
Price stability

Abundant domestic supply is consistent with average US natural gas prices remaining in the range seen in since the onset of the shale “revolution”, largely in the $3–4/mmBtu range over the next decade and $4–5/mmBtu over the subsequent decade. We have not indicated a long-term breakeven price as the cost curve is too flat and the decision will be made on a case by case basis.

Regional distribution

The effect of applying a low demand scenario appears to be distributed across the production nodes, taking off the marginal barrels in each area. The model determines that newer plays with larger and higher cost drilling programmes (i.e. those likely to contribute greatest supply growth) are less certain. This is reflected in plays like Haynesville and Marcellus, where there is greater potential for variation. More expensive production from existing wells may be included in the supply, because their production is assumed to be locked in. Further, smaller plays may find a market despite being at the higher end of the cost curve, due to their local demand and infrastructure constraints. The structure of the US shale production makes it difficult to generalise any particular pattern.

Figure 7: North America carbon supply cost curve, 2015–2035



Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

8. Capex implications

Delivering the low demand scenario requires $1.5 trillion of capex to supply 41,236 bcm of supply over the 2015–35 period. The capex scenarios for the gas markets do not work in the same way as we have analysed them for coal or oil. The effects also vary for each regional market as a reflection of how they operate, and the nature of the projects.

Differences between scenarios

There is limited differences between capex required in the low demand and 450 scenarios due to the following factors:

- Minimal divergence in the Europe and LNG in the first decade
- The significant investment already sunk, particularly in LNG

As noted by broker research, the LNG market is already likely to be oversupplied to 2020 and beyond, with approved project capacity exceeding their projected demand (Goldman Sachs, 2015).

North America

The short-term nature of gas plays in US shale means it is easier for companies to adjust production in response to demand and price movements. Smaller companies may have financial pressures if they need to borrow to drill, and assume a higher gas price than actually results. There is no shortage of gas plays to develop – but unless exports are commercially viable the market is limited to within the continent. As such it does not make sense to talk about what capex could be overcommitted long-term, as the industry has more opportunity to adjust this.

Europe

Supply to the EU is bolstered by piped supply from its neighbours. The overflow of LNG at competitive prices provides an opportunity to diversify European gas supply further. There is a small amount of potential capex that is not needed in a low demand scenario that is above the $10/mmBtu breakeven threshold. The amount of capex that is not already committed is minimal. The degree of further capex required is flexible depending on the political risk situation and the price of LNG. This equates to $26 billion or around an extra 5% of capex over the next decade. $295 billion of the $551 billion capex required in the low demand scenario is for new projects.

Price risk

As LNG projects will largely be contracted in advance to secure demand for the production, this limits the risk of LNG production having no market. This leaves price risk as the main exposure for LNG producers. Traditionally most LNG contracts are linked to oil prices in some way. This has seen Asian LNG contract prices fall significantly over the last year as the oil price has come down. Europe is moving more towards a spot price market, and the nascent US market is dominated by traders pricing relative to the Henry Hub benchmark.

There is clearly a price risk for the producers, who have to take a view on long-term price trends rather than short-term movements. Those with greater exposure to the spot markets will carry higher risks if there continues to be oversupply of LNG. It is the off-takers who are contracted to buy the gas who are taking the risk of mis-reading demand for energy, and more specifically gas' share of it.

Focus on LNG

The infrastructure required for LNG makes it more capital intensive that the other markets considered. LNG projects are the area where it is possible to identify capex options for the future that have not yet been committed. In a low demand scenario there is a significant amount that gets pushed back beyond the next ten years for a final investment decision. Further deferral of projects will be needed if demand for LNG falls short of industry expectations.

We have identified $73bn of capex required to 2025 in a low demand scenario. There is a further $283bn of LNG projects not needed in the next decade.

This capex has not yet been approved by companies, so is not at risk of being wasted yet. However it does challenge the potential for these companies to grow their LNG businesses over the next decade beyond the ample capacity already in development at present.

LNG Capex

Potential LNG developments are concentrated in certain countries. In particular, Canada, US and Australia will be competing as to who gets to develop their LNG in a low demand scenario. Again the data shows how much of the expected LNG demand already has supply matched to it out to 2035. This results in fairly low requirements for further capex in the next ten years.

Limits to growth

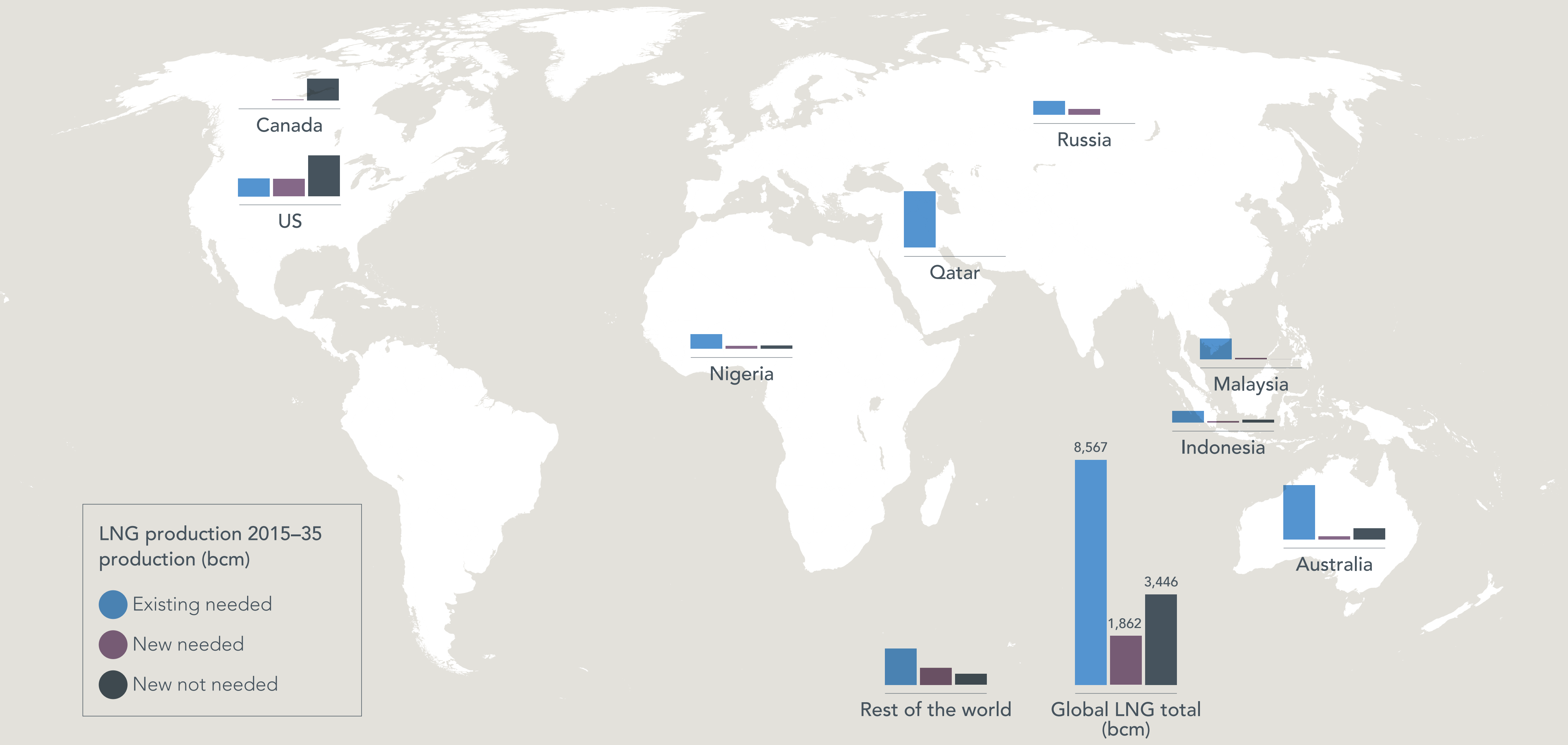
This picture questions whether the gas industry can expand its LNG industry significantly in the next decade beyond what has already been committed to. Companies have options on projects that are being evaluated and designed, but will not go ahead until the demand is certain. Shareholders need to question whether the strategy presentations of the companies add up – they can't all expand LNG as fast as they could build it.

Figure 8: LNG production & capex not needed in the LDS

	2015–35 Production (bcm)				2015–2025 Capex ($bn)			
	Existing	New			Existing	New		
Supply country	Needed	Needed	Not needed	% not needed	Needed	Needed	Not needed	% not needed
Australia	2,069	123	418	77%	87	0	68	100%
Canada	0	22	824	97%	0	0	82	100%
Indonesia	434	50	110	69%	0	0	10	100%
Malaysia	788	45	0	0%	6	0	0	0%
Nigeria	552	100	119	54%	0	0	0	0%
Qatar	2,135	0	0	0%	3	0	0	0%
Russia	527	210	0	0%	35	0	11	100%
US	682	664	1,558	70%	17	26	71	74%
Rest of world	1,382	648	417	39%	4	48	42	47%
Global LNG total	8,567	1,862	3,446	65%	152	73	283	79%

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

Figure 9: Map of LNG production needed and not needed in LDS



Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

Projects deferred

The table shows the breakdown of LNG capex to 2025 and production to 2035 for the 20 largest companies in terms of unneeded capex in the low demand scenario. These are projects that companies could develop in the future but have not made a final investment decision on. In the low demand scenario most of these get deferred beyond the next decade.

Production already covered

Around 82% of production required to 2035 in a low demand scenario is covered by LNG projects that are already under development or producing. This leaves very little opportunity for new LNG projects in this scenario. Amongst the top 20 companies, only ENI, Cheniere and Noble have additional projects that are needed to meet LNG demand under the LDS. Below this are a long list of smaller operators and projects that would also be included in the low demand scenario according to the model.

Existing exposure

The table below lists companies by total potential capex to 2025. The data indicates which companies have already secured a share of the LNG market for the next 20 years. It is not surprising that many of the companies who have options for the future are those that have led the way in developing an LNG portfolio. Amongst the majors Total stands out as only having existing projects, with no major new LNG projects modelled as taking FID within the next decade. This reflects the significant position Total has already secured in the LNG market.

LNG concentration

The oil majors have varying exposure to LNG. Shell has made the biggest play with its proposed takeover of BG Group. Firstly it is worth noting that a significant amount of LNG is already under development by these companies – so they have good exposure to the market that has already been contracted. Beyond this there is a question mark over the level of investment that will be required over the next decade.

At this point there is not a major problem in deferring an LNG project for a decade. However it does assume there will be a conducive demand and price environment that warrants its development in 2025 or beyond.

M&A activity always brings company profiles and strategy under greater scrutiny, especially at the scale of Shell buying BG Group. Aside from boosting its access to oil reserves, this concentrates Shell's options in LNG. Shell's offer is based on Brent oil prices returning to around $90, which translates to an oil-indexed LNG price of around $14–15/mmBtu based on typical contract pricing formulae. The long-term gas price in our low demand scenario is around $10/mmBtu. This would mean oil prices averaging around $62–63 long-term.

The combined entity has $59bn of new projects that are not progressed by the model to 2025. This picture does not improve much to 2035, with $85bn of new projects not needed, and only $6bn of projects going ahead in the low demand scenario modelled.

Figure 10: Company exposure to LNG capex and production

Rank	Company	2015–2025 Capex ($bn) Total	Existing needed (LDS)	New needed (LDS)	New not needed	% new not needed	2015–35 Production (bcm) Existing needed (LDS)	New needed (LDS)	Total needed (LDS)	% of total needed
1	Chevron	34.8	16.9	0.0	17.8	100%	428	35	463	4.7%
2	Shell	34.7	9.0	0.0	25.6	100%	646	46	691	7.0%
3	BG	33.7	0.4	0.0	33.2	100%	218	0	218	2.2%
4	Cheniere	27.0	5.6	13.5	7.8	37%	379	160	539	5.5%
5	ExxonMobil	21.4	5.0	0.0	16.4	100%	586	120	706	7.1%
6	NOVATEK	21.0	21.0	0.0	0.0	-	188	37	225	2.3%
7	PETRONAS	20.6	7.6	0.0	13.0	100%	636	41	677	6.8%
8	Woodside Petroleum	17.4	4.6	0.0	12.8	100%	169	0	169	1.7%
9	Total	15.3	15.3	0.0	0.0	-	430	48	478	4.8%
10	INPEX Corporation	13.5	13.5	0.0	0.0	-	151	29	180	1.8%
11	Apache	12.4	1.7	0.0	10.7	100%	27	3	30	0.3%
12	Noble Energy	11.9	0.0	5.7	6.3	52%	0	23	23	0.2%
13	Eni East Africa	11.2	0.0	11.2	0.0	0%	0	21	21	0.2%
14	Sempra	10.1	3.8	0.0	6.3	100%	113	0	113	1.1%
15	Govt of Indonesia	9.5	0.0	0.0	9.5	100%	0	50	50	0.5%
16	Qatar Petroleum	9.2	1.8	0.0	7.4	100%	1,443	141	1,584	16.0%
17	Kinder Morgan	8.7	0.0	0.0	8.7	100%	0	15	15	0.2%
18	PetroChina	8.3	0.0	0.0	8.3	100%	0	0	0	0.0%
19	BP	8.1	1.0	0.0	7.1	100%	155	8	163	1.6%
20	Energy Transfer Ptnrs	7.6	0.0	0.0	7.6	100%	0	0	0	0.0%
										64.2%
-	Shell + BG aggregate	68.4	9.5	0.0	58.9	100%	863	46	909	9%

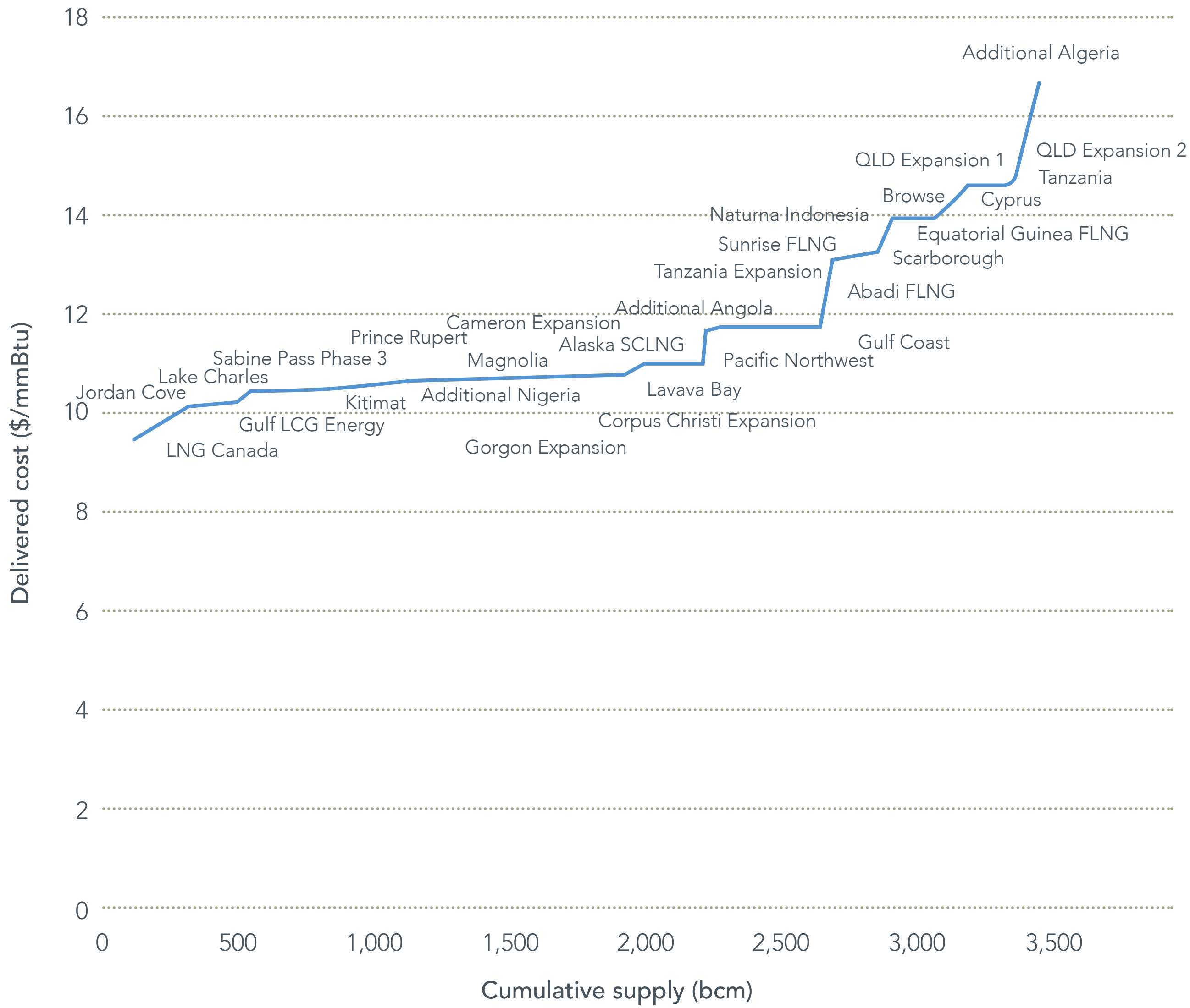
Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

LNG projects not making the cut at $10/mmBtu

The cost curve shows which LNG projects are at the high end of the cost curve, and are not needed in the low demand scenario. This reflects that generally the new US and Canada projects are just above the $10/mmBtu level, with Australian projects even further up the curve. Projects may move along the curve over time depending on changes to cost elements and foreign exchange rates.

This demonstrates to investors that in a low gas demand scenario there are projects that companies may have under consideration which may not be needed in the next couple of decades. This set of projects reflect those identified at the time of modelling as credible projects mentioned by companies which could balance a larger global LNG market, but are not an exhaustive list.

Figure 11: LNG projects not needed in low demand scenario to 2035



Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

9. Conclusions and recommendations

Less potential for wasted capital

The current structure of the gas industry makes it less prone than oil or coal to wasting capital on projects that may not be needed in a low demand scenario. In particular LNG plants are so capital intensive they are usually approved only once the majority of production has been contracted. US unconventionals offer more flexibility due to being a more short-term play – the question is how sustainable the business model is for highly leveraged smaller operators.

Limits to growth

Investors should scrutinise the true potential for growth of LNG businesses over the next decade. The current oversupply of LNG means there is already a pipeline of projects waiting to be next in line to take final investment decision. It is always good to have options, but it is not clear when these projects will actually become real and generate value for shareholders. Shareholders should review how many LNG projects requiring over $10/mmBtu break even sit in the future strategy of the companies they invest in.

Price risk

Gas producers have limited direct exposure to demand risk, so it is price risk that they are more sensitive to. Again this is a regionalised picture with the regions interacting, rather than a simple conclusion. LNG contracts have traditionally been linked to the oil price – leading to exposure to oil price movements. European production is now seeing LNG oversupply compete with its marginal production. The US will continue to need gas prices to continue to strike a balance between competitiveness and revenues.

How much growth?

There is room for some growth in gas supply in the next 20 years. The exact amount in each region will depend on a range of factors, indicating it is not as simple as expecting a coal to gas switch. Cheaper renewables, greater efficiency, new storage technologies, higher carbon prices, and relative commodity prices will all play their part.

For how long?

The continued efforts to agree emissions reductions and improve air quality represent a clear direction of travel for reduced use of fossil fuels. This is reflected in the recent G7 message supporting the phase out of fossil fuels and transformation of energy sectors by 2050; and the Track Zero initiative, co-ordinating governments and businesses seeking to deliver net zero emissions by 2050. Any new gas plants being approved now may have a limited lifetime.

Room for unconventionals?

There appears limited scope for growth of unconventionals outside of the US. Firstly this is due to these projects being in the marginal range of the cost curves. This means they need higher prices to be justified, and also that there is Russian gas that is cheaper to supply. Secondly environmental questions remain, including the significance of fugitive emissions which needs resolving for all gas. Reducing US demand cuts US shale production. Projects to convert US shale into LNG for export are the most GHG intensive option and don’t fit in a low carbon future.

Allocating the carbon budget

Having now analysed oil, coal and gas it brings into focus the potential trade-offs between the fossil fuels in how future energy scenarios may play out. This may get nudged in either direction by factors including CCS, carbon prices, and fugitive emissions. However the conclusion is similar – there is a finite amount of fossil fuels that can be burnt over the next few decades if we are to prevent dangerous levels of climate change.

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For further information about Carbon Tracker
please visit our website

www.carbontracker.org

Exhibit 66

MOODY'S
INVESTORS SERVICE

Announcement: Moody's: Liquefied natural gas projects nixed amid lower oil prices

Global Credit Research - 07 Apr 2015

New York, April 07, 2015 -- Liquefied natural gas (LNG) suppliers are curtailing their capital budgets, amid low oil prices and a coming glut of new LNG supply from Australia and the US, Moody's Investors Service says in a new report, "Lower Oil Prices Cause Suppliers of Liquefied Natural Gas to Nix Projects."

Moody's says low LNG prices will result in the cancellation of the vast majority of the nearly 30 liquefaction projects currently proposed in the US, 18 in western Canada, and four in eastern Canada.

"The drop in international oil prices relative to US natural gas prices has wiped out the price advantage US LNG projects, reversing the wide differentials of the past four years that led Asian buyers to demand more Henry Hub-linked contracts for their LNG portfolios," says Moody's Senior Vice President Mihoko Manabe.

However, projects already under construction will continue as planned, which will lead to excess liquefaction capacity over the rest of this decade. Notably, through 2017, Australia will see new capacity come online from roughly $180 billion in investments, which will result in a 25% increase in global liquefaction capacity. Likewise, the US is poised to become a net LNG exporter after the Sabine Pass Liquefaction LLC (Ba3 stable) project goes into service in the fourth quarter of 2015.

Moody's expects Cheniere Energy's Corpus Christi project will be the likeliest project to move forward this year, since it is among the very few projects in advanced development that have secured sufficient commercial or financial backing to begin construction.

Lower oil prices will result in the deferral or cancellation of most other projects, especially this year. While some companies like Exxon Mobil Corp. (Aaa stable) can afford to be patient and wait several years until markets are more favorable, most other LNG sponsors have far less financial wherewithal, and some may be more eager to capitalize on the billions of dollars of upfront investments they have made already, sooner rather than later.

Greenfield projects on undeveloped property are much more expensive, involve more construction risk, and take longer to build than brownfield projects, which re-purpose existing LNG regasification sites. Greenfield projects are also frequently challenged by local opposition and occasionally by untested laws and regulations. Based on the public estimates of companies building new LNG liquefaction capacity, the median cost to build a US brownfield project is roughly $800 per ton of capacity, compared with the more advanced Australian greenfield projects, now estimated at around $3,400 per ton.

Through the end of the decade, Moody's expects LNG demand will grow more slowly versus supply. China will be the biggest variable and most important driver of global LNG in that timeframe. India will see rapid growth, but not be as big of a player as China. Other more mature LNG markets in Japan, South Korea and Europe, which represent the bulk of demand, will have flat growth.

The report is available to Moody's subscribers at URL:

https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_1002517

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Exhibit 67

Submitted by
Jerry Havens, Distinguished Professor Emeritus
Department of Chemical Engineering, University of Arkansas
April 1, 2019

Regarding the
DRAFT ENVIRONMENTAL IMPACT STATEMENT
FOR THE
JORDAN COVE ENERGY PROJECT
Docket Nos. CP17-494-000 and CP17-495-000
March 2019

My comments, directed simultaneously to FERC and PHMSA,
are not to be attributed to the University of Arkansas.

COMPUTER MODEL USED TO PREDICT LNG EXPORT TERMINAL VAPOR CLOUD EXPLOSION HAZARDS HAS NOT BEEN APPROVED BY PHMSA - PREDICTED EXPLOSION OVERPRESSURES APPEAR SERIOUSLY UNDERESTIMATED

These comments are intended to notify FERC, PHMSA, and the public of critically important developments regarding our expanding knowledge of the risk of cascading fire and unconfined vapor cloud explosion (UVCE) accidents that could occur at the Jordan Cove Export Terminal (JCET). The comments are an expansion on my earlier ones to the Public Workshop on Liquified Natural Gas Regulations Website on July 28, 2016, September 22, 2018, October 2, 2018, and December 3, 2018 - all of which I stand by. They are also intended as a response to the joint news release of August 31, 2018 by PHMSA and FERC, entitled " FERC, PHMSA Sign MOU to Coordinate LNG Reviews**"**, from which I quote - "The MOU establishes a framework **for** coordination between FERC and PHMSA to process LNG applications in a timely and expeditious manner while ensuring decision-makers are fully informed on public impacts". I trust these comments will be helpful to the decision-makers in fully informing the public.

My concerns remain essentially the same as commented to FERC in January 2015 by James Venart and myself[1]. I believe that Government is failing to adequately provide for the risks of potentially devastating Unconfined Vapor Cloud Explosions (UVCEs) of heavier-than-methane hydrocarbons at the JCET.

I remain concerned that the predictions of explosion overpressures (determining explosion damage) presented in the 2015 JCET DEIS were an order of magnitude (factor 10) too low. Such overpressures are not conservative enough to indicate the real hazard that exists, as evidenced by numerous confirmed occurrences of devastating UVCEs involving the same heavy hydrocarbons in similar conditions.

My review of the March 2019 JCET DEIS did not disclose any detailed predictions of vapor cloud explosion (VCE) overpressure for design spills of heavy hydrocarbons. However, I did locate on the FERC Website a report entitled "Facility Siting Hazard Analysis", dated October 2, 2018, which

[1] UNITED STATES LNG TERMINAL SAFE-SITING POLICY IS FAULTY, Comments submitted to FERC by Jerry Havens and James Venart, January 14, 2015, Docket No. CP13-483.

presents a collection of hazard footprints for overpressure, calculated with FLACS, predicted to result from design spills of heavier-than-methane hydrocarbons at the JCET[2]. The collection of calculations presented in that report presents a picture very similar to that presented in the 2015 DEIS. The overpressures presented therein still appear to be significantly lower than those reported for numerous incidents that have occurred with the same materials, in similar amounts and in similar conditions. I cannot determine to what extent these newer predictions have been utilized in the 2019 DEIS, but I am very concerned that such predictions as these might be approved by FERC in the FEIS - repeating the approval of similar predictions prepared for FERC with the same mathematical model (FLACS) in 2015. If that were to happen, I believe a serious error affecting public safety will be the result, because the unrealistically low damage predictions could be used again by FERC as a basis to dismiss the UVCE hazard at the JCET. Continued dismissal of the UVCE hazard would be a very serious error. If the magnitude of the possible overpressures are estimated using actual data (experience) available for UVCEs (rather than predicted with the FLACS theoretical model), the VCE hazard would be clearly indicated as a serious major hazard at the JCET[3]. *UVCEs at numerous similar heavy hydrocarbon handling/storage facilities have resulted in destruction of the facilities as well as injuries and deaths beyond the plant boundaries.*

Contrasting LNG Import and Export Terminal Siting Regulations

I want to state here that if either PHMSA or FERC believes that anything I present is in error I request that I be notified immediately. I will make any corrections as necessary, and I will alter my comments, as necessary, as well. My goal is to ensure that the science-based tools that are used for hazard evaluation in the regulations are applied correctly. I am very concerned that failure to ensure proper, validated, use of mathematical models for UVCE hazard evaluation could result in devastating UVCEs that, in addition to public endangerment, could cripple the industry.

In order to most effectively explain my concerns, I think it helpful to provide a very brief history of the LNG regulations. The provisions of 49 CFR 193. Liquefied Natural Gas Facilities: Federal Safety Standards were developed by PHMSA to govern the siting of LNG peak shaving terminals and import terminals. It has been accepted practice to identify for these two types of terminals only two principal hazards; pool fire hazards and vapor dispersion hazards. A third hazard, Unconfined Vapor Cloud Explosion (UVCE), is generally considered negligible for Import Terminals. This policy is based on the generally accepted fact that import terminals handle and store primarily LNG with methane contents sufficiently high that the LNG can be assumed to be pure methane. Given the very low propensity for explosion of unconfined methane-air clouds, UVCEs at LNG import terminals have historically been neglected as a hazard. As a consequence the present Regulation, 49 CFR 193, does not mandate the consideration of UVCE hazards.

With the advent of LNG export terminals in the United States the requirements for safe siting of LNG terminals have changed importantly. That is because the export terminals typically remove and store large quantities of heavier-than-methane hydrocarbons from the incoming natural gas feed stream. Furthermore, the removal of those heavy hydrocarbons typically requires the use of

[2] https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20181116-5198
Click on "Facility Siting Hazard Analysis" and download

[3] https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=111 Atkinson, G., Vapor Cloud Explosion (VCE) Historical Review, PHMSA Public Workshop on Liquefied Natural Gas (LNG) Regulations, Washington DC, 19 May 2016.

large quantities of refrigerant gases that are heavier-than-methane hydrocarbons. The storage and handling of large quantities of these heavier-than- air hydrocarbons results in a new primary hazard - vapor cloud explosions of the heavy hydrocarbon materials that could follow accidental release.

I have been involved in the development of 49 CFR 193 from its beginning in the early 1980s. My principal involvement has been as an author/evaluator of the DEGADIS model for use in predicting LNG vapor cloud dispersion. DEGADIS is approved by PHMSA for use in predicting the requirements for vapor cloud dispersion exclusion zones for LNG Import Terminals. During the last decade, and coincident with the advent of LNG Export Terminals in the United States, additional vapor dispersion models have been approved by PHMSA for use by LNG terminal companies seeking siting approval.

My comments here are restricted to the FLACS model. The FLACS model is an example of what is known as a computational fluid dynamics (CFD) model. I generally support the use of CFD models for vapor dispersion predictions because they are appropriate for dealing with complexities not catered for by simpler models such as DEGADIS. Accordingly, I supported the approval by PHMSA of the FEM3A model developed by the Lawrence Livermore National Laboratory (LLNL) and I supported the request for PHMSA approval of FLACS for vapor dispersion use. I do not object to FLACS' approval, which PHMSA granted, for vapor dispersion prediction.

FLACS has not been Evaluated or Approved by PHMSA for Explosion Prediction

This is the crux of the matter. There are now four mathematical models approved by PHMSA for vapor dispersion prediction, in order of the time approved; DEGADIS, FEM3A, FLACS, and PHAST. All four were required by PHMSA to be subjected to evaluation of their performance in demonstrating suitable agreement with experimental data available from a collection of field and wind tunnel tests of vapor dispersion.

FLACS (FLame ACceleration Simulator) is a commercial Computational Fluid Dynamics (CFD) software used extensively for atmospheric dispersion modeling and explosion modeling in the field of industrial safety and risk assessment[4]. FLACS has been subjected to the written protocol provided by PHMSA and approved by PHMSA for vapor dispersion predictions required by 49 CFR 193. PHMSA has not completed development of a written protocol for the evaluation of FLACS for explosion prediction. Consequently, FLACS has not been formally evaluated for explosion prediction and has not received approval for the evaluation of UVCE hazards (read explosion overpressures) by PHMSA.

Although it appears that a process for developing a written protocol for evaluation of FLACS for application to the prediction of overpressures was requested by PHMSA to be funded following the LNG Regulation Workshop of 2016[5], I can find no evidence that the required protocol has been completed. It appears that the plans announced at the LNG Workshop of 2016 for a required updating of 49 CFR 193 to cater for the new hazards that will be present at export terminals are currently at a standstill. The only conclusion I am able to reach is that the newly announced JCET DEIS appears to me likely to utilize predictions of explosion overpressures for the heavier-than-methane hydrocarbon design spills selected for analysis that have not been approved by PHMSA. Such a failure to adequately address the risk of UVCEs would mean that potential risks of cascading

[4] https://en.wikipedia.org/wiki/FLACS

[5] https://primis.phmsa.dot.gov/rd/mtgs/111616/WG%205%20Report-Out.pdf – See GAP #4

violent explosions that could destroy the plant as well as extend dangers to the public beyond the facility boundary are effectively being ignored.

PHMSA Contracted for Expert Evaluation of the Risk of Unconfined Vapor Cloud Explosions

Simultaneously with my comments to FERC in 2015 I notified PHMSA of my concerns. I have also filed a total of four comments (to date) on PHMSA's LNG Regulation Workshop site. Further, there have been a series of important developments subsequent to my 2015 comments to FERC, the results of which I think are critically important to consider now.

PHMSA contracted with the British Health and Safety Laboratories (HSL) to prepare the report "Review of Vapour Cloud Explosion Incidents"[6]. Quoting excerpts from the Executive Summary of that report:[7]

> **"T**his review of major vapor cloud incidents has been jointly commissioned by the US Pipeline and Hazardous Materials Safety Administration (PHMSA) and the UK Health and Safety Executive (HSE). The primary objective was to improve understanding of vapor cloud development and explosion in order to examine the potential for these hazards to exist or develop at LNG export plants that store substantial quantities of these flammable gases for use in the liquefaction process or as a by-product from the liquefaction …
>
> This review has not found any historical records of LNG (methane) vapor cloud explosions in open areas with severity sufficient to cause secondary damage to tanks and pipes and consequently rapid escalation of an incident from a minor process leak to a major loss of inventory.
>
> On the other hand some LNG sites (especially export sites) also hold substantial amounts of refrigerant gases and blends containing ethane, propane, ethylene and iso-butane. Higher hydrocarbons may also be produced and stored on LNG export sites as by-products of gas condensation. There are numerous examples of Vapor Cloud Explosions (VCEs) in open areas involving these higher molecular weight materials and the storage and use of higher molecular weight hydrocarbons on LNG export sites which may, if not managed adequately, introduce an additional set of incident scenarios in which VCEs trigger rapid escalation of loss of containment. (emphasis added)
>
> This study involves a review of 24 major VCE incidents focusing on source terms, cloud development and explosion mechanics. The incidents studied are split between permanent fuel gas (C2-C4 (e.g. LPG) and volatile liquids C4-C6 (e.g. gasoline). The source terms for leaks of gases and liquids are different but once a stable current of cold heavy vapor forms, the subsequent development of LPG and gasoline clouds are similar…
>
> An important finding from the review is that a high proportion of vapor cloud incidents occurred in nil/low wind conditions. By the term "nil/low wind" we mean a wind that was so weak close to the ground that it only detrained (stripped away) a small proportion of the vapor accumulating around the source … Rather than being picked up and moved downwind, the vapor flow in this case was gravity driven; spreading out in all directions and or following any downward slopes around the source.
>
> In many of the cases examined, 50% (12/24), there is clear evidence from the well-documented transport of vapor in all directions and/or meteorological records that the

[6] https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=111

[7] HSL Report on PHMSA LNG Regulation Workshop site.

vapor cloud formed in nil/low wind conditions. In a further 21% (5/24), the pattern of vapor suggests nil/low wind conditions but there is insufficient data available to be sure … incidents in nil/low wind conditions apparently make up the majority of historical records of the most serious VCEs … In nil/low wind conditions the cloud continues to grow throughout the time that the tank takes to empty… The maximum area covered by the flammable cloud is typically several hundred times greater in nil/low winds condition than in light winds.

The implication of this type of analysis is that if the density of ignition sources is constant and quite low in the area around the tank the chances of ignition in nil/low wind conditions would be hundreds of times greater for a given release. This illustrates why nil/low wind conditions dominate records of major vapor cloud incidents even though the weather frequency is low. Losses of containment in nil/low wind conditions are also particularly dangerous because a highly homogeneous cloud can be formed that may spread by gravitational slumping (without significant dilution) for hundreds of meters… A very large cloud that is all close to the stoichiometric ratio increases the risk of flame acceleration to a high pressure regime capable of seriously damaging storage and process facilities, when compared with clouds that are entraining air because of wind-driven dilution. This is because fundamental burning rates fall off rapidly for concentrations away from the stoichiometric. Once a high pressure regime is established explosions are not confined to congested areas of a site. In many of the cases reviewed almost all the footprint of the cloud was exposed to pressures in excess of 2000 mbar (29 psi). In at least one case the cloud detonated, causing extremely severe damage over the area covered by the cloud)." (emphasis added)

PHMSA Conducted a Public Workshop on Liquefied Natural Gas (LNG) Regulations

The Workshop was conducted in Washington, DC in May 2016. Quoting excerpts from PHMSA's Statement of Mission (from the Workshop Website):

"Historically, most LNG facilities were peak shavers built to liquefy and store natural gas to be degasified and injected back into the pipeline during periods of peak demand … However, due to the recent abundance of domestic shale gas, LNG export terminals are now being constructed that liquefy vast volumes of natural gas. These facilities require significantly greater quantities of refrigerants to liquefy the natural gas than the amount typically used at peak shavers… Most refrigerant gases and blends used at the export facilities contain ethane, propane, ethylene, and iso-butane and are referred to as heavy hydrocarbons. These gases are similar to gases that have resulted in VCEs at petrochemical facilities…

The understanding of VCEs is evolving. PHMSA recognizes that significant quantities of heavy hydrocarbons present different risks than methane and seeks to better understand that risk. Prior to investigative work on the Buncefield accident, the prevailing understanding was that vapor clouds formed outdoors were unlikely to explode if ignited. Today it is understood that VCEs involving higher hydrocarbons have occurred in outside areas. This paper advances our understanding further. PHMSA sponsored the "Review of Vapour Cloud Explosion Incidents" report with the primary objective to improve the scientific understanding of vapour cloud development and explosion in order to more reliably assess hazards at large Liquid Natural Gas (LNG) export facilities… The aim of reviewing the particular incidents in this report is the extensive forensic evidence available that provides the information needed to study how the vapor cloud formed and ignited, the amount of overpressure exerted, and other information about the mechanism of VCE. This research was performed by the Health and Safety Laboratory (HSL) under a subcontract with the Oak Ridge National Laboratory, a United States Department of Energy (DOE) facility, and was supported by the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (DOT PHMSA and DOE) and the United Kingdom Health and Safety Executive (HSE). The research's objective was to improve understanding of vapor development and explosions in order to more reliably assess hazards and safety measures at facilities that contain significant quantities of heavy hydrocarbons…

The technical review of the report was performed by uncompensated subject matter experts… The purpose of this independent review was to provide candid and critical comments to make the report as sound as possible… The review, comments, and draft manuscript remain confidential to protect the integrity of the deliberative process. The panel reviewed multiple drafts of the report, held several conference calls, and convened a meeting on May 17th (2016) in Washington, D.C. A presentation about the draft report was given at a public meeting, PHMSA's Public Workshop on LNG Regulations, on May 19th, 2016, in Washington, D.C. …" (emphasis added)

The 2018 PHMSA /FERC MEMORANDUM OF UNDERSTANDING

PHMSA is responsible for developing the regulations that specify the means of ensuring public safety in siting LNG terminals. The applicable regulation is 49 CFR 193, Liquefied Natural Gas Facilities: Federal Safety Standards. The present regulation was developed in the early Eighties to regulate LNG peak shaving and import terminals. Consequently, the present PHMSA regulation does not address the "new" hazards of vapor cloud explosions of heavier-than-methane hydrocarbons that are present in large quantities at LNG export terminals. So, during the period following my comments to FERC in 2015 on the UVCE hazard, and until very recently, I failed to understand why the 2015 JCET DEIS included an address of the UVCE hazard (not required by 49 CFR 193) by presenting the extensive predictions of explosion overpressure for heaver-than-methane hydrocarbon/air clouds that could be formed following accidental release at JCET. I remain uncertain why that action was taken, but I am increasingly concerned that the UVCE hazards present in the operation of LNG export terminals are effectively being ignored. My concern is that the order-of-magnitude-too-low predictions of the overpressures used by FERC to evaluate the VCVE hazard in the environmental impact statements for the JCET might result in the continued dismissal of the importance of this hazard for the JCET.

On August 31, 2018, the Federal Energy Regulatory Commission (FERC) and the Hazardous Materials Safety Administration within the U.S. Department of Transportation announced the signing of an agreement to coordinate the siting and safety review of FERC-jurisdictional LNG facilities. Quoting therefrom:

"The Memorandum of Understanding (MOU) establishes a framework for coordination between FERC and PHMSA to process LNG applications in a timely and expeditious manner while ensuring decision-makers are fully informed on public safety impacts. The MOU provides that PHMSA will review LNG project applications to determine whether a proposed facility complies

<u>with the safety standards set forth in PHMSA's regulations, and that PHMSA will issue a letter to FERC stating its findings regarding such compliance.</u> FERC will then consider PHMSA's compliance findings in its decision on whether a project is in the public interest." (emphasis added)

It is my understanding that the JCET DEIS issued in 2019 does not state that FERC received an LOD (letter of determination) from PHMSA that presented its findings regarding compliance with the safety standards set forth in its regulations. It is further my understanding that the FERC/PHMSA MOU effectively requires PHMSA to issue such an LOD by the time the FEIS is completed.

My review of the Reliability and Safety section of the DEIS disclosed no direct reference to the UVCE hazard. It is as if the problem had either been decided as lacking further need of address or that some further address might be forthcoming by the time the EIS is completed.

<u>I respectfully request that I be provided an answer to the following question: Given PHMSA's announcement in 2016 at the Public Workshop on LNG Regulation that 49 CFR 193 appeared to require updating to cater for the new (UVCE) hazards that attend Export Terminal operations, why has that announcement not led to any further analysis and evaluation in the 2019 JCET DEIS?</u>

<u>Unless that question can be answered satisfactorily, it appears that critical safety recommendations by PHMSA requiring changes to 49 CFR 193, backed up by extensive advice from the scientific expert community, are being ignored.</u>

Who Required the UVCE Hazard to be Addressed in the 2015 JCET DEIS?

The only government source I have found for guidance regarding calculations of overpressure required to be presented in the 2015 JCET DEIS is in "Guidance Manual for Environmental Report Preparation, Volume II, LNG Facility Resource Reports 11 & 13 Supplemental Guidance, DRAFT, December 2015", prepared by FERC. Section 13.H.3, "Hazard Analysis Reports" of that draft appears to be the source of the requirement for explosion overpressure that appeared in the 2015 JCET Environmental Impact Statements. The requirement for explosion overpressures remains in the Guidance Manual for Environmental Report Preparation, FINAL, dated February 2017.

It is my understanding that the Draft FERC document providing guidance to JCET for providing VCE overpressure calculations was not based on the requirements of 49 CFR 193. It appears that FERC may have recognized the need to evaluate the UVCE hazards that could attend the operation of the JCET, and that those hazards should be considered in the JCET DEIS. I have no information about why FERC included the requirement to address UVCE hazards in their Guidance Document for preparation of Environmental Impact Statements. In any case, the "requirement" in FERC's Guidance Manual for Environmental Reports appears to demonstrate FERC's awareness of the importance of addressing the UVCE hazard.

The fact remains that the predictions of overpressure that were provided for the JCET DEIS in 2015 were stated therein to be made with the FLACS model, and although FLACS is approved for vapor dispersion calculations required by 49 CFR 193, it is my understanding that <u>FLACS still has not been either evaluated or approved by PHMSA for explosion overpressure determination</u>. If this is the case, then a major course-correction seems required, because comparisons of those (order-of-magnitude-too-low) overpressure predictions with documented measurements of overpressure data for a large number of UVCE events involving the same hydrocarbons, in similar amounts, and in similar atmospheric conditions, will demonstrate that the predictions utilized in the JCET environmental impact statements are in serious error.

If this problem is not addressed, it appears likely that such errors accompanied by FERC's approval thereof will ignore the scientific expert advice that resulted from the PHMSA Workshop conducted in 2016. The effect will be to ignore extensive accident experience that demonstrates the potential for cascading explosions that could destroy the plant and possibly extend damages to the public beyond the facility boundary.

CONCLUSIONS

49 CFR 193 Liquefied Natural Gas Facilities: Federal Safety Standards does not currently provide for adequate consideration of the hazards of Unconfined Vapor Cloud Explosion (UVCE) hazards that attend LNG Export Terminals handling and storing large quantities of heavier-than-methane hydrocarbons.

PHMSA conducted the Public Workshop on Liquefied Natural Gas (LNG) Regulations in Washington, DC, 19 May 2016. The principal purpose of the Workshop was stated to be the intention to address the need for updating 49 CFR 193 in order to cater for any new hazards that could be involved in siting LNG Export Terminals. The Workshop clearly identified the UVCE hazard as being the most important hazard present at Export Terminals that was not currently addressed adequately by 49 CFR 193.

PHMSA initiated a program to address the needs for changes in the regulation to provide for UVCE hazards. It appears that no progress has been forthcoming.

The new Draft Environmental Impact Statement (DEIS) for the Jordan Cove Export Terminal, just issued, continues to seriously underestimate vapor cloud explosion overpressures (damage) that could occur following credible releases of heavy hydrocarbons at the JCET site. The latest predictions that I am aware of appear to be an order of magnitude lower than are indicated by physical evidence of numerous documented UVCEs that have occurred worldwide with the potential to cause injuries and deaths to persons and result in destruction of the facility.

Exhibit 68

https://www.oregonlive.com/business/2019/04/facebook-expects-to-pay-billions-in-privacy-fines.html

Scientists say public safety hazards at Jordan Cove LNG terminal in Coos Bay are underestimated

Updated Jan 16, 2015; Posted Jan 16, 2015

Gallery: Jordan Cove Seismic

By Ted Sickinger| The Oregonian/OregonLive

A pair of scientists told federal regulators this week that safety measures incorporated in a proposed liquefied natural gas terminal in Coos Bay actually increase the chance of a catastrophic failure and present far more serious public safety hazards than those regulators have analyzed and deemed acceptable.

Jerry Havens, a chemical engineering professor at the University of Arkansas, and James Venart, an emeritus professor of mechanical engineering at the University of New Brunswick, filed a public comment Wednesday outlining their concerns with hazard modeling for the proposed Jordan Cove Energy Project.

Those results were summarized in the project's draft environmental impact statement that the Federal Energy Regulatory Commission issued in November.

The modeling addresses the project's most fundamental public safety question – what will happen in the event of an accident, natural disaster or terrorist attack at the facility that results in a leak of natural gas or other chemicals.

FERC staff have concluded that since there are no homes within a mile of the facility, the resulting hazard would be minimal. But the question took center stage at public meetings following the release of FERC's draft analysis. And it's one that politicians say must be adequately addressed.

A sample of the vapor cloud modeling completed for Jordan Cove.

Regulators acknowledge that such leaks could lead to flammable and potentially explosive vapor clouds, liquid pool fires and other knock-on effects. So they require applicants to model various scenarios and demonstrate that they wouldn't pose any risk outside the facility's property line.

Havens and Venart have both researched and published extensively on the fire and explosive risks of LNG and other materials during the last 40 years. Indeed, Havens authored two of the models that the FERC formerly used to model LNG spills and vapor cloud dispersion.

In their public comments, they conclude that Jordan Cove's hazard modeling provides inadequate safety exclusion zones due to the ballooning size of LNG facilities in general, and export facilities in particular due to their use of other chemicals. Those include propane and ethylene used to purify and refrigerate natural gas. Those gases are more flammable than natural gas and subject to high order explosions.

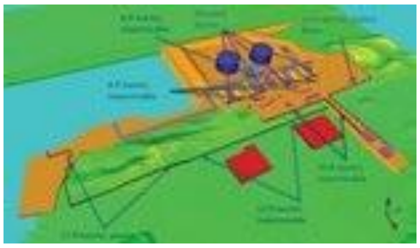
They also contend that the facility design proposed at Jordan Cove would actually increase such risks during a leak. The design includes impermeable barriers as high as 40 feet designed to retain vapor clouds within the facility's property line during a spill.

Yet their read of the modeling results is that vapor clouds would be concentrated by the barriers, enveloping the facility's liquefaction equipment, its massive storage tanks and much of its shipping berth, potentially including a tanker full of LNG docked there. In the event of ignition, the knock-on effects could be disastrous, they contend.

"We believe the hazards attending the operations at the Jordan Cove export facility could have the potential to rise, as a result of cascading events, to catastrophic levels that could cause the near total and possibly total loss of the facility, including any LNG ships berthed there," their comment said. "Such an event could present serious hazards to the public well beyond the facility boundaries."

Havens said Thursday that the risk of such an event is probably very, very low. But in the last decade alone, he said, there have been four major international incidents involving explosions that destroyed facilities using similar gases as Jordan Cove.

Havens and Venart are also concerned that regulators -- primarily the U.S. Department of Transportation -- have switched from using open-source hazard modeling software, where the underlying code was freely available for independent scientific review and verification, to proprietary models developed by private companies.



A site plan of the proposed Jordan Cove LNG terminal on the North Spit of Coos Bay, including vapor barriers.

Activists have also complained that hazard modeling data filed with regulators is often submitted under the designation of "Critical Energy Infrastructure Information," which means it isn't immediately available for outside review.

"I can't accuse them of using models that are wrong, but I can't get inside to even check them," Havens said. "If you can't, as a member of the public, satisfy yourself that these things are being calculated right, it undermines confidence in the entire procedure."

Jordan Cove declined to address specific critiques on Thursday, but a company spokesman, Michael Hinrichs, sent a statement via email.

"We understand that people are likely going to have concerns and that's what the public comment period is all about. Jordan Cove submitted safety information to FERC, DOT, PHMSA and other agencies per regulations and for their review. We believe our data satisfies applicable regulations to meet FERC review standards. The FERC will determine if added regulation or additional modeling is needed."

FERC project manager Paul Friedman said Friday that the agency will address specific issues raised in public comments in its final environmental impact statement.

Oregon Sen. Ron Wyden has expressed strong support for Jordan Cove based on the potential for the $7 billion project to create much needed jobs and tax revenue in Coos County and other locales along the pipeline route . But he has told residents repeatedly that the federal analysis on the project will be done right, and he will insist that community members be provided with full answers to legitimate questions.

Wyden's office sent out a statement indicating that he intends to follow up. "It's unacceptable for FERC to rely on anything other than the most up-to-date modeling when it comes to evaluating safety risks at Jordan Cove. Senator Wyden plans to write to FERC and to ask why the modeling cannot be made public and to make clear FERC needs to make sure it is using the best information available to approve or deny that facility."

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Exhibit 69

NATURAL GAS:

Explosive LNG issues grab PHMSA's attention

Jenny Mandel, E&E reporter

EnergyWire: Tuesday, June 7, 2016

Smoke pours from petroleum storage tanks following a 2009 explosion at the Caribbean Petroleum Corp. refinery in San Juan, Puerto Rico. The blast and fire damaged 17 of the 48 tanks at the site, and flames burned for nearly 60 hours. Photo courtesy of the U.S. Chemical Safety and Hazard Investigation Board.

The Department of Transportation's May 19 workshop on liquefied natural gas (LNG) safety started with a bang.

At DOT's headquarters in Washington, D.C., the agency's Pipeline and Hazardous Materials Safety Administration (PHMSA) hosted an in-depth discussion of what went wrong during a March 2014 explosion at an LNG facility in Plymouth, Wash., that led to five injuries and $72 million in property damage (***EnergyWire***, May 6).

The decision by PHMSA to conduct a broad review of its LNG safety rules -- and kick it off with an unusually open discussion of a fiery accident -- suggests the agency has taken to heart the saltiest criticisms tossed from Capitol Hill. "PHMSA is not only a toothless tiger, but one that has overdosed on Quaaludes and is passed out on the job," Rep. Jackie Speier, a Democrat from San Francisco, said during a congressional hearing in April 2015.

She pointed to the lethal and destructive natural gas pipeline accident in San Bruno, Calif., in 2010. In its aftermath, PHMSA came under fire for being slow to update its safety regulations. Late last year, a leaking Aliso Canyon underground gas storage facility outside Los Angeles, operated by Southern California Gas Co., prompted hand-wringing that regulators were underprepared.

If gas pipelines and storage fields come with risk, researchers are increasingly concerned that the expanding footprint of big LNG export terminals and other facilities along the U.S. coast are also potentially deadly.

LNG is jam-packed with energy. Natural gas is turned into a liquid by supercooling it to minus 260 degrees Fahrenheit, which shrinks its volume 600-fold and makes it easier to transport across the ocean.

Natural gas and its liquid form are flammable and explosive in confined spaces, but researchers say it's not prone to exploding when released in large, open areas. That's not the case for other heavy hydrocarbons such as propane and ethane, which can be stored at large LNG export facilities.

The concern among researchers and regulators grappling with how to regulate LNG safety is the potentially deadly mix of liquid fuels at an LNG site.

Things that go boom

At the DOT workshop last month, a presentation by Graham Atkinson, a principal scientist in the Major Hazards Unit of the Health and Safety Lab in Buxton, England, focused on what happens when heavy hydrocarbons explode.

explode.

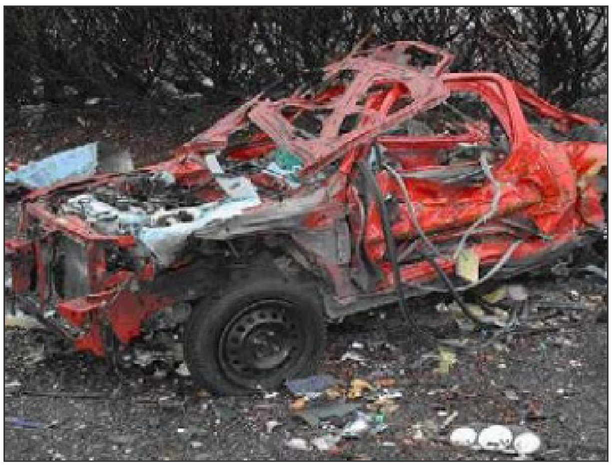
The audience listened, riveted, as Atkinson showed photos -- some not previously seen by the public -- from industrial accidents linked to liquefied petroleum gas (LPG), LNG, gasoline and other petrochemicals.

Four of the incidents took place within the last decade and were explosions of so-called unconfined vapor clouds that led to a series of cascading events that ultimately destroyed the facilities.

Researchers looked at 24 vapor cloud explosions but focused their attention on four major industrial accidents -- at gasoline storage sites in Buncefield, England, in 2005; Jaipur, India, in 2009; San Juan, Puerto Rico, in 2009; and at an LPG storage site at Venezuela's Amuay refinery in 2012.

In work funded by PHMSA through a contract with the Energy Department's Oak Ridge National Laboratory, Atkinson's team reviewed photos and videos from the accidents and conducted tests with gasoline in a range of spill conditions. The team focused on how vapor clouds form in low wind conditions and when barriers keep gases from fully dispersing.

Atkinson said an accident can happen under two conditions. One is a small leak that, after as little as 15 minutes with no wind, can cause a massive explosion that resembles a bomb blast with no epicenter. Devastation is spread evenly across the range of the vapor cloud.



An unconfined vapor cloud explosion at a gasoline storage site in Buncefield, England, in 2005 left bomblike devastation across a wide area. Photo courtesy of the U.K. Health and Safety Laboratory.

The other accident scenario is a large leak on a windy day, when cloud dispersion from the wind cannot keep up with the volume of gas released. That, too, creates a cloud-sized explosion zone. The shape of the plume can be mapped from the destruction.

Pictures from San Juan, Buncefield, Amuay and Jaipur show cars twisted and burned, bombed-out buildings, and flaming storage tanks.

"Fuel tanks are efficiently set on fire in the area covered by the vapor cloud," Atkinson noted, estimating that 95 percent of tanks exposed to the vapor clouds were set on fire. "It means it's a real tough job for all the emergency services. They're dealing with [potentially] 20 tanks set on fire. It's an almost unmanageable situation."

The researchers also looked at cases in which flash fires turned into explosions, finding that in some cases a confined space or a congested intersection of piping turned a fire into a blast.

"In all but one of the incidents reviewed, when a very large cloud was formed, there was a severe explosion," Atkinson said.

In low wind conditions, vapor clouds that accumulated from small, sustained leaks caused blast damage and fatalities 765 yards -- nearly half a mile -- or more from the source.

And if a large cloud of gasoline or LPG accumulates, a "severe explosion" is likely, Atkinson said.

'20 minutes'

After Atkinson spoke, a leader in the LNG industry quickly tried to wrestle control of the discussion, emphasizing that LNG doesn't carry the same risks as the non-methane fuels he had focused on.

Cheniere Energy Inc. is developing the Sabine Pass LNG export terminal in Cameron Parish, La. The terminal already has one processing train up and running to liquefy LNG, and construction plans include four more; the plant is the first modern LNG export facility in the United States (***EnergyWire***, May 3).

Pat Outtrim, vice president of government affairs for Cheniere, questioned Atkinson on his presentation in a rapid-fire series of yes-or-no questions.

Atkinson agreed with Outtrim that the heavy hydrocarbons tested have different properties from methane, and that the alert and emergency shutdown equipment at the facilities studied were absent, nonfunctioning or not able to alert the right people quickly.

But he disagreed with the notion that his results aren't applicable to LNG facilities.

Ethane blends, propane, isobutane and ethylene, as well as hundreds of metric tons of condensates like pentanes and hexanes, might be present at an LNG export site. The explosion research "shows just how important the detection and response protocols are," Atkinson told Outtrim. Vapor cloud explosions like those demonstrated "can't happen at an LNG facility if you detect [a leak] early and shut it down right away," he said.

The takeaway for the LNG industry should include consideration of automatic equipment shut-offs, Atkinson told *EnergyWire*.

"Twenty minutes can be enough to cause a problem," he said. If equipment shut-offs are manual, the staff needs to be well-trained. If sensors indicate a leak, "the response can't be, 'Oh, I need to go tighten it up.'"

"Problems tend to come from people. There are just so many cases where [warning lights] start flashing and people just go to pieces," he said.

One more challenge? Explosion events often occur at night, when wind speeds slow as the air cools. So plant personnel can go from keeping watch over a sleepy facility in the small, dark hours to a rapidly evolving emergency.

"When they decide what's sensible to automate, they ought to think about these factors and take it into account," Atkinson said.

The new LNG era

Still, automated controls are probably not the big worry that set PHMSA down the path of researching old accidents -- especially since many of a plant's most important controls have physical fail-safe mechanisms in case the electronics fail.

So why did PHMSA dedicate so much time to discussion of the hazards tied to gasoline, LPG and other hydrocarbons that are afterthoughts at most LNG installations?

A critique by two longtime LNG researchers offers some insight.

Jerry Havens and James Venart submitted public comments to the Federal Energy Regulatory Commission in January 2015 on a proposal to build the Jordan Cove LNG terminal in Coos Bay, Ore.

A 2009 vapor cloud explosion and ensuing fire at an Indian Oil Corp. facility in Jaipur, India, destroyed the plant and damaged homes more than a mile away, according to an investigation report. Photo courtesy of the U.K. Health and Safety Laboratory.

Havens has worked on LNG safety issues throughout his 40-year career and authored two of the computer models whose use was long required by federal regulators to assess the hazards of proposed LNG facilities. Venart was the longtime director of the Fire Science Centre at the University of New Brunswick in Canada, and studied industrial heat exchange and catastrophic explosions.

The Jordan Cove project proposed a liquefaction plant capable of processing up to 6.8 million metric tons per year of natural gas.

Havens and Venart said they were concerned that regulations governing LNG import terminals had been guided by the premise that LNG, as methane, poses less danger than other gas liquids and petroleum fuels. But with LNG export terminals designed and constructed under regulations used for simpler LNG import facilities, Havens and Venart warned that regulators were overlooking dangers.

"We believe the [Jordan Cove draft environmental impact statement] fails to provide for protection of the public from credible fire and explosion hazards," the researchers said.

The mix of refrigerants used to chill the gas and the heavy hydrocarbon impurities in pipeline gas that are stripped out and stored on-site pose a threat, they said.

"We believe these additional hazards have been discounted without sufficient scientific justification in spite of multiple international reports during the last decade of catastrophic accidents involving unconfined hydrocarbon vapor cloud explosions," Havens and Venart said.

The researchers also raised concerns that Jordan Cove and other proposed facilities would use concrete "vapor walls" to trap a gas cloud on the property and keep the fire hazards from breaching the property lines. But such walls would cause methane and other gases to build up into concentrated vapor clouds several meters deep, increasing the explosion risk.

With densely packed processing equipment on the site and a vapor fence trapping hydrocarbons, "one could hardly design the releases to better maximize the potential for catastrophic explosion hazard," Havens and Venart added.

FERC finalized Jordan Cove's EIS in September. It made no mention of Havens and Venart's comments.

Michael Hinrichs, a spokesman for the Jordan Cove project, noted in an email that "dispersion modeling, safety and security were all thoroughly analyzed and accepted by the FERC, [the Department of Transportation] and PHMSA to be within compliance." The three agencies, he said, "have all upheld the current modeling as meeting the safety criteria for the industry."

The Jordan Cove project's fate has since been thrown up in the air by an unexpected FERC decision to reject the project despite the favorable review by agency staff, pointing to a lack of firm contracts for LNG off-take (***EnergyWire***, April 19).

But Havens continues to be concerned. In a paper at the Health and Safety Laboratory -- where researcher Atkinson works -- in April, he **argued** that regulators are "doing it wrong" when it comes to gauging the explosion hazards of large hydrocarbon clouds.

Havens said PHMSA may be relying on the wrong computer models to assess explosion risks. Most of its results are classified for security reasons.

Divided responsibilities

At the workshop in May, Kenneth Lee, who directs PHMSA's engineering and research division within the Office of Pipeline Safety, declined to say what specific regulatory changes are on the table for an upcoming overhaul of the LNG rulebook, or even what the key questions are, deferring to public input from the meeting to shape the process (***EnergyWire***, May 20).

But the workshop itself, in providing a platform to discuss heavy hydrocarbon risks, points to the potential for new requirements for LNG export facilities. How those requirements might be designed remains to be seen.

Industry has welcomed small tweaks to PHMSA's rules that would bring them up to date, more easily encompass new technologies and be more in line with standards used by regulators in other jurisdictions. But any changes that added new hurdles to the process of siting LNG facilities -- which primarily falls under FERC jurisdiction -- could face opposition from developers. They could raise difficult questions about Sabine Pass LNG and the four other LNG export terminals under construction.

For its part, PHMSA pledges that the coming rulemaking process will be transparent. "We take comments that you submit very seriously," said Julie Halliday, a member of the agency's engineering and research division who coordinated much of the meeting, in a discussion of the next steps. "We will address those points that you submit."

Still, she noted that PHMSA's authority over LNG facility siting is limited. "We don't actually have authority for siting within our regulations," she said, describing the agency's role in that process as working out the public safety "exclusion zones" that extend around the core of the facility.

"It's about a setback. It's not telling you whether you can site a facility at a certain location," she added, noting that other agencies control that question. "If FERC doesn't have jurisdiction to site a facility, it's the local jurisdiction."

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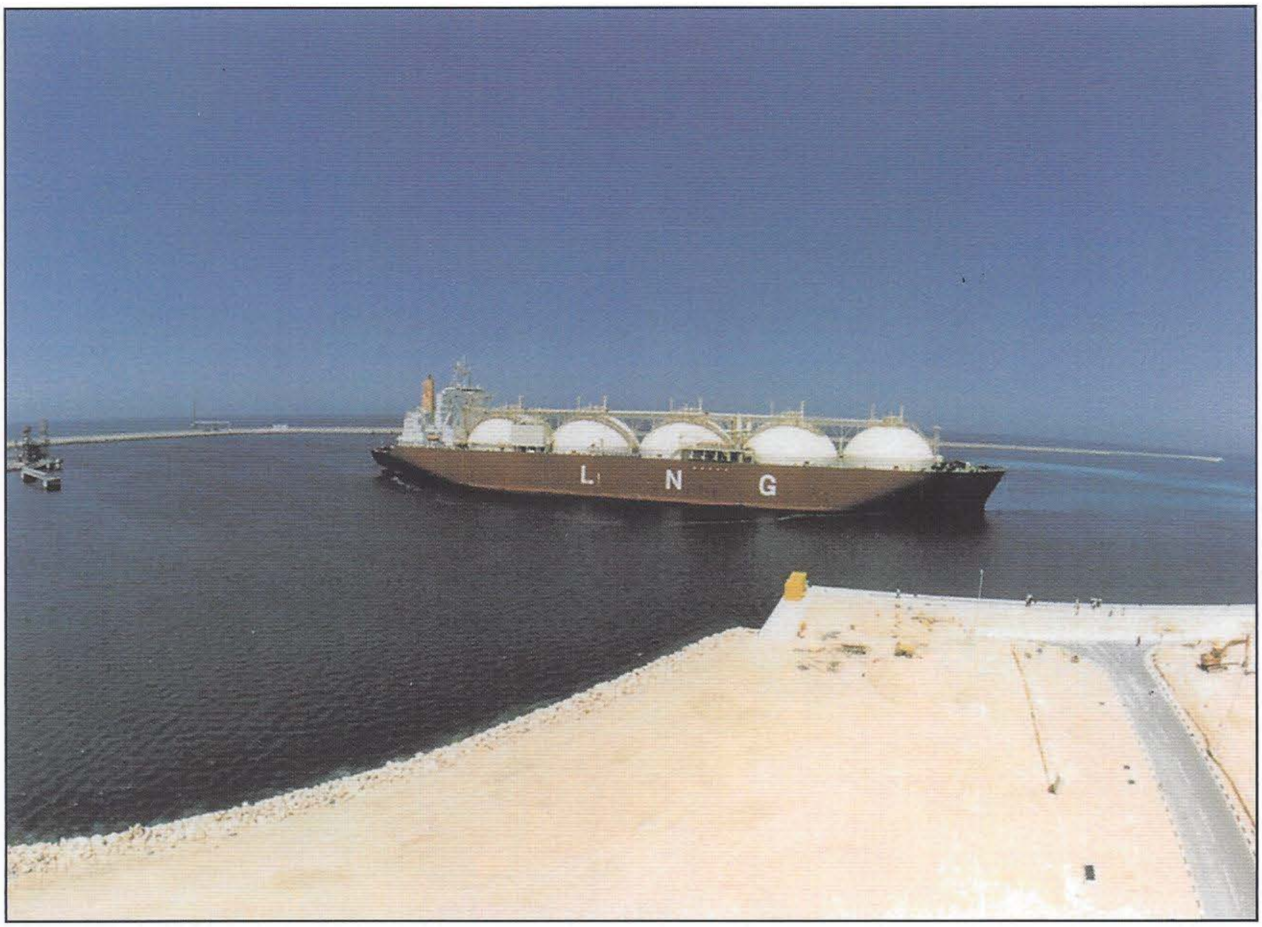
Exhibit 70

Site Selection and Design for LNG Ports and Jetties



Information Paper No. 14

SIGTTO

Site Selection and Design for LNG Ports and Jetties

with views on

RISK LIMITATION during PORT NAVIGATION

and CARGO OPERATIONS

Information Paper No. 14

ISBN 13: 978 1 85609 129 9

First Published 1997
Society of International Gas Tanker and Terminal Operators

British Library Cataloguing in Publication Data

Site selection and design for LNG ports and jetties
1. Risk limitation
2. Port navigation and cargo operations

ISBN-13: 9781856091299

SIGTTO

The Society of International Gas Tanker and Terminal Operators (SIGTTO) is a non-profit making organisation dedicated to protect and promote the mutual interests of its members in matters related to the safe and reliable operation of gas tankers and terminals within a sound environment. The Society was founded in 1979 and was granted consultative status at IMO in November 1983. The Society has over 160 companies in membership who own or operate over 95% of the world's LNG tankers and terminals and over 55% of the world's LPG tankers and terminals.

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Published and Printed by
WITHERBY PUBLISHING.LTD
32/36 Aylesbury Street
London ECIR 0ET, England
Tel No: +44(0)20 7251 5341
Fax No: +44(0)20 7251 1296
www.witherbys.com

WITHERBYS
PUBLISHING

THE QUEEN'S AWARDS FOR ENTERPRISE: INTERNATIONAL TRADE 2007

Contents

NOMENCLATURE

BSI	British Standards Institute
CEN	Comité Européen de Normalisation
ESD	Emergency Shut-Down
ERS	Emergency Release System; a system comprising all ESD and PERC measures
IALA	International Association of Lighthouse Authorities
IAPH	International Association of Ports and Harbors
ICS	International Chamber of Shipping
ISGOTT	International Safety Guide for Oil Tankers and Terminals
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas (butane and propane)
OCIMF	Oil Companies International Marine Forum
PERC	Powered Emergency Release Coupler, with its adjacent quick-acting block valves. This is a device providing a virtual spill-free means of quick disconnection of the hard arm in emergency situations. The block valves are interlocked with the coupler to ensure dual action.
PIANC	Permanent International Association of Navigation Congresses
SIGTTO	Society of International Gas Tankers and Terminal Operators Ltd
TSS	Traffic Separation Scheme
VTS	Vessel Traffic Services

1 SUMMARY

This paper addresses safety issues for LNG ports. It focuses on the elimination of spillages both at the ship/shore interface and in navigational approach channels. The paper concentrates on issues which can be solved when a port is being designed and is, therefore, of benefit to harbour planners and port authorities. Flowing from these considerations, the paper outlines a way forward for the site selection of LNG terminals, establishes a basis for safe jetty design and considers safety factors in the port approach. In developing its first aim, the paper examines existing industry guidelines covering cargo operations at the ship/shore interface. Indeed, the paper suggests that LNG's excellent safety record owes much to the adoption of existing standards. However, with the industry becoming more widespread, as a second aim, continuing success depends not only on better acceptance of existing standards but also on future improvements. Some of these newer aspects are described and a check list is presented in the Appendix giving an overall package of the items considered most essential for LNG.

Bearing in mind the high commercial exposures within LNG projects, the need to maintain its good safety record is vital to all companies concerned. Furthermore, an incident in one port could have serious knock-on effects in others, and may herald constraints in new projects elsewhere. These concerns, coupled with the dangers perceived during public inquiries into LNG transport, make a very strong case indeed for a continuing high level of safety to be applied.

On ships the good safety record for LNG operations is predicated on an excellent standard of management, high quality crews, the structural robustness of ships' hulls and back-up control systems. On shore, also of importance, are the select number of well managed terminals. At these plants the focus of national agencies, port authorities and terminal managers ensure that safety in operations is always an important element.

However, although LNG has an enviable record it is not risk free. Not only are some hazards difficult to eradicate; an accident, albeit rare, is possible as a result of human error or catastrophic event such as an earthquake. Moreover, technical limitations can have an effect and site location may not always achieve a port design which is entirely risk-free. It can be seen, therefore, that there can remain a very remote chance for some incidents to occur. However, a large release of LNG such as through a damaged hard arm or a ruptured cargo containment system — central themes in this paper — should be specially addressed during port design.

Important matters which should be dealt with when choosing the location of a new terminal are covered in the paper. Apart from general considerations, these emphasis the need for the introduction of risk management techniques. A fact which helps to ease the acceptance of these newer concepts in the LNG trade is its relatively close-knit nature and because most of the trade is held by only a few companies within well-defined limits. Also, investments in LNG projects are such that equipment quality can be planned to a high standard.

This paper proposes the adoption of the recommendations outlined in chapter 2. However, criteria such as that for channel width, should not be understood as absolute values; these recommendations are just basic guides to prompt special enquiry into particular aspects. Furthermore, the actual values quoted together with their risk reduction effect, still depend on local conditions which have to be covered individually, port by port.

2 PRINCIPAL RECOMMENDATIONS

2.1 PORT DESIGN

Approach Channels. Harbour channels should be of uniform cross-sectional depth and have a minimum width, equal to five times the beam of the largest ship.

Turning Circles. Turning circles should have a minimum diameter of twice the overall length of the largest ship, where current effect is minimal. Where turning circles are located in areas of current, diameters should be increased by the anticipated drift.

Tug Power. Available tug power, expressed in terms of effective bollard pull, should be sufficient to overcome the maximum wind force generated on the largest ship using the terminal, under the maximum wind speed permitted for harbour manoeuvres and with the LNG carrier's engines out of action.

Traffic Control. A Vessel Traffic Service (VTS) System should be a port requirement and this should be able to monitor and direct the movement of all ships coming within the operating area of LNG carriers.

Operating Limits. Operating criteria, for maximum wind speed, wave height, and current, should be established for each terminal and port approach. Such limits should match LNG carrier size, manoeuvring constraints, and tug power.

Speed Limits. Speed limits should be set for areas in the port approach presenting either collision or grounding risks. These limits should apply not only to LNG carriers but also to any surrounding traffic.

2.2 THE JETTY

Exclusion of Ignition Sources. No uncontrolled ignition source should be within a predetermined safe area centred on the LNG carrier's cargo manifold.

Mooring Layout. The terminal should provide mooring points of a strength and in an array which permits all LNG carriers using the terminal to be held alongside in all conditions of wind and current.

Quick Release Hooks. All mooring points should be equipped with quick release hooks. Multiple hook assemblies should be provided at those points where multiple moorings lines are deployed so that not more than one mooring line is attached to a single hook.

Emergency Release System. At each hard arm the terminal should fit an ERS system, able to be interlinked to the ship's ESD system. This system must operate in two stages: the first stage stops LNG pumping and closes block valves in the pipelines; the second stage entails automatic activation of the dry-break coupling at the PERC together with its quick-acting flanking valves. The ERS System should conform to an accepted industry standard [15].

Powered Emergency Release Couplers (PERCs). The terminal should fit a PERC in each hard arm together with quick-acting flanking valves so that a dry-break release can be achieved in emergency situations.

Terminal Security. An effective security regime should be in place to enforce the designated ignition exclusion zone and prevent unauthorised entry into the terminal and jetty area, whether by land or by sea.

Operating Limits. Operating criteria, expressed in terms of wind speed, wave height, and current, should be established for each jetty. Such limits should be developed according to ship size, mooring restraint, and hard arm limits. Separate sets of limits should be established for (a) berthing, (b) stopping cargo transfer, (c) hard arm disconnection and (d) departure from the berth.

3 ACKNOWLEDGMENTS

The content of this paper is based on reports from a company having SIGTTO membership and, in this respect references [1] and [2] were most valuable. The navigational aspects, as detailed in chapters 9 and 10, came about as personnel in that company assessed marine operational risks for new LNG terminals. In one case, the new project was in Europe where the project analysis was carried out in accordance with a European Council Directive for assessing risks and environmental impacts. This is a process which, while being driven by national law, is also of direct concern to the companies involved.

These requirements led the project leaders to consider how the risk of some classes of accident might be better established and, in particular, what the consequences of a large LNG release might be, either in the port approach — due to grounding or collision; or alongside — due to fracture of the hard arm.

The company concluded that such a large release of LNG had never happened. Nevertheless, in some situations such an event was found to be feasible. From a marine viewpoint the scenarios which could lead to a major release were identified and recommendations were prepared to further reduce the chance of any such happening.

This paper also draws on earlier publications from SIGTTO and similar societies which are relevant to the management of port risks.

4 INTRODUCTION

At the time of site selection, the level of marine risk is determined by the position chosen for the terminal and this is especially true of terminals handling hazardous cargoes such as LNG. Once the port is in operation, the risks identified during planning should be controlled by suitable equipment and pre-arranged procedures. This should include the on-going need to keep other industry or populations remote from the plant.

As can be seen from much of its earlier work, SIGTTO urge acceptance of a wide range of equipment and procedures for the reduction of operational risk. To supplement past work, this paper recommends that for new sites the LNG terminal, and its port area, should be examined as a unique risk system. This paper focuses, therefore, on accident exposure and risk management not only during cargo operations alongside, but also during the port transits of LNG carriers.

Implicit in site selection is the recognition of risk. As described elsewhere [3], risk consists of a combination of event frequency and consequence. Thus, port designers are often faced with a number of choices when selecting a site, and these choices can arise from a variety of competing pressures. As described in risk assessment theory, operational solutions are found by acceptance, or non-acceptance, of some categories of risk. However, whatever remote frequencies may be tolerated for a smaller release, there is no acceptable frequency for a large release.

In essence, the issue being addressed is how best to minimise port risks by design factors at the start of a project. As can be seen in the paper there are three components in this equation. Initially questions on satisfactory jetty position and design are covered. Operational procedures are then addressed. Thereafter, having questioned the robustness of these procedures with respect to human elements, the consequences of collisions and groundings are studied and methods of limiting the effect of such accidents are considered. By this means, any high risk scenario is identified during design and this then requires special handling to restrict occurrence.

From a navigational standpoint and as alluded to in the above paragraph, the paper suggests that while the human controls called upon during ship manoeuvring deserve high ranking, of themselves, they can never be considered one-hundred per cent secure: this is because questions of human error can prevail. However, back-up is achieved if it is known that, in a grounding or collision, an LNG carrier's cargo containment system is most unlikely to be breached. To achieve this end, a detailed study of each port approach is needed and, to give this subject greater clarity, examples are given at section 10.3.

To cover the main risks (as identified), the possibility of liquid spillage during cargo operations at the jetty is also discussed. Here, a three stage solution is offered. First, well deployed moorings. Second, well engineered and interlinked ESD systems. Third, the fitting of PERCs, with quick-acting valves included on either side; all controlled by an ERS system.

Having addressed all risks — big and small — alongside and in the port approach, an outcome from the risk analysis which makes an accident virtually impossible is clearly the most satisfactory. If, however, the outcome shows consequences of a serious nature then, clearly, it is necessary to draw up detailed contingency plans. But, in some circumstances, such as a large LNG release close to a populated area, it may be impossible to devise a realistic contingency plan because of the nature of the problem. Herein lies a conundrum which may only be resolved by further reducing the chance of a major release by designing-out the problem.

The precautions, as recommended by SIGTTO in this paper, do not offer a single package that reduces operational risk to some quantifiable and acceptable level; indeed it is suspected that the pattern of operational risk is too complex to be easily handled in this way. However, this cautionary note aside, the industry's objective must be to further reduce risk whenever possible.

Of course, the safety of life is vital, and so also is continuing public confidence in the trade. However, the enormous financial exposures of LNG projects also must be safeguarded. In some circumstances it is found that the protection given to save life also protects the commercial exposure. In other cases, however, personal safety can be assured while unacceptable business risks remain - so suggesting the improved standards, as recommended in this report, are necessary not only due to personnel hazards but also to protect the business risk.

Important factors such as personnel training, contingency planning or matters of a general safety nature are not covered in this paper; the aim has been to focus more on matters of equipment and issues of navigational interest. Nevertheless, these extra factors are fundamental to future safety in the LNG sector and, as a matter of course, should always be taken into account.

5 DEVELOPMENT OF LNG STANDARDS

The history of developments in the LNG industry has been marked by two separate but interwoven strands. Firstly there was a continuous effort to design systems to reduce the probability of large escapes of gas. On the other hand extra standards — often oil industry based — were re-specified in light of experience and technological improvement. Indeed, as the LNG industry moves into the 21st century it remains true that future improvements should not be altogether separated from progress in the oil world and, where possible, LNG terminalling standards should continue to grow in parallel with port operations generally.

An example of an LNG standard having developed along technological lines is that covering on-shore storage tanks. For a period, earthen embankments were used for support against the force of sudden release from the inner tank. Subsequently, through adoption of improved inner tank material, the probability of catastrophic crack propagation was much reduced. Now, earthen bunds are no longer needed. Similar changes occurred in the design of LNG carriers, where sophisticated methods for assessing crack propagation now allow the secondary barrier to be omitted in two free-standing cargo containment systems - the Moss Rosenberg spherical design and the IHI prismatic design.

To date, the greatest investment to reduce port risks is the limitation of gas escape at the ship/shore interface and on the jetty. Here the application of industry recommendations for jetty design and mooring systems [4] provides a secure base for LNG transfer. Furthermore, the references mentioned in chapter 6 direct port designers to construct jetties handling hazardous cargoes in remote areas where other ships do not pose a (collision) risk and where any gas escape cannot affect local populations. When this advice is combined with that from SIGTTO [5] — as outlined in section 7.2.2 — risks at the jetty are vastly reduced.

It can be seen, therefore, that progress in defining LNG standards have taken a step-by-step pattern which can be summarised as follows:

- a start was made with the existing framework of standards for oil
- these were then adapted for the characteristics of LNG
- changes in shipping and terminalling standards were then addressed, and
- finally the engineering challenges for cryogenic systems were answered

Present day standards for limiting problems are thus the result of sensible evolution rather than a well-focused set of risk related measures. Indeed, experience shows that the process was, simply, one of progressive improvement, the motivation being a desire to make operations safer. However, it is at the time of site selection that the foundations of high quality risk management can be laid and where overall cost/benefit judgements are best formed and it is in these areas where this paper recommends the introduction of risk management techniques.

Although the criteria for site selection may differ between LNG terminals, the majority are common to all. Some, such as the proximity of the plant to centres of population, lie beyond the pure marine interest and outside the main scope of this paper. But others, including the harbour movements of LNG carriers, the density of marine traffic (covering the nautical risks to LNG carriers) and the terminal itself, much influence the overall risk which eventually has to be controlled and these concepts are covered in more detail in the following chapters.

6 SITE SELECTION

6.1 GENERAL

At its most elementary level, site selection for LNG loading terminals is predicated by the location of production areas and, at receiving terminals, the situation is dependant upon the location of markets. Thereafter, fine tuning within the selection process is influenced by the optimisation of infrastructure costs such as gas transmission systems, access to trunklines and other distribution networks.

Hence, site selection is driven largely by factors aimed at minimising transportation and storage costs. With this in mind, it can be appreciated that marine criteria are only a part of the overall process. Therefore, at the stage of site selection, input from marine experts consists mainly in optimising fleet capacity (numbers and sizes of ships) and checking civil engineering matters at the ship/shore interface, at the terminal and in the terminal/port approach. This latter aspect is achieved by obtaining the required depth of sheltered water, providing good access to the sea and achieving immediate adjacency to the LNG terminal.

From a marine viewpoint there is little prospect to escape from these basic factors. Prices and hence, to a large extent demand, remain linked to the costs of alternative energies and, LNG's unique environmental benefits notwithstanding, the product must retain market competitiveness. Thus, as the future unfolds, continuing efforts to economise on handling costs and freight rates are likely.

In the site selection process the challenge, therefore, is to limit marine risks while positioning the jetty within realistic limits. Already there are generally accepted criteria and regulatory requirements to guide port designers in achieving this synthesis and most are covered in this paper.

6.2 JETTY LOCATION

The recommended site selection process removes as many risks as possible by placing LNG terminals in sheltered locations remote from other port users. References [6], [7] and [8] all direct port designers to construct jetties handling hazardous cargoes in remote areas where other ships do not pose a (collision) risk and where any gas escape cannot affect local populations.

Furthermore, choosing a jetty position within a sheltered location limits the dynamic forces acting on a ship from sea-waves which, in turn, could break a ship's mooring lines. Considering the standard LNG carrier of about 135,000 m^3 capacity, the waves likely to have such effects are those approaching from directly ahead or astern, having *significant heights* exceeding 1.5 metres and *periods* greater than 9 seconds. Seas approaching the berthed ship from an incidence angle of 90° (to the bow) have much lower cut-off points. It is, therefore, recommended that harbour protection be provided against low frequency waves, either by choice of location or by construction of an effective breakwater. Alternatively, an enhanced mooring system may be designed, suited to dynamic effects (but also taking into account the suitability of gangway access for the moving ship). Without such assurance the mooring system, which is the only defence against ship break-out, could be put at risk.

Jetty location should also be chosen to reduce the risk of passing ships striking a berthed LNG carrier but subjective judgement comes into assessing safety from this standpoint. The acceptability of such positions should be determined only after detailed consideration of local circumstances. However, as far as port design is concerned, some features are clear cut. For example, positioning an LNG terminal on the outside of a river bend raises the risk that a passing ship may strike the berthed carrier if the manoeuvre is not properly executed. This is possible because, at some point on the bend, the manoeuvring ship must head directly at the berthed LNG carrier. In this respect, and following the reasoning in reference [3], ships of over 10,000 tonnes displacement operating at normal harbour speeds — say 10 knots — when striking at 90°, present a hazard to a berthed LNG carrier's containment system. It follows, therefore, that building a jetty in such locations is normally considered unsuitable.

Furthermore, large ships passing near to a berthed LNG carrier can cause surging or ranging along the jetty, with consequential risks to the moorings and this phenomenon should be guarded against. This can occur at jetties located in channels used by large ships and, because of this, these positions are not recommended.

The added risks from increased traffic encounters, and extended shallow-water navigation, when positioning an LNG jetty farther inside a port, must also be considered — but these risks are covered more fully in chapters 9 and 10.

As can be seen, choosing the site for an LNG jetty comprises a mixture of checks, some derived from quantitative analyses, others owing more to subjective judgement. However, when considering an LNG carrier alongside, site selection is directed mainly at minimising the risks of ship strikings, limiting interactive effects from passing ships and reducing the risks of dynamic wave forces within mooring lines.

7 DESIGN CRITERIA FOR JETTIES

When the site selection process finally establishes the best position for an LNG terminal, its design is set within two sets of criteria — root criteria and specific criteria. These are categorised as shown below.

7.1 ROOT CRITERIA FOR HAZARDOUS LIQUID CARGOES

Basic safety for gas, chemical or oil tankers and their respective terminals is governed by ISGOTT [9]. This book contains an essential list of design and operational practices and is amended from time to time in accordance with new experience. In addition to ISGOTT, in establishing safe designs, the use of other guidelines published by SIGTTO, OCIMF, IAPH, PIANC, IALA, and BSI is encouraged. Some of these documents are referred to in chapter 11 — see references [10], [11] and [12]. However, most of these industry documents are general in nature and seldom discuss event frequency nor, for that matter, specific ship-types. In order to cover the hazards more effectively, reference [13] is of help in the gas trades — although written more from the viewpoint of existing plant.

Until the publication of this paper, within the standard suite of industry publications, the possible consequences of an accident are also left largely unaddressed. Previously, it was only reference [14] which gave some guidance on this subject. However, taken together, these older sources provide a robust framework of root criteria around which jetty designs are established and other standards (specific criteria — see below) are then specially tailored to the needs of LNG.

Thus, existing recommendations provide the root criteria for jetty design, in terms of:

- strength of mooring systems
- positioning breasting dolphins
- position, size, and spacing, of hard arms
- depth, width, and alignment, of harbour channels

Such recommendations provide terminals with a good set of design standards. They are not, however, exhaustive nor can they be applied without knowledge of local conditions, so they can rarely be used to prepare a complete checklist for LNG — other measures must be adopted (see section 7.2).

It can be seen, therefore, that within the root criteria, a system is established for securing a safe berth; but this is one within which there may remain a significant, albeit remote, probability for an accident to happen. In developing criteria suited to LNG the separation of each risk into its frequency and consequence is crucial. Thus, when considering even the remote possibility of major accidents, the application of existing standards, though relevant, is insufficient to obtain suitable assurance. Accordingly, at LNG jetties, risk related methods should be adopted which address event probabilities, and seek, as far as possible, to quantify the frequency of occurrence.

7.2 SPECIFIC CRITERIA FOR LNG

7.2.1 General

Although the root criteria, as discussed above, are included in LNG terminal design, risk considerations usually identify the need for yet other equipment or procedures — the site specific criteria. These methods can be more demanding than the root criteria and are often applicable to operational practices and geographical areas for which industry guidance is not yet fully established. However, a new series of standards from CEN, entitled Installations and Equipment for Liquefied Natural Gas, will be appropriate to European usage — perhaps even further afield.

Additional specific criteria are also found from risk factors lying beyond normal operations at the ship/shore interface. These conditions can include hazards from outside influences such as other marine traffic and nearby ignition sources. As an example, some LNG terminals patrol the perimeter of the offshore safety zones with guard boats — see section 7.2.4. A further example is to declare the air-space over an LNG terminal as being a restricted zone where no aircraft is allowed to fly without written permission.

The specific criteria have thus grown through experience in analysing and managing terminals. They have wide application in the reduction of risks at LNG terminals and are therefore included among the recommendations to be applied during terminal design. In the following sections some specific criteria are discussed in greater detail.

7.2.2 Mooring

For the LNG trades, site selection includes extensive collection of environmental data, including wave spectra. From this, the oscillations of berthed ships are estimated and the individual loads in each mooring line are pre-calculated for critical conditions. Within the trade, this means that not only mooring standards [4] should apply but also the additional force of dynamic wave action should be taken into account. So, while the root criteria for mooring systems act as the design basis, the behaviour of mooring and cargo handling equipment is made site specific for the prevailing conditions. These analyses establish jetty specifications for:

- mooring bollard strength and position
- mooring load-monitoring equipment, and
- hard arm envelopes and cut-off points for automatic operation of the ERS system

7.2.3 Cargo Transfer Operations

All LNG companies ensure that gas carriers can lie safely alongside while transferring cargo. Here, references [14] and [15] are of great value in achieving this aim. By adding the standards for ship's cargo manifolds and detail on surge pressure control [16], which are among the many valuable contributions made in recent years, even greater assurance is provided. Yet experience shows that specific criteria should be adopted to adequately control risks over the whole spectrum of port and terminalling operations and these should find a place in the design. In this respect, to guard against the consequences of hard arm failure, specific criteria should limit the possibility of significant LNG spills. This question is addressed in reference [15] where the following equipment is recommended to be fitted at hard arms:

- interlinking of ship and shore ESD systems
- establishing a common standard of linkage for ship/shore ESD control
- fitting PERCs and their quick-acting valves
- linking ESD systems and PERCs into a unified control system called ERS

In addition to other matters, reference [5] takes a fresh look at the operation of Emergency Release Systems (ERSs) where it will be found that many events can cause triggering of the system. For the purposes of this paper it should be noted, however, that the ERS is expected to function in two distinct steps. The first step is cargo pump stoppage and closure of the ESD valves in pipelines, both on-board ship and on shore. The second step is closure of the quick acting valves (at the PERC) and the release of the PERC by automatic means. More detail may help to explain this two-stage operation. Here, it should be appreciated that within the ERS's electronic logic for the hard arm, sensors are installed to detect ship movement. Some movements are within the proscribed limits; others are of significance; and yet others are dangerous. Ship movements to the outer edge of the safe area may trigger an alarm. However, movements into the first ERS area activate valve closure and pump stoppage (ESD) — this is still an intermediate area but one in which automatically initiated controls are considered necessary. Finally, if the ship moves beyond this intermediate zone — into the danger area — automatic release of the PERC is actuated quite independently from human intervention.

To illustrate this concept a diagram is provided below.

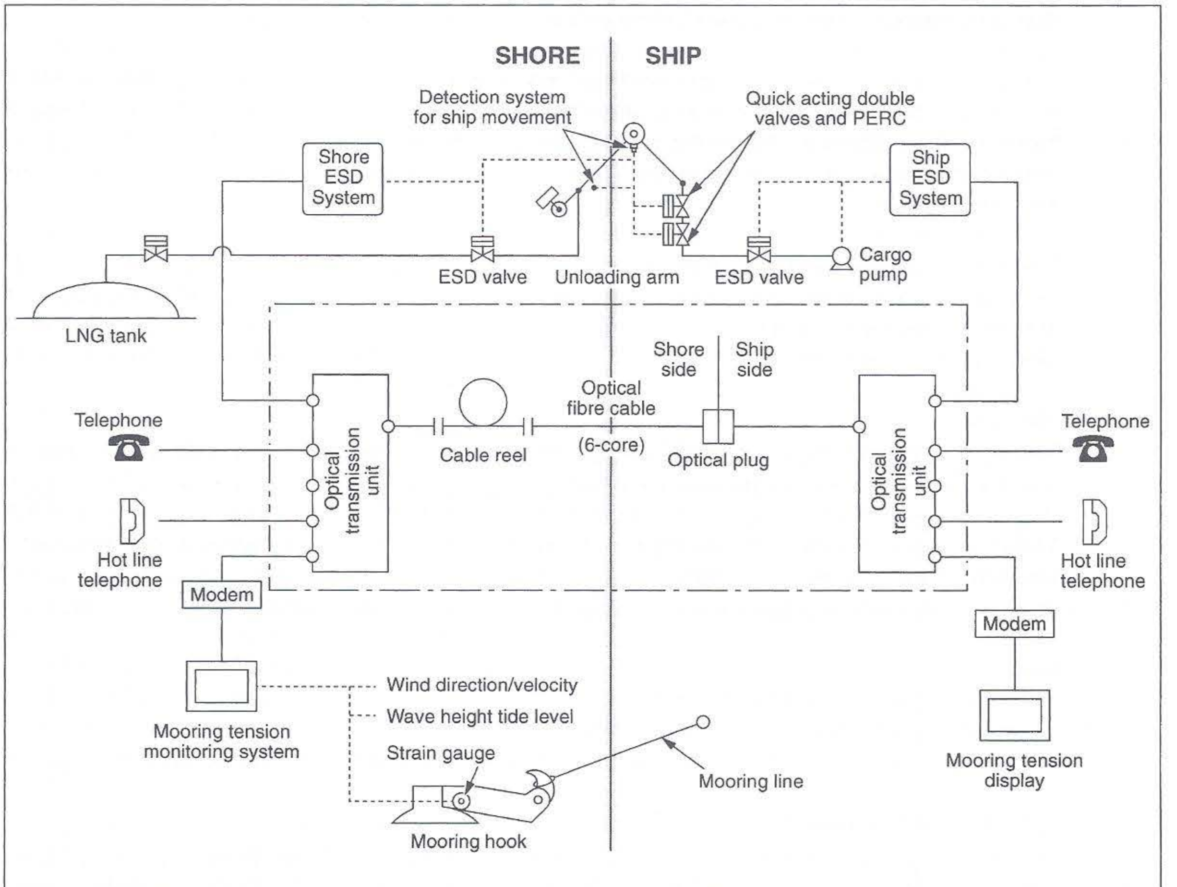

Figure 1: Interlinkage of ESD Systems and PERC Operation - The ERS

In developing these criteria, the underlying rationale is that the mooring lines must provide secure attachment between ship and shore allowing very little relative movement. This means the hard arms also remain secure and the risk of arm rupture, caused by ship break-out, should not occur. However, although this basic framework underpins safety at the ship/shore interface, it provides only a single defence against risk of spillage and the generation of dangerous gas clouds.

Therefore, a second defence comprising an interlinked ESD system is used, this being manually activated by the jetty operator or automatically by ship movement beyond the limits of a predetermined envelope. Automatic activation is triggered (amongst other alarms — see reference [5]) when sensors in the ERS system detect unacceptable ship movement so allowing the ESD controls to stop cargo flow and close pipeline valves — usually within 30 seconds. The progress of activation must be first to stop the pump and then to close the valve nearest to the pump — this restricts the magnitude of surge pressures so limiting any risk of hard arm damage because of high transient over-pressures.

However, and as mentioned above, it is recommended that a third defence be provided to ensure protection for the hard arms against damage from ship break-out and further reduce the maximum quantity of LNG spilled. This is the inclusion of PERCs (fitted within the arms) which allow hard arms to be safely, quickly (about 5 seconds), and automatically disconnected if an LNG carrier should break-out from its jetty. Hence, if all else fails and an LNG carrier breaks away from a jetty the maximum spill is no more than about 15 litres of liquid for the standard 16 inch diameter arm.

Safety issues apart, the PERC (and its accompanying ERS system) is a highly desirable protection of business interests. Often the jetties at LNG installations are but single entities, and if put out of action, total supply can be severely jeopardised. It will be seen, therefore, that in LNG projects, where massive investments are involved and the income of many parties depend on uninterrupted cargo deliveries, any risk of damage to jetties must be eliminated as far as possible. For these reasons, SIGTTO believe that such equipment is an essential risk reduction technique.

Further measures to prevent gas release include surge pressure control systems. Because surge pressures can cause hard arm and pipeline damage, the cargo handling system must be designed by keeping the possibility of surge in mind. This may lead to increased scantlings for pipelines, the fitting of bursting discs with surge pressure drums, or quick-acting relief lines returning surge pressures to the cargo tank.

7.2.4 Ignition Risk

In the event of an LNG spill the possible extent of a gas cloud must be considered. Here it should be appreciated that the risk of ignition from spilled LNG can extend for some considerable distance and, therefore, ignition controls must extend beyond the immediate area and this may be both inside and outside the terminal boundary.

Clearly, it is important to remove all risks of ignition as far as it is practicable to do so. Procedures taken to limit the risk of spills, and minimise their scale, reduce the probability of gas cloud ignition. But even the marginal risks remaining can be unacceptable in a business where a first rate safety record is vital to sustain confidence. Further precautions are therefore adopted to limit ignition sources on the jetty and in its environs.

As mentioned in section 7.2.1, in some ports guard boats are used to patrol the offshore safety zones with a view to excluding other traffic. Often these craft are also fitted out for other emergency purposes and feature in contingency plans. Figure 2 below shows the general arrangement for one such craft.

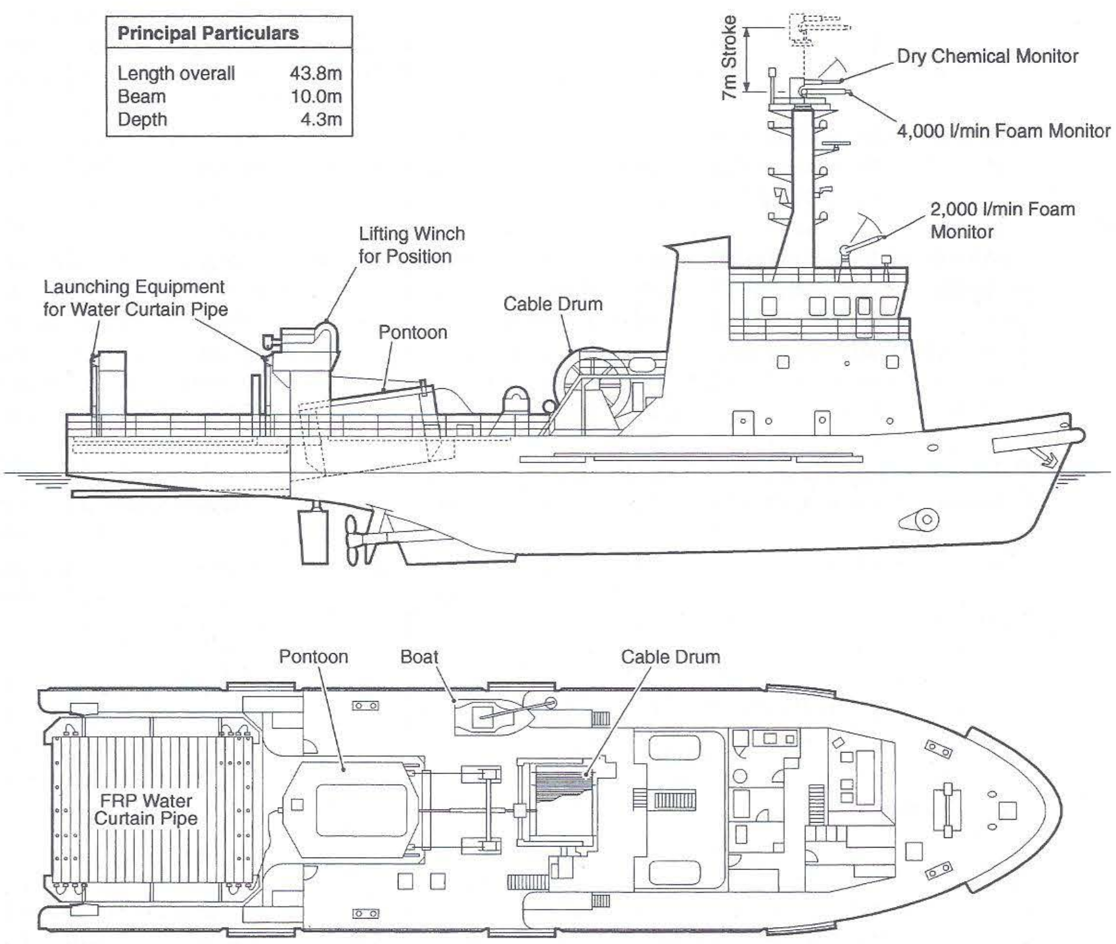

Figure 2: A Guard Boat Outfitted for Emergency Response
Details from Tokyo Electric Power Co. Inc. (see LNG 10, Conference Proceedings)

The area over which ignition-free zones should extend is determined by an analysis of the formation and dispersion characteristics of gas clouds resulting from a range of spill scenarios under a variety of weather conditions. The result provides the likelihood and possible extent of gas clouds in the vicinity of the jetty.

The range of a flammable gas cloud generated by a spill is principally dependant on spill rate and duration but inevitably some subjectivity must accompany the assessment of each spill scenario. Other factors such as climatic conditions, wind direction and speed are also of importance. In addition local topography such as harbour structures and the presence of the LNG carrier itself can have an effect.

Thus, determination of the minimum area from which all ignition sources must be excluded will vary from terminal to terminal and such determination should form part of the design considerations. Sometimes quite large zones, free from ignition sources, are considered desirable especially when terminal safety systems such as fire pumps could be engulfed within the gas cloud.

7.2.5 Specific Criteria - a Summary

In summary the essentials for a safe LNG berth are as follows:

Essential design for a safe LNG jetty

- find a location suitably distant from centres of population
- provide a safe position, removed from other traffic and wave action
- construct mooring points in a satisfactory array and of suitable strength
- use hard arms for cargo transfer
- interlink ship and shore ESD systems
- provide a two stage ERS system, linking ESD protocols with PERC operation
- fit hard arms with PERCs, together with quick acting valves
- fit wind speed and direction monitoring equipment
- install load monitoring equipment on mooring line quick release hooks
- determine maximum credible spill, gas cloud range, and ignition-free safety zones

Apart from the essential design factors listed above, the following terminal procedures should be in place.

Terminal procedures for the LNG carrier alongside

- set limits on the mooring system for wind speed, wave height, and current
- set wind limits for cargo stoppage, hard arm disconnection, and unberthing
- restrict the speed of large ships passing close to berthed LNG carriers
- control visitors and vehicles coming into jetty safety zones
- establish ignition-free offshore zones to stop entry by small craft
- disallow simultaneous LNG operations and ship movements at adjacent jetties
- have available local weather forecasts with suitable warning systems
- have pilots and tugs ready at short notice for emergency departure

Port planning should also ensure that advance procedures are available to control a ship's port entry. In this regard it is most important that each arrival is carefully agreed between the ship and terminal. In particular this should include up-to-the-minute information on berth availability, especially in times of bad-weather forecasts, when last minute changes in berth availability can be anticipated. To safeguard ships in transit from any last-minute change in status on berth availability a contingency plan should be available to include detail on suitable anchorages, lay-by areas or turning circles where the ship can wait or turn round to proceed back to the port entrance.

As a port moves into the operational phase critical revision of existing port procedures is recommended on a frequent basis. By this means, ship operators and terminal managers can be continually assured that cargo planning procedures remain valid, tugs numbers (and power) remain suitable and that matters of contingency planning remain up to date.

8 RISK MANAGEMENT IN THE PORT APPROACH

National authorities and LNG companies devote considerable resources to reduce any risk that an LNG terminal may present to the port environs. This is most apparent during design when special emphasis on the security of nearby population centres is obtained by applying Environmental Impact Assessments and application of references [6] and [8]. At this stage, the risks associated with an LNG carrier as it navigates through the port approach are also addressed and, to illustrate these matters, typical safety routines for the offshore areas are listed in the following paragraphs. Reference may also be made to publications from IAPH, PIANC, BSI and IALA on this subject and some of these standards are given in chapter 11.

8.1 PORT CONTROLS

Taken globally, the frequency of nautical accidents, such as strikings, collisions and groundings, to any class of ship are greater in port approaches and during berthing when compared to frequency rates at sea. For the whole class of gas carriers (LNG and LPG) such accidents account for over half the total reported and, when time factors are taken into account, this confirms that the opening statement also holds true in the gas trade. However, from historical records, it is good to report that serious incidents of this type are extremely rare for LNG carriers; indeed, only one such incident (a grounding) is known to have occurred at a receiving port, none at a loading port and none at all anywhere in the world since 1980.

This successful management of LNG ports can be explained only by the controls unique to the LNG business which have a significant risk reduction effect. At present these distinguishing features consist of:

- effective VTS (traffic management) and the use of escort craft
- adequate tug power to control LNG carriers, even in dead-ship conditions
- strict operating conditions
- regular ships in each trade, and
- high quality seagoing personnel

Some of these points are further explained below:

8.1.1 Vessel Traffic Systems (VTS)

Establishing safe conditions for the port transit of LNG carriers is always a matter of importance. This is usually a direct responsibility of the port authority. However, operational risk management on a day by day basis is a task shared between port authority, terminal owner and ship operator. In most cases there is agreement over the procedures required to assure low risk levels but, as a minimum, a good VTS system, as specified by the International Maritime Organization (Resolution A.578-14) for marine traffic management is recommended to prevent close encounters between LNG carriers and other ships.

Subordinate specifications concerning traffic management, such as the safe distances for other ships to pass LNG carriers, depend on the risks identified in particular situations. For example, in areas of high traffic density, the shore-based VTS may be supplemented by an escort craft (or guard boat) to attend the LNG carrier; in other situations, the VTS may suspend other traffic movements in the channel during the LNG carrier's approach. Whatever specific arrangements are made, they should aim to much limit collision risks caused by close encounters with other ships.

Other conditions for establishing safe operations in port are similar to those required for the harbour movements of any large ship, such as, adequate navigation marks and lights, limiting ship movements in poor visibility, and a high standard of pilotage service all of which contribute to minimising the risk of grounding.

The quality of pilotage service is particularly important. As part of terminal planning it is vital to secure not only consistent high quality in harbour pilotage operations but also to fix pilot boarding areas at a suitable distance offshore, beyond which the LNG carrier is not allowed to continue inwards without the pilot being on board. Many port authorities use navigational simulators for training their harbour pilots and, when used wisely, simulator courses can yield valuable results. Not least among the advantages of simulator training are the benefits which can be gained by learning how to build good bridge teamwork and an appreciation of Passage and Voyage Planning routines.

In another context, (see section 6.2) marine traffic management can also be important when the position of the jetty is taken into account. If large ships are allowed to pass close by, interactive effects can cause mooring line failure on the LNG carrier. Although such locations are not recommended, depending on the site chosen for the terminal, it may be necessary to limit the speed of passing ships and this may be achieved by VTS controls.

8.1.2 Tugs

Following the same weather which determines port design parameters, the operating limits for LNG carriers should also be specified in terms of wind speed and current drift. These parameters are then used to calculate the maximum wind forces acting on the largest LNG carrier using the port, and thence the number and power of the tugs needed for berthing manoeuvres is specified. There must always be sufficient tug assistance to control LNG carriers in the maximum permitted operating conditions and this should be specified assuming the ship's engines are not available. This method gives different results from one terminal to another. Accordingly, minimum tug power is not an absolute value. Nevertheless, it has been found that for LNG carriers of 135,000 m^3 capacity, acceptable standards are usually in the range of three or four tugs having a combined bollard pull between 120 to 140 tonnes. These tugs should be able to exert approximately half of this total power at each end of the ship. Given that four tugs are provided, in terms of tug propulsion, this suggests that each tug should have engines capable of a minimum of 3,000 horsepower, although this is dependant on propeller configuration.

8.1.3 Operating Conditions

When port design is being considered the aim should be to limit navigational risks involving LNG carriers within the port area. The extent of the system developed depends on factors such as:

- number and type of ships and other craft using the port
- port accident records
- navigational distances and difficulty through the port and jetty approach
- the maximum draft of the ships
- the nature of the sea-bed (rock, sand or mud)
- tidal conditions (tidal ranges and tidal currents)
- weather conditions (wind, waves, sea-ice and visibility)
- proximity of the terminal to populated areas and industrial sites

After studying such factors, port designers and port authorities can introduce LNG-related provisions appropriate to the local port. The operational procedures and equipments which follow from these considerations, and already adopted in many LNG ports, are summarised below.

8.1.4 Summary of LNG Port Procedures

Port procedural limits for weather

- establish weather limits for port closure
- draw up procedures to give advance weather warnings to ships
- restrict port manoeuvring of LNG carriers in strong winds
- restrict port manoeuvring of LNG carriers in reduced visibility
- establish safe anchorages at the port entrance and within the harbour

Port controls for approach channels

- provide suitable short range navigational aids for approach channels
- provide escape routes in cases where a ship is unable to berth
- establish port suitability for day and night transits
- set safe manoeuvring limits for, visibility, wind, current, and wave height
- relate channel widths to the beam of the largest ship
- relate turning circle diameters to the length of the largest ship
- set speed limits for channels to limit heavy groundings or penetrating collisions

Port controls for tugs and escort craft

- set safe weather limits for berthing
- provide tugs farther to seaward; beyond the normal 'assistance' area
- provide escort craft suited to the circumstances
- establish tug power as being sufficient to overcome maximum set wind conditions
- have pilots and tugs available at short notice for emergency departures

Procedures and systems regarding traffic control

- establish a VTS control to coordinate the movement of all craft within the port
- limit other traffic movements in the port while LNG carriers are in transit
- set a moving safety zone in approach channels ahead and astern of LNG carriers
- adopt Traffic Separation Schemes (TSS) in appropriate approach channels

In addition to these points other operational factors should be addressed. These can include instructing ships to carry appropriate charts and nautical publications and to implement Voyage Planning routines. Port authorities should also ensure that harbour pilots use the practice of Voyage Planning. However, being more in the realms of ship operation, these issues fall beyond the scope of this paper.

Study of the foregoing lists shows that only rarely are the criteria absolute, or conditions unchanging. Obviously water depth is critical, as are severe weather conditions, but in many other cases either the procedures, or the conditions they are set to control, have flexible application. Indeed, it is suggested in reference [14] that the principal value of listing the criteria is to identify the hazards with a view to setting operational procedures to control them. Similar reasoning is evident in reference [1], and its check list of risk reduction options is used as a basis for the Appendix to this paper. Hence, within many existing navigational controls, it is usual, as a consequence of human factors, for a low level of residual risk to remain. Under present industry guidelines, this is true even after the optimisation process for site selection is complete. Thus, in some existing ports this risk remains to be controlled on a day by day basis.

Of course, for new terminals, present day standards involving Environmental Impact Assessments, and similar procedures, should be even more effective in securing a low risk operation. However, within these systems, expert marine advice is necessary to ensure that, when a large gas release is considered, limited only by human elements, the consequences are controlled by other methods such as those discussed in chapters 9 and 10.

9 THE HUMAN ELEMENT

Accident reports show that effective risk management, whether in port or at sea, is often frustrated by an inability to completely obviate human error or uncharacteristic human behaviour. Indeed, the large majority of shipping casualties continue to occur as a result of the human element. But the relationship between operator error and risk assessment remains obscure; this is because human responses are difficult to predict and the process of human reaction is not fully understood.

For these reasons, risk management systems usually take the possibility of human error into account, attempting to control it by other means. Such methods can include alarms, ESD systems, engineered fail-to-safe equipment, equipment redundancy (back-up), and procedures. As appropriate, these devices include multiple cross-checking features. The positive contribution of all these measures to risk reduction is clear. However, casualty data shows (see sections 8.1 and 10.1), that even for LNG carriers, current techniques involving human controls are less than one-hundred per cent effective. Thus, when limiting the chance of a significant accident — to match a very low risk exposure — the range of industry standards covered in chapter 8 are found to be less than foolproof.

This paper suggests, therefore, that it is necessary in the port approach, to adopt a method of risk management which, as far as possible, discounts the contribution of human judgement. In particular, this chapter not only addresses the need to consider accidents where human judgement has proved helpful in limiting the consequences but also to consider the increased risk in some areas when human controls have failed — perhaps thus endangering the ship's cargo tank containment system.

Drawing on the discussion in chapter 10, the ship's speed which may damage the cargo containment system can be estimated. By this means, for parts of the port approach, speed controls can be established to limit the consequences of collisions, strikings and groundings. In the case of a ship grounding it is possible to assess whether the potential damage might cause cargo containment system rupture. This can be done by:

- reference to the quality of the sea-bed
- assessing the possible courses of the grounding ship
- estimating the ship's speed at the time, and
- applying the criteria given in references [17] and [18]

A similar list of criteria can be developed for collisions but the first item, as listed above, would be omitted and another added; vis, the angle of strike. In addition, references [19] to [26] should be studied.

This paper suggests, therefore, that each port should be investigated for the presence of the dangers which could cause critical impacts during the harbour transit of an LNG carrier and recommends that port designers, when assessing individual hazards, take the possibility of human error into account. This should be done to ensure a satisfactory safety margin is provided — that is, in the event of accident, an assurance ruling out cargo containment system rupture. It can be seen therefore that, when using this method, the following listing of existing safeguards are assumed to fail:

- operational procedures
- back up system warnings, and
- human controls

Evidently (see chapter 10) such high risk events are extremely rare in LNG shipping. Nevertheless, only after the above investigation has been completed can appropriate assurance be secured which protects a ship's cargo containment system against rupture. Because of the unquantifiable nature of the human element, this paper suggests that only by removal of all possibilities for containment system penetration can the correct level of port security be obtained.

10 GROUNDING AND COLLISION RISK

With respect to ship navigation, any hazard which may result in a large release of LNG can be identified by assessment of the energy necessary to penetrate the ship's inner and outer hulls. The double-hull arrangement provides LNG carriers' containment systems with protection to all but high impact. This means that, as part of port design there is every prospect for preventing a large gas release without introducing unrealistic port restrictions. However, and following from chapter 9, it should be seen that an important element to avoid, where possible, is any procedure over-dependant on human controls.

In this chapter, therefore, consideration is given to LNG carrier groundings and collisions with a view (through ship operation and port design) to reduce the risk of major gas releases. Clearly, once a terminal is in operation, knowledge that such accidents are virtually impossible, provides valuable input for future operations.

10.1 HULL DAMAGE - A HISTORICAL REVIEW

Analysis of SIGTTO and other casualty records give a reliable picture of the accident profile of the LNG shipping industry in the period between 1982 and 1996. However, because some categories of minor incident were considered unreportable, it is probable that the data is incomplete. Nevertheless, it is virtually certain that the data includes every incident, such as grounding and collision, having potential for damaging a ship's cargo containment system.

The data-base shows that the cargo handling and port-related accidents recorded in this period, and with the ships fully operational, numbered only ten. Of these:

- one occurred whilst manoeuvring in a port (propeller struck channel buoy)
- five involved ships breaking out from the jetty with the hard arms connected
- three involved mechanical failure, and
- one records a fire on the engine room switchboard

In none of these cases was the LNG carrier's cargo containment system put at risk.

For the period between 1962 and 1982 the data is less comprehensive, but still it is extremely unlikely that any significant incident, threatening an LNG carrier's cargo containment system, would have gone unreported. In this period there are only six accidents which might be categorised as posing a hazard to the ship's cargo containment system. Within this time frame there are five reported collisions and five reported groundings. One of the collisions involved an LNG carrier being struck whilst berthed, the others were outside port and none resulted in serious damage to the cargo containment system. Of the groundings only two (one in port and the other at sea) involved serious structural damage to the ship's bottom and in neither case was the cargo tank containment system penetrated.

The two serious grounding incidents demonstrate the capacity of LNG carriers to sustain bottom damage without experiencing rupture of the containment system.

Records show that there are no comparable data that would similarly demonstrate the resistance of an LNG carrier's side structures to collisions. Nevertheless, there are tools available for predicting such resistance, giving results which, when used with care, are able to establish the minimum energy required to put a cargo containment system at risk — see section 10.2.2.

So, although it has never happened over some three decades of LNG carriage, an important risk to be considered in port analysis is the possible release of cargo during groundings or collisions. Though open to interpretation, good estimates are available for the energy required to penetrate an LNG carrier's double hull so putting the ship's internal cargo tank containment system at risk. It is therefore possible to identify accident scenarios with potential for such damage and plan to remove them from port areas. Accordingly, when designing a port, the aim should be to limit the probability of high energy impacts on LNG carriers, such that damage to a ship's hull is minimised.

10.2 RISK OF STRUCTURAL DAMAGE TO LNG CARRIERS

10.2.1 General

The structure of LNG carriers, incorporating double bottom tanks and double sides, gives high resistance to the impact of grounding and collision. This is supported over many years of research (see references [17] to [26]), some of which is described in the following sections.

10.2.2 Collision Damage

One method [19], in which collision energy is assumed to be absorbed by the structures of both ships was, for many years, the accepted way for assessing collision resistance. Predictions using this method relied upon empirical resistance factors, mostly derived using data from actual impacts. More recent methods (see chapter 11), which include a better understanding of failure and collapse mechanisms, have led to more accurate predictions and these methods seem to be especially effective for low energy collisions; although the method first mentioned still gives acceptable results in high energy situations.

The results of such analyses are dependant on the impact angle (of the striking ship), the bow shape of the striking ship and the structure of the struck ship. Therefore conservative interpretations must be placed on such analyses, particularly if the results are intended to support the conclusions of a wider risk assessment.

Significant studies on the question of collision damage are included in the references. Based upon published methods, the following table lists examples of the resistance of a stationary 135,000 m^3 LNG carrier, expressed against the critical impact speed required to hole the outer hull but not to rupture the cargo tank containment system.

Hull Resistance for a 135,000 m^3 LNG Carrier	
Displacement of Colliding Ship (tonnes)	Critical Impact Speed (knots)
93,000	3.2
61,000	4.2
20,000	7.3

For the reasons indicated above, the results shown in the table are considered to be realistic and provide conservative estimates — so allowing a satisfactory margin for error.

10.2.3 Grounding Damage

Typical publications covering grounding damage are listed in the references — in some cases a reference may dwell on oil tanker topics, however, with respect to the double bottom depths, as present day oil tanker design is similar to that in LNG carriers, the references remain helpful. Indeed the references suggest that the similar structure in LNG carriers gives the same level of protection from low energy grounding and similar assurance in a significant proportion of high energy incidents.

Accurate prediction of damage in grounding incidents is difficult. But, given a smooth sea-bed of sand or mud, impact energy is usually spread over a large area of the ship's bottom and, with this cushioning effect, upward penetration is minimised. Rock bottoms cause more jagged penetrations with the impact being absorbed over a much smaller area.

10.2.4 Hazardous Penetration

As can be seen from the foregoing overview, analytical tools are available which can, with reasonable accuracy, predict damage to ship's hulls in collision and grounding situations. This means it is possible to set criteria for accident severity (in terms of ship's speed) below which rupture of the cargo containment system is virtually impossible.

It therefore becomes feasible to consider ways to analyse port approach channels so that any risk of cargo containment rupture can be removed and the remote possibility of an uncontrolled release of LNG reduced to non-credible proportions.

Hence, by removing individual risks in each port such as:

- rock outcrops or reefs
- underwater obstructions, and
- close encounters with other ships

from the main shipping channels and their immediate environs, port risks can be reduced to a level where a large release of LNG becomes too remote to imagine.

10.3 EXAMPLES

In this section practical application of the recommendations given in sections 10.1 and 10.2 is illustrated by simplified examples for a hypothetical port. The port in question is shown in Figure 3.

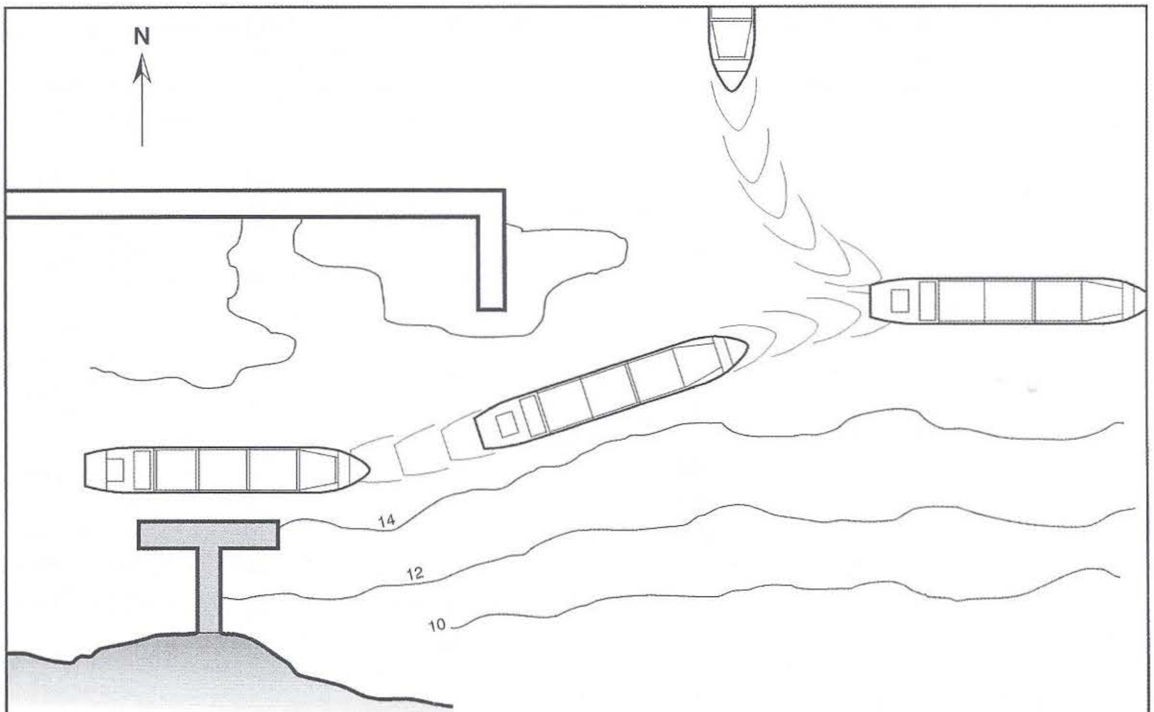

Figure 3: The port geography addressed in the examples

10.3.1 Striking a Fixed Structure - Example 1

Harbour entry is carried out in accordance with the manoeuvre illustrated in Figure 3. This involves moving stern-first through the port entrance under the control of tugs.

The following conditions are assumed to apply:

- Tug numbers, tug power, and operating conditions are specified for the port such that the LNG carrier is fully controlled by tugs alone, even in case of ship engine failure.
- Penetration of the ship's outer hull, through striking the corner of the harbour wall, is calculated to require a side-on speed of 5 knots. Furthermore, the calculations show that this damage will not extend to the cargo tank containment system. (For this scenario, the worst case condition occurs with impact on the ship's parallel body and with the transverse velocity at 90° to the point of impact).
- Misjudgment by those controlling the manoeuvre is assumed.
- At a point on the ship's track (from which impact on the corner of the harbour wall is possible) simultaneous failure of the ship's engines, and sufficient of the tugs for loss of control, is assumed. This is assessed as being possible once in 5 million operations.
- The most likely part of the ship to strike the wall is the ship's stern structure. Collision damage in this area cannot put the cargo containment system immediately at risk.

- The critical speed of 5 knots for a side-on striking cannot be achieved from any point in the manoeuvre since the ship's maximum drift speed in open sea conditions, in wind speeds of 30 knots, is calculated as just 4 knots. This wind produces conditions in which tugs cannot operate; and therefore, under such conditions, the port would be closed. In any case the wind does not contribute sufficient extra speed, to that already given by the tugs, for a 5 knot side-on speed to be achieved from the stern-first manoeuvre.

Solution

With the effects of harbour wall fendering discounted and the resistance of the cargo tank containment system ignored, the probabilities of sustaining cargo tank containment system penetration through striking the harbour wall are assessed as non-credible.

10.3.2 Grounding - Example 2

Assuming human error has occurred, the arriving LNG carrier overshoots the initial port-hand turn of the entry manoeuvre with excessive speed and, through technical failure or misjudgment, the tugs fail to stop the ship. As a result the carrier enters shallow water to the east of the jetty and grounds.

- It is assumed that the ship's last course before grounding can result in angles of impact from head-on (bow-on) to beam-on (side-on).
- Head-on grounding is assumed to have a higher speed than from other directions since any other angle of impact implies a change of course — hence speed loss.
- The sea-bed is free of obstructions and smooth, hence point penetrations are not possible. The slope of the sea-bed is two metres in every 100 metres over the ground.
- The maximum possible head-on grounding speed is assessed at 12 knots. Higher speeds are considered impossible because of shallow water effects, which slow the ship, and because the ship should have put its engines into manoeuvring mode (slower than full sea speed) well in advance. For this reason, grounding speeds for all other angles of impact must be less than 12 knots.
- Impact energy for a head-on grounding is mostly absorbed by structural damage forward of the cargo containment area, and the ship's forward speed is reduced to less than 6 knots (half the initial speed) before the ship's bottom under the cargo tanks takes the ground. The residual impact energy is then spread broadly through the bottom structure as the ship runs over a 2:100 gradient and this is calculated to be insufficient (with a smooth sea-bed) to achieve penetration of the cargo containment system.
- Groundings with the LNG carrier at any other angle to the shore, other than head-on, involve progressive combinations of speed reduction and structural deformation of the ship's bottom forward of the cargo tanks - until, with the beam-on grounding, the impact is taken wholly on the ship's side, but with a speed less than 6 knots.

Solution

Actual grounding incidents and theoretical calculations together suggest that rupture of the cargo containment system is non-credible in any of the cases.

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APPENDIX

LNG PORTS - RISK REDUCTION OPTIONS

General Requirements for LNG Carriers (Where figures are given they refer to LNG carriers of 135,000 m^3 capacity)	
1	**The Port**
1.1	**Port Analysis**
	Speed restrictions for LNG carriers should be appropriate to limit grounding and collision damage.
1.2	**Approach Channels and Turning Basins**
	Navigable depths (for most LNG carriers) should generally not be less than 13 metres below the level of chart datum.
	Under-keel clearances should be established in accordance with the sea-bed quality.
	Channel width should be about five times the beam of the ship (approximately 250 metres).
	Turning areas should have a minimum diameter of two to three times the ship's length (approximately 600 to 900 metres).
	Short approach channels are preferable to long inshore routes which carry more numerous hazards
	Traffic separation schemes should be established in approach routes covering many miles.
	Anchorages should be established at the port entrance and inshore, for the safe segregation of LNG carriers and to provided lay-by facilities in case, at the last moment, the berth proves unavailable.
1.3	**Navigational Aids**
	Buoys to mark the width of navigable channels should be placed at suitable intervals.
	Leading marks or lit beacons, to mark channel centrelines and to facilitate rounding channel bends, should be appropriately placed.
	Electronic navigational aids, to support navigation under adverse weather conditions, are needed in most ports.
	Lit navigational aids should be provided to allow ship movements at night.
1.4	**Port Services**
	Tugs should be made available and three to four are normally required giving 140 tonnes total bollard pull. (Tugs may be required to meet LNG carriers farther offshore).
	Mooring services are often required and these services should normally provide a minimum of two boats, each having at least 400 horsepower.
	Escort services comprising fast patrol craft, to clear approach channels, turning areas, jetty, etc. should be provided in busy port areas.
	Firefighting services comprising specially equipped craft, or, one or more suitably equipped tugs should be provided.

1.5	**Port Procedures**
	Traffic control or VTS systems should be strictly enforced to ensure safe harbour manoeuvring between the pilot boarding area and the jetty.
	Speed limits should be introduced in appropriate parts of the port approach, not only for the LNG carrier but also for other ships.
	Pilotage services should be required to provide pilots of high quality and experience. Pilot boarding areas should be at a suitable distance offshore.
	Ship movements by nearby ships, when the LNG carrier is pumping cargo, should be disallowed.
	Pilots and tugs should be immediately available in case the LNG carrier has to leave the jetty in an emergency.
1.6	**Port Operating Limits**
	Environmental limits for wind, waves, and visibility should be set for ship manoeuvres and these should ensure adequate safe margins are available under all operating conditions.
	Weather limits for port closure should be established.
1.7	**Weather Warnings**
	Forecasting for long range purposes should be provided to give warning of severe storms, such as typhoons and cyclones.
	Forecasting for short range purposes, such as those required for local storms and squalls, should be made available.
2	**The Jetty**
2.1	**Jetty Location**
	Jetty location should be remote from populated areas and should also be well removed from other marine traffic and any port activity which may cause a hazard.
	The maximum credible spill and its estimated gas-cloud range should be carefully established for the jetty area.
	River bends and narrow channels should not be considered as appropriate positions for LNG carrier jetties.
	Breakwaters should be constructed for jetty areas exposed to sea action, such as excessive waves and currents.
	Restrictions, such as low bridges, should not feature in the jetty approach.
	Ignition sources should be excluded within a predetermined radius from the jetty manifold.
2.2	**Jetty Layout**
	Mooring dolphin spacing - between the outermost dolphins - should not be less than the ship's length (approximately 290 metres).
	Mooring dolphins should be situated about 50 metres inshore from the berthing face.
	Mooring points should be suitably positioned, and have suitable strength, for the environmental conditions.
	Quick-release hooks should be provided at all mooring points.

	Breasting dolphin spacing should be designed to ensure that the parallel body of the ship is properly supported.
	Fendering for the dolphins, and for the berth face, should be to a suitable standard.
2.3	**Jetty Equipment**
	Pipelines and pumps etc should be designed to provide a rapid port turn-round.
	Emergency Release Systems at the hard arms should be fitted in accordance with industry specifications. The ERS should be suited to both ship and shore by interlinking and a PERC should be fitted to each hard arm for emergency stoppage and quick release purposes.
	Emergency shut-down valves should be fitted to both ship and shore pipelines and should form part of the ERS system.
	Powered emergency release couplings (PERCs) with flanking quick-acting valves should be fitted to the hard arm as part of the ERS system.
	Plugs both on ship and shore to carry all ESD and communication signals should be standardised.
	Surge pressure control should be provided in LNG pipelines.
	Communications equipment (telephone, hot-line and radios) should be provided for ship/shore use.
	Load monitors, to show the mooring force in each mooring line, should be fitted to quick release hooks.
	Gangways should be provided to give safe emergency access to or from the ship.
2.4	**Basic Firefighting Facilities**
	Water curtain pumps and pipelines should be provided.
	Fixed Dry Powder systems should be provided.
	Gas detection monitors should be fitted at strategic locations.
	Fireproof material should be used for the construction of hard arms (no aluminium).
2.5	**Jetty Procedures**
	On shore jetty safety zones should be effectively policed while the ship is alongside thus providing control over visitors and vehicles.
	Offshore safety zones should be effectively policed by a guard boat to limit the approach of small craft.
	Passing ships, close to the jetty, should have their speed controlled by the harbour VTS system.
	Communications procedures should be well established and tested.
	Contingency plans should be available in written form.
	Operating procedures should be available in written form.
	A Port Information/Regulation Booklet should be provided for passing operational advice to the ship.

Exhibit 71

United States Government Accountability Office

GAO

Report to Congressional Requesters

February 2007

MARITIME SECURITY

Public Safety Consequences of a Terrorist Attack on a Tanker Carrying Liquefied Natural Gas Need Clarification

GAO-07-316

GAO
Accountability·Integrity·Reliability
Highlights

Highlights of GAO-07-316, a report to congressional requesters

February 2007

MARITIME SECURITY

Public Safety Consequences of a Terrorist Attack on a Tanker Carrying Liquefied Natural Gas Need Clarification

Why GAO Did This Study

The United States imports natural gas by pipeline from Canada and by tanker as liquefied natural gas (LNG) from overseas. LNG—a supercooled form of natural gas—currently accounts for about 3 percent of total U.S. natural gas supply, with an expected increase to about 17 percent by 2030, according to the Department of Energy (DOE). With this projected increase, many more LNG import terminals have been proposed. However, concerns have been raised about whether LNG tankers could become terrorist targets, causing the LNG cargo to spill and catch on fire, and potentially explode. DOE has recently funded a study to consider these effects; completion is expected in 2008.

GAO was asked to (1) describe the results of recent studies on the consequences of an LNG spill and (2) identify the areas of agreement and disagreement among experts concerning the consequences of a terrorist attack on an LNG tanker. To address these objectives, GAO, among other things, convened an expert panel to discuss the consequences of an attack on an LNG tanker.

What GAO Recommends

GAO recommends that the Secretary of Energy ensure that DOE incorporates into its LNG study the key issues identified by the expert panel.

In reviewing our draft report, DOE agreed with our recommendation.

www.gao.gov/cgi-bin/getrpt?GAO-07-316.

To view the full product, including the scope and methodology, click on the link above. For more information, contact Jim Wells at (202) 512-3841 or wellsj@gao.gov.

What GAO Found

The six unclassified completed studies GAO reviewed examined the effect of a fire resulting from an LNG spill but produced varying results; some studies also examined other potential hazards of a large LNG spill. The studies' conclusions about the distance at which 30 seconds of exposure to the heat (heat hazard) could burn people ranged from less than 1/3 of a mile to about 1-1/4 miles. Sandia National Laboratories (Sandia) conducted one of the studies and concluded, based on its analysis of multiple attack scenarios, that a good estimate of the heat hazard distance would be about 1 mile. Federal agencies use this conclusion to assess proposals for new LNG import terminals. The variations among the studies occurred because researchers had to make modeling assumptions since there are no data for large LNG spills, either from accidental spills or spill experiments. These assumptions involved the size of the hole in the tanker; the volume of the LNG spilled; and environmental conditions, such as wind and waves. The three studies that considered LNG explosions concluded explosions were unlikely unless the LNG vapors were in a confined space. Only the Sandia study examined the potential for sequential failure of LNG cargo tanks (cascading failure) and concluded that up to three of the ship's five tanks could be involved in such an event and that this number of tanks would increase the duration of the LNG fire.

GAO's expert panel generally agreed on the public safety impact of an LNG spill, but believed further study was needed to clarify the extent of these effects, and suggested priorities for this additional research. Experts agreed that the most likely public safety impact of an LNG spill is the heat hazard of a fire and that explosions are not likely to occur in the wake of an LNG spill. However, experts disagreed on the specific heat hazard and cascading failure conclusions reached by the Sandia study. DOE's recently funded study involving large-scale LNG fire experiments addresses some, but not all, of the research priorities identified by the expert panel. The leading unaddressed priority the panel cited was the potential for cascading failure of LNG tanks.

LNG Tanker Passing Downtown Boston on Its Way to Port

Source: GAO.

Contents

Abbreviations

BLEVE	boiling liquid expanding vapor explosion
DOE	Department of Energy
DOT	Department of Transportation
FERC	Federal Energy Regulatory Commission
kW/m^2	kilowatts per square meter
LNG	liquefied natural gas
LPG	liquefied petroleum gas
m^2	square meters
m^3	cubic meters
m/s	meters per second
RPT	rapid phase transition
WSA	Waterway Suitability Assessment

GAO
Accountability * Integrity * Reliability

United States Government Accountability Office
Washington, DC 20548

February 22, 2007

The Honorable John D. Dingell
Chairman
The Honorable Joe Barton
Ranking Member
Committee on Energy and Commerce
House of Representatives

The Honorable Bennie G. Thompson
Chairman
The Honorable Peter King
Ranking Member
Committee on Homeland Security
House of Representatives

The Honorable Edward J. Markey
House of Representatives

Worldwide, over 40,000 tanker cargos of liquefied natural gas (LNG) have been shipped since 1959, and imports of LNG are projected to increase over the next 10 years. LNG is a supercooled liquid form of natural gas—a crucial source of energy for the United States. Natural gas is used in homes for cooking and heating and as fuel for generating electricity, and it accounts for about one-fourth of all energy consumed in the United States each year. Prices for natural gas in the United States have risen over the past 5 years as demand for natural gas has increased faster than domestic production. To make up for the domestic shortfall, the United States imports some natural gas in pipelines from Canada. However, most reserves of natural gas are overseas and cannot be transported through pipelines. Natural gas from these reserves has to be transported to the United States as LNG in tankers. Because of the projected increase in LNG tankers arriving at U.S. ports, concerns have been raised about whether the tankers could become terrorist targets.

LNG—primarily composed of methane—is odorless and nontoxic. It is produced by supercooling natural gas to minus 260 degrees Fahrenheit at atmospheric pressure, thus reducing its volume by more than 600 times. This process makes transport by tankers feasible. The tankers are double-hulled, with each tanker containing between four and six adjacent tanks heavily insulated to maintain the LNG's supercool temperature. Generally, these ships can carry enough LNG to supply the daily energy needs of over 10 million homes. Importing LNG requires specialized facilities—called regasification terminals—at ports of entry. At these terminals, the liquid is reconverted into natural gas and then injected into the pipeline system for consumers. Currently, the United States has a total of five LNG import terminals—four are considered onshore terminals, that is, they are located within 3 miles of the shore; one is an offshore terminal located 116 miles off the Louisiana coast in the Gulf of Mexico.[1]

The United States imports about 3 percent of its total natural gas supply as LNG in recent years, but by 2030, LNG imports are projected to account for about 17 percent of the U.S. natural gas supply, according to the Department of Energy's (DOE) Energy Information Administration. To meet this increased demand, energy companies have submitted 32 applications to build new terminals for importing LNG in 10 states and five offshore areas. Figure 1 shows the locations of LNG terminals that are operational, approved, and proposed.

[1]The onshore facilities are near Boston, Massachusetts; Cove Point, Maryland; Savannah, Georgia; and Lake Charles, Louisiana. The United States also has one LNG export facility in Kenai, Alaska, that ships LNG to Japan.

Figure 1: Existing, Approved, and Proposed LNG Terminals in the United States, as of October 2006

Sources: FERC and GAO.

As of October 2006, the Federal Energy Regulatory Commission (FERC)[2]—responsible for approving onshore LNG terminal siting applications—and the U.S. Coast Guard[3]—responsible for approving offshore LNG terminal siting applications—had together approved 13 of these applications. In addition, the Coast Guard contributes to FERC's review of onshore LNG facilities by reviewing and validating an applicant's Waterway Suitability Assessment (WSA) and reaching a preliminary conclusion as to whether the waterway is suitable for LNG operations with regard to navigational safety and security considerations. The WSA includes a security risk assessment to evaluate the public safety risk of an LNG spill from a tanker following an attack. The security risk assessment analyzes potential types of attacks, their probability, and the potential consequences. The WSA also identifies appropriate strategies that can be used to reduce the risk posed by a terrorist attack on an LNG tanker, either by reducing the probability of an attack, or by reducing its consequences. If the WSA deems the waterway suitable for LNG tanker traffic, the Coast Guard provides FERC with a "Letter of Recommendation," which describes the overall risk reduction strategies that will be used on LNG tankers traveling to the proposed terminal. The Coast Guard is the lead federal agency for ensuring the security of active LNG import terminals and tankers traveling within U.S. ports.

As figure 1 shows, six new facilities have been proposed for the northeastern United States, a region that faces gas supply challenges. The Northeast has limited indigenous supplies of natural gas, and receives most of its natural gas either through pipelines from the U.S. Gulf Coast or Canada, or from overseas via tanker as LNG. The pipelines into the Northeast currently run at or near capacity for much of the winter, and demand is projected to significantly increase over the next 5 years, exceeding available supply by 2010. To meet the increasing demand, new supplies of natural gas must reach the Northeast by expanding existing pipeline capacity, constructing new pipelines, or constructing new LNG terminals—all of which have risk associated with them. Difficulties siting LNG facilities in the Northeast could lead to higher natural gas prices

[2]Under the Natural Gas Act, as amended, FERC has exclusive authority to approve or deny an application for the siting, construction, or operation of onshore LNG terminals, including pipelines, and offshore facilities in state waters—that is, generally within 3 miles of shore.

[3]The Coast Guard, along with the Department of Transportation's Maritime Administration, has jurisdiction under the Deep Water Port Act of 1974, as amended, to approve the siting and operation of offshore LNG facilities in federal waters.

unless additional supply can be brought into the region via new, or expansion of old, pipelines.

Scientists and the public have raised concerns about the potential hazards that an LNG spill could pose. When LNG is spilled from a tanker, it forms a pool of liquid on the water. Individuals who come into contact with LNG could experience freeze burns. As the liquid warms and changes into natural gas, it forms a visible, foglike vapor cloud close to the water. The cloud mixes with ambient air as it continues to warm up and eventually the natural gas disperses into the atmosphere. Under certain atmospheric conditions, however, this cloud could drift into populated areas before completely dispersing. Because an LNG vapor cloud displaces the oxygen in the air, it could potentially asphyxiate people who come into contact with it. Furthermore, like all natural gas, LNG vapors can be flammable, depending on conditions.[4] If the LNG vapor cloud ignites, the resulting fire will burn back through the vapor cloud toward the initial spill. It will continue to burn above the LNG that has pooled on the surface—this is known as a pool fire. Experiments to date have shown that LNG fires burn hotter than oil fires of the same size. Both the cold temperatures of spilled LNG and the high temperatures of an LNG fire have the potential to significantly damage the tanker, causing multiple tanks on the ship to fail in sequence—called a cascading failure. Such a failure could increase the severity of the incident. Finally, concerns have been raised about whether an explosion could result from an LNG spill.

Although LNG tankers have carried over 40,000 shipments worldwide since 1959, there have been no LNG spills resulting from a cargo tank rupture. Some safety incidents, such as groundings or collisions, have resulted in small LNG spills that did not affect public safety. In the 1970s and 1980s, experiments to determine the consequences of a spill examined small LNG spills of up to 35 meters in diameter. Following the terrorist attacks of September 11, 2001, however, many experts recognized that an attack on an LNG tanker could result in a large spill—a volume of LNG up to 100 times greater than studied in past experiments. Since then, a number of studies have reevaluated safety hazards of LNG tankers in light of a potential terrorist threat. Because a major LNG spill has never occurred, studies examining LNG hazards rely on computer models to

[4]LNG vapors only ignite when they are in a 5 percent to 15 percent concentration in the air. If the LNG concentration is higher, there is not enough oxygen available for fire. If the concentration is lower, there is likewise not enough fuel for fire.

predict the effects of hypothetical accidents, often focusing on the properties of LNG vapor fires. The Coast Guard uses one of these studies, conducted in 2004 by Sandia National Laboratories,[5] as a basis for conducting the security risk assessment required in the WSA for proposed onshore LNG facilities.[6] Access to accurate information about the consequences of LNG spills is crucial for developing accurate risk assessments for LNG siting decisions. While an underestimation of the consequences could expose the public to additional risk in the event of an LNG spill, an overestimation of consequences could result in the use of inappropriate and costly risk mitigation strategies. DOE recently funded a new study—to be completed by Sandia National Laboratories in 2008—that will conduct small- and large-scale LNG fire experiments to refine and validate existing models (such as the one used by Sandia National Laboratories in their 2004 study) that calculate the heat hazards of large LNG fires.

In this context, you asked us to (1) describe the results of recent unclassified studies on the consequences of an LNG spill and (2) identify the areas of agreement and disagreement among experts concerning the consequences of a terrorist attack on an LNG tanker.

To address the first objective, we identified eight unclassified, completed studies of LNG hazards and reviewed the six studies that included new, original research (either experimental or modeling) and clearly described the methodology used. While we have not verified the scientific modeling or results of these studies, the methods used seem appropriate for the work conducted. We also interviewed agencies responsible for LNG regulations and visited all four onshore LNG import facilities and one export facility. To address the second objective, we identified 19 recognized experts in LNG hazard analysis and convened a Web-based expert panel to obtain their views on LNG hazards and to get agreement on as many issues as possible. In selecting experts for the panel, we sought individuals who are widely recognized as having experience with one or more key aspects of LNG hazard analysis. We sought to achieve balance in representation from government, academia, consulting,

[5] Sandia National Laboratories. *Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water*. Albuquerque: 2004.

[6] DOE is also sponsoring additional research that applies the 2004 Sandia National Laboratories' methodology to LNG tankers larger than those previously studied, which is expected to be completed in July 2007.

research organizations, and industry. Additionally, we ensured that our expert panel included at least one author from each of the six unclassified studies of LNG hazards. Because some of the studies conducted are classified, this public version of our findings supplements a more comprehensive classified report produced under separate cover. A more detailed description of our scope and methodology is presented in appendix I. We conducted our work from January 2006 through January 2007 in accordance with generally accepted government auditing standards.

Results in Brief

The six unclassified studies we reviewed all examined the heat impact of an LNG pool fire but produced varying results; some studies also examined other potential hazards of a large LNG spill and reached consistent conclusions on explosions. Specifically, the studies' conclusions about the distance at which 30 seconds of exposure to the heat could burn people ranged from about 500 meters (less than 1/3 of a mile) to more than 2,000 meters (about 1-1/4 miles). The Sandia National Laboratories' study concluded that the most likely distance for a burn is about 1,600 meters (1 mile). These variations occurred because researchers had to make numerous modeling assumptions to scale-up the existing experimental data for large LNG spills since there are no large spill data from actual events. These assumptions involved the size of the hole in the tanker, the number of tanks that fail, the volume of LNG spilled, key LNG fire properties, and environmental conditions, such as wind and waves. Three of the studies also examined other potential hazards of an LNG spill, including LNG vapor explosions, asphyxiation, and cascading failure. All three studies considered LNG vapor explosions unlikely unless the LNG vapors were in a confined space. Only the Sandia National Laboratories' study examined asphyxiation, and it concluded that asphyxiation did not pose a hazard to the general public. Finally, only the Sandia National Laboratories' study examined the potential for cascading failure of LNG tanks and concluded that only three of the five tanks would be involved in such an event and that this number of tanks would increase the duration of the LNG fire.

Our panel of 19 experts generally agreed on the public safety impact of an LNG spill, disagreed with a few conclusions reached by the Sandia National Laboratories' study, and suggested priorities for research to clarify the impact of heat and cascading tank failures. Experts agreed that (1) the most likely public safety impact of an LNG spill is the heat impact of a fire; (2) explosions are not likely to occur in the wake of an LNG spill, unless the LNG vapors are in confined spaces; and (3) some hazards, such as freeze burns and asphyxiation, do not pose a hazard to the public. Experts disagreed with the heat impact and cascading tank failure conclusions reached by the Sandia National Laboratories' study, which the Coast Guard uses to prepare WSAs. Specifically, all experts did not agree with the heat impact distance of 1,600 meters. Seven of 15 experts thought Sandia's distance was "about right," and the remaining eight experts were evenly split as to whether the distance was "too conservative" or "not conservative enough" (the other 4 experts did not answer this question). Experts also did not agree with the Sandia National Laboratories' conclusion that only three of the five LNG tanks on a tanker would be involved in a cascading failure. Finally, experts suggested priorities to guide future research aimed at clarifying uncertainties about heat impact distances and cascading failure, including large-scale fire experiments, large-scale LNG spill experiments on water, the potential for cascading failure of multiple LNG tanks, and improved modeling techniques. DOE's recently funded study involving large-scale LNG fire experiments addresses some, but not all, of the research priorities identified by the expert panel.

We are recommending that DOE incorporate into its current LNG study the key issues identified by the expert panel. We particularly recommend that DOE examine the potential for cascading failure of LNG tanks.

Background

Natural gas is primarily composed of methane, with small percentages of other hydrocarbons, including propane and butane. When natural gas is cooled to minus 260 degrees Fahrenheit at atmospheric pressure, the gas becomes a liquid, known as LNG, and it occupies only about 1/600th of the volume of its gaseous state. Since LNG is maintained in an extremely cooled state—reducing its volume—there is no need to store it under pressure. This liquefaction process allows natural gas to be transported by trucks or tanker vessels. LNG is not explosive or flammable in its liquid state. When LNG is warmed, either at a regasification terminal or from exposure to air as a result of a spill, it becomes a gas. As this gas mixes with the surrounding air, a visible, low-lying vapor cloud results. This vapor cloud can be ignited and burned only within a minimum and maximum concentration of air and vapor (percentage by volume). For methane, the dominant component of this vapor cloud, this flammability range is between 5 percent and 15 percent by volume. When fuel concentrations exceed the cloud's upper flammability limit, the cloud cannot burn because too little oxygen is present. When fuel concentrations are below the lower flammability limit, the cloud cannot burn because too little methane is present. As the cloud vapors continue to warm, above minus 160 degrees Fahrenheit, they become lighter than air and will rise and disperse rather than collect near the ground.

If the cloud vapors ignite, the resulting fire will burn back through the vapor cloud toward the initial spill and will continue to burn above the LNG that has pooled on the surface. This fire burns at an extremely high temperature—hotter than oil fires of the same size. LNG fires burn hotter because the flame burns very cleanly and with little smoke. In oil fires, the smoke emitted by the fire absorbs some of the heat from the fire and reduces the amount of heat emitted. Scientists measure the amount of heat given off by a fire by looking at the amount of heat energy emitted per unit area as a function of time. This is called the surface emissive power of a fire and is measured in kilowatts per square meter (kW/m^2). Generally, the heat given off by an LNG fire is reported to be more than 200 kW/m^2. By comparison, the surface emissive power of a very smoky oil fire can be as little as 20 kW/m^2. The heat from fire can be felt far away from the fire itself. Scientists use heat flux—also measured in kW/m^2—to quantify the amount of heat felt at a distance from a fire. For instance, a heat flux of 5 kW/m^2 can cause second degree burns after about 30 seconds of exposure to bare skin. This heat flux can be compared with the heat from a candle—if a hand is held about 8 to 9 inches above the candle, second degree burns could result in about 30 seconds. A heat flux of about 12.5 kW/m^2, over an exposure time of 10 minutes, will ignite wood, and a heat flux of about 37.5 kW/m^2 can damage steel structures.

Four types of explosions could potentially occur after an LNG spill: rapid phase transitions (RPT), deflagrations, detonations, and boiling-liquid-expanding-vapor-explosions (BLEVE).[7] More specifically:

- An *RPT* occurs when LNG is warmed and changes into natural gas nearly instantaneously. An RPT generates a pressure wave that can range from very small to large enough to damage lightweight structures. RPTs strong enough to damage test equipment have occurred in past LNG spill experiments on water, although their effects have been localized at the site of the RPT.

- *Deflagrations and detonations* are explosions that involve combustion (fire). They differ on the basis of the speed and strength of the pressure

[7]Generally, an explosion is an energy release associated with a pressure wave. Some explosions are large enough that the pressure wave can break windows or damage structures, while others are much smaller.

wave generated: deflagrations move at subsonic velocities and can result in pressures (overpressures) up to 8 times higher than the original pressure; detonations travel faster—at supersonic velocities—and can result in larger overpressures—up to 20 times the original pressure. Methane does not detonate as readily as other hydrocarbons; it requires a larger explosion to initiate a detonation in a methane cloud.

- A *BLEVE* occurs when a liquefied gas is heated to above its boiling point while contained within a tank. For instance, if a hot fire outside an LNG tanker sufficiently heated the liquid inside, a percentage of the LNG within the tank could "flash" into a vapor state virtually instantaneously, causing the pressure within the tank to increase. LNG tanks do have pressure relief valves, but if these were inadequate or failed, the pressure inside the tank could rupture the tank. The escaping gas would be ignited by the fire burning outside the tank, and a fireball would ensue. The rupture of the tank could create an explosion and flying debris (portions of the tank).

World natural gas reserves are abundant, estimated at about 6,300 trillion cubic feet, or 65 times the volume of natural gas used in 2005. Much of this gas is considered "stranded" because it is located in regions far from consuming markets. Russia, Iran, and Qatar combined hold natural gas reserves that represent more than half of the world total. Many countries have imported LNG for years. In 2005, 13 countries shipped natural gas to 14 LNG-importing countries. LNG imports, as a percentage of a country's total gas supply, for each of the importing countries ranged from 3 percent in the United States to nearly 95 percent in Japan. In 2005, LNG imports to the United States originated primarily in Trinidad and Tobago (70 percent), Algeria (15 percent), and Egypt (11 percent). The remaining 4 percent of U.S. LNG imports came from Oman, Malaysia, Nigeria, and Qatar.

LNG tankers primarily have two basic designs, called membrane or Moss (see fig. 2). Both designs consist of an outer hull, inner hull, and cargo containment system. In membrane tank designs, the cargo is contained by an Invar, or stainless steel double-walled liner, that is structurally supported by the vessel's inner hull. The Moss tank design uses structurally independent spherical or prismatic shaped tanks. These tanks, usually five located one behind the other, are constructed of either stainless steel or an aluminum alloy. LNG tankers ships are required to meet international maritime construction and operating standards, as well as U.S. Coast Guard safety and security regulations.

Figure 2: LNG Membrane Tanker

Source: GAO.

Studies Identified Different Distances for the Heat Effects of an LNG Fire

The six studies we examined identified various distances at which the heat effects of an LNG fire could be hazardous to people. The studies' variations in heat effects result from the assumptions made in the studies' models. Some studies also examined other potential hazards such as LNG vapor explosions, other types of explosions, and asphyxiation, and identified their potential impacts on public safety.

Studies Identified Various Distances That the Heat Effects of an LNG Fire Could Be Hazardous to People because of Assumptions Made

The studies' conclusions about the distance at which 30 seconds of exposure to the heat could burn people ranged from about 500 meters (less than 1/3 mile) to more than 2,000 meters (about 1-1/4 miles). The results—size of the LNG pool, the duration of the fire, and the heat hazard distance for skin burn—varied in part because the studies made different assumptions about key parameters of LNG spills and also because they were designed and conducted for different purposes. Key assumptions made included the following:

- *Hole size and cascading failure.* Hole size is an important parameter for modeling LNG spills because of its relationship to the duration of the event—larger holes allow LNG to spill from the tanker more quickly, resulting in larger LNG pools and shorter duration fires. Conversely, small holes could create longer-duration fires. Cascading failure is important because it increases the overall spill volume and the duration of the spill.

- *Waves and wind.* These conditions can affect the size of both the LNG pool and the heat hazard zone. One study indicated that waves can inhibit the spread of an LNG pool, keeping the pool size much smaller than it would be on a smooth surface, and thereby reducing the size of the LNG pool fire. Wind will tend to tilt the fire downwind (like a candle flame blowing in the wind), increasing the heat hazard zone in that direction (and decreasing it upwind).

- *Volume of LNG spilled.* The amount of LNG spilled is one of the factors that can affect the size of the pool.

- *Surface emissive power of the fire.* While the amount of heat given off by a large LNG fire is unknown, assumptions about it directly affect the results for the heat hazard zone. It is expected that the surface emissive power of LNG fires will be lower for large fires because oxygen will not circulate efficiently within a very large fire. Lack of oxygen in the middle of a large fire would lead to more smoke production, which would block some of the heat from the fire.

The LNG spill consequence studies' key assumptions and results are shown in table 1.

Table 1: Key Assumptions and Results of the LNG Spill Consequence Studies

	Key assumptions						Key results		
			Environmental conditions modeled:						
	Hole size (m^2)	Number of tanks that rupture (cascading failure	Wind speed and its effect on waves (m/s)	Wind speed and its effect on fire (m/s)	Spill volume (m^3)	Fire surface emissive power (kW/m^2)	Pool diameter (meters)	Distance to the $5kw/m^2$ heat level (meters)	Duration (minutes)
Quest Consultants Inc. (Quest)[a]	19.6	1	1.5	1.5	12,500	[b]	156	497	14.3
	19.6	1	5.0	5.0	12,500	[b]	146	531	16.6
	19.6	1	9.0	9.0	12,500	[b]	110	493	28.6
Sandia National Laboratories (Sandia)	2	3	[c]	[c]	37,500	220	209	784	20
	5	3	[c]	[c]	37,500	220	572	2,118	8.1
	5	1	[c]	[c]	12,500	350	330	1,652	8.1
	5[d]	1	[c]	[c]	12,500	220	330-405	1,305-1,579	5.4-8.1
	12	1	[c]	[c]	12,500	220	512	1,920	3.4
Pitblado, et al. (Pitblado)[e]	1.77	1	[c]	3.0	17,250	[b]	171	750	32
ABS Consulting (ABSC)[f]	0.79	1	[c]	8.9	12,500	265	200[g]	650	51
	19.6	1	[c]	8.9	12,500	265	620[g]	1,500	4.2
Fay (Fay)[h]	20	1	[c]	[c]	14,300	[b]	[b]	1,900	3.3
Lehr and Simecek-Beatty (Lehr)[i]	[b]	[b]	[c]	[c]	500	200	[b]	500	2-3

Source: GAO analysis of spill consequence studies.

[a]"Modeling LNG Spills in Boston Harbor." Copyright© 2003 Quest Consultants, Inc., Norman, OK 73609; Letter from Quest Consultants to DOE (October 2, 2001); Letter from Quest Consultants to DOE (October 3, 2001).

[b]Information not available.

[c]Not included in the model.

[d]The study examined multiple scenarios of $5m^2$. The ranges listed summarize the highest and lowest values for those scenarios.

[e]R. M. Pitblado, J. Baik, G. J. Hughes, C. Ferro, and S. J. Shaw. "*Consequences of Liquefied Natural Gas Marine Incidents*." *Process Safety Progress* 24 no. 2 (June 2005).

[f]ABS Consulting Inc. *Consequence Assessment Methods for Incidents Involving Releases from Liquefied Natural Gas Carriers*. May 13, 2004. FERC "Staff's Responses to Comments on the Consequence Assessment Methods for Incidents Involving Releases from Liquefied Natural Gas Carriers," June 18, 2004.

[g]ABS Consulting modeled pool size as a semicircle and reported the radius of that semicircle in the study. The reported radii were used to calculate the diameter of the semicircle so the study results could be compared with the other studies.

[h]J.A. Fay. “Model of Spills and Fires from LNG and Oil tankers.” *Journal of Hazardous Materials* B96 (2003): 171-188.

[i]William Lehr and Debra Simecek-Beatty. “Comparison of Hypothetical LNG and Fuel Oil Fires on Water.” *Journal of Hazardous Materials* 107 (2004): 3-9.

In terms of the studies’ results, we identified the following three key results:

- *Pool size* describes the extent of the burning pool—and can help people understand how large the LNG fire itself will be.
- *Heat hazard distance* describes the distance at which 30 seconds of exposure could cause second degree burns.
- *Fire duration* of the incident describes how long people and infrastructure will be exposed to the heat from the fire. The longer the fire, the greater potential for damage to the tanker and for cascading failure.

Although all the studies considered the consequences of an LNG spill, they were conducted for different purposes. Three of the six studies—Quest, Sandia, and Pitblado—specifically addressed the consequences of LNG spills caused by terrorist attacks. Two of these three studies—Quest and Sandia—were commissioned by DOE. The Quest study, begun in response to the September 11, 2001, attacks, was designed to quantify the heat hazard zones for LNG tanker spills in Boston Harbor. Only the Quest study examined how wind and waves would affect the spreading of the LNG on the water and the size of the resulting LNG pool. The Quest study based its wind and wave assumptions on weather data from buoys near Boston Harbor. The Quest study found that, while the waves would help reduce the size of the LNG pool, the winds that created the waves would tend to increase the heat hazard distance downwind. To simplify the modeling of the waves, the Quest study considered “standing” waves (rather than moving waves) of various heights and, therefore, did not consider the impact of wave movement on LNG pool spreading. The ABSC study expressed concern that Quest’s standing wave assumption resulted in pool sizes that were too small because wave movement might help spread the LNG.

The 2004 Sandia study was intended to develop guidance on a risk-based analysis approach to assess potential threats to an LNG tanker, determine the potential consequences of a large spill, and review techniques that could be used to mitigate the consequences of an LNG spill. The assumptions and results in table 1 for the Sandia study refer to the scenarios Sandia examined that had terrorist causes. According to Sandia, the study used available intelligence and historical data to develop credible and possible scenarios for the kinds of attacks that could breach an LNG tanker. Sandia then modeled how large a hole each of the weapon scenarios could create in an LNG tanker.[8] Two of these intentional breach scenarios included cascading failure of three tanks on an LNG tanker. In these cases, the LNG spill from one tank, as well as the subsequent fire, causes the neighboring two tanks to fail on the LNG tanker, resulting in LNG spills from three of the five tanks on the tanker. After considering all of its scenarios, Sandia concluded that, as a rule-of-thumb, 1,600 meters is a good approximation of the heat hazard distance for terrorist-induced spills. However, as the table shows, one of Sandia's scenarios—for a large spill with cascading failure of three LNG tanks—found that the distance could exceed more than 2,000 meters and that the cascading failure would increase the duration of the incident.

Finally, the stated purpose of industry's Pitblado study was to develop credible threat scenarios for attacks on LNG tankers and predict hazard zones for LNG spills from those types of attacks. The study identified a hole size smaller than the other studies that specifically considered terrorist attacks.

The other studies we reviewed examined LNG spills regardless of cause. FERC commissioned the ABS Consulting study to develop appropriate methods for estimating heat hazard zones from LNG spills. FERC uses these methods, in conjunction with the Sandia study, to examine the public safety consequences of tankers traveling to proposed onshore LNG facilities before granting siting approval. The two scenarios in the ABSC study illustrate how small holes could result in longer fires, which have a higher potential to damage the tanker itself. One scenario used a hole size of 0.79 square meters and the other a hole size of about 20 square meters. The difference in duration is striking—it takes 51 minutes and 4.2 minutes, respectively, for the fire to consume all the spilled LNG.

Finally, the Lehr and Fay studies compared the fire consequences of LNG spills with known information about oil spills and fires. Although most

[8]Please note that the information used to develop Sandia's terrorist scenarios is classified and will be discussed in GAO's classified report.

studies made similar assumptions about the volume of LNG spilled from any single LNG tank, Lehr examined a much smaller spill volume—just 500 cubic meters of LNG, compared with a range of 12,500 to 17,250 cubic meters.

Some Studies Examined Other Potential Hazards and Identified Their Impact on Public Safety

Three of the studies also examined other potential hazards of an LNG spill, including LNG vapor explosions, other types of explosions, and asphyxiation.

LNG vapor explosions. Three studies—Sandia, ABSC, and Pitblado—examined LNG vapor explosions, and all agreed that it is unlikely that LNG vapors could explode and create a pressure wave if the vapors are in an unconfined space. Although the three studies agreed that LNG vapors could explode only in confined areas, they did not conduct modeling or describe the likelihood of such confinement after an LNG spill from a tanker. The Sandia study stated that fire will generally progress through the vapor cloud slowly and without producing an explosion with damaging pressure waves. The study did suggest, however, that if the LNG vapor cloud is confined (e.g., between the inner and outer hull of an LNG carrier), it could explode but would only affect the immediate surrounding area. The ABSC study and the Pitblado study agreed that a confined LNG vapor cloud could result in an explosion.

Other types of explosions. Three studies—Sandia, ABSC, and Pitblado—examined the potential for RPTs. The Sandia study concluded that, while RPTs have generated energy releases equivalent to several pounds of explosives, RPT impacts will be localized near the spill. Sandia also noted that RPTs are not likely to cause structural damage to the vessel. The ABSC study noted that their literature search suggested that damage from RPT overpressures would be limited to the immediate vicinity, though it noted that the literature did not include large spills like those that could be caused by a terrorist attack. Only one study, Pitblado, discussed the possibility of a BLEVE. According to our discussions with Dr. Pitblado, an LNG ship with membrane tanks could not result in a BLEVE, but he said that Moss spherical tanks could potentially result in a BLEVE. A BLEVE could result because it is possible for pressure to build up in a Moss tanker. A 2002 LNG tanker truck incident in Spain resulted in an explosion that some scientists have characterized as a BLEVE of an LNG truck. Portions of the tanker truck were found 250 meters from the accident itself, propelled by the strength of the blast.

Asphyxiation. Only the Sandia study examined the potential for asphyxiation following an LNG spill if the vapors displace the oxygen in the air. It concluded that fire hazards would be the greatest problem in most locations, but that asphyxiation could threaten the ship's crew, pilot boat crews, and emergency response personnel.

Experts Generally Agreed That the Most Likely Public Safety Impact of an LNG Spill Is Fire's Heat Effect, but That Further Study Is Needed to Clarify the Extent of This Effect

Our panel of 19 experts generally agreed on the public safety impact of an LNG spill and disagreed with a few of the conclusions of the Sandia study.[9] The experts also suggested priorities for future research—some of which are not fully addressed in DOE's ongoing LNG research—to clarify uncertainties about heat impact distances and cascading failure. These priorities include large-scale fire experiments, large-scale LNG spill experiments on water, the potential for cascading failure of multiple LNG tanks, and improved modeling techniques.

Experts Agreed That the Heat from an LNG Fire Was Most Likely to Affect Public Safety, but That Explosions from an LNG Spill Are Unlikely

Experts discussed two types of fires: vapor cloud fires and pool fires. Eighteen of 19 experts agreed that the ignition of a vapor cloud over a populated area could burn people and property in the immediate vicinity of the fire. While the initial vapor cloud fire would be of short duration as the flames burned back toward the LNG carrier, any flammable object enveloped by the vapor cloud fire could ignite nearby objects, creating secondary fires that present hazards to the public. Three experts emphasized in their comments that the vapor cloud is unlikely to penetrate very far into a populated area before igniting. Expanding on this point, one expert noted that any injuries from a vapor cloud fire would occur only at the edges of a populated area, for example, along beaches. One expert disagreed, arguing that a vapor cloud fire is unlikely to cause significant secondary fires because it would not last long enough to ignite other materials.

[9]We considered experts "in agreement" if more than 75 percent of experts indicated that they completely agreed or generally agreed with a given statement. Not all experts commented on every issue discussed.

Experts agreed that the main hazard to the public from a pool fire is the heat from the fire but emphasized that the exact hazard distance depends on site-specific and scenario-specific factors. Furthermore, a large, unconfined pool fire is very difficult to extinguish; generally almost all the LNG must be consumed before the fire goes out. Experts agreed that three of the main factors that affect the amount of heat from an LNG fire are the following:

- *Site-specific weather conditions*. Weather conditions, such as wind and humidity, can influence the heat hazard distances. For example, more humid conditions allow heat to be absorbed by the moisture in the air, reducing heat hazard distances.

- *Composition of the LNG*. The composition of the LNG can also affect the distance at which heat from the fire is felt by the public. In small fires, methane, which comprises between 84 percent and 97 percent of LNG, burns cleanly, with little smoke. Other LNG components—propane and butane—produce more smoke when burned, absorbing some of the fire's heat and reducing the hazard distance. As the fire grows larger, the influence of the composition of LNG is hypothesized to be less pronounced because large fires do not burn efficiently.

- *Size of the fire*. The size of the fire has a major impact on its surface emissive power; the heat hazard distance increases with pool size up to a point but is expected to decrease for very large pools, like those caused by a terrorist attack.

Experts also discussed the following hazards related to an LNG spill:

- *RPTs*. Experts agreed that RPTs could occur after an LNG spill but that the overpressures generated would be unlikely to directly affect the public.

- *Detonations and deflagrations*. Experts made a key distinction between these types of explosions in confined spaces as opposed to unconfined spaces. For confined spaces, they agreed that it is possible, under controlled experimental conditions, to induce both types of explosions of LNG vapors; however, a detonation of confined LNG vapors is unlikely following an LNG spill caused by a terrorist attack. Experts were split on the likelihood of a confined deflagration occurring after a terrorist attack: eight thought it was unlikely, four thought it likely, and five thought neither likely nor unlikely.[10] For unconfined spaces, experts were split on

[10]Two experts did not comment.

whether it is possible to induce such explosions; however, even experts who thought such explosions were possible agreed that deflagrations and detonations in unconfined spaces are unlikely to occur following an LNG spill caused by a terrorist attack.

- *BLEVE*. Experts were split on whether a BLEVE is theoretically possible in an LNG tanker. Of the ten experts who agreed it was theoretically possible, six thought that a BLEVE is unlikely to occur following an LNG spill caused by a terrorist attack on a tanker.[11]

- *Freeze burns and asphyxiation*. Experts agreed that freeze burns do not present a hazard to the public because only people in close proximity to LNG spill, such as personnel on the tanker or nearby vessels, might come into contact with LNG or very cold LNG vapor. For asphyxiation, experts agreed that it is unlikely that an LNG vapor cloud could reach a populated area while still sufficiently concentrated to pose an asphyxiation threat.

Experts Disagreed with a Few Key Conclusions of the Sandia National Laboratories Study

Experts disagreed with heat hazard and cascading failure conclusions of the Sandia study. Specifically, 7 of 15 experts thought Sandia's heat hazard distance was "about right," and the remaining 8 experts were evenly split as to whether the distance was "too conservative" (i.e., larger than needed to protect the public) or "not conservative enough" (i.e., too small to protect the public). Experts who thought the distance was too conservative generally listed one of two reasons. First, the assumptions about the surface emissive power of large fires were incorrect because the surface emissive power of large fires would be lower than Sandia assumed. Second, Sandia's hazard distances are based on the maximum size of a pool fire. However, these experts pointed out that once a pool fire ignites, its diameter will begin to shrink, which will also reduce the heat hazard distance. Experts who thought Sandia's heat hazard distance was not conservative enough listed a number of concerns. For example, Sandia's distances do not take into consideration the effects of cascading failure. One expert suggested that a 1-meter hole in the center tank of an LNG tanker that resulted in a pool fire could cause the near simultaneous failure of the other four tanks, leading to a larger heat hazard zone.

[11]Three experts said that BLEVEs were "neither likely nor unlikely," and one expert thought that BLEVEs were likely.

Officials at Sandia National Laboratories and our panel of experts cautioned that the hazard distances presented cannot be applied to all sites. According to the Sandia study authors, their goal was to provide guidance to federal agencies on the order of magnitude of the hazards of an LNG spill on water. As they pointed out in interviews and in their original study, further analysis for specific sites is needed to understand hazards in a particular location. Six experts on our panel also emphasized the importance of site-specific and scenario-specific factors. For instance, one expert explained that the $5kW/m^2$ hazard distance depends on the size of the tanker and the spill scenario, including factors such as wind speed, timing of ignition, and the location of the hole. Other experts suggested that key factors are spill volume and the impact of waves. Additionally, two experts explained that there is no “bright line” for hazards—that is, 1,599 meters is not necessarily “dangerous,” and 1,601 meters is not necessarily “safe.”

Only 9 of 15 experts agreed with Sandia’s conclusion that only three of the five LNG tanks on a tanker would be involved in cascading failure. Five experts noted that the Sandia study did not explain how it concluded that only three tanks would be involved in cascading failure. Three experts said that an LNG spill and subsequent fire could potentially result in the loss of all tanks on board the tanker.

Twelve of 16 experts agreed, however, with Sandia’s conclusion that cascading failure events are not likely to greatly increase (by more than 20 to 30 percent) the overall fire size or heat hazard ranges. The four experts who disagreed with Sandia’s conclusion about the public safety impact of cascading failure cited two main reasons: (1) Sandia did not clearly explain how it reached that conclusion and (2) the impact of cascading failure will partly depend on how the incident unfolds. For instance, one expert suggested that cascading failure could include a tank rupture, fireball, or BLEVE, any of which could have direct impacts on the public (from the explosive force) and which would change the heat hazard zones that Sandia identified.

Finally, experts agreed with Sandia’s conclusion that consequence studies should be used to support comprehensive, risk-based management and planning approaches for identifying, preventing, and mitigating hazards from potential LNG spills.

Experts Suggest Future Research Priorities to Determine the Public Safety Impact of an LNG Spill

In the second iteration of the Web-based panel, we asked the experts to identify the five areas related to the consequences of LNG spills that need further research. Then, in the final iteration of the Web-based panel, we provided the experts with a list of 19 areas—generated by their suggestions and comments from the second iteration—and asked them to rank these in order of importance. Table 2 presents the results of that ranking for the top 10 areas identified and indicates those areas that are funded in the DOE study discussed earlier.

Table 2: Expert Panel's Ranking of Need for Research on LNG

Rank	Research area	Funded in DOE's study
1	Large fire phenomena	√
2	Cascading failure	
3	Large-scale spill testing on water	√
4	Large-scale fire testing	√
5	Comprehensive modeling: interaction of physical processes	
6	Risk tolerability assessments	
7	Vulnerability of containment systems (hole size)	
8	Mitigation techniques	
9	Effect of sea water coming in as LNG flows out	
10	Impact of wind, weather, and waves	

Source: GAO.

Note: A rank of 1 is the highest rank, and a rank of 10 is the lowest. Panel members ranked 19 areas of research from 1 to 19; a score was calculated for each area based on this ranking. Only the 10 areas with the highest scores are presented in this table.

As the table shows, two of the top five research areas identified are related to large LNG fires—large fire phenomena and large-scale fire testing. Experts believe this research is needed to establish the relationship between large pool fires and the surface emissive power of the fire. Experts recommended new LNG tests for fires between 15 meters and 1,000 meters. The median suggested test size was 100 meters. Some experts also raised the issue of whether large LNG fires will stop behaving like one single flame but instead break up into several smaller, shorter flames. Sandia noted in its study that this behavior could reduce heat hazard distances by a factor of two to three.

Experts also ranked research into cascading failure of LNG tanks second in the list of priorities. Concerning cascading failure, one expert noted that, although the consequences could be serious, there are virtually no data looking at the hull damage caused by exposure to extreme cold or heat.

As table 2 shows, DOE's recently funded study involving large-scale LNG fire experiments addresses some, but not all, of the research priorities identified by the expert panel. For DOE, Sandia National Laboratories plans to conduct large-scale LNG pool fire tests beginning with a pool size of 35 meters—the same size as the largest test conducted to date. Sandia will validate the existing 35-meter data and then conduct similar tests for pool sizes up to 100 meters. The goal of this fire testing is to document the impact of smoke on large LNG pool fires. Sandia suggests that these tests will create a higher degree of knowledge of large-scale pool fire behavior and significantly lower the current uncertainty in predicting heat hazard distances.

According to researchers at Sandia National Laboratories, some of the research our panel of experts suggested may not be appropriate. Sandia indicated that comprehensive modeling, which allows various complex processes to interact, would be very difficult to do because of the uncertainty surrounding each individual process of the model. One expert on our panel agreed, noting that while comprehensive modeling of all LNG phenomena is important, combining those phenomena into one model should wait for experiments that lead to better understanding of each individual phenomenon.

Conclusions

It is likely that the United States will increasingly depend on the importation of LNG to meet the nation's demand for natural gas. Understanding and resolving the uncertainties surrounding LNG spills is critical, especially in deciding on where to locate LNG facilities. Because there have been no large-scale LNG spills or spill experiments, past studies have developed modeling assumptions based on small-scale spill data. While there is general agreement on the types of effects from an LNG spill, the results of these models have created what appears to be conflicting assessments of the specific consequences of an LNG spill, creating uncertainty for regulators and the public. Additional research to resolve some key areas of uncertainty could benefit federal agencies responsible for making informed decisions when approving LNG terminals and protecting existing terminals and tankers, as well as providing reliable information to citizens concerned about public safety. Although DOE has recently funded a study that will address large-scale LNG fires, this study will address only 3 of the top 10 issues—and not the second-highest ranked issue—that our panel of experts identified as potentially affecting public safety.

Recommendation for Executive Action

To provide the most comprehensive and accurate information for assessing the public safety risks posed by tankers transiting to proposed LNG facilities, we recommend that the Secretary of Energy ensure that DOE incorporates the key issues identified by the expert panel into its current LNG study. We particularly recommend that DOE examine the potential for cascading failure of LNG tanks in order to understand the damage to the hull that could be caused by exposure to extreme cold or heat.

Agency Comments and Our Evaluation

We requested comments on a draft of this report from the Secretary of Energy (DOE). DOE agreed with our findings and recommendation. In addition, DOE included technical and clarifying comments, which we included in our report as appropriate.

As agreed with your offices, unless you publicly announce the contents of this report earlier, we plan no further distribution until 30 days from the report date. At that time, we will send copies to interested congressional committees, the Secretary of Energy, and other interested parties. We also will make copies available to others upon request. In addition, the report will be available at no charge on the GAO Web site at http://www.gao.gov.

If you or your staff have any questions regarding this report, please contact me at (202) 512-3841 or wellsj@gao.gov. Contact points for our Offices of Congressional Relations and Public Affairs may be found on the last page of this report. Key contributors to this report are listed in appendix IV.

Jim Wells

Jim Wells
Director, Natural Resources
and Environment

Appendix I: Scope and Methodology

To address the first objective, we identified eight unclassified, completed studies of liquefied natural gas (LNG) hazards and reviewed the six studies that included new, original research (either experimental or modeling) and clearly described the methodology used. While we have not verified the scientific modeling or results of these studies, the methods used seem appropriate for the work conducted based on conversations with experts in the field and our assessment. We also discussed these studies with their authors and visited all four onshore LNG import facilities and one export facility. We attended a presentation on LNG safety and received specific training on LNG properties and safety. We also conducted interviews with officials from Sandia National Laboratories, Federal Energy Regulatory Commission, Department of Transportation, Department of Energy, and the U. S. Coast Guard. During our interviews, we asked officials to provide information on past LNG studies and plans for future LNG spill consequences work.

To obtain information on experts' opinions of the public safety consequences of an LNG spill from a tanker, we conducted a three-phase, Web-based survey of 19 experts on LNG spill consequences. We identified these experts from a list of 51 individuals who had expertise in one or more key aspects of LNG spill consequence analysis. In compiling this initial list, we sought to achieve balance in terms of area of expertise (i.e., LNG experiments, modeling LNG dispersion, LNG vaporization, fire modeling, and explosion modeling). In addition, we included at least one author of each of the six major LNG studies we reviewed, that is, studies by Sandia National Laboratories; ABS Consulting; Quest Consultants Inc.; Pitblado, et al.; James Fay (MIT); and William Lehr (National Oceanic and Atmospheric Administration). We gathered resumes, publication lists, and major LNG-related publications from the experts identified on the initial list.

We selected 19 individuals for the panel. One or more of the following selection criteria were used: (1) has broad experience in all facets of LNG spill consequence modeling (LNG spill from hole, LNG dispersion, vaporization and pool formation, vapor cloud modeling, fire modeling, and explosion modeling); (2) has conducted physical LNG experiments; or (3) has specific experience with areas of particular importance, such as LNG explosion research. In addition, we included: (1) at least one author from each of the major LNG studies and (2) representatives from private industry, consulting, academia, and government. All 19 experts selected for the panel agreed to participate. The names and affiliations of panel members are included in appendix II.

To obtain consensus concerning public safety issues, we used an iterative Web-based process. We used this method, in part, to eliminate the potential bias associated with group discussions. These biasing effects include the potential dominance of individuals and group pressure for conformity. Moreover, by creating a virtual panel, we were able to include more experts than possible with a live panel.

For each phase in the process, we posted a questionnaire on GAO's survey Web site. Panel members were notified of the availability of the questionnaire with an e-mail message. The e-mail message contained a unique user name and password that allowed each respondent to log on and fill out a questionnaire but did not allow respondents access to the questionnaires of others.

In the questionnaires, we asked the experts to agree or disagree with a set of statements about LNG hazards derived from GAO's synthesis of major LNG spill consequence studies. Prior to the first iteration, we had an LNG spill consequence expert who was not a part of the panel review each statement and provide comments about technical accuracy and tone. Experts were asked to indicate agreement on a 3-point scale (completely agree, generally agree, do not agree) and to provide comments about how the statements could be changed to better reflect their understanding of the consequences of LNG spills.

If most experts agreed with a statement during the first iteration, we did not include it in the second iteration. If there was not agreement, we used the experts' comments to revise the statements for the second iteration. The second iteration was posted on the Web site, using the same protocol as used for the first. Again, panel members were asked to agree or disagree and provide narrative comments. We revised the statements where there was disagreement and posted them on the Web site again for the third iteration. At the end of the third iteration, at least 75 percent of the experts agreed or generally agreed with most of the ideas presented.

Because some of the studies conducted are classified, this public version of our findings supplements a more comprehensive classified report produced under separate cover. We conducted our work from January 2006 through January 2007 in accordance with generally accepted government auditing standards.

Appendix II: Names and Affiliations of Members of GAO's Expert Panel on LNG Hazards

Myron Casada	ABS Consulting
T.Y. Chu	Sandia National Laboratories
Philip Cleaver	Advantica
Bob Corbin	U.S. Department of Energy
John Cornwell	Quest Consultants, Inc.
James Fay	Massachusetts Institute of Technology
Louis Gritzo	FM Global
Jerry Havens	University of Arkansas
Benedict Ho	BP
Greg Jackson	University of Maryland
Ron Koopman	Hazard Analysis Consulting
Bill Lehr	National Oceanic and Atmospheric Administration
Georges Melhem	ioMosaic Corporation
Gordon Milne	Lloyd's Register
Robin Pitblado	Det Norske Veritas
Phani Raj	Technology and Management Systems, Inc.
Velisa Vesovic	Imperial College
Harry West	Texas A&M University
John Woodward	Baker Engineering and Risk Consultants, Inc.

Appendix III: Summary of Expert Panel Results

For each question below, we show only those responses that were selected by at least one expert. The number of responses adds up to 19—the total number of experts on the panel. Percentages may not add to 100% due to rounding.

Introduction

Large LNG spills from a vessel could be caused by an accident, such as collision or grounding, or by an intentional attack. While large accidental LNG spills are highly unlikely given current LNG carrier designs and operational safety policies and practices, these spills do pose a hazard to the public if they occur in or near a populated area. **What is your level of agreement with this paragraph?** (Finalized in the second iteration.)

Count	Percentage	Label
8	42.11%	Completely agree
11	57.89%	Generally agree

LNG Hazards

Overall Hazards

LNG is a cryogenic liquid composed primarily of methane with low concentrations of heavier hydrocarbons, such as ethane, propane, and butane. LNG is colorless, odorless, and nontoxic. When LNG is spilled, it boils and forms LNG vapor (natural gas). The LNG vapor is initially denser than ambient air and visible; LNG vapor will stay close to the surface as it mixes with air and disperses. LNG and LNG vapor pose four possible hazards: freeze burns, asphyxiation, fire hazard, and explosions. **What is your level of agreement with this paragraph?** (Finalized in the second iteration.)

Count	Percentage	Label
5	26.32%	Completely agree
12	63.16%	Generally agree
2	10.53%	Do not agree

LNG Hazards-Freeze Burns

LNG poses a threat of freeze burns to people who come into contact with the liquid or with very cold LNG vapor. Since LNG boils immediately and vaporizes after it leaves an LNG tank and LNG vapor warms as it mixes with air, only people in close proximity to the release, such as personnel on the tanker or nearby escort vessels, might come into contact with LNG or LNG vapor while it is still cold enough to result in freeze burns. Freeze burns do not present a direct hazard to the public. **What is your level of agreement with this paragraph?** (Finalized in the second iteration.)

Count	Percentage	Label
14	73.68%	Completely agree
5	26.32%	Generally agree

LNG Hazards-Asphyxiation

After an LNG spill, LNG vapor forms a dense, visible vapor cloud that is initially heavier than air and remains close to the surface. The cloud warms as it mixes with air and as portions of the cloud reach ambient air temperatures, they begin to rise and disperse. Asphyxiation occurs when LNG vapor displaces oxygen in the air. Asphyxiation is a threat primarily to personnel on the LNG tanker or to people aboard vessels escorting the tanker at close range. An LNG vapor cloud could move away from the tanker as it mixes with air and begins to disperse. However, it is unlikely that the vapor cloud could reach a populated area while still sufficiently concentrated to pose an asphyxiation threat to the public. **What is your level of agreement with this paragraph?** (Finalized in the second iteration.)

Count	Percentage	Label
8	42.11%	Completely agree
10	52.63%	Generally agree
1	5.26%	Do not agree

LNG Hazards-Vapor Cloud: Wind Effect

The effect of wind on an LNG vapor cloud varies with wind speed. The most hazardous wind conditions, however, are low winds, which can push a vapor cloud downwind without accelerating the LNG vapor dispersion into the atmosphere. Low wind conditions have the highest potential of allowing an LNG vapor cloud to move a significant distance downwind.

What is your level of agreement with this paragraph? (Finalized in the third iteration.)

Count	Percentage	Label
8	42.11%	Completely agree
10	52.63%	Generally agree
1	5.26%	Do not agree

LNG Hazards-Fire Hazard

Because LNG vapor in an approximately 5 to 15 percent mixture with air is flammable, LNG vapor within this flammability range is likely to ignite if it encounters a sufficiently strong ignition source such as a cigarette lighter or strong static charge. **What is your level of agreement with this paragraph?** (Finalized in the third iteration.)

Count	Percentage	Label
13	68.42%	Completely agree
6	31.58%	Generally agree

LNG Hazards-Fire Hazard: Thermal Hazard End Point

The main hazard to the public from a pool fire is the thermal radiation, or heat, that is generated by the fire rather than the flames themselves. Often this heat is felt at considerable distance from the fire. Scientific papers have used two different thresholds as end points to describe the impact of thermal radiation on the public: 5 kilowatts per square meter and 1.6 kilowatts per square meter.
Which level do you think is the appropriate end point to use to define thermal hazard zones in order to protect the public? *(Please indicate your response, then provide an explanation in the textbox below your answer.)*

Count	Percentage	Label
8	42.11%	5 kilowatts per square meter
2	10.53%	1.6 kilowatts per square meter
6	31.58%	Other
3	15.79%	I do not have the expertise necessary to respond to this question.

Of the six experts who answered “other,” two experts indicated that $5kW/m^2$ is a useful or appropriate level for measuring the impact on people. One expert suggested that dosage (a measure that combines thermal radiation and duration of exposure) is most appropriate. Another expert suggested that both thresholds are appropriate, depending on the circumstances of the analysis. (Finalized in the first iteration.)

LNG Hazards-Fire Hazard: Pool Fire

A pool fire could form in the wake of a vapor cloud fire burning back to the source or just after an LNG spill, if there is immediate ignition of the LNG vapor. A pool fire burns the vapor above a liquid LNG pool as the liquid boils from the pool. A large, unconfined pool fire is very difficult to extinguish; generally almost all the LNG must be consumed before the fire goes out. **What is your level of agreement with this paragraph?** (Finalized in the second iteration.)

Count	Percentage	Label
13	68.42%	Completely agree
5	26.32%	Generally agree
1	5.26%	Do not agree

The main hazard to the public from a pool fire is the thermal radiation, or heat, from the fire. This heat can be felt at a considerable distance from the flames themselves. Numerous factors can impact the amount of thermal radiation that could affect the public: site-specific weather conditions, including humidity and wind speed and direction, the composition of the LNG, and the size of the fire. **What is your level of agreement with this paragraph?** (Finalized in the second iteration.)

Count	Percentage	Label
13	68.42%	Completely agree
6	31.58%	Generally agree

The wind speed and direction also affect the distance at which thermal radiation from the fire is felt by the public. In high winds, the flames will tilt downwind, increasing the amount of heat felt downwind of the fire and decreasing the amount of heat felt upwind. More humid conditions allow heat to be absorbed by the moisture in the air reducing the heat felt by the public. **What is your level of agreement with the above paragraph?** (Finalized in the second iteration.)

Count	Percentage	Label
6	31.58%	Completely agree
11	57.89%	Generally agree but suggest the following clarification.
2	10.53%	I do not have the expertise necessary to respond to this section.

The composition of the LNG can also affect the distance at which thermal radiation from the fire is felt by the public. In small fires, methane, which comprises between 84 percent and 97 percent of LNG, burns cleanly, with little smoke. Cleaner-burning LNG fires, particularly those burning LNG with higher methane content, result in higher levels of thermal radiation than oil or gasoline fires of the same size because the smoke generated by oil and gasoline fires acts as a shield, reducing the amount of thermal radiation emitted by the fire. While LNG composition can have a large impact on the thermal radiation from small LNG fires, as LNG fires get larger, these effects are hypothesized to be less pronounced. **What is your level of agreement with this paragraph?** (Finalized in the third iteration.)

Count	Percentage	Label
5	26.32%	Completely agree
10	52.63%	Generally agree
3	15.79%	Do not agree
1	5.26%	I do not have the expertise necessary to respond to this section.

The size of the fire has a major impact on the thermal radiation from an LNG pool fire. Thermal radiation increases with pool size up to a point but is expected to decrease for very large pools, like those caused by a terrorist attack. **What is your level of agreement with this paragraph?** (Finalized in the second iteration.)

Count	Percentage	Label
4	21.05%	Completely agree
10	52.63%	Generally agree
4	21.05%	Do not agree
1	5.26%	I do not have the expertise necessary to respond to this section.

LNG Hazards–Vapor Cloud Fire

If an LNG vapor cloud formed in the wake of an LNG spill and drifted away from the tanker as it warmed and dispersed, the vapor cloud could enter a populated area while areas of the cloud had LNG vapor/air mixtures within the flammability range. Since populated areas have numerous ignition sources, those portions of the cloud would likely ignite. The fire would then burn back through the cloud toward the tanker and continue to burn as a pool fire near the ship, assuming that liquid LNG still remains in the spill area. Ignition of a vapor cloud over a populated area could burn people and property in the immediate vicinity of the fire. While the initial fire would be of short duration as the flames burned back toward the LNG carrier, secondary fires could continue to present a hazard to the public. **What is your level of agreement with the above paragraph?** (Finalized in the second iteration.)

Count	Percentage	Label
7	36.84%	Completely agree
11	57.89%	Generally agree but suggest the following clarification
1	5.26%	Do not agree

LNG Hazards–Vapor Cloud Fire: Burn Back Speed

After ignition of a vapor cloud that drifted away from an LNG tanker spill, how fast could the flame front travel back toward the spill site if it was unconfined or confined? (Finalized in the second iteration.)

Count	Percentage	Label
15	78.95%	Not checked
2	10.53%	I do not have the expertise necessary to respond to this section.
2	10.53%	No answer

Experts did not agree on the speed of a flame front traveling through an LNG vapor cloud in either a confined or unconfined state. Responses varied from less than 5 meters per second up to 50 meters per second in unconfined settings and from 0 meters per second to 2,000 meters per second in confined settings.

Explosions-RPT

A rapid phase transition (RPT) can occur when LNG spilled onto water changes from liquid to gas virtually instantaneously due to the rapid absorption of ambient environmental heat. While the rapid expansion from a liquid to vapor state can cause locally large overpressures, an RPT does not involve combustion. RPTs have been observed during LNG test spills onto water. In some cases, the overpressures generated were strong enough to damage test equipment in the immediate vicinity. Overpressures generated from RPTs would be very unlikely to have a direct affect on the public. **What is your level of agreement with this paragraph?** (Finalized in the second iteration.)

Count	Percentage	Label
15	78.95%	Completely agree
4	21.05%	Generally agree

Explosions-Deflagrations and Detonations

Deflagrations and detonations are rapid combustion processes that move through an unburned fuel-air mixture. Deflagrations move at subsonic velocities and can result in overpressures up to eight times the original pressure, particularly in congested/confined areas. Detonations move at supersonic velocities and can result in overpressures up to 20 times the original pressure. **What is your level of agreement with this paragraph?** (Finalized in the third iteration.)

Count	Percentage	Label
1	5.26%	Not checked
7	36.84%	Completely agree
10	52.63%	Generally agree
1	5.26%	Do not agree

Explosions—Deflagrations, Detonations, and BLEVEs

Please choose the response that best describes your opinion about each type of explosion of LNG vapors in each setting described. (Finalized in the third iteration.)

Answer	Deflagration with overpressure in an unconfined setting	Deflagration with overpressure in a confined setting	Detonation in an unconfined setting	Detonation in a confined setting	Boiling-liquid-expanding-vapor-explosion (BLEVE)
Under controlled experimental conditions, it is possible to induce this type of explosion in this type of setting.	7	18	4	15	11
This type of setting cannot support this type of explosion.	8	0	11	2	7
More research is necessary to answer this question.	3	0	3	0	0
I don't have the expertise necessary to answer this question.	0	0	0	1	0
No answer/not checked	1	1	1	1	1

If experts answered that "under controlled experimental conditions, it is possible to induce this type of explosion in this type of setting," they were asked to answer the following question:

What is the likelihood of a each type of explosion of LNG vapors in each setting described occurring following an LNG spill caused by a terrorist attack on a tanker? (Finalized in the third iteration.)

Answer	Deflagration with overpressure in an unconfined setting	Deflagration with overpressure in a confined setting	Detonation in an unconfined setting	Detonation in a confined setting	Boiling-liquid-expanding-vapor-explosion (BLEVE)
Highly unlikely	3	6	1	7	4
Unlikely	2	2	3	3	2
Neither likely nor unlikely	1	5	0	3	3
Likely	1	4	0	2	1
Highly likely	0	0	0	0	0
No answer/ not checked	0	1	0	0	1

LNG Hazards–Is BLEVE the Worst?

A BLEVE is the worst potential hazard of an LNG spill. It would result in the rupture of one or more LNG tanks, perhaps simultaneously, on the ship, with potential rocketing debris and damaging pressure waves. **What is your level of agreement with the above paragraph?** (Finalized in the first iteration.)

Count	Percentage	Label
2	10.53%	Completely agree
16	84.21%	Do not agree (Please explain in the textbox below.)
1	5.26%	No answer

Questions About the 2004 Sandia National Laboratories Study[1]

The Sandia report concluded that the most significant impacts to public safety exist within 500 meters of a spill, with much lower impacts at distances beyond 1,600 meters even for very large spills. **Please choose the response that best describes your opinion about these hazard distances.** (Finalized in the third iteration.)

[1]Since two of the experts were authors of the Sandia study, their responses to ALL the questions related to the study below have been excluded. For the questions related to the Sandia study, there are 17 experts responding.

Count	Percentage	Label
4	23.54%	They are too conservative (i.e., should be smaller)
7	41.18%	They are about right
4	23.53%	They are not conservative enough (i.e., should be larger)
2	11.76%	No answer

The Sandia report concluded that large, unignited LNG vapor clouds could spread over distances greater than 1,600 meters from a spill. For a nominal intentional spill, the hazard range could extend to 2,500 meters. The actual hazard distances will depend on breach and spill size, site-specific conditions, and environmental conditions. **Please choose the response that best describes your opinion about these hazard distances**. (Finalized in the third iteration.)

Count	Percentage	Label
4	23.53%	They are too conservative (i.e., should be smaller)
6	35.29%	They are about right
4	23.53%	They are not conservative enough (i.e., should be larger)
1	5.88%	Do not have the expertise to answer
2	11.76%	No answer

The Sandia report concluded that cascading damage (multiple cargo tank failure) due to brittle fracture from exposure to cryogenic liquid or fire-induced damage to foam insulation is possible under certain conditions but is not likely to involve more than two or three cargo tanks for any single incident. **What is your level of agreement with this paragraph**? (Finalized in the third iteration.)

Count	Percentage	Label
3	17.65%	Completely agree
6	35.29%	Generally agree
6	35.29%	Do not agree
2	11.76%	I do not have the expertise necessary to respond to this section.

The Sandia report concluded that cascading events are not expected to greatly increase (not more than 20-30 percent) the overall fire size or hazard ranges (500 meters for severe impacts, much lower impacts beyond 1,600 meters) but will increase the expected fire duration. **What is your level of agreement with this paragraph?** (Finalized in the third iteration.)

Count	Percentage	Label
7	41.18%	Completely agree
5	29.41%	Generally agree
4	23.53%	Do not agree
1	5.88%	No answer

The Sandia report suggested that consequence studies should be used to support comprehensive, risk-based management and planning approaches for identifying, preventing, and mitigating hazards to public safety and property from potential LNG spills. **What is your level of agreement with this paragraph?** (Finalized in the third iteration.)

Count	Percentage	Label
8	47.06%	Completely agree
8	47.06%	Generally agree
1	5.88%	Do not agree

Commodity Comparison

In your opinion, what is the risk to public safety posed by an attack on tankers carrying each of the following energy commodities? (Finalized in the first iteration.)

Answer	Liquefied natural gas	Crude oil	Diesel	Gasoline	Heating oil	Jet fuel	Liquefied petroleum gas
Little to None	1	2	1	0	1	1	0
Little	3	10	11	5	11	6	1
Medium	6	3	3	8	3	6	4

Answer	Liquefied natural gas	Crude oil	Diesel	Gasoline	Heating oil	Jet fuel	Liquefied petroleum gas
Large	3	0	0	2	0	2	5
Very Large	2	0	0	0	0	0	5
No expertise to answer	1	1	1	1	1	1	1
No answer	3	3	3	3	3	3	3

Future Research

In the first and second survey iterations, you noted areas related to LNG spill consequences that need further research. We are interested in your thoughts on the relative level of need for research in these areas, and also the five areas you think should be of highest priority in future research.

Please indicate the degree to which further research is needed in each of the areas listed below. (Finalized in the third iteration.)

Responses to each part of this question are in the table below, which is sorted by mean score so that the highest-ranked research priorities appear first.

Type of research	Very great need (1)	Great need (2)	Moderate need (3)	Some need (4)	Little to no need (5)	Do not have the expertise to answer (6)	No answer (7)	Mean score
Large fire phenomena (impact of smoke shielding, large flame versus smaller flamelets)	9	5	3	0	1	1	0	4.17
Cascading failure	5	9	4	1	0	0	0	3.95
Large-scale LNG spill testing on water[a]	7	7	2	1	2	0	0	3.84
Large-scale fire testing[b]	7	6	3	2	1	0	0	3.84
Comprehensive modeling allowing different physical processes to interact	2	10	3	4	0	0	0	3.53
Risk tolerability assessments	5	4	3	1	3	1	2	3.44

Type of research	Very great need (1)	Great need (2)	Moderate need (3)	Some need (4)	Little to no need (5)	Do not have the expertise to answer (6)	No answer (7)	Mean score
Vulnerability of LNG containment systems, including validating hole size predictions for the double hull ship structure	5	4	3	5	2	0	0	3.26
Mitigation techniques	3	5	6	3	2	0	0	3.21
Effect of sea water pouring into a hole as LNG flows out	2	6	5	3	2	0	1	3.17
Impact of wind, weather, and waves (on pool spread size, evaporation rate, pool formation, etc.)	3	4	6	3	3	0	0	3.05
Improvements to 3-D computational fluid dynamics dispersion modeling	0	4	6	6	2	1	0	2.67
Effects of different LNG compositions (on vaporization rates, thermal radiation, explosive behavior, etc.)	2	2	4	8	3	0	0	2.58
Whether an explosive attack will result in immediate vapor cloud ignition	0	5	4	5	4	1	0	2.56
Rapid phase transitions: likelihood in various scenarios and impact	1	2	6	6	4	0	0	2.47
Effects of igniting LNG vapors in containment or ballast tanks	0	5	3	5	6	0	0	2.37
BLEVE properties of tanks on LNG ships	1	4	3	4	7	0	0	2.37
Deflagration/detonation of LNG	1	0	5	8	5	0	0	2.16
Effects of a large, unignited vapor cloud drifting from the incident site	0	0	7	5	7	0	0	2.00

Type of research	Very great need (1)	Great need (2)	Moderate need (3)	Some need (4)	Little to no need (5)	Do not have the expertise to answer (6)	No answer (7)	Mean score
Effect of clothing and obstructions on the radiant heat level received by the public	1	1	2	6	9	0	0	1.89
Other[c]	12	2	0	0	0	0	5	[d]

[a]Experts suggested pool sizes of 15 meters up to 1,000 meters, though the median response was 100 meters.

[b]Experts suggested pool sizes of 15 meters up to 1,000 meters, though the median response was 100 meters.

[c]Experts suggested frequency modeling, determination of acceptable risk to society, analysis of foam on LNG tankers, risk analysis for larger LNG tankers, CFD modeling for pool spreading and evaporation, and improvement to existing techniques used for fighting LNG fires.

[d]Not applicable.

Appendix IV: GAO Contact and Staff Acknowledgments

GAO Contact

Jim Wells, (202) 512-3841, or wellsj@gao.gov

Staff Acknowledgments

In addition to the individual named above, Mark Gaffigan, Amy Higgins, Lynn Musser, Janice Poling, Rebecca Shea, Carol Herrnstadt Shulman, and James W. Turkett made key contributions to this report.

GAO's Mission

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Exhibit 72

U.S. DEPARTMENT OF ENERGY

Liquefied Natural Gas Safety Research

Report to Congress
May 2012

United States Department of Energy
Washington, DC 20585

Message from the Assistant Secretary for Fossil Energy

The Explanatory Statement accompanying the Consolidated Appropriations Act, 2008[1] and the House Report on the House of Representatives version of the related bill[2] requested the Department of Energy to submit a report to Congress addressing several key liquefied natural gas (LNG) research priorities. These issues are identified in the February 2007 Government Accountability Office Report (GAO Report 07-316), *Public Safety Consequences of a Terrorist Attack on a Tanker Carrying Liquefied Natural Gas Need Clarification*.

In response to this request, the Department of Energy tasked Sandia National Laboratories (SNL) with expanding the scope of the Department's LNG safety research program to address the research priorities identified in GAO Report 07-316. To accomplish this, SNL performed LNG field research and testing and conducted advanced computational modeling, simulation, and analyses over a three year period from May 2008 through May 2011. This report contains the findings, results, and conclusions of this research.

I am pleased to submit the enclosed report entitled, *Liquefied Natural Gas Safety Research Report to Congress*. The report was prepared by the Department of Energy's Office of Fossil Energy and summarizes the progress being made in this important area of research. This report is being provided to the following Members of Congress:

- **The Honorable Joseph R. Biden, Jr.**
  President of the Senate

- **The Honorable John Boehner**
  Speaker of the House of Representatives

- **The Honorable Daniel K. Inouye**
  Chairman, Senate Committee on Appropriations

- **The Honorable Thad Cochran**
  Vice Chairman, Senate Committee on Appropriations

- **The Honorable Dianne Feinstein**
  Chairman, Senate Subcommittee on Energy and Water Development
  Committee on Appropriations

- **The Honorable Lamar Alexander**

[1] Explanatory Statement accompanying Public Law 110-161 (Dec. 26, 2007) at page 570.
[2] H.Rept. 110-185 accompanying Energy and Water Development Appropriations Bill, 2008 (H.R. 2641) at page 73.

Ranking Member, Senate Subcommittee on Energy and Water Development
Committee on Appropriations

- **The Honorable Harold Rogers**
  Chairman, House Committee on Appropriations

- **The Honorable Norm Dicks**
  Ranking Member, House Committee on Appropriations

- **The Honorable Rodney P. Frelinghuysen**
  Chairman, House Subcommittee on Energy and Water Development
  Committee on Appropriations

- **The Honorable Pete Visclosky**
  Ranking Member, House Subcommittee on Energy and Water Development
  Committee on Appropriations

If you need additional information, please contact me or Mr. Jeff Lane, Assistant Secretary, Office of Congressional and Intergovernmental Affairs, at (202) 586-5450.

Sincerely,

Charles D. McConnell

Executive Summary

The February 2007 Government Accountability Office Report (GAO Report 07-316), *Public Safety Consequences of a Terrorist Attack on a Tanker Carrying Liquefied Natural Gas Need Clarification*, identified several key Liquefied Natural Gas (LNG) research priorities highlighted by a GAO-convened panel of experts on LNG safety in order to provide the most comprehensive and accurate information for assessing the public safety risks posed by LNG tankers transiting to LNG facilities. To address these issues, Congress provided funding to the Department of Energy (DOE) to expand their LNG safety research program to focus on the major LNG research priorities contained in the GAO report. Sandia National Laboratories (SNL) supported the DOE in this effort starting May 2008 through May 2011 by conducting a series of large-scale LNG fire and cryogenic damage tests, as well as detailed, high performance computer models and simulations of LNG vessel damage resulting from large LNG spills and fires on water.

The key findings from these efforts include the following:

- For the large breach and spill events considered, as much as 40 percent of the LNG spilled from the LNG vessel's cargo tank is likely to remain within an LNG vessel's structure, leading to extensive cryogenic fracturing and damage to the LNG vessel's structural steel. In addition to the cryogenic damage, the heat fluxes expected from an LNG pool fire would severely degrade the structural strength of the inner and outer hulls of an LNG vessel. The extent of the cryogenic and fire damage on an LNG vessel resulting from large spills and associated pool fires would significantly impact the LNG vessel's structural integrity, causing the vessel to be disabled, severely damaged, and at risk of sinking.
- Current LNG vessel and cargo tank design, materials, and construction practices are such that simultaneous, multi-cargo tank cascading damage spill scenarios are extremely unlikely, though sequential multi-cargo tank cascading damage spill scenarios may be possible. Should sequential cargo tank spills occur, they are not expected to increase the hazard distances resulting from an initial spill and pool fire; however, they could increase the duration of the fire hazards.
- Based on the data collected from the large-scale LNG pool fire tests conducted, thermal (fire) hazard distances to the public from large LNG pool fires will decrease by at least two to seven percent compared to results obtained from previous studies.
- Risk management strategies to reduce potential LNG vessel vulnerability and damage from breach events that can result in large spills and fires should be considered for implementation as a means to eliminate or reduce both short-term and long-term impacts on public safety, energy security and reliability, and harbor and waterways commerce. Approaches to be considered should include implementation of enhanced operational security measures, review of port operational contingency plans, review of emergency response coordination and procedures, and review of LNG vessel design, equipment and operational protocols for improved fire protection.

LIQUEFIED NATURAL GAS SAFETY RESEARCH

Table of Contents

I. Legislative Language

This report responds to legislative language set forth in the Explanatory Statement accompanying the Consolidated Appropriations Act, 2008 (2008 Act)[3] and the House Report on the House of Representatives version of the related bill[4].

The Explanatory Statement, at page 570, provides as follows:

> "*… The Department is directed to submit to the House and Senate Committees on Appropriations a report on liquefied natural gas (LNG), as outlined in the House report…*"

House Report 110-185, at page 73, similarly requested the Department of Energy to address several key LNG research priorities in a liquefied natural gas report:

> "*… Liquefied Natural Gas (LNG) Report.—The February 2007 Government Accountability Office report, 'Public Safety Consequences of a Terrorist Attack on a Tanker Carrying Liquefied Natural Gas Need Clarification,' found that the most likely public safety impact of an LNG spill is the heat hazard of a fire, but disagreed with the specific heat hazard of a fire and cascading damage failure conclusion, which is used by the Coast Guard to prepare Waterway Suitability Assessments for LNG facilities. Additionally, GAO found that the Department's 'recently funded study involving large-scale LNG fire experiments addresses some, but not all, of the research priorities identified by the expert panel.' Therefore, the Committee directs the Department to incorporate the following key issues, as identified by the expert panel, into its current LNG study: cascading failure, comprehensive modeling (interaction of physical processes), risk tolerability assessments, vulnerability of containment systems (hole size), mitigation techniques, the effect of sea water coming in as LNG flows out, and the impact of wind, weather, and waves.*"

II. LNG Cargo Tank Breach and Spill Analyses

For this study, the larger classes of Moss and Membrane LNG vessels were analyzed. The dimensions of the vessels considered are summarized in Table 1. The sizes selected span many of the LNG vessels used in the U.S., including the largest LNG vessels in operation today.

Table 1. Dimensions of Moss and Membrane LNG Vessels Evaluated

Dimension	Moss	Membrane
Length	280 m (924 ft)	330 m (1090 ft)
Breadth	45 m (150 ft)	54 m (178 ft)
Draft	10.4 m (34 ft)	11.5 m (38 ft)
LNG Cargo Capacity	140,000 m^3	260,000 m^3

[3] Explanatory Statement accompanying Public Law 110-161 (Dec. 26, 2007).
[4] H.Rept. 110-185 accompanying Energy and Water Development Appropriations Bill, 2008 (H.R. 2641) at page 73.

The geometric models, which were created using detailed structural drawings of actual LNG vessels, are shown in cross-sections in Figures 1 and 2.

Figure 1. Moss LNG Vessel cross-section.

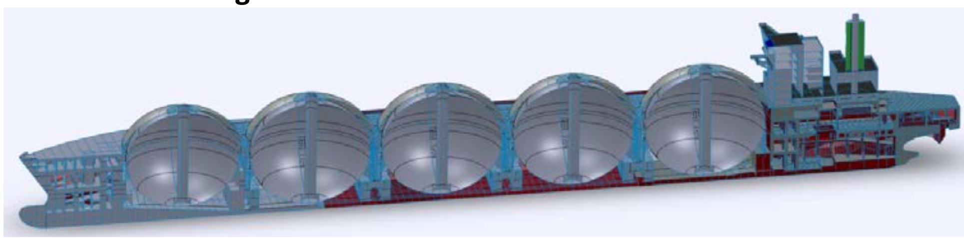
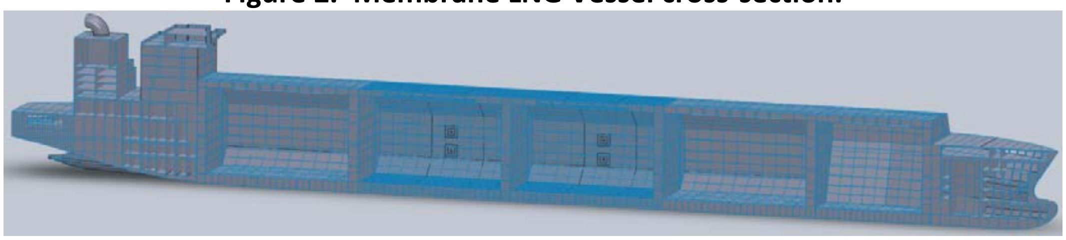


Figure 2. Membrane LNG Vessel cross-section.



LNG Cargo Tank Breach Analyses

Many potential accidental and intentional damage scenarios have been considered for LNG hazard analyses in previous DOE-directed public safety analyses for large LNG spills over water, including Hightower et al., 2004 and Luketa et al., 2008. For this study, Sandia reassessed threats and potential credible event scenarios for LNG marine transportation with marine safety, law enforcement, and intelligence agencies. The evaluations considered a wide range of possible threats. These included accidents, as well as intentional events such as attacks with shoulder-fired weapons, explosives, and attacks by small to medium size boats and aircraft. Potential threats and possible breach events are always site-specific and will vary depending on the location of the LNG vessel, such as inner harbor, outer harbor, or offshore Deep Water port.

The breach sizes calculated were based on detailed, two- and three-dimensional, shock physics/structural interaction and damage models. The breach modeling included detailed representations of the LNG vessel's structural design and materials of construction, cargo tank construction and materials, and the location and energy content of the threats identified. The range of breach sizes calculated for specific threats are presented in classified reports, but Table 2 provides a summary of the range of the cargo tank breach sizes considered for this study. To simplify integration with the structural geometry and construction of LNG vessels, square holes were assumed in all analyses.

Table 2. LNG Cargo Tank Breach Sizes Considered

Type	Breach Area	Breach Dimension
Very Small	0.005 m^2	(0.25 ft x 0.25 ft)
Small	0.5 m^2	(2.3 ft x 2.3 ft)
Medium	2-3 m^2	(5.0 ft x 5.0 ft)
Large	5 m^2	(7.3 ft x 7.3 ft)
Very Large	15 m^2	(12.7 ft x 12.7 ft)

The breach events evaluated can occur at a range of locations. While many accidental and intentional threats fall into the very small and small breach size categories, the major focus of the spill and damage analyses were for medium to very large hole sizes that are difficult to analyze without the use of high performance modeling and computing capabilities.

LNG Spill Analyses

To determine the extent of LNG flow during a breach event, three-dimensional computational fluid dynamics (CFD) analyses of the internal and external flow of LNG from a breach of Moss and Membrane LNG cargo tanks were performed for the small through very large hole sizes. The spill analyses considered the entire flow physics of the problem, including the draining of the breached cargo tank, the timing and flow of the LNG internal and external to the vessel, and LNG vaporization during a spill. The flow modeling and analysis conducted are presented in detail in Figueroa et al., 2011. Figures 3 and 4 show examples of LNG flow analyses conducted for the Moss and Membrane LNG vessels.

Figure 3. Moss LNG vessel spill and internal flow analysis example.

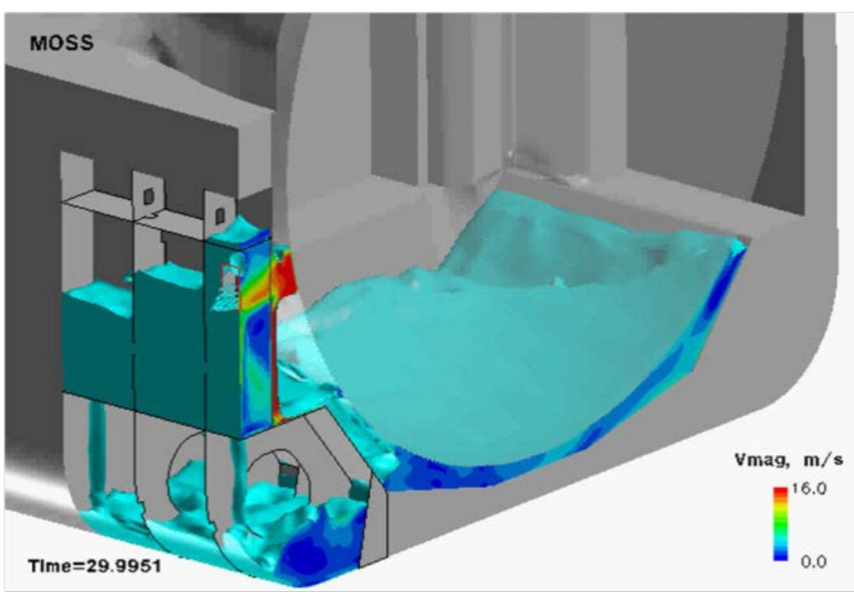
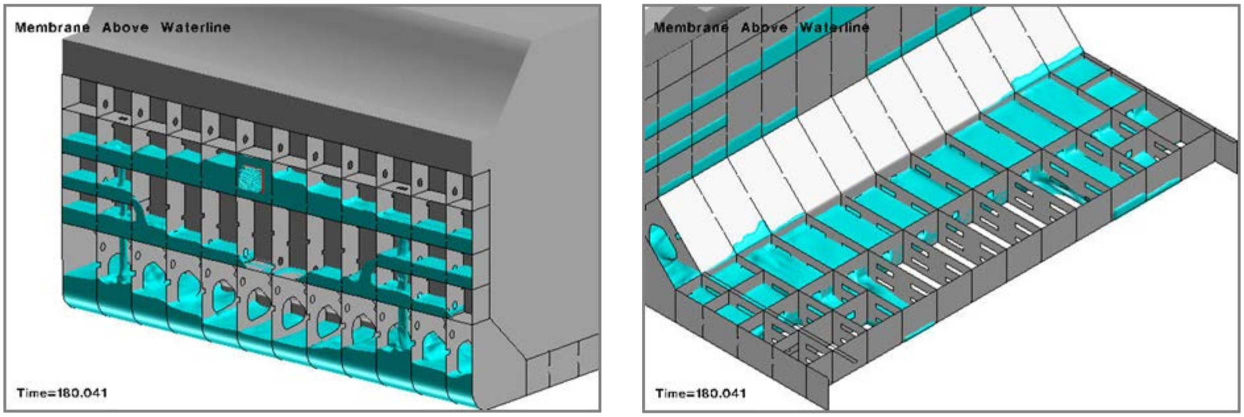


Figure 4. Membrane LNG vessel spill and internal flow analysis examples.



The spill analyses indicate that for the larger breach and spill events, as much as 40 percent of the cargo tank LNG volume will likely remain within the LNG vessel. The spill and flow analyses show that for medium and larger spills, the internal flow of LNG into a Moss LNG vessel will be completed within ten to fifteen minutes, at which time the remaining LNG will all flow out onto the water. For a Membrane LNG vessel, LNG flow within the vessel for medium to larger spills will be completed in about 10 minutes, and then the remaining LNG will flow out onto the water. For smaller breach events, the spills are smaller and the spill durations longer.

The results for the external flow analyses showed that for the larger breach events, LNG pool diameters between 180 m to 350 m can be expected for the Moss LNG vessels, while LNG pool diameters between 205 m to 330 m can be expected for the Membrane LNG vessels. Smaller breach events result in spills of much smaller volumes of LNG and have much smaller pools.

The flow results obtained should be considered as providing qualitative information on the general pattern, timing, and magnitude of the internal and external LNG flows for different breach and spill events.

III. Large LNG Pool Fire Experimental Results

The focus of the efforts for this part of the study was to improve the understanding of the physics and hazards of large LNG spills and fires on water. The key LNG pool fire issues to be addressed included:

- Determining the Surface Emissive Power (SEP) of large LNG pool fires;
- Determining the fuel vaporization rate of LNG fires on water; and
- Determining the flame height to diameter ratios for large LNG pool fires.

This effort was accomplished through the collection of data obtained during a series of LNG pool fire tests on water. A summary of the test data collected is presented here, while the detailed test data and results are presented in Blanchat et al., 2010.

Shown in Figure 5 is the large scale LNG pool fire test site. The site design included: 1) using soil excavated from the creation of a two meter deep, 120 m diameter pond to create a 310,000 gallon compacted soil LNG storage reservoir; 2) covering the reservoir with a double insulated cover and insulated liner to minimize LNG vaporization; 3) use of prefabricated reinforced concrete pipes to transport the LNG from the base of the reservoir to the center of the pool; and 4) use of simple, liftable plugs to allow gravity-driven high LNG flow rates from the reservoir to the pool. This approach enabled LNG flow rates representative of large spills, while minimizing the need for cryogenic rated high flow volume pumps, associated hardware, and fire rated LNG storage tanks.

Figure 5. Large-scale LNG pool fire test site.

Numerous cameras, spectroscopic diagnostics, and heat flux sensors were used to obtain extensive heat flux, flow rate, and fire size data from the resulting fires for each test. The spreading pool fire area was photographed with the aid of gyroscopically stabilized cameras deployed in U.S. Air Force helicopters.

Figures 6 and 7 are pictures of the two large LNG pool fires, conducted in February 2009 and December 2009.

Figure 6. LNG Test 1 – 21 m diameter LNG spill and pool fire.

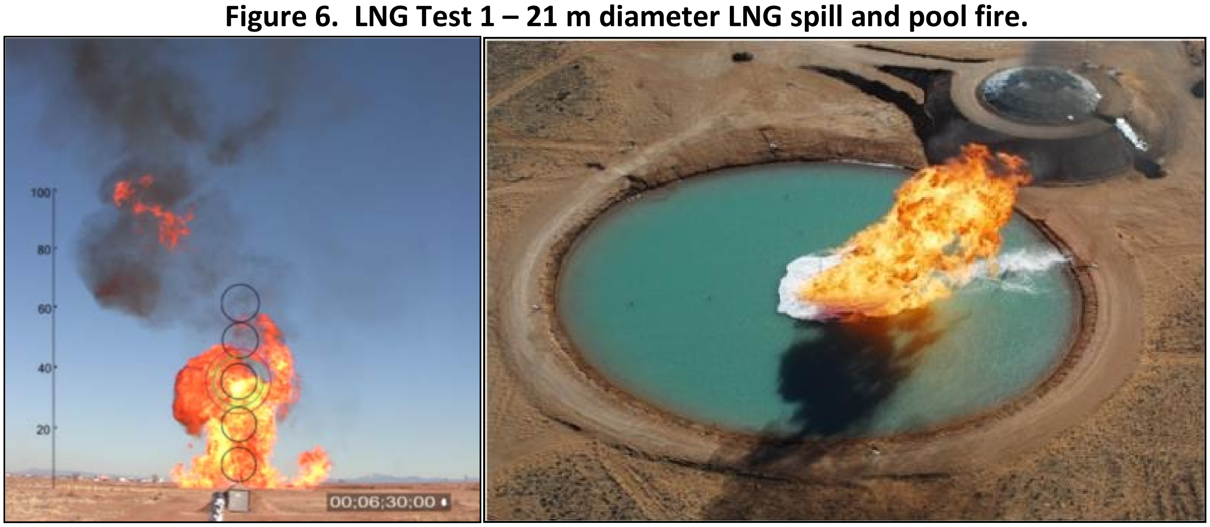


Figure 7. LNG Test 2 – 83 m diameter LNG spill and pool fire.

A summary of the major pool fire parameters measured during these tests are provided below in Table 3.

Table 3. Large LNG Pool Fire Data

Test	Volume Discharged (gallons)	Avg. Flame Height (m)	Flame Diameter (m)	Wind Speed (m/s)	Flame Tilt (degrees)	Vap. Rate (kg/m^2s)	Surface Emissive Power (kW/m^2) (narrow/wide)
1	15,000	70	20.7	4.8	50	0.15	238/277
2	52,000	146	56 (83 m spill)	1.6	Negligible	Not obtained	316/286

The thermal radiation spectra as a function of height and time were acquired using a scanning mid-infrared (1.3-4.8 µm) spectrometer. Analyzed spectra determined that the dominant contributor to the thermal radiation was from broadband soot emission. The overall thermal radiation reaching the spectrometer was attenuated by atmospheric water and CO_2 which resulted in a decrease in intensity at different wavelength bands. In LNG Test 2, at ~40 m to 103 m above the ground surface, the data is fairly consistent with spectra-derived flame temperatures of between 1300-1600°C and emissivity values between ~0.3 -0.4.

In both of the tests conducted for this study, there was no evidence of smoke shielding. There were a few instances when small amounts of smoke were seen in LNG Test 2 during the production of large scale vortices that rolled up from the base of the flame when the fire exhibited a puffing behavior. Very little smoke shielding was also observed in pool fire data obtained from a previous, smaller scale (~10 m diameter) test conducted by SNL.

The trend in the data from these tests indicate that the SEP for LNG fires on water level off at about ~280-290 kW/m^2 and might be expected for spreading pools with diameters in the range of 100 m. This is a reasonable value for use in hazard calculations for structures, such as the LNG vessel or shoreline areas, adjacent to or near the fire. Larger LNG fires would likely have some smoke shielding in the upper portions of the flame plume that will lower the overall flame-average SEP for far afield objects.

The collected data showed some unique and unexpected results. Specifically, the fire diameter was not the same size as the spreading pool diameter, as had been assumed by most analyses to date. Previous studies with stagnant pools in pans resulted in fire diameters the same size as the pool diameter. However, in all such studies, the pans had edges that can result in flame stabilization that would not be available in open water scenarios. The data collected further showed that in both very light and significant cross-winds, the flame will stabilize on objects projecting out of the fire, suggesting the vessel itself will act as a flame anchor.

Flame Height-to-Diameter Testing

To develop a flame height-to-diameter correlation, a large (3 m diameter) gas burner was used to create fully turbulent methane fires at the Sandia Thermal Test Complex, which more closely simulates large fire behavior. The data collected was compared with other common height-to-diameter correlations conducted for smaller and less turbulent fires. The Sandia data collected suggests that the fire height for large LNG spills would be much lower than often used in many fire hazard analyses. The Sandia data suggest the fire height-to-diameter ratios for LNG pool fires greater than 300 m in diameter would be less than 1.5 and would approach 0.7 for LNG pool fires about 1,000 m in diameter. Previously, many studies used a constant height-to-diameter ratio of 1.5. The data from the two large LNG pool fire tests conducted as part of this study closely match the gas burner flame height-to-diameter correlation identified.

IV. LNG Vessel Thermal/Structural Analyses

This section provides a summary of the development of LNG vessel structural steel thermal material property data, LNG vessel cryogenic fracture and fire damage testing and analysis, and development of cryogenic and fire thermal loading models needed to identify the time varying thermal stress states on a vessel structure during a large LNG spill and fire. The detailed material testing, and thermal damage testing and analysis efforts conducted are presented in two technical reports Kalan and Petti, 2011 and (Figueroa et al., 2011).

LNG Vessel Structural Steel Material Property Testing

It is well known that many structural steels are susceptible to low temperature brittle fracturing and high temperature softening. In order to perform the thermal (both cryogenic and high temperature) structural damage analyses required for LNG vessels during a spill and fire, information on vessel structural steel material properties and material response at extreme temperatures (from -161°C for cryogenic LNG temperatures and up to 1000°C for LNG fire temperatures), as well as suitable damage models were required. In both cases, neither existing data nor appropriate damage models existed for LNG vessel steels for this range of temperatures. Therefore, a series of material property and material failure tests were performed on two American Bureau of Shipping (ABS) steels representative of the structural steels used in standard LNG vessel construction. The data collected was used to develop cryogenic fracture and fire-induced structural damage models based on vessel structural features, stress states, and temperatures. The material and cryogenic fracture and damage response testing is summarized here, but is discussed in detail in Kalan and Petti, 2011.

ABS Grades A and EH round bar tensile test data were collected at temperatures ranging from -161°C to 800°C. In addition, notched tension specimens and Charpy V-notch testing was performed from -191^{o}C (far below the brittle transition region) to -24^{o}C (above the brittle transition region) for both ABS steels. The tensile test data showed low residual strength (20 percent of yield strength) of LNG vessel steels at LNG fire temperatures for extended periods. The Charpy V-notch energy absorption test results showed low fracture toughness for both materials at cryogenic LNG temperatures, highlighting the susceptibility to fracture of LNG vessel structural steels if contacted by LNG for any extended period.

LNG Vessel Cryogenic Fracture Testing

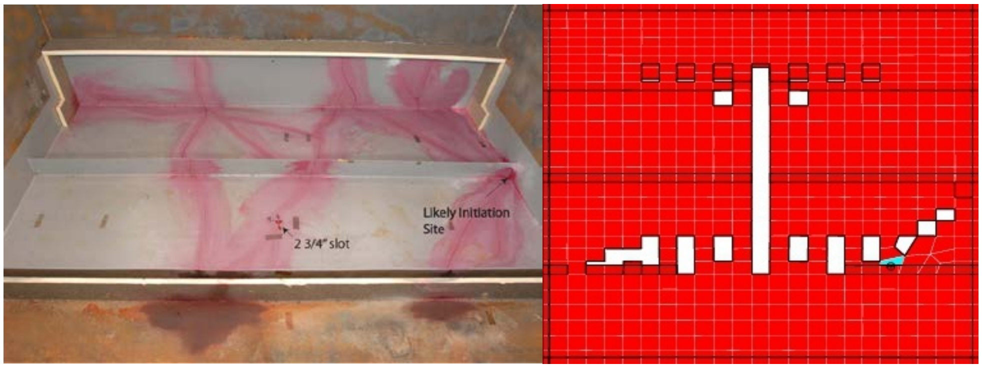
In order to predict how structural sections of an LNG vessel would respond to contact with cryogenic LNG, we conducted a series of large scale LNG spill and fracture tests on ABS Grades A and EH steels. Three series of fracture tests were conducted that included testing of large steel plates that were constrained on their edges, and the testing of large, welded, three dimensional, steel structures representative of LNG vessel structural elements and vessel construction approaches. For these tests, a region in the center of the plate or structure was cooled with liquid nitrogen, which was used for safety considerations. However, testing conducted with LNG showed similar cool down rates of the steel as using liquid nitrogen. The cooling rate and cooling distribution from each test was monitored at several locations on the plates and structures using thermocouples, and fractures were identified after each test. The tests were conducted with prescribed flaw sizes, boundary conditions, and flow rates to provide extensive, high quality data to develop and validate a cryogenic fracture and damage model.

From the fracture data collected, a vessel fracture damage model was developed and was used to predict structural fracture for several simulated LNG vessel structural elements. The development and validation of the cryogenic damage model is discussed in detail in Petti et al., 2011. For verification of the fracture and damage model, a finite element model of a large test structure was developed, and a cryogenic flux was applied to the model that represented the cooling rate data measured in the large structure tests. The cracking observed was compared to the fracturing predicted from the structural model. What was important was to predict the general direction, amount, and propagation of fractures and cracks through structural elements based on the identified temperature and stress states.

Figure 8 shows a comparison of model predictions and test data, and shows that the general extent and direction of cracking is similar relative to crack directions and elements damaged.

These efforts verified that damage could be estimated based on the LNG flow, temperature, and the stress state of the vessel structure.

Figure 8. Comparison of damage analysis to experimental test results.



LNG Vessel Structural Cooling Evaluation

The internal and external regions of the LNG vessel's structure that come into contact with spilled LNG become cooled. To determine cooling rates, experimental data was obtained from a series of structural steel cooling experiments. LNG was pooled on ¾ inch thick carbon steel plates with various surface coatings that included bare steel, primed only, and primed and painted surfaces. The tested surface coatings used consisted of primers and paints used on LNG vessels. The temperature response of the test plates was used to estimate convective heat transfer coefficients. The data and supporting analyses lead to an estimation of lower and upper bound heat transfer coefficients of 400 and 1080 W/m^2-K. The test data also showed that cooling occurs essentially only in the area in contact with the LNG. Based on this data, the regions identified from the flow analysis that come into contact with LNG were reduced linearly in temperature from 20^oC to -148^oC over 10 minutes.

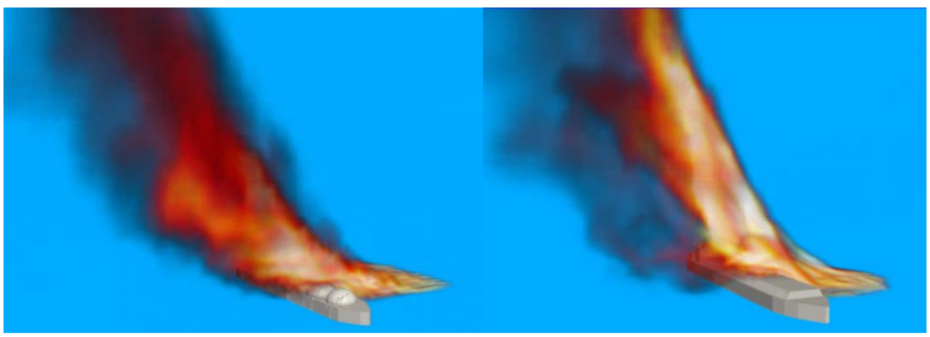
The cooling of LNG vessel steel in contact with seawater was also evaluated. The cooling rates were determined using a finite difference heat transfer analysis. The analysis calculated ice growth depending on the water/ice or water/vessel interface temperature. At interface temperatures below the freezing point of seawater (-1.9°C), the analysis allowed ice to accumulate. For a case with a reasonable external current velocity (1 knot) and for a wide range of bulk seawater temperatures, it was determined sufficient ice forms to insulate the outer hull and allow it to cool to temperatures approaching the temperature of the LNG. The cooling rate calculated was close enough to the cooling rate value determined for air to support using the same cooling rates for vessel steels above and below the waterline contacted by LNG.

LNG Vessel Structural Heating Evaluation

LNG vapors burn at temperatures of about 1500°C, which will negatively impact an LNG vessel's structural integrity if a fire lasts for a significant period of time. For medium to larger spills, the flow analysis indicated the maximum pool diameters would be approximately 180 m to 350 m. Using these pool diameters, pool fire analyses were conducted to estimate the thermal heating rate of the LNG vessel's structural steel. Fuego, a CFD fire code developed and used by Sandia, was used to estimate the envelope of an LNG fire on LNG vessels under various environmental, wind, and humidity conditions. Historical wind speed information was obtained from the National Data Buoy Center (www.ndbc.noaa.gov) for various harbors in the U.S. and was evaluated to obtain a typical wind speed for these harbors. Based on this data, an average wind speed of 9 m/s (20 mph) was considered directed toward the LNG vessels.

As shown in Figure 9, the analyses suggest that in average winds, fire can overlay onto the vessels and impact the tops and sides of the vessels, which should be included in evaluating vessel and cargo tank damage and integrity during a fire.

Figure 9. Large pool fire impacts on Moss and Membrane vessels.



The surface emissive power obtained from the large LNG pool fire experiments was used to define the LNG pool fire heating rates to the LNG vessel structures. Based on these analyses, the temperatures of the outer hulls were calculated to reach approximately $1000^{o}C$, while the inner hulls can reach about $775^{o}C$. These results compare favorably with vessel hull heating data collected from cargo tank insulation damage testing discussed later in this report. The results suggest that the outer and inner hull structural elements exposed to LNG pool fires for more than 10-20 minutes can experience about a 75 to 80 percent reduction in strength.

V. LNG Vessel Cascading Damage Analyses

The key LNG vessel damage issues Congress wanted addressed as part of this study included:

- Improved understanding of cryogenic fracture and damage to LNG vessels;
- Improved understanding of fire damage to LNG vessels; and
- Improved understanding of the potential for cascading damage from a large spill.

A summary of the cryogenic and fire related vessel damage analyses and the potential for cascading damage to the vessel from an initial spill is presented in this section, while the detailed modeling and analysis results are presented in Petti et al., 2011. The focus of the LNG vessel cascading damage analysis efforts was to use detailed vessel structural and thermal damage models, along with high performance computing resources, to improve the ability to assess and predict cascading damage potential to an LNG vessel from an initial spill.

LNG Vessel Structural Analysis Model Development

For the final vessel cascading damage analyses, detailed finite element structural analysis models were created for both the Moss and Membrane LNG vessels. For the structural analyses, elements with 0.1 m (4 inch) edge lengths were used in the regions where damage and fracturing could potentially occur to allow all of the major structural elements, including the longitudinal stiffeners attached to the inner and outer hulls, to be modeled explicitly in detail. In regions outside of the areas of potential fracturing, the elements were gradually increased to a maximum of approximately 1 m, with most elements in the 0.3 m to 0.5 m range. This helped to reduce the structural analysis complexity and computing resources needed. This approach produced two structural models, each with between four and five million elements.

To ensure the proper mass distributions, both the steel density and the thickness of the shell elements need to be defined as input parameters in the structural models. In the detailed mid-ship sections of the vessel, the thickness of the steel plating was set to the as-built thicknesses since all of the major structural elements were modeled explicitly. For the less detailed fore and aft sections, where the longitudinal stiffeners were not modeled explicitly, the thickness of the inner and outer hulls was increased to account for both the global and local stiffness lost by not including these members. In addition to the thickness of the steel plating, the densities of the blocks in various sections of the vessels were adjusted to account for various non-structural items including LNG cargo, cargo tank insulation, piping, machinery, anchors, fuel, water, etc.

LNG Vessel Damage Analysis Approach

From the spill and flow analyses conducted, the medium to very large breach events give very similar overall LNG flow results within the vessel structures, with the major difference being some variation in the timing of cooling of different regions. For this reason, a single detailed structural damage analysis was performed for each type of LNG vessel. For these analyses, gravitational loads, exterior seawater hydrostatic loads, and internal LNG cargo tank hydrostatic loads were applied to the vessel structural models to first obtain the initial stress states of the vessels. ABS Grade A and EH steels were used to model the structural steel in each vessel. For regions with lower fracture toughness materials (ABS Grades A, B, D, and E) ABS Grade A properties were used, and in regions with higher fracture toughness materials (ABS Grades AH32, AH36, DH32, DH36, EH32, and EH36) ABS Grade EH properties were used. This was done to simplify the structural model input and quality assurance checks needed. The initial load condition chosen was the Summer Arrival Condition where the LNG cargo tanks are 97 percent filled for the Moss LNG vessel and 98.5 percent filled for the Membrane LNG vessel.

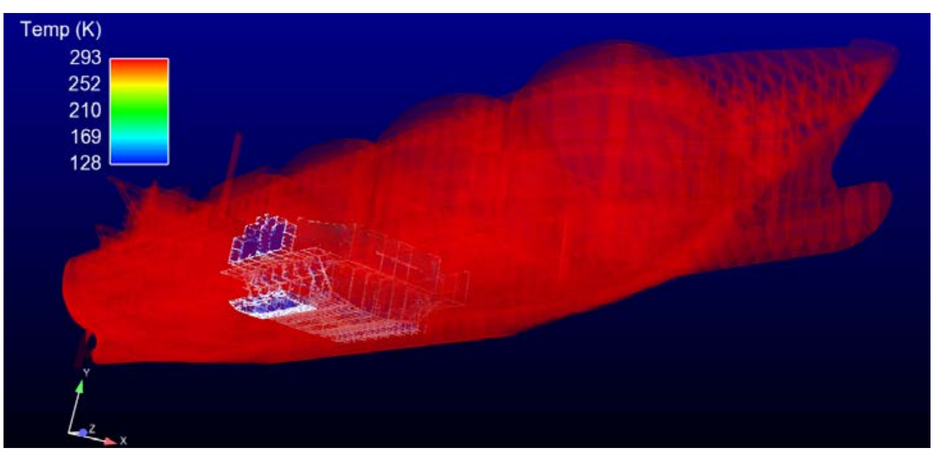
After establishing the initial load and stress states and vessel stability and draft of the structural analysis models for these conditions, temperature changes were applied to the structural models in accordance with the LNG flow, cooling rate, and fire heating rate values discussed in previous sections of this report. These thermal changes, along with the initial stress states and structural steel material properties, were used to track the progression of calculated damage (summarized below) for the LNG vessel. All vessel damage analyses were conducted using high performance computing resources, and the structural damage models were run using approximately 500 parallel computer nodes, each with multiple processors.

Moss LNG Vessel Medium to Large Spill Damage Analysis

The flow analysis showed widespread LNG contact with steel plate surfaces within 30 seconds of a large breach event. As the flow progressed, different regions started to cool at different times. These delays were used to simulate the timing of the flow of LNG within the space surrounding the cargo tank for up to approximately 14 minutes. Beyond that time, the LNG has filled the internal spaces and spills out onto the water. The initial analysis assumed that spilled LNG would not come into contact with the LNG vessel's structure just above the bilge area. However, in some cases the LNG could come into contact with this area. Because of this, the final structural damage results presented include damage in the bilge area in estimating the worst case damage scenarios.

An example of the resulting structural cryogenic damage from a large cargo tank breach and spill is shown in Figure 10.

Figure 10. Example of Moss vessel damage due to cryogenic LNG flow.

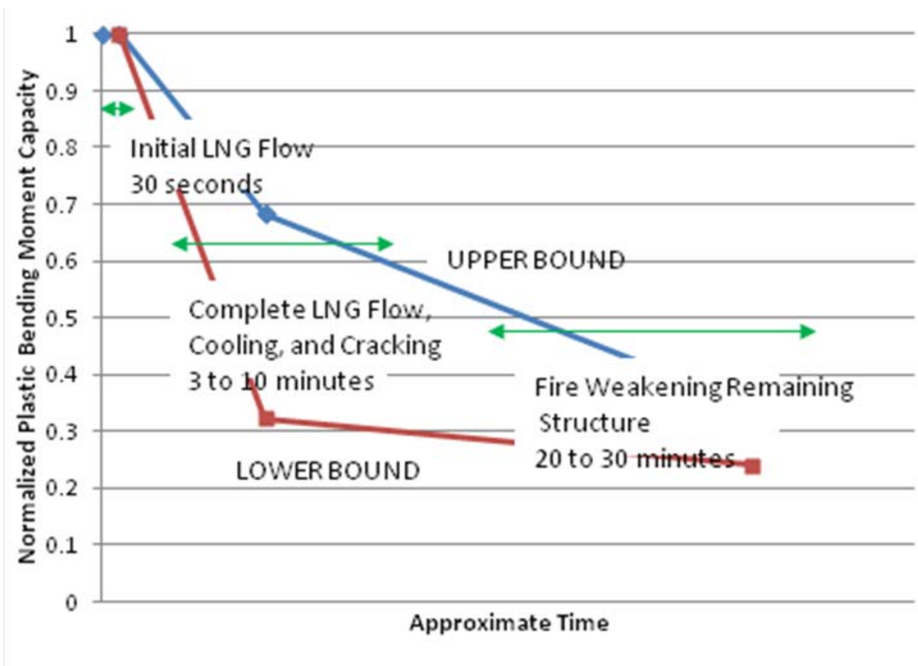


The white colored elements indicate the structural elements that reached the critical fracture damage criterion. The transparent view of the vessel shows both the cryogenic cracking and damage in the outer and inner hull surrounding the cargo tank. The significant damage to the inner hull causes the outer hull to deform upward into the vessel as the hydrostatic pressure from the seawater is no longer resisted by the damaged vessel's inner and outer hulls. The estimated displacement of the outer hull could be as much as one meter. The analysis predicts cryogenic cracking will occur throughout the portions of the vessel that were exposed to LNG flow. No damage was predicted to occur in regions beyond where the LNG flowed.

Based on the cryogenic structural damage analysis, much of the inner hull near a large breach event was damaged. As a result of the pool fire, much of the vessel's structure near the fire on both the side and top of the vessel will reach temperatures of between 775°C and 1000°C for the inner and outer hulls. At these temperatures, the vessel's structural steels are severely weakened, having less than 25 percent of their original strength, and will deform significantly.

Based on the combined cryogenic and fire damage estimated, the plastic bending moment capacity for the Moss LNG vessel as a function of time is presented in Figure 11.

Figure 11. Moss LNG vessel reduction in plastic bending moment capacity for large spills.



The plastic bending moment capacity is defined as the bending moment that would lead to the entire cross-section of the vessel yielding and creating essentially a plastic *hinge*. The plastic bending moment capacity is often used in extreme event risk analyses to evaluate the level of residual structural capacity following an extreme event.

The moment capacity is normalized by the full undamaged plastic moment capacity of the section. The cryogenic damage causes an approximate 30 to 70 percent reduction within

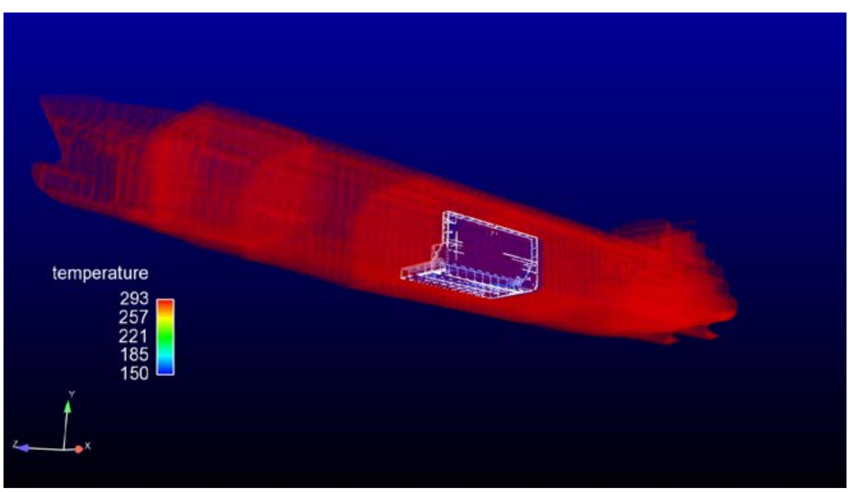
3 to 10 minutes, with the fire causing an additional 10 to 20 percent reduction between 20 and 30 minutes. However, the upper bound capacity estimates assume that the cross-section is in a condition to obtain the full strength of the materials without section buckling. However, the cryogenic damage modeling shows local buckling and material displacement that suggests that the lower bound moment capacity could occur since the sections of the inner and outer hull at the top of the vessel are affected by the fire and have little resistance to tension.

Based on the reduction in plastic moment capacity, the vessel is judged to have essentially no remaining structural strength in the affected region, and will most likely be disabled, severely damaged, and at risk of sinking. Based on the flow and damage analysis, the LNG vessel's structural design limits the LNG flow to the initially damaged region, and the four remaining cargo tanks not breached during the initial event should be unaffected by the cryogenic damage. Also, because the Moss cargo tanks are independent and do not rely on the vessel's hull structure for support, a simultaneous release of LNG from the undamaged cargo tanks due to cascading failure is considered highly unlikely.

Membrane LNG Vessel Medium to Large Spill Damage Analysis

The flow results were used to develop a series of cooled regions for the cryogenic damage analysis. Widespread LNG flow between the inner and outer hulls occurs within 2 and 3 minutes, with subsequent filling of the compartments. At approximately 6 to 10 minutes into the spill, a significant portion of the ballast tank and areas between the inner and outer hulls are filled. While complete filling of the ballast compartments and areas between the double hulls does not occur, the open spaces are small and would contain cold LNG vapor and therefore, the entire ballast tank was included as one large, cooled region. Finally, the same assumptions were made for the Membrane vessel as the Moss vessel regarding cooling rates below the waterline and the eventual entrainment of seawater into the vessel for some breach events and their inclusion in the damage conclusions. Figure 12 shows an example of the Membrane vessel with temperatures and damage plotted.

Figure 12. Example Membrane vessel damage due to cryogenic LNG flow.

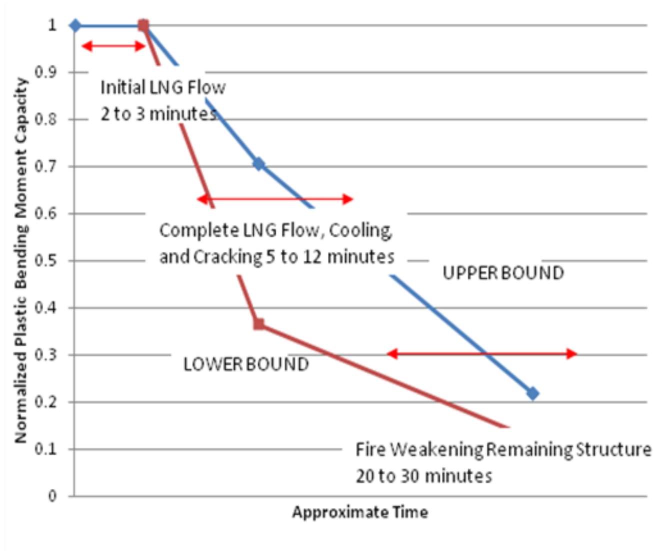


The white colored elements indicate the cryogenic fractures calculated after reaching the critical strain criterion during cooling. The transparent view shows both the cracking in the outer hull and inner hull surrounding the cargo tank. Here, the extent of the damage to vessel structure surrounding the breached cargo tank can be seen. The analysis predicts cracking will occur throughout the entire cooled region, which reflects those portions of the vessel that were exposed to LNG flow.

The damage was predicted to occur primarily near the cooled region boundaries. This is likely an artifact of the sharp gradient from cool to warm material along this boundary. Once the cracks occurred in the structural model, these elements were removed, and much of the stress was reduced in the interior of the cooled region, preventing further apparent damage. The cryogenic fracture and cracking in an actual event is expected to extend throughout much of the cooled region, especially in areas of flaws or stress concentration such as welds, corrosion, and so on. As with the Moss vessel analysis, no damage was predicted to occur in regions outside of the cooled areas. The effective damage to the Membrane LNG vessel is initially localized on one side of the vessel. The majority of the inner and outer hull was damaged, severely reducing the ability of the vessel to resist hydrostatic loads from the surrounding seawater. Unlike the Moss LNG vessel, in which the LNG cargo tank is structurally independent from the inner hull, the Membrane LNG vessel's inner hull provides the structural support for the cargo tank. With the damage to the inner hull, the cargo tank in the affected region will likely not be capable of fully containing the LNG cargo that remains below the breach. This would lead to additional inner hull damage and expanding damage of the inner hull to both sides of the vessel.

From the fire analysis, much of the vessel structure near the fire on both the side and top of the Membrane LNG vessel could reach temperatures of between 775°C and 1000^{o}C for the inner and outer hulls. Since the LNG vessel's inner hull and internal structural members provide the structural support for the Membrane cargo tanks, thermal degradation of both the outer and inner hulls from an LNG pool fire would likely cause damage to the cargo tanks. Based on the cryogenic and fire damage estimated, the reduced cross-sections and weakened materials analysis results were used to estimate the plastic bending moment capacity for the Membrane vessel as a general function of time and are shown in Figure 13.

Figure 13. Membrane LNG vessel reduction in plastic bending moment capacity for large spills.



The cryogenic damage causes an approximate 40 to 70 percent reduction within 5 to 12 minutes (including several minutes to account for the slower flow calculated for the Membrane vessel design) with the fire causing a 80 to 90 percent total reduction in the plastic bending moment capacity between 20 and 30 minutes. The fire has a more significant effect on the Membrane vessel section modulus due to the greater amount of structural cross-section that is exposed to the fire.

The damage to the vessel also introduces concerns related to a reduced buckling capacity for structural regions in compression. The sections of the inner and outer hull at the top of the vessel are affected by the fire and have little resistance to tension. Based on the reduction in plastic bending moment capacity, the vessel is judged to have essentially no remaining structural strength in the affected region, and will most likely be disabled, severely damaged, and at risk of sinking.

Based on the flow and damage analysis, the LNG vessel's structural design limits the LNG flow to the initially damaged region. Although the four remaining cargo tanks were not calculated to have been breached during the initial event, the Membrane cargo tanks are integrated tanks and rely on the vessel's hull structure for support, and the release of their cargo is slightly more uncertain. One of the tanks adjacent to the initially breached tank was calculated to experience cracking in the corner of the inner hull exposed to LNG. The breach of this adjacent tank is possible, but not certain. Even so, if this adjacent tank were to experience a leak, it would most likely progress slowly and/or occur during the fire portion of the event when the fire would weaken the vessel structure in the adjacent tank. This would have the effect of extending the duration of an initial fire, but not increasing the size of the pool fire to any significant degree.

LNG Vessel Damage from Smaller Spills

For very small breach events (0.005m^2 Breach Area; 0.25 ft x 0.25 ft Breach Dimensions; from Table 2), which could occur from a number of credible intentional or accidental events, the spill rates will be more than a factor of 1,000 times less than that of the larger breach events considered. This puts small spills into categories that would typically fall within current spill detection and safety systems and allow a significantly extended response time for both Moss and Membrane LNG vessels. The large reduction in spill rates, cryogenic damage and fire damage potential suggests that should a smaller breach event occur, both Moss and Membrane LNG vessels would have sufficient time to transit to an appropriate anchorage location and work with the Coast Guard and other public safety agencies to perform a damage assessment and initiate appropriate action.

For small breach events (0.5 m^2 Breach Area; 2.3 ft x 2.3 ft Breach Dimensions; from Table 2), the physics of the flow conditions will reduce the LNG flow rate into an LNG vessel by a factor of approximately six, relative to the larger LNG spills, and the full cryogenic cooling and damage of all the compartments between the LNG hulls for each vessel type could take as much as six times as long. However, based on the flow analysis conducted for these holes, the LNG flow internal to the vessel reaches the keels of the LNG vessels only a few minutes later than for the larger spills. This suggests that for spills from small breach events, the full cryogenic damage could take from 10 minutes to 60 minutes longer than for the larger spills. Unfortunately, the fire damage will still occur over the original time period calculated, and therefore the overall reduction in structural capability will most likely occur within one hour of the event.

VI. Additional Cascading Damage Analyses

A number of additional cascading damage issues were addressed in this study, including:

- Cargo tank insulation damage during a fire;
- Overpressure of an LNG cargo tank during a fire;
- Impact of Rapid Phase Transitions (RPTs) during a spill; and
- LNG vaporization, deflagration, and associated damage during a spill.

A summary of the testing and analysis efforts conducted to assess the potential impacts of these kind of cascading damage scenarios is presented in this section, while the detailed test data and analyses are presented in Blanchat et al., 2011, Morrow, 2011, and Figueroa et al., 2011.

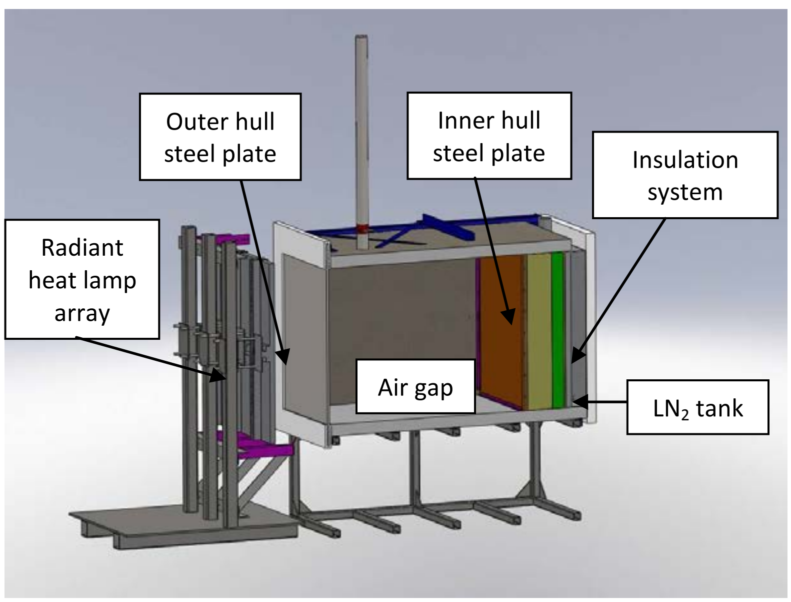
LNG Cargo Tank Insulation Fire Damage Testing

To assess the thermal resistance of LNG cargo tank insulation materials and systems in a fire, large-scale thermal damage experiments and testing were conducted on four major LNG cargo tank insulation systems (two Moss and two Membrane systems), which represent most of the current LNG insulation systems being used in U.S. ports. The testing of each insulation system was coordinated through LNG vessel designers and cargo tank insulation system manufacturers, and each insulation system tested was either provided by the insulation manufacturers or was fabricated at Sandia to the insulation system design and construction specifications provided by the manufacturers. LNG vessel representatives witnessed their insulation system test setup, experiments, data collection and evaluation, and participated in post-test insulation system inspection.

The experiments were designed to test the insulation systems for the fire durations expected from a large LNG spill. Based on the latest information on large-scale LNG spills and associated fires (Luketa et al., 2008), fires from 20 to 40 minutes long might be possible. Therefore, all the insulation systems were tested for at least 40 minutes. All tests were performed using a radiant heat assembly that allowed identical and reproducible heat flux boundary conditions for each test. All tests were performed to yield a continuous incident heat flux to the outer hull (for the membrane) or weather cover (for the Moss) insulation systems of ~270 kW/m^2. This value was based on preliminary, flame-averaged steady-state surface emissive powers measured in the large-scale LNG pool fire tests previously discussed and presented in (Blanchat et al., 2010).

The insulation tests were conducted in the test apparatus shown in Figure 14.

Figure 14: LNG cargo tank insulation testing layout.



It was approximately one meter by one meter square, and approximately two meters long and designed to allow testing of large representative LNG insulation panel systems with minimal edge effects such that a thermal environment representative of a large fire could be created. The testing apparatus included a radiant heat lamp assembly, mild steel plates representing Membrane LNG vessel outer and inner hulls or the Moss LNG vessel weather cover, an air gap inerted with nitrogen during testing, the insulation system being tested, and an aluminum tank filled with liquid nitrogen (LN_2) to represent a cold LNG cargo tank boundary condition. Liquid nitrogen was used for safety reasons, since it is not flammable, and has a similar temperature as LNG.

A summary of all the insulation test results are shown in Table 4. Heat flux was measured by heat flux gauges attached to the tank and by evaluating the change in the liquid nitrogen boil-off rate in the LN_2 tank.

Table 4. LNG Cargo Tank Insulation System Fire Damage Test Results

LNG Vessel	Insulation Type	Thickness	Fire Survivability	LN_2 Tank Heat Flux
Moss	Extruded polystyrene panel	~300 mm	> 40 min	< 7 kW/m^2
Moss	Polyurethane foam/ phenolic resin foam composite panel	~300 mm	> 40 min	< 5 kW/m^2
Membrane	Polyurethane foam and plywood panel	~300 mm	> 40 min	< 5 kW/m^2
Membrane	Perlite-filled plywood boxes	~500 mm	> 40 min	< 5 kW/m^2

LNG Cargo Tank Pressure Safety Relief Valve Evaluation

There has been much discussion on the impacts of a large LNG pool fire on increasing vaporization of LNG in undamaged tanks and the capacity of the current pressure safety relief valves to handle this increased vaporization. The concern is that if pressure builds up during a fire and cannot be adequately handled by the pressure safety relief valve systems, then a cargo tank could become over-pressurized, fail, lead to additional LNG spills, and increase hazards. A particular concern was Moss LNG cargo tanks, since some Moss insulation systems were considered to be quite vulnerable to high temperature degradation.

The significant reduction in heat transfer levels measured in the insulation damage testing discussed previously indicates that during the tests, charred insulation and soot formation is interfering with flux between the weather cover and the liquid nitrogen tank. Several possibilities exist; the atmosphere between the two surfaces could be acting as a participating media blocking heat flow. Alternatively, a very thin layer of insulation is left on the surface of the tank interfering with heat flux, or the charred insulation continues to act as a heat flux barrier along with the undamaged insulation. These possibilities suggest that different heat flux models should be considered and assessed.

Therefore, three models were considered as a way to bracket the potential range of heat flux values that an LNG cargo tank could experience during a fire. The estimates of heat flux to the cargo tank based on the experimental data and analysis from the cargo tank insulation damage testing suggests a potential range of values from 3-7 kW/m^2, with a most likely minimum value of ~5 kW/m^2. This value would be representative of a simple radiation heat transfer value. In considering both a participating media heat transfer analysis and a free convection heat transfer analysis for a Moss LNG cargo tank, the analyses support maximum heat flux estimates of up to 10 kW/m^2. Based on the fire modeling information, these heat flux values can be assumed to occur during free convection over the full tank surface area, including the area of the cargo tank below the main deck of the LNG vessel.

From the analyses, a heat flux of 5 kW/m^2 will result in an average pressure equivalent to the normal operating pressure of the cargo tank (~1.3 psig). A heat flux of 10 kW/m^2 will result in an average pressure of ~2.8 psig, and for the free convection case, a pressure of ~14.7 psig. Moss LNG cargo tanks are constructed to a design pressure which significantly exceeds the highest estimated pressure from the above scenarios. While the increased heat flux will cause some vaporization of the LNG in the vessel's cargo tanks, the cargo tank pressure relief valves are adequately sized to handle the resulting vapor production rates. Due to the combination of adequately sized cargo tank pressure relief valves and cargo tank design standards, there is a minimal likelihood of a Moss LNG cargo tank being damaged from a fire due to vapor over pressurization.

This approach was compared to an analysis performed by the Society of International Gas Tanker and Terminal Operators (SIGTTO) in 2009. This was an industry-wide study conducted to assess LNG cargo tank safety relief valve performance in the face of a large pool fire. The SIGTTO approach used standard handbook sizing algorithms and simplifying assumptions on fire/vessel interactions and cargo tank insulation damage rates, but reached similar conclusions. Overall, the testing and analyses suggest that the Moss LNG cargo tank insulation materials currently used can provide protection of the cargo tanks in a fire, and LNG vaporization would not increase to a level that would exceed the pressure safety relief valve capacity or damage the LNG vessel's cargo tanks. These analyses are presented in greater detail in Morrow, 2011.

LNG Vaporization and Deflagration Analysis

During an LNG spill, as the cryogenic LNG flows over the relatively warm structural steel within an LNG vessel, the LNG will begin to vaporize. Likewise, if a breach is at, near, or below the waterline, the LNG will also vaporize when it comes in contact with the relatively warm water. In both cases, the methane generated is flammable within a certain concentration range by volume in air (5 to 15 percent). Below five percent concentration, the vapor is too lean to burn, and above 15 percent concentration there is not enough air to sustain combustion.

During the spill flow analyses conducted, LNG vaporization and concentrations were also calculated. This provided an estimate of the amount and timing of the vapor generated and the likelihood of ignition, especially between the double hulls. In evaluating the calculated vaporization data, the combustible vapor concentrations varied spatially and temporally in each compartment and the ignitable concentrations in any region only lasted a few to ten seconds. Therefore, it is unlikely that ignition of methane vapors would occur inside the double hull compartments.

LNG Spill on Water Rapid Phase Transition Damage Analysis

A Rapid Phase Transition (RPT) is a phenomenon observed when two liquids of very different temperatures come into contact. LNG spilled onto water and undergoing a series of RPTs can create localized overpressures that look, sound, and behave like a small explosions. Where the explosive pressure is confined or where it is near structural elements, severe structural damage can occur.

In a review of the existing RPT information and data from LNG spills on water, the primary observation is that RPTs generally occur when LNG is either poured at high velocity onto water, or when water is sprayed at high velocity onto LNG. Therefore, we used the LNG flow results to identify and evaluate events with high LNG mixing rates. The results show that only a few events cause significant mixing. Those events that create the most mixing, and therefore the greatest likelihood of RPTs, occur relatively far away from an LNG vessel's outer hull. Therefore, the direct or additional damage of an RPT or a series of RPTs on the LNG vessel's outer hull is possible, but would likely cause minimal additional damage to the vessel.

VII. Large LNG Pool Fire Hazard Analyses

In this section we provide summarized thermal hazard distances resulting from large LNG spills and pool fires on water using solid flame models while the information is presented in detail in Luketa, 2011. The LNG pool fire hazard analysis parameters used in the 2004 and 2008 Sandia LNG reports (Hightower, et al. 2004) (Luketa, 2008) were based on LNG pool fire data of much smaller scale. In keeping with the principle of using the best available data, the parameters in those reports have been updated to reflect the newly acquired LNG pool fire and cascading damage data from this study. The former and updated fire parameter values are noted in Table 5 and are appropriate for use with common Solid Flame Fire Models. These types of models are suggested for their ease of use in estimating general hazard distances for a range of spills (Luketa, 2011).

Table 5: Recommended Nominal Values for Solid Flame Model

Nominal value	***2004 and 2008 Sandia LNG reports***	***Current report***
Burn rate (m/s)	3.0×10^{-4}	3.5×10^{-4}
Flame height (m)	Moorhouse correlation	Sandia correlation
SEP (kW/m^2)	220	286
Transmissivity	0.8	Wayne formula

As in the 2004 and 2008 Sandia reports, it must be emphasized that hazard distances from an LNG spill and fire will change depending on site-specific environmental conditions and breach scenarios, and site-specific analyses should be considered when appropriate.

Table 6 provides predicted thermal hazard distances for intentional events using the updated parameters and the same scenario matrix for hole sizes and tanks breached as presented in the 2004 Sandia report, which are contained in Table 7. The average pool size is calculated using the same approach as in the 2004 report, and the discharge coefficients also have not changed. Note the calculated pool diameter for the nominal cases are representative of pool diameters of 180 m to 350 m calculated for the spill and flow analyses conducted for this study.

The updated parameter values suggest the use of a higher heat flux, lower flame height, and the same pool diameters previously used, which result in about a two percent decrease in the thermal hazard distances relative to those predicted in the 2004 Sandia report for spills from smaller LNG vessels. Using the same approach, the hazard distances are reduced by about 7 to 8 percent relative to the 2008 Sandia report for larger vessels and larger spills.

From a cascading damage viewpoint, the analyses presented suggest that significant LNG vessel damage is likely from a large spill, but the major damage occurs about 15-30 minutes after an initial breach and spill. This is about the same time that a fire from an initial breach will begin to die out from a large spill. Therefore, it is expected that if cascading damage occurs, it will likely be a sequential, but not simultaneous, breach of other LNG cargo tanks, and suggests that evaluating hazard distances based on a nominal one-tank spill, with a maximum of a three-tank spill, as has been recommended in the 2004 Sandia report, is still appropriate for estimating hazard distances.

Table 6: Thermal hazard distances using parameters from the 2009 large pool fire test data

HOLE SIZE (m^2)	TANKS BREACHED	DISCHARGE COEFFICIENT	BURN RATE (m/s)	SURFACE EMISSIVE POWER (kW/m^2)	τ	POOL DIAMETER (m)	BURN TIME (min)	DISTANCE TO 37.5 kW/m^2 (m)	DISTANCE TO 5 kW/m^2 (m)
INTENTIONAL EVENTS									
2	3	0.6	3.3×10^{-4}	286	nom	199	20	299	895
5	3	0.6	3.3×10^{-4}	286	nom	546	8.1	697	1894
5*	1	0.6	3.3×10^{-4}	286	nom	315	8.1	433	1266
5	1	0.3	3.3×10^{-4}	286	nom	223	16	329	974
5	1	0.6	1.9×10^{-4}	286	nom	415	8.1	471	1180
5	1	0.6	5.1×10^{-4}	286	nom	253	8.1	393	1252
5	1	0.6	3.3×10^{-4}	286	low	315	8.1	320	922
5	1	0.6	3.3×10^{-4}	248	nom	315	8.1	404	1183
5	1	0.6	3.3×10^{-4}	326	nom	315	8.1	479	1347
12	1	0.6	3.3×10^{-4}	286	nom	488	3.4	636	1748

*nominal case

Table 7: Thermal hazard distances in the 2004 Sandia LNG report

HOLE SIZE (m^2)	TANKS BREACHED	DISCHARGE COEFFICIENT	BURN RATE (m/s)	SURFACE EMISSIVE POWER (kW/m^2)	τ	POOL DIAMETER (m)	BURN TIME (min)	DISTANCE TO 37.5 kW/m^2 (m)	DISTANCE TO 5 kW/m^2 (m)
INTENTIONAL EVENTS									
2	3	.6	3×10^{-4}	220	.8	209	20	250	784
5	3	.6	3×10^{-4}	220	.8	572	8.1	630	2118
5*	1	.6	3×10^{-4}	220	.8	330	8.1	391	1305
5	1	.3	3×10^{-4}	220	.8	233	16	263	911
5	1	.6	2×10^{-4}	220	.8	395	8.1	454	1438
5	1	.6	8×10^{-4}	220	.8	202	8.1	253	810
5	1	.6	3×10^{-4}	220	.5	330	8.1	297	958
5	1	.6	3×10^{-4}	175	.8	330	8.1	314	1156
5	1	.6	3×10^{-4}	350	.8	330	8.1	529	1652
12	1	.6	3×10^{-4}	220	.8	512	3.4	602	1920

*nominal case

VIII. LNG Spill Prevention and Risk Management

As noted in both the 2004 and 2008 Sandia LNG reports, risk prevention and mitigation techniques can be important tools in reducing both the potential for a spill and the hazards from a spill, especially in locations where the potential impact on public safety and property can be high. However, what might be applicable for cost-effective risk reduction in one location might not be appropriate at another location. Therefore, coordination of risk prevention and management approaches with local and regional emergency response and public safety officials is important in providing a comprehensive, efficient, and cost-effective approach to protect the public and property at a given LNG import or export location.

From an LNG vessel damage viewpoint, the analyses conducted and presented in this report suggest that significant damage is likely to LNG vessels from medium and large breach events and spills. Therefore, a large breach and spill could have both short-term and long-term impacts on public safety, energy security and reliability, and harbor and waterway commerce at some sites. For this reason, significantly more attention and proactive measures should be considered for preventing the possibility of larger breach and spill events or for mitigating the cryogenic and fire impacts of larger spills on LNG vessels.

Risk management options should be focused on approaches that can be used to actively prevent or mitigate larger spills. Some risk management approaches that can be considered to help reduce the possibility of an event occurring, or reduce the hazards to the vessel and the public should an event occur include:

- Implementation of enhanced operational security measures, to include:
  - Positive control of other vessel movements during LNG vessel transits and operations;
  - Review of LNG vessel escort protocols and operations to improve the ability to enforce exclusion zones through enhanced standoff and active interdiction approaches;
- Review of port operational contingency plans to ensure procedures are in place to address larger spills, to include options for moving the vessel to a safe anchorage to monitor, inspect, and assess damage, and for longer-term response options, including vessel lightering;
- Review of emergency response coordination and procedures for the LNG vessel, terminal or port, port authority, and emergency response groups to reduce the overall impacts and consequences of larger spills; and
- Review LNG vessel design, equipment, and operational protocols for improved fire protection to the LNG vessel, terminals, and vessel personnel from a large LNG fire.

IX. Conclusions

The major findings for smaller breach events include:

- For the very small breach events, which could occur from a number of credible accidental or intentional events, the spill rates are more than a 1,000 times less than that of potential larger breach events.
- This puts smaller spills into a regime that would typically fall within current spill detection and safety systems on LNG vessels such that it is extremely likely there would be sufficient time to move the vessel to a safe anchorage to monitor, inspect, and assess damage and long-term response options.

The major findings for medium and larger breach events:

- Large-scale fracture testing, cryogenic flow analyses, and fire modeling indicated that LNG vessels would be disabled, severely damaged, and at risk of sinking.
- For these events, LNG vessels would not be capable of movement to a safe anchorage, and would require longer periods to monitor, inspect, assess, and establish long-term response and remediation measures.

The major findings for Cascading Damage Hazards:

- Current LNG vessel and cargo tank design, materials, and construction practices are such that simultaneous multi-cargo tank cascading damage spill scenarios are extremely unlikely, though sequential multi-cargo tank cascading damage spill scenarios are possible.

- Should sequential cargo tank spills occur, they are not expected to increase hazard distances resulting from an initial spill and pool fire, but could increase the duration of the fire hazards.
- Based on the data collected from the large-scale LNG pool fire tests conducted, thermal (fire) hazard distances to the public from a large LNG pool fire will decrease by at least 2 to 7 percent compared to results obtained from previous studies.
- Risk management strategies to reduce potential LNG vessel vulnerability and damage from breach events which can result in large spills and fires should be considered for implementation as a means to eliminate or reduce both short-term and long-term impacts on public safety, energy security and reliability, and harbor and waterways commerce.

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Exhibit 73

CALIFORNIA PUBLIC UTILITIES COMMISSION

CPSD

Consumer Protection and Safety Division

An Assessment of the Potential Hazards to the Public Associated with Siting an LNG Import Terminal in the Port of Long Beach

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September 14, 2005

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EXECUTIVE SUMMARY

This report was prepared at the request of the Consumer Protection and Safety Division of the CPUC for an assessment of public safety issues that should be considered regarding the proposed siting of an LNG import terminal in the Port of Long Beach.

The history of LNG importation in the United States is reviewed, describing the siting and continuing operation of the present six LNG import terminals, and the proposal for a very large expansion in the country's LNG infrastructure - more than fifty proposals for LNG import terminals to be located in the continental United States, Southern Canada, Mexico, and the Caribbean Islands – is described. As there appear to be many more proposals than for which there is a demonstrated need, it is all the more important to ensure that the siting process involves, to the maximum extent possible, careful consideration of potential hazards to the public and adjacent infrastructure so as to give full consideration to the best alternatives available.

The potential hazards to the public of the proposed POLB terminal are defined as fire and explosion hazards, and an assessment is provided of the adequacy of the present regulation, 49 CFR 193, to protect the public.

Since the regulations were promulgated in the early Eighties, after the terminals now operating had been built and commenced operation, and since there was no rush to build additional LNG import terminals until about the year 2000, the regulations were largely unused for import terminal siting. As a result, the regulations did not, and still do not, give serious consideration to the terrorist threat that began in this country September 11, 2001. The current regulations do not effectively address the many serious questions posed by the present requirement to consider events that could be caused by malicious intent, nor is sufficient attention being paid to the reality that malicious intent changes the whole safety picture – hence the process has outrun the development of the regulations to deal with it, and the present regulations fail to address this most important new paradigm.

Most importantly in consideration of the post 9/11 threat, there is presently no requirement, much less enforcement, of exclusion zones to protect the public from LNG spills which could occur from the ships that serve the import terminal. The failure to provide for the protection of the public and surrounding infrastructure from major releases of LNG that could occur from the ships serving the facility must be considered all the more important now as a result of recent government sponsored reports, for which there is now scientific consensus, that indicate that the danger zones extending from large, but credible, spills on water are likely to pose greater threats than would either accidental or terrorist caused releases from the land part of the terminal.

The regulation does not provide for consideration of boiling liquid expanding vapor explosions (BLEVEs) or unconfined vapor cloud explosion (UVCE) hazards, although the proposed terminal is designed to import LNG containing natural gas liquids (NGL) in amounts sufficient to raise serious questions about the potential for UVCEs following

large LNG spills. The possibility of BLEVEs of LNG ship tanks, particularly the ship tanks which rely on non-fire-resistive insulation to keep the LNG from vaporizing, is not considered, although it is clear that there is a significant potential for occurrence of cascading failures that could jeopardize the ship and all of its content of LNG.

The report then presents an assessment of the consequences to the public that could result from credible accidental or terrorist caused releases of flammable liquefied fuels, either from the land part of the facility or the ships that would serve it.

Accidents and Terrorist Actions

The current regulations, particularly regarding provisions for public safety, focus on the land based part of the terminal. There are specific requirements for liquid containment and impoundment systems that are designed to limit the spreading of LNG that might be released either from the LNG tanks themselves or from transfer lines in the facility. But such control and mitigation measures could not be effectively applied to releases that could occur from an LNG ship, either at the jetty or in transit thereto, because spills onto water could not be effectively contained.

For spills on water, there have been government sponsored studies that provide information sufficient to define the (credible) spills that could occur as well as the consequences that could result.

The ABS Group and Sandia reports agree that the release of LNG in the amount of approximately 3,000,000 gallons (half of one typical LNG ship tank) is credible,

- in that such a release could result from accidental collisions between ships with sufficient momentum (mass and speed) to cause such a breach of containment, or

- that such a release could be caused by terrorists with means that are readily available to them.

Furthermore, the ABS Group and Sandia reports agree that a release of 3,000,000 gallons of LNG onto water could result in:

- Pool fires which would expose persons with unprotected skin to thermal fluxes (5 KW/m^2) that could cause second degree burn injury in approximately 30 seconds at a distance of approximately 1 mile, and

- Flammable vapor clouds, if the spilled material were not ignited upon release, that could extend downwind to distances between 2 and 3 miles. It is reasonable to assume that persons caught in the fire if the cloud were ignited would be killed or seriously injured.

The author is in essential agreement with these consequence estimates but believes the following modifications are required if they are to be used to ensure public safety:

- Since the thermal radiation flux criterion (5 KW/m^2) used by Sandia and the ABS Group could cause second degree burns in thirty seconds, it is not sufficiently protective of public safety; a lower value, approximately 1.5 KW/m^2, is recommended here. This value is already being used by other segments of the regulatory system, both nationally and internationally, based on its definition as the highest thermal flux to which an unprotected person can be continuously exposed without injury. If the 1.5 KW/m^2 criterion is used, it is anticipated that the distance of 1 mile (associated with the higher flux level) would be increased to between 1 ½ and 2 miles.

- As the Sandia Report states unequivocably that cascading failures of ship tanks cannot be ruled out and further states that in their opinion failures of as many as 3 tanks could occur, this scenario must be considered credible. As Sandia estimates that the hazard distance from this scenario could be extended by approximately one-third, the distance to the 1.5 KW/m^2 flux level would then be increased to approximately 2 ½ to 3 miles.

- The ABS Group's high-end estimates for the vapor cloud distance to the 2.5 % gas concentration level (based on releases from a 5 meter diameter hole in the containment) are approximately 3 miles. The Sandia estimates for the credible scenario analyzed are closer to 2 miles, but their calculations reflect the distance to the 5% gas concentration level rather than the 2.5% level which is accepted to represent the better criterion for vapor cloud travel distance that could pose a hazard to the public. Use of the lower flammable gas concentration criteria would be expected to extend the hazard distance to about 3 miles.

Based on this information, which the author believes to be the best available, and which is in general agreement with widely held views in the scientific community, a minimum distance is specified here for the extent to which the public could be put in harm's way from the initial release of approximately 3,000,000 gallons of LNG onto water at the POLB. It is approximately 3 miles.

Consideration of Worst Possible Cases

A minimum 3 mile radius circle around the proposed terminal is proposed to demarcate the area in which events deemed credible could cause serious injury to the public. The minimum distance to demarcate expected damage to infrastructure would be of lesser extent, depending on the criterion selected for damage. Any consideration of the consequences to POLB infrastructure must consider the wide variety of flammable and other hazardous materials routinely handled, as the area in which significant damage to infrastructure could occur (beyond the terminal and the ship) encompasses sections of one of the largest and busiest ports in the country. The POLB receives very large crude oil carriers (VLCC) at a jetty located within several hundred feet of the eastern boundary of the proposed LNG facility, and a major container terminal which almost certainly receives hazardous cargo lies adjacent to the western side of the proposed site, along which the LNG ship will be berthed.

It must be emphasized that the 3 mile distance recommended here is based primarily on the assumption that approximately 3,000,000 gallons of LNG is spilled onto water, as it appears there is little doubt that either pool fire radiation thermal fluxes or flammable vapor clouds from such a spill could put the public in harm's way out to that distance. However, it is a minimum specification, because it does not address the possibility of more serious events which could occur.

There is very real concern that such events as provide the basis for the 3 mile consequence distance would be of such severity as to make it highly likely, if not almost certain, that further failures of containments would occur. In particular, there is serious concern that the exposure to the ship from such a pool fire would have the potential to cause cascading failures of the remaining tanks on the vessel, resulting in total loss of the vessel and burning of its contents. There can be no doubt that the consequences of such a worst-possible-case event could be more severe.

Finally, the report states that the vulnerability of the land based part of the facility needs to be considered more carefully, as the author believes that insufficient attention has been given to the vulnerability of the land based facility to such natural phenomena as earthquakes and tsunamis, as well as to the facility's vulnerability to terrorist attack.

CHAPTER 1

INTRODUCTION

This report was prepared for the Consumer Protection and Safety Division (CPSD) of the California Public Utilities Commission. The CPSD requested that I prepare a science-based assessment of public safety issues that should be considered regarding the proposed siting of an LNG import terminal in the Port of Long Beach, California.

My resume is attached as Exhibit A. I have been researching methods for assessing the potential consequences of major spills of liquefied natural gas (LNG) and natural gas liquids (NGL) for more than thirty years. As the history of LNG import terminal siting in the United States, indeed the world, is largely confined to a similar period, I believe that I have a unique perspective on the issue of the hazards which LNG terminal activities can pose to public safety. I also believe that it is important to consider LNG safety issues in the broader context of increasing usage by society of other liquefied fuel and chemical gases that pose similar hazards. I particularly appreciate this opportunity to put the issues of public safety surrounding the proposed siting of an LNG import terminal in the Port of Long Beach into a scientifically reasoned context - based on my observation and study during the last three decades to understand the consequences that could occur to the public as a result of major spills of liquefied gaseous fuels onto land or water.

In my view, the importance of careful and sober consideration of the potential threat to public safety and to critical infrastructure of the decision to site a large LNG import terminal in the Port of Long Beach cannot be overstated. No liquefied fuel import terminals have been sited in urban areas of the United States since the Distrigas plant began operation in Everett, MA, in Boston Harbor, in 1971. In the interim three decades the world has experienced several catastrophic industrial accidents which were so severe as to importantly influence worldwide regulatory controls intended to lessen the likelihood as well as the potential consequences of accidental releases. Most importantly, no LNG facilities at all have been sited in this country since 9/11, and I believe that 9/11 completely changed, or should and will change, our methods as well as our thinking about the new paradigm in which major hazards complexes must be considered.

It is important for the reader to understand that this assessment is intentionally and solely directed to the realistic definition of the consequences to the public and surrounding infrastructure that could occur from a major release of flammable liquids at the proposed terminal or from the ships that will serve it, with no consideration given to the likelihood of occurrence of the events which are considered I believe that the first step in determining a rationale for a decision whether or not to site the proposed LNG terminal in the Port of Long Beach is to define the possible (credible) consequences of major releases of hazardous materials, and I believe that such determination should be made independently of any arguments advanced regarding the probability (likelihood) of such events' occurrence.

This approach is all the more appropriate since the tragic events of 9/11, as historical experience regarding LNG accidents (or accidental occurrences of any kind) cannot be used to quantify the probability of a terrorist attack.

1.1 LNG Importation in the United States

Proposals for large scale importation into the United States are not new, importation of LNG into the States having begun in the early Seventies. Although the technology of LNG storage and shipping has advanced in several areas, there are many similarities between the storage and shipping methods utilized in the Seventies and those proposed today. Indeed, all of the import terminals built in the Seventies are still in operation, and are proposed for operation for at least two decades into the future.

By the early Seventies the marine carriage of LNG had been proven technologically, and several ventures were proposed to import LNG into the United States, at the time principally from Algeria to the east and gulf coasts and from far-east gas sources such as Indonesia to the west coast. By the end of the Seventies, four import terminals were operating on the east and gulf coasts of the United States – at Everett, Massachusetts, beginning in 1971; near Savanna (Elba Island), Georgia, beginning in 1978; at Cove Point, Maryland, beginning in 1978; and at Lake Charles, Louisiana, beginning in 1982. A fifth terminal, at Kenai, Alaska, intended for export, principally to Japan, began operation in 1969. The terminal in Everett has been in operation continuously; the terminals at Elba Island, Cove Point, and Lake Charles are currently operating after a period in mothballs (different for each) which resulted from decreased need for LNG importation. The fifth import terminal was constructed and began operating in Penuelas, Puerto Rico, in 2000, and the Gulf Gateway Energy Bridge deepwater port commenced operation this year in the Gulf of Mexico.

To serve the needs of these United States import terminals as well as the needs of even faster growing LNG importation by Japan and Europe, a fleet of LNG carriers was constructed. Currently, there are approximately 165 LNG carriers in service worldwide, several of which were built for the trade that began in the Seventies. Eighteen carriers have been retired from service, and approximately 85 new ones are on order. Typical LNG carriers built in the Seventies, some of which are in use today, carry approximately 125,000 cubic meters of LNG, but the proposed terminals today are planned to receive carriers with capacity up to 250,000 cubic meters (approximately 66 million gallons).

During the period in which the first four terminals (described above) were constructed, there were additional proposals to build and operate LNG import terminals in California, with three specific sites receiving principal consideration – Los Angeles Harbor (Terminal Island), Point Conception, and Oxnard. For all three of these proposed locations, detailed risk assessment studies were prepared to define the hazards to the public that might occur as a result of accidental spills of LNG. None of the proposed California terminals were built, presumably as a result of indications that they would not be profitable in view of a reassessment of the demand for natural gas. It is important to note that because the terminal project applications were withdrawn for reasons other than consideration of their safety hazards, it is fair to say that the issues of public safety were never effectively resolved, and consideration of the risks to the public of such ventures languished - until about the year 2000.

1.2 Proposed Expansion in LNG Importation

The United States is presently considering a very large expansion of its LNG import infrastructure. As addition to the five land and one offshore import terminals currently operating in this country, as many as fifty new LNG import terminals to be sited in the continental United States, Southern Canada, Mexico, and the Caribbean Islands have been proposed. Additional proposals have been announced during the preparation of this report. All of these plans are said to be based on projections for greatly increased LNG use, both in quantity and as a percentage of total energy use.

Although this report is not intended to address the need for new LNG import terminals, I think that it should be noted that there have been no projections of demand for LNG that suggest our need (before 2025) for more than perhaps as many as a third of this number, and quite likely fewer. Viewed thus, the large number of proposals appears to be in some important part the result of significant competition to “win” in the selection process.

Although the majority of these terminals have been proposed at onshore locations, including some proposed for urban areas, as in Long Beach, a significant number are now planned for installation offshore.

With more proposed terminals than for which there is a justified need, I believe it all the more important to ensure that the siting process involves, to the maximum extent possible, careful consideration of potential hazards to the public and adjacent infrastructure.

1.3 Public Safety Concerns about LNG Terminal Siting

To begin, let me define the terms liquefied natural gas (LNG) and natural gas liquids (NGL).

LNG is natural gas that has been cooled, at normal atmospheric pressure, to approximately -260 ^{o}F, its liquefaction temperature varying depending on the composition of the gas. Methane, the principal component of LNG, cannot be liquefied by pressure alone. Although liquefaction by cooling to higher temperatures (> -260 ^{o}F) at elevated pressure is possible (combinations of cooling and pressurization are utilized in some LNG applications, such as vehicle fuels), the LNG that would be received at the Long Beach Terminal would be contained in ship tanks designed for nominal atmospheric pressure operation, i.e., with design pressures not exceeding approximately one atmosphere, and stored in land tanks under similar, nominally atmospheric pressure, conditions. Based largely on historical precedent, most LNG safety and risk assessments have assumed LNG to be principally methane, and present regulatory requirements for determining danger zones around LNG spills allow, at least implicitly, description of its composition as pure methane.

However, the composition of the LNG that would arrive at the proposed Long Beach terminal will depend upon several variable factors, including the location of gas production (the composition of natural gas from different producing fields can vary significantly) and the degree of processing of the natural gas, either during liquefaction at the export terminal or following the receipt of the LNG at the import terminal, to remove heavier molecular weight hydrocarbons such as ethane, propane, and butane. Such heavier molecular weight compounds, mixed in varying concentrations, are commonly referred to as natural gas liquids (NGL). Since the proposed terminal in Long Beach could import LNG containing substantial amounts of natural gas liquids, and since the terminal is designed to process the LNG after receipt to separate the NGL for (separate) distribution, a thorough assessment of the hazards which could be posed to the public should consider both the LNG and NGL components of the facility. Furthermore, since the degrees of hazard to the public depend, beyond the most immediate and compelling factor of the very large quantities of LNG, on important differences that are known to exist in the fire and explosion hazard potentials of LNG and NGL, any assessment of the potential hazards to the public from the proposed terminal should consider the hazards specific to LNG and NGL, as well as any potential for more serious events which could result from the storage and handling of the materials in combination.

The concerns for public safety associated with the current proposals to site new LNG terminals are essentially the same as those identified in the Seventies when LNG terminals were introduced to the United States. I have observed that the degree to which the public raised concerns about public safety varied considerably in the gulf, east, and west coast regions. There appeared to be the least opposition in the gulf coast region, with somewhat greater resistance on the east coast, particularly in New York and New England, and perhaps greatest regarding the siting of the three terminals proposed in California. It is significant, I believe, to the present discussion to note (again) that the Distrigas terminal in Everett, Massachusetts, is the only terminal constructed to date in a major urban area in the United States. There have been voiced far more concerns about the Everett facility than for the other terminals, which by comparison are located more remotely (from the public).

It is also my observation that similar variations exist in these same regions today in their response to LNG terminal siting proposals – least in the gulf region (with the notable exception of Mobile, Alabama, where Exxon Mobil has withdrawn its proposal for a terminal in Mobile Bay), followed by similar responses (both for and against the projects) from the public to proposals on the east and west coasts. So far, the proposals for terminals to be sited in unarguably urban areas, notably Fall River, Massachusetts, on the east coast, and Long Beach on the west coast, appear to be among the most contentious (regarding the public safety issue) of the proposals under active evaluation.

But there are present today (at least) three new and significant factors that require careful consideration before reaching a decision to site a liquefied gas import terminal, particularly if the site is in an urban area.

The first is the aforementioned offshore placement of LNG import terminals. Although at the beginning of the current expansion phase, there were many objections advanced to the offshore alternative, including most prominently issues of economy (it was suggested that offshore installations would be too expensive) and increased vulnerability to scheduling interruptions caused by weather, the offshore option appears to be gaining acceptance, with several terminals proposed for offshore locations off of the west, gulf, and east coasts. At least one offshore LNG facility (The Gulf Gateway Energy Bridge deepwater port, owned by Excelerate Energy Limited Partnership) has commenced operation this year in the Gulf of Mexico. It appears that the viability, of at least this type of offshore importation project (Energy Bridge), is no longer in question.

Second, during the ensuing three decades since the LNG terminals on the east and west coasts commenced operation, the world has experienced several catastrophic industrial accidents, the major consequences of which should be seriously considered before reaching a decision to site a potential major hazard industrial facility, such as the proposed LNG terminal, in a congested area such as the Port of Long Beach. Most importantly to the present in that regard, there have been a substantial number of liquefied gaseous fuel accidents involving containment failures due to boiling liquid expanding vapor explosions (BLEVEs) as well as unconfined vapor cloud explosions (UCVEs), the most severe in this hemisphere (in terms of human casualties) having occurred in an outlying area of Mexico City in 1984. That event resulted in more than 600 deaths, thousands of serious injuries, and the complete devastation of an entire NGL storage and distribution facility.

Third, and perhaps of greatest importance to the present consideration of siting an LNG terminal in the Port of Long Beach, is the terrorist threat, which the public perceives with growing concern. Although sabotage appears to have been given some consideration in the siting of terminals in the Seventies, to my knowledge no organized efforts were undertaken at that time to quantify the consequences that might result from sabotage or to attempt to quantify the likelihood of such occurrences. But, since 9/11, concerns about terrorist attacks that could pose significant threats to public safety are very real, and they are fast growing. The energy infrastructure of our country is of particular concern, because of the potential for terrorist attacks to cause events that could directly endanger the public as well as deprive us of energy that we require.

The Department of Homeland Security has identified LNG infrastructure, one component of the much larger chemical/energy infrastructure, as a potential terrorist target of concern. The Department's concern results, primarily I believe, from the recognition that liquefied gas fuel storage tanks, either on land or on ships, must necessarily concentrate very large amounts of energy (as LNG and NGL) in individual containment systems in order to be economical. The terminal proposed for the POLB will have storage capacity for approximately 86,000,000 gallons of LNG, and the ships that are initially planned to serve the terminal will carry approximately 38,500,000 gallons of LNG. However, the facility is being constructed so as to enable it to receive ships carrying up to about 53,000,000 gallons of LNG, and possibly more. The potential for terrorist attack to release large quantities of highly flammable fuels from such large storage vessels thus is seen to carry with it the potential for such attacks to endanger the public offsite as well as to effect horrendous damage to infrastructure. In my opinion, these factors demand that LNG infrastructure such as the proposed Long Beach terminal be identified as potential terrorist targets of opportunity.

I believe, and have so testified before Congress, that since 9/11 we no longer have the luxury of considering only means for reducing the probability of accidents (through more effective management strategies) to a level that is considered to justify the attendant risk – we now are forced to consider malicious acts as well. And, I believe that it is imperative that the dangers to the public from possible spills that could occur as a result of terrorist attack, particularly those spills which might occur from a tankship and thus onto water (for which there are few if any control measures), be most carefully considered in the current rush to site additional LNG import terminals in our country. Finally, in this regard, I have notified the Secretary of Homeland Security (Exhibit B) of my concerns about specific features of LNG carriers which I believe may make those ships vulnerable to terrorist attack. The specific issues, which I will address later in order to put them into a proper context, are the use of non-fire-resistive insulation on the containment vessels (LNG tanks) and the potential for major failures of the ship's structure due to direct contact with spilled LNG, which, having temperatures as low as (minus) 260 ^{o}F, has been demonstrated repeatedly to cause brittle fracture of carbon steels. Since my appeal to the Department of Homeland Security, there have appeared important reports of studies designed to clarify several outstanding issues, particularly those issues regarding the consequences that can be anticipated from large releases of LNG onto water; I will attempt to summarize the current state of our knowledge regarding these critically important matters in this report.

Finally, I have tried to prepare this report in a form which will be useful to policy makers, whom I believe are not always sufficiently informed on such matters, and to the public, whom I believe are becoming increasingly concerned, as I am, that issues of public safety surrounding the nation's chemical/energy infrastructure are not receiving the attention that is demanded, particularly post 9/11. Quoting from the foreword which I wrote for the chapter on Major Hazard Control, in <u>Lee's Loss Prevention in the Process Industries</u>, "It is my belief that the major hazards problems society faces are less a problem of insufficient information about those hazards and more a problem of insufficient application of the tools that we have in hand." In this regard, I believe it is important to note that the reports on LNG hazards which have been recently prepared and mentioned above, especially the reports by the ABS Group and the Sandia Group, do provide information which provides effective answers to several technical questions concerning large spills of LNG onto water which have been particularly contentious. It is in that vein that I have prepared this report with a view to cutting through the technical details to provide the public with my summary of the information which is now available, along with my candid view of what that information should mean to the public and its policy makers whom are considering the siting of an LNG import terminal in the POLB. I believe it is absolutely imperative that we get this one right, as it will have the potential for setting extremely important precedents in our attempts to balance the risks and benefits of increased LNG importation, that task having been made immensely more difficult by the threat of terrorist attack.

CHAPTER 2

POTENTIAL HAZARDS TO THE PUBLIC OF THE PROPOSED LNG TERMINAL IN THE PORT OF LONG BEACH

2.1 Location and Description of the Proposed Terminal

Location

The satellite photo below shows the harbors of Los Angeles and Long Beach, with adjacent cities of Los Angeles to the west and north and Long Beach to the north and east. The proposed location of the LNG terminal in the Port of Long Beach is on an approximately twenty-five acre site on the east side of Pier T. For purposes of scaling, a circle with one mile radius is centered on the location of the tanker offloading site, which will be on the west side of the land parcel designated "TERMINAL".[1]

[1] This satellite view, which extends to distances of three to four miles from the proposed terminal, will be used later in this report to delineate the minimum extent of zones in which the public and infrastructure could be endangered by major releases from containment of flammable liquefied gases - for which there is now good scientific agreement that are deemed to be credible.

Descripton

For purposes of this report, which is primarily directed to consideration of public safety issues, the principal components of the LNG terminal are summarized below.

- An LNG ship berth with 4 LNG unloading arms;
  - 2 liquid arms designed for a capacity of 24,150 gallons per minute (gpm) each, allowing ship offloading at 48,300 gpm,
  - 1 liquid/vapor hybrid arm, and
  - 1 vapor arm.

- 2 LNG receiving tanks, each with a gross volume of 42.3 million gallons of LNG at a temperature of -260 F and a normal pressure of 1 to 3 psig. (LNG-1, LNG-2 on plot plan);

- 6 in-tank LNG pumps, each sized for 2,500 gpm;

- Seven LNG primary booster pumps, each sized for 1,830 gpm;

- Seven LNG secondary booster pumps; each sized for 1980 gpm;

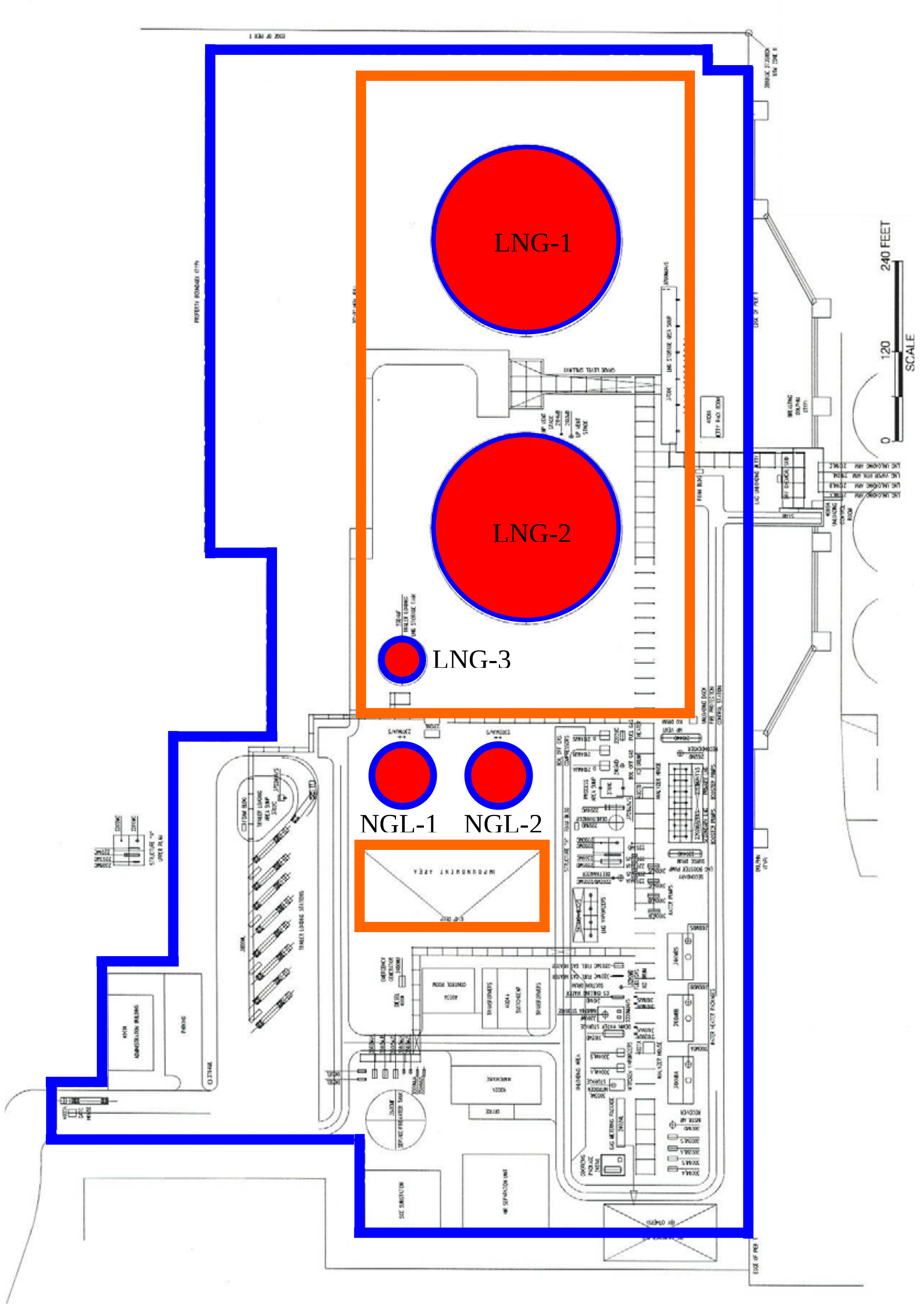
- Four shell and tube vaporizers, each sized for 350 million standard cubic feet of gas per day using a primary closed loop water system heated with three direct-fired heaters and circulation pumps;

- Three boiloff gas compressors and associated condensing systems;

- An LNG trailer truck loading facility, including an LNG receiving/storage tank with a capacity of 1,000,000 gallons of vehicle quality LNG for distribution via eight trailer loading bays (LNG-3 on plot plan). An average of 45 trucks will be loaded per day.

- An NGL recovery system, for which the final design appears to remain under consideration, will provide for the recovery and distribution off site of natural gas liquids, principally ethane and propane, via pipeline and/or trailer truck loading;

The terminal plot plan follows, with designation of the location of the primary storage tanks (in red), spill impoundments (in orange), and site boundary in blue. The total area of the site is approximately 25 acres. (Information from Sound Energy Solutions Long Beach LNG Import Project Resource Report 1, General Project Description, Jan. 2004)



***The author is aware that consideration is being given to altering the requirements for NGL storage, perhaps even eliminating it. As the author is not privy to any final decision in this regard, this description is based on the site description from SES' January 2004 report.

2.2 LNG (Liquefied Natural Gas) and NGL (Natural Gas Liquids) Hazards

The primary hazards (to the public) that can result from the errant release of liquefied gas fuels such as LNG and NGL from the proposed terminal activities in the POLB are:

- Fire hazard
  - Liquid pool fires
  - Vapor cloud fires

- Explosion hazards
  - Confined vapor cloud explosions
  - Unconfined vapor cloud explosions (UVCE)
  - Boiling liquid expanding vapor explosions (BLEVE)

There are other hazards that require identification and consideration. However it is noted here that they can be of different degrees of concern for LNG and NGL and, in any case, are of less concern than the fire and explosion hazards because, with caveats noted in the specific descriptions that follow, these hazards would not be expected to extend offsite and therefore would not directly affect the public:

- Toxicity hazard
- Cryogenic ("cold" burn) hazard
- Rapid phase transition (flameless explosion) hazard

These last three hazards will be described briefly, for completeness, and then relegated to secondary importance in order to prioritize the main concerns for public safety.

2.2.1 Toxicity Hazards

LNG is natural gas that has been cooled to its condensation temperature; its composition can vary significantly depending upon the source of the gas. However, LNG normally contains as its principal component methane, with heavier hydrocarbons such as ethane, propane, butane, etc., comprising the much smaller remainder.

For purposes of assessing the hazards of LNG, it is appropriate to consider the toxicity of LNG vapor to be that of methane, the principal component, with modification as deemed necessary to allow for consideration of the toxicity of the heavier components which may be present.

Since methane is not a toxic material, it normally poses a hazard only if breathed in sufficient quantity to displace necessary quantities of oxygen (asphyxiation). Consequently methane is not expected to pose a toxicity hazard to the public at the proposed terminal since the public would not be expected to be exposed to high enough concentrations to result in severe displacement of oxygen. Furthermore, the toxicity of the heavier components contained in the LNG, which for our purposes here also can be considered to be simple asphyxiants, is not expected to pose a hazard to the public because of the low concentrations to which the public would be exposed.

Similarly to LNG, which usually contains small amounts of NGL, the components of NGL (ethane and propane are suggested to be the primary natural gas liquids to be stored at the Long Beach Terminal) are not expected to pose a primary hazard to the public, since concentrations of these gases sufficient to asphyxiate people would not be expected to extend off site except in the most extreme conditions, and in such cases the fire and explosion hazards pose much greater hazards.

2.2.2 Cryogenic ("Cold Burn") Hazards

LNG, as pure methane, has a temperature of approximately -260 F. It is a cryogenic liquid, and exposure of human tissue to such temperatures can cause immediate severe injury. The author investigated an accidental release of LNG that occurred in 1977 in Arzew, Algeria, where a man was killed as a result of being deluged with LNG from a ruptured cryogenic valve. However, injury to the public is not expected to occur by exposure to such extreme temperatures because the region near a release of LNG where contact with either the liquid or cold vapor could cause such "cold" burns would not be expected to extend to distances where the public could be exposed.

Natural gas liquids such as ethane and propane, unlike methane, can be liquefied by pressure alone. Consequently, NGL can be stored either under pressure, refrigerated, or in combination. However, since refrigerated NGL is at a much higher temperature than LNG, and since low gas temperatures that could result due to depressurization of (pressurized) NGL would not be expected to extend to distances where the public could be exposed, NGL is not expected to pose "cold burn" hazards to the public at the POLB.

2.2.3 Rapid Phase Transition (Flameless Explosion) Hazards

If a small volume of LNG is rapidly poured into water, the LNG can be heated by the water to temperatures greater than its normal boiling point while remaining in the liquid state. The (liquid) LNG is then said to be *superheated*. If several degrees of superheat are achieved, the evaporation (boiling) process which follows can be essentially instantaneous, with the result that significant pressure increases (overpressures) can result. Such overpressures can cause damage similar to the overpressures caused by more *conventional explosions* which are normally associated with rapid combustion of a chemical or fuel.

The rapid phase transition (RPT) of LNG added to water was first observed, unexpectedly, in a laboratory experiment performed in the Sixties at the U. S. Bureau of Mines. Subsequent research into the phenomenon has been performed by several organizations, most prominently by inhouse industry research programs. All of the work of which I am aware is relatively small scale, but there have been calls for additional research to better determine the scaling characteristics of rapid phase transitions.

As in the case of cryogenic (cold burn) hazards, the damaging overpressures that could occur from rapid phase transitions would be local, and the resulting overpressures are not expected to extend to distances which could endanger the public.

However, there is continuing interest in, and a need for, further research to study the scaling characteristics of RPT's. Although dangers to the public are not expected to result directly from RPT overpressures, their importance in the public safety context lies in the potential for RPT's to cause secondary damage which could lead to cascading failures and further releases of LNG.

The author is not aware of damaging rapid phase transitions having occurred for spills of NGL onto water, although the NGL content of LNG, which is much colder, appears to have some relation to RPT occurrence (as it does as well to UVCE occurrence, as we will see). In any case, as large spills onto water at the POLB terminal are expected primarily from the LNG carrier, and since impoundment areas are expected to be provided for any NGL storage tanks, large spills onto water of NGL at the terminal are not expected.

2.2.4 Fire Hazards

There are two ways that very large fires (that could endanger the public) can result from a major LNG spill – pool fires and vapor cloud fires.

Pool Fires on Land

Spilled LNG will evaporate rapidly due to high rates of heat transfer from the warm surroundings (primarily the earth's surface) to the cold liquid. The vapor evolving from the liquid pool will mix with air to form a gas-air mixture which will burn in the concentration range of approximately 5% to 15% LNG vapor (the concentration range that is flammable for methane-air mixtures). Such mixtures of LNG vapor and air will inevitably form when LNG is spilled, and if an ignition source such as an open flame or spark is present at a location where the gas mixture is within the flammable range a large pool fire will result. In this instance the fire will immediately burn through the gas mixture from the point of ignition to the liquid pool. The resulting "pool fire" is similar in many ways to any other pool fire where liquid hydrocarbons, such as gasoline, are burning – but it should be noted that because the LNG is so cold, heat transferred from the surroundings will cause the LNG to evaporate much faster, thus effectively "feeding" the fire at much higher rates than would occur from a gasoline spill, and even faster than would occur for a refrigerated NGL spill (because the NGL is not nearly as cold). In any case, the fire results from the combustion of the fuel vapors which have evaporated from the liquid pool and have been mixed with air to result in flammable concentrations. An LNG pool fire, which has the potential to burn significantly "faster" than higher boiling point hydrocarbons, can seriously endanger the public, either through direct contact with the fire, or through heat radiated by the fire.

It should be noted here that it is in this context that the statement that “LNG does not burn”, or variations thereon, is frequently found in the literature purporting to educate the public regarding LNG safety. While the statement is literally true, it is not helpful, and it can be seriously misleading, as the statement is also (literally) true if applied to any other liquid hydrocarbon fuel such as gasoline or NGL. It can be misleading because the statement that LNG does not burn could imply that there is something different in the combustion mechanism of LNG from other hydrocarbon fuels – in this sense, there is not.

Because very large releases of LNG, attended as they would likely be by violent circumstances which could result in ignition (thus preventing the formation of a flammable vapor cloud that could leave the site), I believe that the potential danger to the public from LNG spills is probably greatest from the very large pool fires that would more likely occur. I emphasize that I am talking about fires resulting from the spillage of several millions of gallons of LNG (each of the two primary storage tanks at the POLB terminal will contain more than 40,000,000 gallons of LNG). We have no experience with such fires, but we do know that they could not be extinguished and would just have to burn themselves out, and the radiant heat extending outward from the fires edge could ignite combustible materials as well as cause serious burns to people at considerable distances from the fire’s edge. The distances from such fires to which harm to the public could extend will be a primary focus of this report.

NGL pool fires on land may be considered similarly with LNG pool fires, with at least two potentially important differences, the implications of which are not completely understood, especially for very large fires:

- NGL, whether it be pressurized or refrigerated, will not evaporate as fast as LNG will due to heat transfer from the ground surface, hence the burning rate (and associated heat flux from the fire) may be somewhat smaller.

- NGL fires have been observed to produce more smoke than LNG fires, with the result that the heat flux radiated out from the fires edge can be significantly changed.

Vapor Cloud Fires

If LNG is spilled and evaporates to form a gas/air mixture in which there are located no sources of ignition (an ignition source is a high temperature “point” source of energy such as a spark or flame), the gas-air mixture (“gas cloud”) which forms, although possibly containing a large amount of gas that is in the flammable concentration range, will not ignite, and the cloud will drift until it either contacts an ignition source or all of the cloud becomes diluted below its *lower flammable limit* (approximately 5% methane in air) - it will then disperse harmlessly. If ignition occurs during the drifting of the cloud the result is a vapor cloud fire.

If the gas cloud formed is not ignited immediately it will be carried downwind, or will spread more or less radially (due to gravity forces on the heavier-than-air gas mixture) in the absence of wind. Both spreading by the wind and gravity spreading are accompanied by gas-air mixing and thus dilution of the cloud.[2]

If, however, an ignition source is encountered at a location where the gas concentration is within the flammable concentration range, ignition will occur (at that location) and the fire will spread throughout the part of the cloud which is in the flammable concentration range. This is the so-called "flash fire" or vapor cloud fire. An LNG vapor cloud fire can endanger the public, either through direct contact with the fire, or through radiated heat from the burning cloud.

I think it important to state here again that my opinion that pool fires pose a greater risk than vapor cloud fires (see above) is based on the potential for high consequences *accompanied by the high probability that ignition will occur* as a result of the violent circumstances that would be expected to effect such a release. However, as I have said above, the consequences of credible events that might occur that could impact public safety require determination *independently* of consideration of the likelihood of the occurrence. Finally, I note here that the current federal regulations for siting LNG facilities require the determination of vapor cloud dispersion exclusion zones to protect the public safety, and no consideration is given to ignition probability in the determination of those exclusion zones. Therefore, it remains critically important to

[2] Photograph of an LNG spill onto water at Maplin Sands, UK, in the Eighties. The LNG spill volume was of order 10,000 gallons, with a moderate wind from top right to bottom left. White objects are floating instrument platforms. For scaling, radius of circle (dike) is approximately 450 feet. This spill volume is representative of the largest LNG spills that have been conducted on water to study vapor dispersion.

determine the potential consequences of delayed ignition of large flammable vapor clouds.[3]

[3] Sequence of photographs (top to bottom) showing an LNG vapor cloud fire over water – tests conducted at Maplin Sands, UK, in the Eighties. Wind is from right to left with maximum visible cloud extent at the left of the top picture. Ignition occurred near the left side of the gap in the cloud in the top photograph, and the cloud has burned nearly back to the liquid pool in the bottom photograph. Spill volumes are similar to the photograph in footnote 1, and the diameter of the circular dike is approximately 900 feet.

Vapor cloud fires that would result if an NGL vapor cloud were ignited may be also considered similarly to LNG fires, with at least three potentially important differences:

- The flammability range for NGL is significantly different than for methane, the principal component of LNG. Most importantly here, the lower flammable limit for NGL is lower than that for LNG; for ethane it is about 3%, and for propane it is just over 2%. This is significant because it means that NGL vapor clouds will remain flammable at lower concentrations, and therefore will have the potential to remain flammable for greater distances (than for an equivalent volume of methane vapor). As a result, the extent of potential danger to the public is increased.

- NGL vapors may be heavier than air because of their higher molecular weights. For example, propane's molecular weight is 44, causing its density to be about 50% greater than air at the same temperature and pressure. This is important because the density stratification in such a vapor cloud decreases the dispersion rate (by decreased mixing with air) and can result in increased downwind travel before the gas cloud concentration falls below the lower flammable limit, thus increasing the extent of potential danger to the public.

- As will be discussed in more detail below, NGL vapor clouds are known to be susceptible to high-order explosion if ignited, even in the absence of confinement. Therefore, the improbability of explosion due to absence of confinement, a factor which is considered highly important in the assessment of LNG safety, does not apply to NGL vapor clouds. As there have been several catastrophic explosions of NGL vapor clouds, this hazard will be considered prominently in this report.

2.2.5 Confined Vapor Cloud Explosion Hazards

There is no need here to further define the potential for explosions of confined LNG or NGL vapor/air mixtures, of which we are all aware. However, the potential for explosions of confined LNG or NGL vapors are important to this hazard assessment because they have the potential for release of energy and ejection of projectiles that could jeopardize other NGL or LNG containments.

2.2.6 Unconfined Vapor Cloud Explosion (UVCE) Hazards

The term explosion is used here to describe combustion reactions (that we normally call "burning", i.e., reaction of the gas in question with the oxygen in the air) which achieve such rapid rates that significant overpressures (local pressures higher than the atmospheric pressure) develop. Such overpressures can cause severe damage – they constitute the "blast" effect in conventional explosions.

The forces released in conventional explosive materials (such as dynamite) typically result from very rapid *reactions of materials that are totally contained in the explosive* *material*. In such materials both the “fuel” and the “oxidizer” are already present. In contrast, explosions of fuel gases such as methane or propane cannot occur unless the gas (fuel) is mixed with air (containing oxygen) such that the mixture has a concentration within the flammable range (for methane this is approximately 5% to 15% in air). Such *physical* processes (as mixing with air), which are necessary for the gas to burn (or explode), place gas/air fires and explosions in a lower hazard class than materials like dynamite, which are “ready to go” if ignited, i.e., without the necessity that the material first be mixed with anything else. Furthermore, if the methane concentration is less than 5% (the *lower flammable limit*) concentration, the mixture will not burn, much less explode – it is said to be too *lean*. Similarly, if the methane concentration is higher than 15% (*the upper flammable limit*) concentration, the mixture will not burn (or explode) – it is said to be too *rich*.

If a methane/air mixture within the flammable concentration range is ignited, the rate of reaction (the burning rate, i.e., how fast the flame moves through the gas mixture) varies depending on a number of factors, one of the most important of which is *confinement.* We all know that natural gas (normally principally composed of methane) explodes all of the time – *when it is confined*. We all have read about, and many have experienced, the blast effect that occurs when leaking (flammable) gas is released into a confined volume (say the kitchen) and its ignition (say by a light switch) blows the building apart.

Conventional wisdom, even scientific opinion, held until fairly recently (the Seventies) that unconfined gas/air clouds such as are formed by gases such as methane, propane, and the higher molecular weight hydrocarbon, will not explode if unconfined. This is important to the present discussion because it goes straight to the question of whether the cloud formed by LNG vapors mixing with air following a major LNG spill could explode (develop damaging overpressures) when the cloud is not confined.

Today, damaging explosions of hydrocarbon gas/air mixtures are of very great concern because of accidents which have demonstrated the propensity of some hydrocarbon gases, when mixed to the correct proportions with air, to explode with devastating damage, *even when unconfined*. There is not time or space here to provide the details, but it can be stated that at least three such unconfined vapor cloud explosions (UVCEs) that occurred at Flixborough, England, in 1974; Mexico City in 1984; and in Pasadena, Texas, in 1989, were so devastating that they resulted in extensive changes in the national and international regulatory requirements for dealing with chemical hazards.

What does this have to do with LNG? There is a scientific consensus (supported by experimental data) that methane/air mixtures which are unconfined are very unlikely to explode. The LNG industry and the Government are sufficiently confident of this fact that the explosion of an unconfined LNG vapor/air cloud is not considered credible. As a result, the most severe hazard is considered to be fire. I have studied this question, and I agree with the contention that unconfined methane/air mixtures are very unlikely (but not impossible) to explode.

But the story doesn't end there. It has already been stated that the composition of LNG imported into the United States varies significantly depending on several factors, most prominently the gas source location. LNG is imported from some locations that provide nearly pure methane. LNG is also imported from some other locations with concentrations of heavier hydrocarbons as high as 15-20%. Such gas is termed "hot gas" in the industry because its calorific value (energy content) is higher than an equivalent volume of methane. Typical heavy hydrocarbon gases present in LNG are ethane and propane, but others are present as well.

We know now that even unconfined vapor cloud explosions (UVCEs) cannot be dismissed for LNG spills if the gas contains significant amounts (say greater than about 12 to 18%, based on Coast Guard sponsored tests at China Lake in the Eighties) of gas components heavier than methane. Furthermore, enrichment in higher boiling point components of the liquid remaining as the LNG vaporizes can lead to vapor cloud concentrations that could pose a UVCE hazard, even if the concentration of the heavies in the liquid initially spilled do not. Since the LNG terminal proposed to be located in the POLB is planned to receive "hot gas"[4], and to engage in the storage and distribution of natural gas liquids (NGL) that are separated from the imported LNG, *questions of whether major releases of LNG at the terminal might pose an unconfined vapor cloud explosion hazard, with the attendant potential to initiate further cascading effects, remain highly relevant*.

There is now no question that GNL vapor clouds can explode with devastating force. Consequently, as the POLB terminal will have some, perhaps yet to be determined, quantities of GNL on the site (primarily ethane and propane), the potential for releases at the terminal to result in high order vapor cloud explosions must be given primary consideration in the assessment of potential hazards to the public and surrounding infrastructure.

Although there are numerous examples of unconfined vapor cloud explosions that have occurred in the chemical manufacturing, storage, and transportation sectors, it is not necessary, nor is there time here, to give a complete list of occurrences. Two events which appear to be highly relevant to this POLB hazard assessment will be highlighted here:

- A fire and explosion occurred in 2004 at the LNG export terminal in Skikda, Algeria. Preliminary reports indicate that damaging unconfined vapor cloud explosions appear to have occurred. If so, this would be the first UVCE which has been reported in an LNG terminal (to the author's knowledge). Final reports have not been released, so there is admittedly some speculation involved here. That said, it appears to the author that damaging explosions did occur both in confined spaces and in unconfined spaces in the export terminal at Skikda. It is important to point out that since the releases are believed to have occurred in parts

[4] The author is aware of consideration being given to changing the specifications of the LNG that would be accepted by the proposed terminal. As stated earlier, this report has been prepared based on the descriptions made available from the SES Resource Report dated January 2004.

of the facility which would not have been handling LNG, but rather natural gas liquids, that the unconfined vapor cloud explosions experienced probably involved NGL. Nevertheless, particularly since the POLB will handle similar natural gas liquids, the recent experience in Algeria is highly relevant.

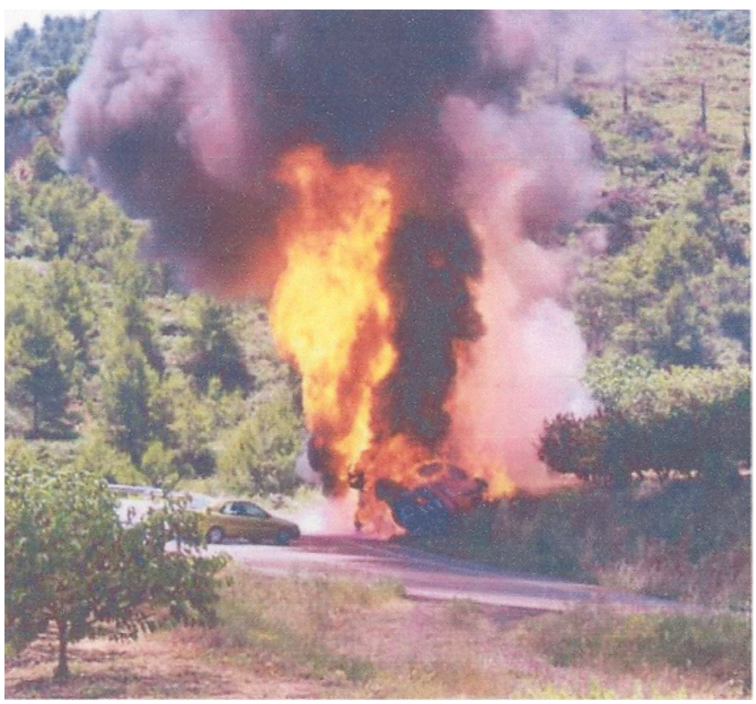
- The disaster which occurred on November 19, 1984, in San Juan Ixhuatepec (Mexico City), Mexico, is directly relevant to the consideration of the POLB LNG terminal, because the Mexico City facility provided for storage of quantities of NGL which are very similar to the quantities that could be stored at the NGL component of the POLB terminal. The Mexico City terminal, built for the distribution of LPG which came by pipeline from distant refineries, had an overall storage capacity of approximately 4,200,000 gallons of LPG in 6 large spherical tanks and 48 horizontal cylindrical tanks. The catastrophe started with the rupture, due to pumping overpressure, of an eight inch transfer line. The LPG thus released caught fire, causing fire impingement on one of the spherical tanks. The resulting cascading failure involved multiple unconfined vapor cloud explosions (UCVEs) accompanying the large fires which occurred. 574 people are reported to have been killed and more than 7,000 injured, of whom 144 later died in the hospital. Some 39,000 people were rendered homeless or were evacuated, and the terminal was destroyed.

2.2.7 Boiling Liquid Expanding Vapor Explosion (BLEVE) Hazards

The acronym BLEVE is short for “Boiling Liquid Expanding Vapor Explosion”. There have been a large number of devastating BLEVEs in the chemical process industry and in the transportation sector, including railroad and highway truck incidents. BLEVEs occur when a pressure vessel containing a flammable liquid is exposed to fire so that the metal comprising the containment loses strength and ruptures. When a vessel containing liquid under pressure is exposed to fire, the liquid heats up and the vapor pressure rises, increasing the pressure in the vessel. When this pressure reaches the set pressure of the pressure relief valve (PRV), the valve opens to relieve the pressure. The liquid level in the vessel falls as the vapor is released to the atmosphere. While the liquid is effective in cooling that part of the vessel wall which is in contact with it, those parts of the wall (above the liquid) that are exposed to vapor are not as effectively cooled. After a time, as metal which is not cooled by liquid is exposed to fire, the metal becomes hot and weakens and is subject to rupture. It is important to note that rupture can occur even though the pressure relief valve is operating correctly as designed. This is because a pressure vessel is designed to withstand the relief valve set pressure, but only at the design temperature conditions. If the metal is heated to higher temperature, it may lose strength sufficiently to rupture. Further, and most importantly to the consideration of the failure of LNG tanks to fire exposure, the pressure relief valves must be sized to allow relief of the vapor produced with fire exposure to the tank. I will return to this question when the vulnerability of LNG containments is considered.

Just as the conventional wisdom before about 1970 minimized the potential for explosion of unconfined LNG vapor clouds, that wisdom has also held that boiling liquid expanding vapor explosions of LNG containments are not possible. It appears that the conventional wisdom may have to be updated for BLEVEs of LNG as well.

An LNG road tanker exploded on 22 June 2002 near Tivissa, Catalonia (Spain), after the driver lost control on a downhill section of the C-44 road.[5] The tanker turned over, tipping onto its left side. Witnesses said that flames[6] appeared immediately between the cabin and the trailer, and after approximately 20 minutes, the tank exploded. There was a small explosion, then a strong hiss and then a much larger explosion. Immediately after the small explosion, the fire disappeared and a white cloud appeared. This cloud ignited immediately, giving rise to the larger explosion, a fireball. Assuming that all of the mass initially contained in the tank was involved in the fireball, approximately 12,700 gallons of LNG would have burned. Accepted mathematical modeling techniques suggest that the fireball diameter would have been about 500 feet, the height about 370 feet, and the duration approximately 12 seconds. These model predictions appear to be consistent with the facts that the fireball resulted in serious burns to two persons at a distance of 650 feet from the tanker. Major parts of the truck were projected to significant distances. The rear part of the tank, including the rear undercarriage of the truck, was ejected to a distance of 260 feet. A section of the front of the truck with maximum dimension of approximately 12 feet was projected more than 400 feet, and the motor and cabin covered a distance of more than 840 feet from the explosion.



[5] Planas-Cuchi, E., et.al, “Explosion of a road tanker containing liquefied natural gas”, Journal of Loss Prevention in the Process Industries, 17 (2004), pp 315-321.

[6] The photograph shows the jet fire from the tanker 2 minutes after the accident and approximately 18 min before the BLEVE. The author is not aware of any photographs of the fireball (but see footnote 7).

This LNG truck accident has been described in some detail because its occurrence suggests, if not demands, that renewed consideration be given to the potential for BLEVEs of LNG containers to occur. Perhaps most importantly, the road tanker was insulated with polyurethane insulation, and the early failure of the insulation would be expected to allow the container to more quickly reach temperatures giving rise to failure as well as allow heat transfer to the cargo which would significantly elevate the pressure in the tank beyond the ability of the PRV to relieve the greatly increased LNG vaporization. It is this mechanism, failure of the insulation followed by overpressure of the tank leading to rupture, which may have been exemplified in the Spanish road tanker explosion, that I have appealed to the Department of Homeland Security to consider as being applicable to LNG ships whose containers are insulated with foamed plastic insulation materials such as polystyrene and polyurethane[7].

There have been repeated incidents of BLEVEs of truck and rail containers of NGL, many having occurred in the Seventies and Eighties before the mechanism of the occurrence was understood. And, as was stated earlier, there have been devastating occurrences of BLEVEs in industrial storage and distribution facilities, perhaps most appropriately exemplified here by the disaster of November 19, 1984, in San Juan Ixhuatepec (Mexico City), Mexico. The Mexico City disaster is particularly relevant to the present considerations because the quantity of NGL stored in the Mexico City facility was similar to the quantity that could be stored in the POLB LNG terminal. Although the catastrophe started with the rupture of an eight inch transfer line, the first subsequent major failure is thought to have been a BLEVE of one of the NGL storage spheres, and the subsequent cascading failures involved multiple large BLEVEs.

[7] On July 5, 1973, in Kingman, AZ, a rail car containing approximately 10,000 gallons of propane began leaking during unloading, and the gas ignited. About a half hour later the tank BLEVE'd. The diameter of the fireball was approximately 400 feet, similar, if somewhat smaller, than the size predicted for the LNG BLEVE described in footnote 6. Note telephone poles for scaling and the railcar end being projected.

2.2.8 Special Hazards of LNG and NGL Spills on Water

There are special hazards of spills of LNG or NGL that could result from spills of either material on water, because, in addition to the (lesser) hazards of rapid phase transitions that could result from LNG spills considered earlier, it would be impracticable, if not impossible, to contain the spread of either of these liquid fuels on water. Consequently, there would be nothing to limit the size of the liquid pool that would result except the limiting amount of material spilled and the physical constraints which would limit its spread on the water. Since the size of the liquid fuel pool would determine the size (areal extent) of the fire, large spills on water could easily result in fires much larger than those which would be contained in the purpose-designed spill impoundment areas on land.[8]

[8] The photograph illustrates an LNG pool fire on water. Somewhat less than 10,000 gallons of LNG was spilled; the resulting fire is about 50 feet in diameter and 250 feet high. This test, conducted by the U.S. Coast Guard at China Lake, CA, in the Eighties, is also representative of the largest LNG pool fires that have been studied.

As will be described and justified in more detail subsequently in this report, there is now scientific consensus that rapid spillage of at least one half of a typical single LNG ship container, approximately 3,000,000 gallons, is a “credible event”, as it has been determined that it could be caused by an intentional (terrorist) act with means that are readily available to such groups. The fire from such a spill, particularly if it occurred onto water and was therefore uncontained, would be very large, perhaps up to a half-mile in diameter, or larger if more of the containment system failed. We have no experience with such fires, but we do know that they could not be extinguished and would just have to burn themselves out, and the radiant heat extending outward from the fires edge could ignite combustible materials as well as cause serious burns to people at substantial distances from the fire’s edge. The distances from such fires to which harm to the public, as well as damage to infrastructure, could extend will be a primary focus of this report.

Furthermore, although it is considered highly likely (but we do not know enough to say impossible) that early, if not immediate, ignition of the gas air mixtures above such a spill would occur as a result of the violent circumstances (as in an allision or collision of a ship or a terrorist attack) that would be expected to accompany such a major release, it is imperative that the extents of flammable vapor cloud travel that might result from major spills of LNG onto water (which are most likely to occur from the ship) be considered in the assessment of hazards that could result at the POLB LNG terminal.

CHAPTER 3

ADEQUACY OF CURRENT REGULATIONS TO PROVIDE FOR PUBLIC SAFETY

This part of my report gives my answer to the question: *To what extent do present U.S. regulations that govern LNG terminal siting adequately protect the public from the consequences of LNG releases that could occur?*

Although U.S. Regulations currently require enforcement of <u>some</u> safety exclusion zones intended for the protection of the public (by prohibiting their presence therein), I believe they fall seriously short of achieving the intended objective:

- The regulations were promulgated in the early Eighties largely as a result of concerns for public safety that arose in the Seventies. Since there was no rush to build additional LNG import terminals until about the year 2000, the regulations were largely unused for import terminal siting. As a result, the regulations did not, and still do not, give serious consideration to the terrorist threat that began in this country September 11, 2001. Instead, the regulation method and approach relied on, and still relies on, consideration only of accidental occurrences that could affect the public. Hence, the current regulations do not effectively address the many serious questions posed by the present requirement to consider events that could be caused by malicious intent. Nor is sufficient attention being paid to the reality that malicious intent changes the whole safety picture. We no longer have the option to just "better" manage the risks involved so as to reduce the probability of occurrence of accidents to an acceptable level. The siting in an urban area of an LNG terminal, with its requirements to concentrate immense quantities of hazardous materials, takes on a new dimension. Unfortunately, the process has outrun the development of the regulations to deal with it, and the present regulations fail to address this most important new paradigm.

- Perhaps most importantly, in consideration of the post 9/11 threat, there is presently no requirement, much less enforcement, of exclusion zones to protect the public from LNG spills which could occur from the ships that serve the import terminal. The failure to provide for the protection of the public and surrounding infrastructure from major releases of LNG that could occur from the ships serving the facility must be considered all the more important now as a result of recent government sponsored reports, for which there is now scientific consensus, that indicate that the danger zones extending from large, but credible, spills on water are likely to pose greater threats than would either accidental or terrorist caused releases from the land part of the terminal.

3.1 49 CFR 193 LNG Terminal Siting Provisions for Public Safety

The regulation that specifies requirements for siting LNG import terminals in the United States is 49 CFR 193, entitled *Liquefied natural gas facilities: Federal standards*.

Part 193 -- *Liquefied natural gas facilities: Federal standards* contains numerous sections describing requirements designed to provide for safe operation of an LNG import terminal. However, most of these sections are directed to the attainment of safe operation of the plant, and therefore they do not directly address the public safety issue. There are two sections of the regulation that directly address requirements to provide for safety of the public (offsite):

193.2057 *Thermal Radiation Protection,*

and

193.2059 *Flammable vapor dispersion protection*.

It is noted that the three other LNG hazards described earlier; toxicity, cryogenic ("cold burn"), and rapid phase transition, are not addressed, as these three potential hazards are not expected to affect the public offsite. Explosion hazards (not covered by the regulation) will be considered herein.

Before proceeding to the description of Sections 193.2057 and 193.2059, and to the question of their adequacy to provide protection to the public, I believe it will be helpful to briefly summarize the development of these two sections of the regulation.

During the Seventies, when the four presently operating LNG facilities were constructed in the United States, 49 CFR 193 had not yet been promulgated. The applications for certification of the terminals that were built in Everett, Massachusetts; Cove Point, Maryland; Elba Island, Georgia; and Lake Charles, Louisiana, were decided largely based on guidance contained in industry consensus standards, notably NFPA (National Fire Protection Agency) 59A – *Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG).*

However, as a result of public concerns that arose during the Seventies about LNG terminal siting safety issues, notably those that arose in California regarding the proposals to site terminals at Los Angeles, Oxnard, and Point Conception, Congress mandated a research program on LNG safety, and authorized an expenditure of approximately $40,000,000 (in 1977 dollars) on LNG safety studies. That research program carried out basic LNG safety research directed to development of methods to define more accurately and realistically the consequences that could result from major spills of LNG. The research effort was directed to three hazards which were considered highest priority;

- liquid pool fires,
- vapor cloud fires, and
- vapor cloud explosions.

Following completion of these research programs, which still constitute much if not most of the research results and data relating to LNG spill consequences that are available in the public domain, 49 CFR 193 was promulgated - in the early Eighties.

I was called upon from time to time for advice by persons in the U.S. Department of Transportation who were preparing the draft regulations that evolved into 49 CFR 193, primarily in the area of my principal expertise, LNG vapor dispersion. My association (with DOT, at that time) was with Mr. Walter Dennis. Walter Dennis was actively involved in the drafting of the sections of 49 CFR 193 identified above (Sections 2057 and 2059), and I had several conversations with him regarding these sections of the regulation, particularly regarding the selection and application of methods for determining vapor dispersion distances. I believe that Walter Dennis was the person primarily responsible for developing Sections 193.2057 and 2059. This is important to the present discussion because Mr. Dennis subsequently advised industry (at their request) regarding the methods to be followed in the determination of exclusion zones required by the regulation. Walter Dennis died (in the late Eighties, I believe) when interest in LNG importation was languishing. I believe that his advice regarding the determination of vapor cloud exclusion zones has been used improperly so as to downplay the severity of the hazards which the regulation is designed to protect against.

(At least partly) as a result, there remains confusion even today about the correct determination of vapor cloud dispersion exclusion zones for spills of LNG which could occur into impoundments on the land terminal. I have prepared reports for the City of Fall River, MA, and I have filed testimony with FERC as well, which describe errors that I believe were made in the preparation of the Draft Environmental Impact Statement for the Weaver's Cove Project proposed to be sited in the Taunton River at Fall River.

With that background, I return to consideration of 49 CFR 193. When 49 CFR 193 was promulgated in the Eighties, it provided for the determination of *exclusions zones* for *vapor dispersion* and *thermal radiation*. The term *exclusion zone* is defined in the current regulation:

"Exclusion zone means an area surrounding an LNG facility in which an operator or government agency legally controls all activities in accordance with Sec. 193.2057 and Sec. 193.2059 for as long as the facility is in operation."

This definition is critically important because it follows that the intent of the regulation is that the *consequences* of vapor cloud dispersion and fire radiation scenarios must be specified by determination of the distances to which each of these hazards would extend from the spill, and once those distances are determined, the resulting exclusion zones must be controlled by the owner of the facility or the government. Thus the regulation provides for the prevention of members of the public from occupying the areas included by the exclusion zones, and therefore prevents them from being exposed to the associated hazards. Importantly, no consideration is given to the probability of such hazards being realized (the regulation is *consequence* driven, i.e. it gives no consideration to the probability of the occurrence), it simply defines the extents of the *exclusion zones* which are enforced to ensure that the public is not exposed to danger. *As I have stated earlier, I believe that such a consequence driven requirement for the establishment of exclusion zones to protect the public is all the more appropriate today in view of the potential* *severity of the terrorist threat, for which historical accident experience, however good, provides little assurance to the public.*

It is noted here that there is no mention in 49 CFR 193 of explosions, either vapor cloud explosions (confined or unconfined) or boiling liquid expanding vapor explosions. I will return to this important omission later.

3.1.1 Exclusion Zones for LNG Pool Fires

Section 193.2057 of the Federal Standard is excerpted below.

Sec. 193.2057 Thermal radiation protection.

Each LNG container and LNG transfer system must have a thermal exclusion zone in accordance with section 2-2.3.1 of ANSI/NFPA 59A with the following exceptions:

(a) The thermal radiation distances shall be calculated using Gas Research Institute's (GRI) report GRI-89/0176, which is also available as the "LNGFIRE III" computer model produced by GRI. The use of other alternate models which take into account the same physical factors and have been validated by experimental test data shall be permitted subject to the Administrator's approval.

(b) In calculating exclusion distances, the wind speed producing the maximum exclusion distances shall be used except for wind speeds that occur less than 5 percent of the time based on recorded data for the area.

(c) In calculating exclusion distances, the ambient temperature and relative humidity that produce the maximum exclusion distances shall be used except for values that occur less than five percent of the time based on recorded data for the area.

Amdt. 193-17, 65 FR 10958, Mar. 1, 2000]

It is critically important to note here that the determination of exclusion zones for LNG pool fires requires specification of the criterion to be used to define the extent of the thermal flux hazard, i.e., a criteria for determining how far away from the fire must the public be to be protected. 49 CFR 193 presently requires that thermal exclusion zones be defined by the (mathematical model) prediction of the distance to which a person, at ground level, would be exposed to thermal radiation flux of 5 KW/m^2 (~1600 $Btu/hr/ft^2$). This thermal flux has been determined to have the potential to cause second degree burns to unprotected skin in approximately 30 seconds.

But, as I have previously testified to FERC, I believe that the criterion of a 5 KW/m^2 flux level merits further consideration, because exposure at this intensity to persons could result in serious burns within time periods which would not be sufficient for evacuation or escape. Further, although fire fighting personnel equipped with protective gear could work in such an environment for considerable time, they would not be able to provide evacuation or removal of unprotected persons in time to prevent injury. It is known that the flux level would have to be reduced to about 1.5 KW/m^2 before unprotected persons could be exposed continuously without thermal radiation injury. Consequently, I believe that serious consideration should be given to defining exclusion zones to protect the public from thermal radiation hazards using such a lower (~1.5 KW/m^2) thermal radiation flux criterion. However, whether or not DOT defines the exclusion zone using such a lower thermal radiation flux criterion, I believe that FERC should use the lower thermal flux criteria in order to protect the public from such very large fires. It is very important to recognize that a policy which prevents public presence only where there would be exposure to 5 KW/m^2 or greater is not consistent with the public interest, because the public could receive serious injuries at lower flux levels if exposed for longer time periods (including time periods that would still be insufficient to provide for sheltering or evacuation). That is why I have suggested that serious consideration of the lower value of 1.5 KW/m^2 as the "safety" criterion – as this value is widely recognized as being the highest value of thermal radiation exposure from which the public would not receive serious injury even if exposed for longer time periods."

For the determination of thermal radiation exclusion zones for the land side of the facility, the credible spill scenario must be defined for input to the LNGFIRE III model. The scenario then is defined by specifying the dimensions of the impoundment area that will contain the spill, and then specifying the rate and total amount of LNG that is spilled. Two types of spill scenarios are possible:

- Spillage from the LNG storage tank

and

- Spillage from a part of the piping system external to the storage tank.

Spillage from the LNG Storage tank

It is my understanding that the storage tank design proposed for the Long Beach Long Beach facility is a Total Containment design, which means essentially that the inner tank in contact with the LNG is surrounded by a prestressed concrete outer tank wall and covered with a similarly constructed roof. To my knowledge, no tanks of the this type have so far been constructed in the continental United States (the Penuelas, Puerto Rico, tank has a prestressed concrete outer tank, but I do not believe it has a concrete roof), but such tanks are currently being proposed for several other locations. It is my understanding that there remain some questions about the procedures to be followed for such installations, even questions relating to the lack of "definitions" for the various tank systems that are being considered. Nevertheless, 49 CFR 193 appears to have been interpreted by DOT, at least in the case of the DEIS and EIS's prepared for the Weaver's Cove terminal in Fall River, MA, in such a manner that the regulation does not require consideration of LNG spills that would penetrate the outer containment wall. It is my understanding, based on DEIS's that have been produced for terminals with similar tank design proposals, that the thermal radiation zones for fires associated with spills from the inner tank are (therefore) to be determined by assuming that the spilled LNG would be *contained* by the concrete outer wall. As a result, the fire scenario envisioned is an elevated, or "tank-top", fire with the diameter (size) of the fire determined by the diameter of the outer concrete tank. For such determinations, I believe that application of the prescribed method (LNGFIRE III) is adequate.

However, there remains a question about the validity of the assumption that failure of the outer concrete wall is incredible. Although I agree that such a failure due to accident would seem to be extremely remote, I cannot agree that such an event is impossible for a terrorist to achieve – witness our tragic experience on 9/11 when two large airliners were highjacked and flown into the World Trade Towers with devastating results. To my knowledge no analyses have been made available to the public which address the possibility of complete failure of a "total containment" LNG storage tank. I will return to the consideration of "worst case" events after consideration of the current requirements for determination of exclusion zones.

<u>Spillage from the Piping System</u>

Here, also, the regulations prescribe detail that cannot be adequately described here. However, it is my understanding that the intent of the regulation is to prescribe the credible spill events (for determination of exclusion zones) by identifying the portions of the pipeline systems that carry LNG at the largest rates in the facility, and then to assume a guillotine break in said line with flow at the maximum rate maintained for a period of ten minutes. It appears that negotiations with DOT in the past have in some cases resulted in approval of procedures which will ensure limiting the duration of flow (by automatic shut-off systems) to shorter periods, but I assume here the requirement for a ten-minute spill duration.

In either case, LNGFIRE III application is straightforward, since the fire size is prescribed by the outer boundary of the area (impoundment) into which the spill occurs. In summary, I believe the application of LNGFIRE III, to LNG pool fires contained in liquid impoundment areas, adequately describes the thermal radiation hazard for the purpose of determining exclusion zones to protect the public.

3.1.2 Exclusion Zones for Vapor Cloud Dispersion

Section 193.2059 of the Federal Standard is excerpted below.

Sec. 193.2059 Flammable vapor-gas dispersion protection.

Each LNG container and LNG transfer system must have a dispersion exclusion zone in accordance with section 2-2.3.2 of ANSI/NFPA 59A with the following exceptions:

(a) Flammable vapor-gas dispersion distances must be determined in accordance with the model described in the Gas Research Institute report GRI-89/0242, ``LNG Vapor Dispersion Prediction with the DEGADIS Dense Gas Dispersion Model." Alternatively, in order to account for additional cloud dilution which may be caused by the complex flow patterns induced by tank and dike structure, dispersion distances may be calculated in accordance with the model described in the Gas Research Institute report GRI 96/0396.5, ``Evaluation of Mitigation Methods for Accidental LNG Releases. Volume 5: Using FEM3A for LNG Accident Consequence Analyses". The use of alternate models which take into account the same physical factors and have been validated by experimental test data shall be permitted, subject to the Administrator's approval.

(b) The following dispersion parameters must be used in computing dispersion distances:

(1) Average gas concentration in air = 2.5 percent.[9]

(2) Dispersion conditions are a combination of those which result in longer predicted downwind dispersion distances than other weather conditions at the site at least 90 percent of the time, based on figures maintained by National Weather Service of the U.S. Department of Commerce, or as an alternative where the model used gives longer distances at lower wind speeds, Atmospheric Stability (Pasquill Class) F, wind speed = 4.5 miles per hour (2.01 meters/sec) at reference height of 10 meters, relative humidity = 50.0 percent, and atmospheric temperature = average in the region.

(3) The elevation for contour (receptor) output H = 0.5 meters.

(4) A surface roughness factor of 0.03 meters shall be used. Higher values for the roughness factor may be used if it can be shown that the terrain both upwind and downwind of the vapor cloud has dense vegetation and that the vapor cloud height is more than ten times the height of the obstacles encountered by the vapor cloud.

(c) The design spill shall be determined in accordance with section 2-2.3.3 of ANSI/NFPA 59A.

[Amdt. 193-17, 65 FR 10959, Mar. 1, 2000]

Again, it is important to note that the DEGADIS and FEM3A model(s) for calculating the exclusion zones for vapor cloud dispersion are *prescribed*. The DEGADIS model was promulgated in the regulation in an amendment dated in the early Nineties, and the

[9]The 2.5 percent concentration represents one half the lower flammable limit concentration of methane (5%). This concentration level is intended to define the cloud average concentration at a point which would prevent the presence of flammable (greater than or equal to 5 %) "pockets" of gas which could be ignited. Hence this concentration level is used as the criterion for delineating the hazard distance.

(alternate) FEM3A model was promulgated in the regulation in the amendment dated Mar. 1, 2000. I am the co-author, with Dr. Tom Spicer, of the DEGADIS model, and Dr. Spicer and I directed the research program sponsored by GRI (since about 1985) to validate a computational fluid dynamics model (FEM3A was ultimately selected, based on consideration of several candidate models) for LNG vapor dispersion application. I support the use of the DEGADIS and FEM3A models. Based on my knowledge of the models and my review of the development of both, I believe that, together, they incorporate reasonably the latest information obtained in the federally sponsored large scale LNG field test programs conducted by the Coast Guard at China Lake, CA, and at the Liquefied Gaseous Fuels Spill Test Facility (LGFSTF) located near Mercury, Nevada, in the Seventies and Eighties, as well as the results of other research programs that have been conducted, principally in the Chemical Hazards Research Center Wind Tunnel at the University of Arkansas.

The DEGADIS model is limited to application to dispersion of vapor clouds (including LNG vapor clouds) resulting from spills onto a flat surface (ground or water) with dispersion over flat, obstacle-free terrain. FEM3A was developed in a followup effort (to DEGADIS) to provide a mathematical model applicable to the determination of the effects on dispersion of manmade obstacles (such as tanks, dikes, or process equipment and structures) and/or significant terrain features. I believe that these two models, correctly applied for the situations for which they are designed, are adequate tools for determining vapor cloud exclusion zones which will ensure public safety. And, similarly to the previous discussion on thermal radiation exclusion zones, I believe that the application of these models, *respecting the limitations of each*, is relatively straightforward for the determination of vapor cloud exclusion zones extending from spills bounded by containment structures (dikes and impoundments) on land.

It is clearly the intent of 49 CFR 193 that enforcement of a vapor cloud dispersion protection exclusion zone implies that the area included be controlled by the facility operator or an agency of the government. It is also clear that the intent of the regulation is to provide for the enforcement of vapor cloud dispersion protection zones as the method for ensuring the safety of the public, since such exclusion zones clearly prohibit the presence of the public therein.

For the determination of vapor cloud dispersion exclusion zones for the land side of the facility, the credible spill scenario must be defined for input to either the DEGADIS model or the FEM3A model. The scenario is defined by specifying the dimensions of the impoundment area that will contain the spill, and then specifying the rate and total amount of LNG that is spilled. Again, two types of spill scenarios are possible:

- Spillage from the LNG storage tank

and

- Spillage from a part of the piping system external to the storage tank.

<u>Spillage from the LNG Storage tank</u>

As stated before, it is my understanding that the storage tank design proposed for the Long Beach Long Beach facility is a Total Containment design, which means essentially that the inner tank in contact with the LNG is surrounded by a prestressed concrete outer tank wall.

Further, it is my understanding, based on DEIS's that have been produced for terminals with similar tank design proposals, that the vapor cloud dispersion exclusion zones associated with spills from the inner tank are to be determined by assuming that the spilled LNG would be *contained* by the concrete outer wall. As a result the vapor cloud dispersion scenario envisioned is an elevated, "tank-top" vapor release, with the diameter (size) of the release determined by the diameter of the outer concrete tank. For such determinations, I believe that application of the FEM3A method, although untested for such use, is appropriate. However, the DEGADIS model was designed for applications to *ground level* releases, and I cannot recommend it to describe the tank-top release scenario.

I do note that vapor releases from the top of the tank would be expected to pose significantly less hazard to the public than would equivalent releases at ground level, particularly if accompanied by high wind conditions.

However, as in the case of the determination of fire radiation exclusion zones, there remains a question about the validity of the assumption that failure of the outer concrete wall is incredible, as (to my knowledge) no analyses have been made available to the public which address the possibility of complete failure of a "total containment" LNG storage tank. I will return to the consideration of "worst case" events after consideration of the current requirements for determination of exclusion zones.

<u>Spillage from the Piping System</u>

Here, also, the regulations prescribe detail that cannot be adequately described here. However I believe that the intent of the regulation was, and remains, to prescribe the credible spill events (for determination of exclusion zones) by identifying the portions of the LNG transfer systems (pipes) that carry LNG at the largest rates in the facility, and then to assume a guillotine break in said (pipe)line with flow at the maximum rate maintained for a period of ten minutes. I do note here that DOT has considered, and approved, procedures which would ensure limiting the duration of flow (by automatic shut-off systems) to shorter periods, but here I assume the requirement for a ten-minute spill duration.

For such spillage into an impounded (or diked) area, the containment afforded limits the liquid (LNG) spreading that can occur, and therefore effectively determines the area extent of the source of vapor (evolving from the spilled LNG).

But, there remain questions even about the requirements for specification of the leak rates that have not been resolved. I have filed testimony with FERC which describes my complaints that the present specification of "accidental leakage rate" design spills by NFPA 59A (which has been incorporated in 49 CFR 193 since the year 2000, effectively replacing the previous requirement for 10 minute full flow spills from the largest transfer line in the facility), have the effect of reducing the requirement for consideration of these (larger spills) that were the intent of the regulation - with the final result that the downwind vapor hazard is downplayed. FERC has not even been consistent in this regard, since they have given approval for submissions from facility applicants that contained transfer line spills with volumes ranging from 28,900 gallons (3-inch line break) all the way to 812,000 gallons (guillotine rupture of ship unloading line).

But, however the spill rate and volume is determined, the vapor cloud dispersion protection exclusion zone determination is not as straightforward as that for the determination of the thermal radiation protection exclusion zone, because:

- DEGADIS was designed to predict dispersion from spills on a flat surface, with dispersion proceeding on a flat surface, *in the absence of significant terrain features or manmade structures that would obstruct the wind or gas cloud flow*. A dike (or the vertical walls of an impoundment) designed to contain the spilled LNG (liquid) causes "holdup" of the gas until the gas overflows the impounded volume. The DEGADIS model does not allow direct accounting for the effect of the vapor "holdup" that occurs within the impounded/diked area. Although provisional methods have been suggested in the past for using DEGADIS under such conditions, such methods have been demonstrated to be in error, as will be discussed subsequently. It is now clear that utilization of certain methods provisionally suggested in the Eighties (for determining gas "holdup") can lead to serious errors in the determination of vapor cloud dispersion protection exclusion zones.

- Research conducted during the last two decades has resulted in the Department of Transportation's acceptance and approval of the use of the FEM3A vapor dispersion model. The FEM3A model *provides for prediction of the holdup that occurs in an impoundment area* as well as for other effects of obstacles or terrain features on dispersion of an LNG vapor cloud.

3.2 The Potentials for Unconfined Vapor Cloud Explosions and Boiling Liquid Expanding Vapor Explosions are not Addressed

Unconfined Vapor Cloud Explosion Hazard

The concern for the potential of unconfined vapor cloud explosion hazards at the proposed LNG terminal in Long Beach is directly related to the composition of the LNG that will be imported to the facility. It is anticipated that significant quantities of "hot gas", i.e., LNG containing significant quantities of hydrocarbons heavier than methane will be received at the terminal., and the plant is being designed to remove such heavy components (ethane, propane, etc.) for marketing and distribution from the facility.

Since it does not appear practicable to remove the heavier components of the gas *as it is being unloaded from the tanker into the storage tanks*, it is presumed that the "hot gas" NGL components will have to be stored, at least temporarily, prior to their distribution off site. Consequently, it is presumed that there could be significant quantities of LNG containing heavier hydrocarbons such as ethane, propane, etc., that will be stored and handled in the facility.

The problem of explosion potential of LNG vapor clouds has been studied. I quote directly from U.S. Coast Guard Report CG-M-03-80 entitled *U.S. Coast Guard Liquefied Natural Gas Research at China Lake*, dated January 1, 1980 (pages 12-13):

"Since unconfined vapor clouds composed of LPG have detonated after tank car and pipeline accidents, the next group of high explosive direct initiator tests involved the system methane-propane stoichiometric in air, always using a 1.35 kg Composition B initiator in a 5 m hemisphere.

….

The test series was run in the sequence 90% methane-10% propane, 57.6%-42.4%, 76.8%-23.2%, 81.6%-18.4%, and 86.4%-13.6%. Only methane concentrations above 81.6% failed to produce a vapor cloud detonation. The velocity of the fuel-air detonation wave was 1800 m/s and the maximum pressure was 15.5 bars in the 81.6%-18.4% test. Clearly, for the 1.35 kg initiator, the critical percentage of propane for the methane-propane-air detonation is between 13.6% and 18.4% propane; financial restrictions prevented the determination of critical concentrations for other initiator sizes. Theory suggests that the use of propane as a sensitizer is representative of all hydrocarbons heavier than methane. The 13.6% sensitizer concentration has special consideration as the commercial LNG being imported into the U.S. east coast has about 14% higher hydrocarbons."

Based on this report, which to my knowledge has not been called into question, it is clear that there is a potential unconfined vapor cloud explosion (UVCE) hazard associated with the errant release of LNG containing heavier (than methane) hydrocarbons in amounts in the range 13 -18% (and higher).

Furthermore, it is important to note that the explosions described in the Coast Guard Report were gas phase *detonations*, which means that the flame (reaction front) speeds were greater than the speed of sound in the unburned gas mixture. It is now well understood that damaging overpressures can occur in unconfined vapor cloud explosions even when flame speeds are well below those which result in detonations. The bottom line here is that LNG with concentrations above the range 13-18% has been shown to have the potential to *detonate when unconfined*, and there is consequently a very real potential for UVCE's to occur with damaging overpressures when such (unconfined) gas-air mixtures are ignited.

Consequently, although the present regulations do not require consideration of the UVCE hazard associated with vapor clouds that might result from spills of LNG, consideration of the UVCE hazard is relevant for the proposed Sound Energy Solutions terminal *if it is to import "hot gas" that may have concentrations of heavier components in the range above approximately 13-18%*.

Finally, it is noted that enrichment in higher boiling point components of the liquid remaining on the water as the LNG vaporizes can lead to vapor cloud concentrations that pose a UVCE hazard, even if the concentration of the heavies in the liquid initially spilled do not.

Boiling Liquid Expanding Vapor Explosions

If the decision is made to install NGL storage at the facility, consideration must be given to the potential for BLEVEs to occur in the event that the storage tanks are exposed to fire. The potential for NGL BLEVEs to threaten either public safety or infrastructure to distances greater than are already anticipated to be credible for large LNG pool fire or vapor cloud dispersion hazards appears to be low; however there is very real potential for severe mechanical damage (by explosive force or due to ejected missile impact) to the primary LNG storage facilities (or a ship at the jetty) that could cause cascading events that would worsen the situation.

In view of the recent apparent occurrence of a BLEVE of an LNG tank truck in Spain, the potential for BLEVEs of the trucks serving the facility, as well as LNG storage tanks, cannot be ruled out. However, the potential for BLEVE-like explosions appear to be much more likely from the ship containers than from the more heavily constructed and more fire-resistively insulated LNG storage tanks on land.

3.3 There is a Critical Need for Exclusion Zones for LNG Spills on Water

The potential for catastrophic releases from LNG carriers that service an LNG import terminal are acknowledged by FERC in several Draft and Final Environmental Impact Statements, including both for the Weaver's Cove Project in Fall River, MA. FERC has consistently stated that such catastrophic releases would be most likely caused by terrorist attack, and FERC's own analyses have shown that the consequences of such ship-side releases that have been identified tentatively as "credible" are far greater than the hazards posed by the land-side LNG spill scenarios. Nevertheless, the Commission continues to dismiss these hazards on the grounds that the threat of such events (large pool fires on water, or large vapor cloud formation following a spill on water) can be "managed".

I cannot support FERC's statement (from the Weaver's Cove and other Impact Statements) that "While the risks associated with the transportation of any hazardous cargo can never be entirely eliminated, they can be managed". In my opinion, this statement, with no justification provided, does nothing to provide the public confidence in FERC's ability to "manage" these risks. Indeed, I believe that it downplays the importance of the principal threat to public safety that is associated with the operation of any LNG import terminal – a terrorist attack that could result in catastrophic spills of LNG onto water.

I believe my recent testimony before the Subcommittee on Energy Policy, Natural Resources and Regulatory Affairs, provides adequate explanation of my view on this matter. Although the inclusion here of that testimony is repetitive of my earlier comments, I believe such repetition is warranted:

Testimony of Dr. Jerry Havens
Before the Congressional Subcommittee on Energy Policy,
Natural Resources and Regulatory Affairs
Tuesday, June 22, 2004

Mr. Chairman and Members of the Committee: My name is Jerry Havens. I am a Distinguished Professor of Chemical Engineering at the University of Arkansas. I appreciate this opportunity to address this hearing on Federal and State Roles in LNG Import Terminal and Deepwater Port Siting. I am speaking here today as a citizen-scientist, and not as an agent of my University.

I have for some thirty years been studying methods for assessing the potential consequences of major accidental releases of LNG. My remarks here today are about the estimation of the extents of danger to the public around such spills.

I believe that the potential danger to the public from LNG spills is mainly from the very large fires that could occur. I want to emphasize that I am talking about fires resulting from the spillage of several millions of gallons of LNG – a single tank on a typical LNG carrier contains six or more million gallons of liquefied natural gas. The fire from such a spill, if it occurred onto water and was therefore uncontained, would be very large, perhaps up to a half-mile in diameter, or larger if more of the containment system failed. We have no experience with fires this large, but we do know that they could not be extinguished, they would just have to burn themselves out, and the radiant heat extending outward from the fires edge could cause serious burns to people even at larger distances.

There are two ways that very large fires can follow a major LNG spill. If LNG is spilled it will rapidly evaporate and the vapors will mix with air to form a mixture which will burn in the concentration range of approximately 5% to 15% LNG vapor. Such mixtures of LNG vapor and air will inevitably form when LNG is spilled, and if an ignition source such as an open flame or spark are present, as would be highly likely to accompany the violent circumstances that would cause a major release, a large pool fire will result. However, if no ignition sources are present in the flammable gas mixture a vapor cloud will result, and the cloud will spread downwind from the spill until it either contacts an ignition source or becomes diluted below its flammable concentration - it will then disperse harmlessly.

The maximum distances of the danger zones extending from a pool fire or a flammable vapor cloud determine the zones which would endanger the public. It is the estimation of these distances, which are identified in 49 CFR 193 as <u>pool fire radiation</u> and <u>vapor cloud dispersion exclusion zones</u>, that I want to inform you about, because such exclusion zones are required in order to ensure that people are not exposed to danger if such a fire should occur, and such requirements determine the effectiveness of the LNG siting regulations to provide for public safety.

I first began studying the prediction with mathematical models of vapor cloud travel distances in the 1970's, when as this Committee knows, the first wave of interest in LNG importation arrived in the United States. I am privileged to have had an important role in the development of the current regulatory requirements for determining vapor cloud exclusion zones to support requests to FERC for LNG terminal siting. Both of the computer models currently required by 49 CFR 193 for calculating vapor cloud exclusion distances were the result of developments by my Associates and I at the University of Arkansas. I have also followed closely and have been involved in, if less directly, the development of the methods required by 49 CFR 193 for determining pool fire radiation exclusion zones.

In my opinion the current requirements in 49 CFR 193 for determining both pool fire radiation and vapor cloud dispersion exclusion zones around LNG terminals are based on good science, and they are adequate for their purpose. Indeed, the present regulations are the result of considerably more research on LNG safety than has been performed for many other hazardous materials that are routinely transported and stored in very large quantity. Furthermore, I believe it is important to emphasize that the hazards associated with LNG, aside from the localized dangers involved with handling any cryogenic fluid, are neither unique nor extreme when compared with other hazardous materials handled in bulk. The potential dangers we are discussing today are brought into the present focus because of the enormous amount of energy that must necessarily be concentrated to enable economical transport of liquefied natural gas across the world's oceans.

However, the suitability of the methods required by the regulations for determining exclusion zone distances is not in serious dispute. The problem lies in the specification of the LNG spill scenarios that must be considered.

Current U.S. regulations require that exclusion zones be calculated for spills in the land-based portion of an LNG import terminal only – the regulations do not currently apply to spills that might occur from the LNG vessel onto water.

Because spills on land are subject to a variety of control measures to limit the area extent of the spill, such as dikes or impoundment systems, exclusion zones in support of requests for siting land-based LNG terminals are typically, in my experience, less than one thousand feet. However, if exclusion zones were required to protect the public from LNG spills onto water from an LNG vessel at the jetty or in route to or from the terminal, there is good scientific consensus that the fire radiation exclusion zones could extend to a mile *or more if the entire contents of a single tank were rapidly spilled, and the vapor cloud dispersion zone could extend for a similar spill to several miles. Obviously, if the regulations were applied to the determination of exclusion zones to protect the public from LNG tanker spills onto water, it would have a very important effect on siting decisions. It seems clear to me that such consideration would raise very serious concerns about the siting of LNG terminals where people within the exclusion zone distances would be endangered. It is very sobering to me to realize that the ongoing LNG siting debate regarding public safety comes down to this, and I sincerely hope that those responsible for protecting the public recognize and seriously consider this very important question.*

Since 911 we no longer have the luxury of considering only means for reducing the probability of accidents to a level that justifies the attendant risk. I believe that it is imperative that the dangers to the public from possible releases from a LNG carrier onto water be considered in the siting of LNG terminals in our country.

I must also tell you that I am very concerned that spills from LNG vessels caused by terrorist attack might not be limited to the partial contents of a single tank on the vessel, as is widely assumed. Because of those concerns, I wrote to the Secretary of Homeland Security in late February to urge the Department to consider the vulnerability of LNG carriers to terrorist attacks as part of their deliberations on LNG terminal siting. Because some of the matters that I believed worthy of consideration are sensitive, I do not think it is appropriate to discuss them in detail here, but I will try as best I can to address any questions you may have about this subject. I am very disappointed that I have not received any response from the Department of Homeland Security regarding my concerns.

Thank you, that concludes my comments.

I stand by this statement, and I believe it is particularly relevant to the consideration of siting the Sound Energy Solutions LNG Project in Long Beach Harbor.

Today, although the science community has acknowledged the need for additional experimental data that can be used to address some uncertainties which remain in the extrapolation of consequence distances from the approximately 10,000 gallon spill range that has been studied to the approximately 10,000,000 gallon range that has been determined to be credible to result from a terrorist attack on an LNG ship, it is clear that there is scientific (and government) consensus that methods which have recently been evaluated by the ABS Group for FERC and by the Sandia National Laboratory for the Department of Energy are suitable for the estimation of the extent of the thermal radiation or vapor cloud dispersion hazard distances that would extend from major releases of LNG onto water in the Port of Long Beach.

It is not necessary to repeat in detail the findings of either the ABS Group or Sandia Lab reports, both of which are attached as exhibits to this report. I will just summarize my reading of the conclusions of both reports which I believe are germane to the consideration of the proposed LNG terminal in the POLB.

The ABS Group and Sandia Lab reports, which appear to be now largely accepted by all of the regulatory agencies involved, including the Coast Guard, as being the best current guidance on these matters, emphasize for their extensive analyses of the consequences of marine spills just one (size) spill scenario. That is the spillage onto water of 12,500 cubic meters LNG – this figure being representative of approximately one half of a single tank on a typical LNG ship. The choice of spillage of half a tank (rather than a full tank) appears to be the result of the reports' authors' consideration of the extreme implausibility if not impossibility of the rapid spillage of the entire tank as an initial result of a terrorist attack.

Thermal Radiation from LNG Pool Fires on Water

Setting aside unnecessary precision, I believe that the ABS Group and Sandia Lab reports are in essential agreement that persons exposed to the thermal radiation from a pool fire burning on a 12,500 cubic meter (approximately 3,000,000 gallons) spill on water could receive second degree burns on unprotected skin in about 30 seconds at a distance of approximately one mile from the center of the spill.

I endorse these findings on thermal radiation consequences of LNG pool fires on waters from the ABSG and Sandia Reports, as far as they go.

But, as I have stated before, I do not think these predictions address sufficiently the real requirements to provide for public safety. I am convinced that the use of a thermal flux criterion that would result in second degree burns in 30 seconds is not appropriate for delineating distances necessary to ensure public safety. This (second degree burn criteria) is not sufficient because such exposure essentially ensures that serious burns will occur at that distance to persons who cannot gain shelter within 30 seconds. In addition to the obvious difficulties that would confront any able-bodied individual's attempt to flee from such a threat, there remain very serious questions about the almost certain inability of those less able to do so. As considerably lower thermal flux criteria (~1.5 KW/m^2) are prescribed in other national and international regulations designed to provide safe separation distances for the public from fires, I believe that FERC should consider such a lower thermal flux criteria, which could increase the distances prescribed in the ABSG and Sandia reports by as much as one and a half to two times, to ensure the public safety from such large LNG fires.

Finally, regarding calls for more research in this area, I have already stated that there are some important needs. It is my understanding that Sandia and others are considering the need for more large scale LNG fire testing. If such tests were conducted with appropriate scientific planning, and if such tests were conducted for the purpose of obtaining experimental data which could be used to verify mathematical modeling methods (as opposed to one-time "demonstration" tests), I would endorse them, as I feel that additional testing would be worthwhile to provide better means of predicting the consequences of very large fires that could follow massive LNG spillage onto water.

LNG Vapor Cloud Dispersion from Spills on Water

I here also endorse the estimates of LNG vapor cloud dispersion presented in the Sandia and ABS Group reports, which range, considering all of the uncertainties identified in the reports, between approximately two and three miles. I note that while I have reviewed and am in agreement with the methodology used by the ABS Group for making these estimates (they in part used DEGADIS, of which I am a co-author), the Sandia report estimates were reportedly obtained using a CFD model called VULCAN, which I have not had the opportunity to evaluate, and which to my knowledge has not been independently evaluated for such use. I believe that the estimate of two to three miles of flammable vapor cloud travel that could result from an unignited spill of one half of the LNG contained in a single containment is at once reasonable and sufficient for consideration of the consequences of such spills of LNG in the POLB.

There is a Real Concern for Cascading Failures to Occur

But, I believe that limiting our consideration of the potential consequences of a very large LNG release and fire on water to the initial result of a terrorist attack is not sufficient. That would be like ignoring the collapse of the Twin Towers, because their collapse was not the initial result of the attack. Lest I neglect the consideration due of the worst case consequences of large scale tanker spills, it is important to note that the Sandia report states unequivocably that cascading events that could result either from brittle fracture of structural steel on the ship (due to LNG contact with the steel) or failure of the vaporization of the cargo at rates exceeding the capability of the pressure relief valves, cannot be ruled out.

We know that foamed plastic insulation, widely used on LNG carriers, including ships with both of these tank types, would be highly susceptible to failure by melting or decomposition. It is a cardinal safety rule that the pressure limits on tanks carrying flammable or reactive materials not be exceeded, as such exceedance portends catastrophic rupture of the containment. Such a rupture could lead to the release of a full tank of roughly 6,000,000 gallons of LNG, as well as the release from multiple tanks. While, as has been stated, the Sandia report concludes that such cascading events would be very unlikely to involve more than three of the five tanks on a typical LNG carrier – for a total release of 18,000,000 gallons (or more from the larger carriers now proposed) compared to the 3,000,000 gallon release on which all the modeling has been based – the basis for the Sandia report's “optimism” in this regard is unexplained. Once cascading failures begin, I do not know what would stop the process from resulting in the total loss and burning of all of the LNG aboard the carrier.

CHAPTER 4

CONCLUSIONS

CONSEQUENCES OF CREDIBLE ACCIDENTS AND TERRORIST ACTIONS, AND CONSIDERATION OF WORST POSSIBLE CASES

The objective here is to specify, based on observations of historical and experimental data, and supported by science-based guidance regarding the possibility of occurrence of postulated scenarios, the distances from such credible events to which the public as well as important infrastructure could be in harm's way.

Such a *consequence assessment* is a two step process:

1. The credibility (meaning here, the consistency of the event's occurrence with natural laws which we know to control such processes) of the postulated event must be established. For example, we can respond quickly and certainly to statements that an LNG ship contains the equivalent of fifty or more Hiroshima-size atomic bombs (a literal truth) with a certainty, based on physical laws, that the energy contained in an LNG storage tank cannot be released in a time frame sufficiently short to allow a meaningful comparison with the effects of fifty nuclear weapons each with a nominal 20 kiloton explosive energy release. It just cannot happen. However, we cannot dismiss the hazard on that basis either; instead we must consider the physical limitations which determine the length of time during which that energy could be released (in this case, by fire) in order to objectively define the consequences which could result.

2. Starting with the defined credible event, it is then required to determine the distance to which the hazard would extend. This process typically requires specification of both the total amount (of the hazardous material, measured here as energy content) released and the time frame over which the release occurs. As is true of many of the arguments advanced in this report, this is really just application of common sense - a very small spill rate, even continued for a very long time, would not be expected to pose the fire hazard that would result from the more rapid release of the same amount of material. An objective quantitative determination of the (hazard) distance is also a two step process.

    a. First a criterion for damage must be selected. For the present case these criteria are; for fires, specification of the permissible level of thermal flux exposure; and for vapor clouds, specification of the concentration level below which the cloud does not pose a flammable hazard because it could not be ignited.

    b. Finally, as the scenario being considered often involves releases with magnitudes potentially much more damaging than have been experienced, we have to extrapolate our experience to determine an

> objective measure of the consequence that can be expected. The best, if not the only, tools we have for such extrapolations are physical (such as wind tunnel) or mathematical models.

Utilizing information summarized in Chapters 2 and 3 of this report, I will summarize what I believe to be the present state of information about the quantities (and rates of release) of liquefied energy fuels that could occur associated with the operation of the proposed LNG terminal in the POLB, as well as the consequences to the public and infrastructure that could result.

Accidents and Terrorist Actions

The current regulations, particularly regarding provisions for public safety, focus on the land based part of the terminal. There are specific requirements for liquid containment and impoundment systems that are designed to limit the spreading of LNG that might be released either from the LNG tanks themselves or from transfer lines in the facility. But such control and mitigation measures could not be effectively applied to releases that could occur from an LNG ship, either at the jetty or in transit thereto, because spills onto water could not be effectively contained, and these concerns appear to have spurred the government's completion of two recent reports that deal with the tanker safety issue.

Before moving to consideration of the potential for, and consequences of, large LNG spills on water, I think it important to state that, in contrast to the attention given to the potential for large spills on water, very little attention is presently given to the vulnerability of land storage tanks to terrorist attack, or even to the vulnerability of land storage tanks to natural events such as earthquakes and tsunamis, consideration of which would appear to be highly relevant for the proposed POLB terminal. I believe that the vulnerability of the land tanks to such accidental or terrorist caused events, as well as to natural events such as earthquakes and tsunamis, needs to be considered carefully in order to provide the public assurance that we understand the potential consequences of releases that could occur on land as well as we now know them for spills on water. Fortunately, we have much more complete information regarding LNG spills onto water.

The ABS Group and Sandia reports agree that the release of LNG in the amount of approximately 3,000,000 gallons (half of one typical LNG ship tank) is credible,

- in that such a release could result from accidental collisions between ships with sufficient momentum (mass and speed) to cause such a breach of containment, or

- that such a release could be caused by terrorists with means that are readily available to them.

Furthermore, the ABS Group and Sandia reports agree, within the precision required here, that a release of 3,000,000 gallons of LNG onto water could result in:

- Pool fires which would expose persons with unprotected skin to thermal fluxes that could cause second degree burn injury in approximately 30 seconds (5 KW/m^2) at a distance of approximately 1 mile.

- Flammable vapor clouds, if the spilled material were not ignited upon release, that could extend downwind to distances between 2 and 3 miles. It is assumed here that persons that were caught in such a fire as might occur if the flammable cloud were ignited would be seriously injured, if not killed.

The author is in essential agreement with these consequence estimates but believes the following modifications are required if they are to be used to ensure public safety:

- Since the thermal radiation flux criterion (5 KW/m^2) used by Sandia and the ABS Group could cause second degree burns in thirty seconds, it is not sufficiently protective of public safety; a lower value, approximately 1.5 KW/m^2, is recommended here. This value is already being used by other segments of the regulatory system, both nationally and internationally, based on its definition as the highest thermal flux to which an unprotected person can be continuously exposed without injury. If the 1.5 KW/m^2 criterion is used, it is anticipated that the distance of 1 mile (associated with the higher flux level) would be increased to between 1 ½ and 2 miles.

- As the Sandia Report states unequivocably that cascading failures of ship tanks cannot be ruled out and further states that in their opinion failures of as many as 3 tanks could occur, this scenario must be considered credible. As Sandia estimates that the hazard distance from this scenario could be extended by approximately one-third, the distance to the 1.5 KW/m^2 flux level would then be increased to approximately 2 ½ to 3 miles.

- The ABS Group's high-end estimates for the vapor cloud distance to the 2.5 % gas concentration level (based on releases from a 5 meter diameter hole in the containment) are approximately 3 miles. The Sandia estimates for the credible scenario analyzed are closer to 2 miles, but their calculations reflect the distance to the 5% gas concentration level rather than the 2.5% level which is accepted to represent the better criterion for vapor cloud travel distance that could pose a hazard to the public. Use of the lower flammable gas concentration criteria would be expected to extend the hazard distance to about 3 miles.

Based on this information, which is believed to be the best that is available - and is in general agreement with widely held views in the scientific community, a <u>minimum</u> distance is specified here for the extent to which the public could be exposed to injury from the initial release of approximately 3,000,000 gallons of LNG onto water at the POLB. It is approximately 3 miles.

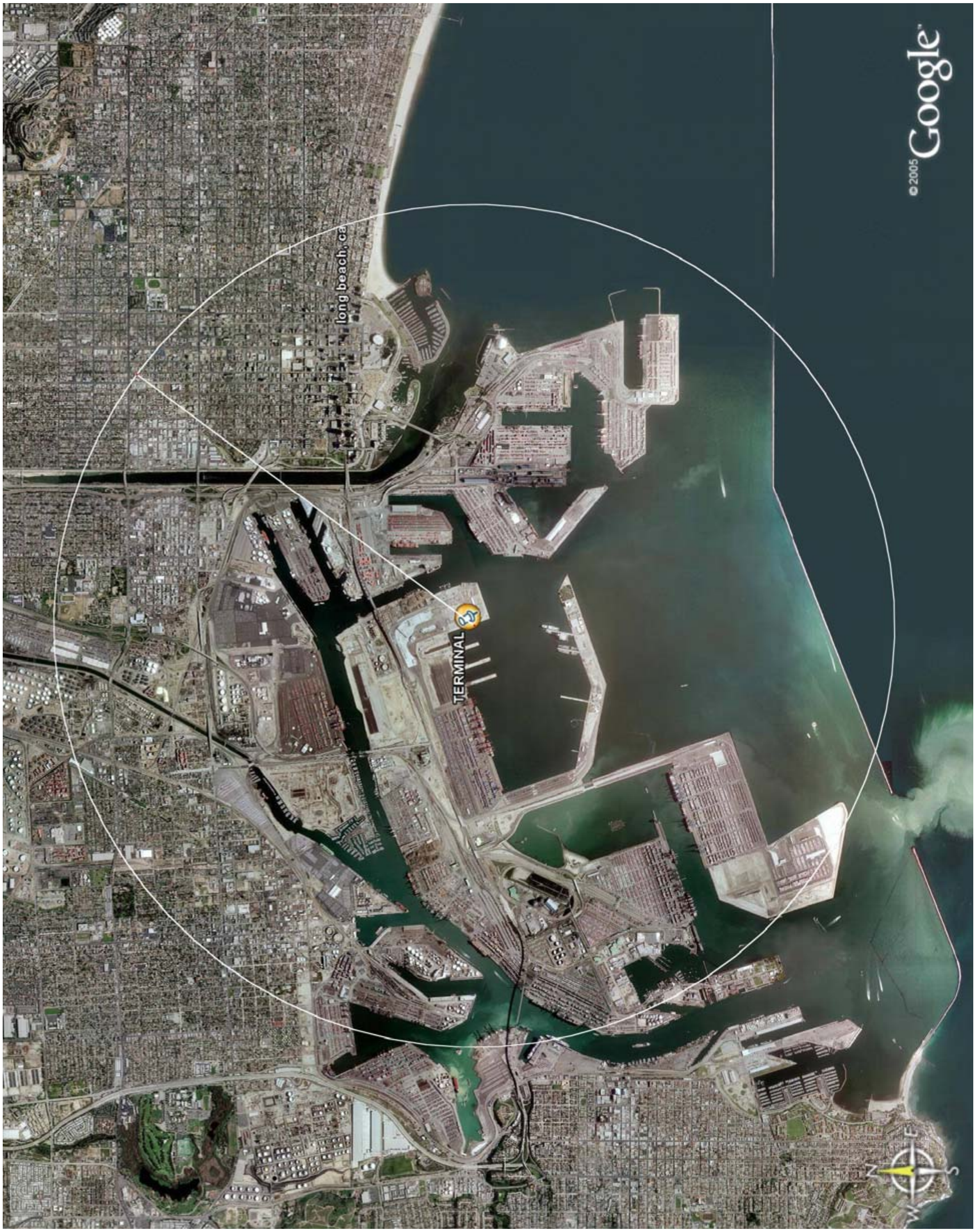
Consideration of Worst Possible Cases

I am recommending a minimum 3 mile radius circle around the proposed terminal to demarcate the area in which events deemed credible could cause serious injury to the public. The minimum distance to demarcate expected damage to infrastructure would be of lesser extent, depending on the criterion selected for damage.

As I have stated that the danger zone around the tanker extends to the route of the tanker approach to the facility, I observe that exposure of the public from incidents of spillage onto the water from the ship appears to be greatest when the ship is at the terminal jetty, rather than during its approach, since the terminal appears to be closer to populated areas than is any segment of its route to the terminal. Exposure of port infrastructure during the approach, based on my observation of the aerial view, would seem to be similarly concentrated at the terminal site, but such a conclusion does not consider any special hazards or vulnerabilities at different locations in the port. Estimation of the consequences to the POLB of a large release of LNG in the port must consider the wide variety of flammable and other hazardous materials routinely handled, as the area in which significant damage to infrastructure could occur (beyond the terminal and the ship) encompasses large sections of one of the largest and busiest ports in the country. The POLB receives very large crude oil carriers (VLCC) at a jetty located within several hundred feet of the eastern boundary of the proposed LNG facility, and a major container terminal which almost certainly receives hazardous cargo lies adjacent to the western side of the proposed site, along which the LNG ship will be berthed. It is noted that the area designated for the terminal's construction, approximately 25 acres, appears to be significantly smaller than the other (existing) terminals in the United States (with the possible exception of the Everett terminal – I do not know at the time of writing what the Everett terminal's area is). In any case, there is very minimal separation between the LNG spill impoundments and the facility's property line in the proposed terminal in the POLB; indeed, it is difficult for me to see how the applicant can meet the exclusion zone requirements of 49 CFR 193, much less provide a reasonable safety zone for the public or surrounding infrastructure.

It must be emphasized that the 3 mile zone is based primarily on the assumption that approximately 3,000,000 gallons of LNG is spilled onto water, as it appears there is little doubt that either pool fire radiation thermal fluxes or flammable vapor clouds from such a spill could put the public in harms way at that distance. However, it is a minimum specification, because it does not address the possibility of even more serious events.

I am very concerned that such events as provide the basis for the 3 mile consequence distance would be of such severity as to make it highly likely, if not almost certain, that further failures of containments, either of LNG or NGL, would occur. In particular, I repeat here my concern that the exposure to the ship of such a pool fire would have the potential to cause cascading failures of the remaining tanks on the vessel, resulting in total loss of the vessel and burning of its contents. There can be no doubt that the consequences of such a worst-possible-case event could be more severe than the rapid release of approximately 3,000,000 gallons of LNG onto water considered in this report.



The radius of the circle extending from the terminal location is three miles.

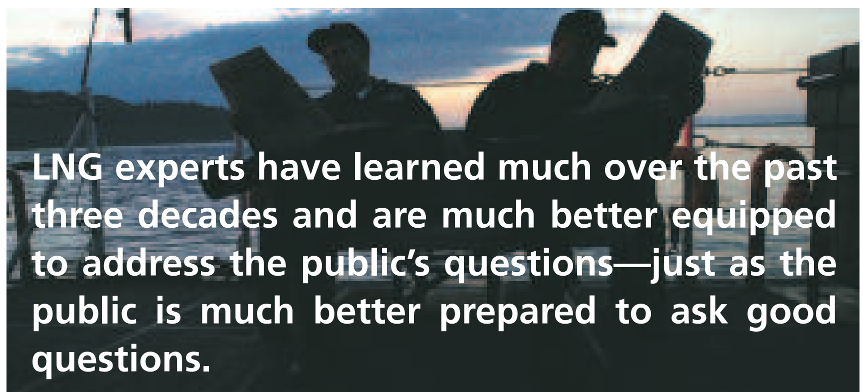
Exhibit 74

LNG and Public Safety Issues

Summarizing current knowledge about potential worst-case consequences of LNG spills onto water.

by Jerry Havens
Professor, Chemical Engineering, University of Arkansas

In 1976 Coast Guard Admirals were being called to Capitol Hill to answer the question: If 25,000 m^3 of liquefied natural gas (LNG) were spilled on water without ignition, how far might a flammable cloud travel before it would not pose a hazard? As technical advisor to the Office of Merchant Marine Safety in the Coast Guard's Bulk Hazardous Cargo Division, I was assigned to provide an answer on the LNG vapor cloud issue within a couple of weeks. Although no longer with the Coast Guard, I am still working on the problem 30 years later.



Past Lessons

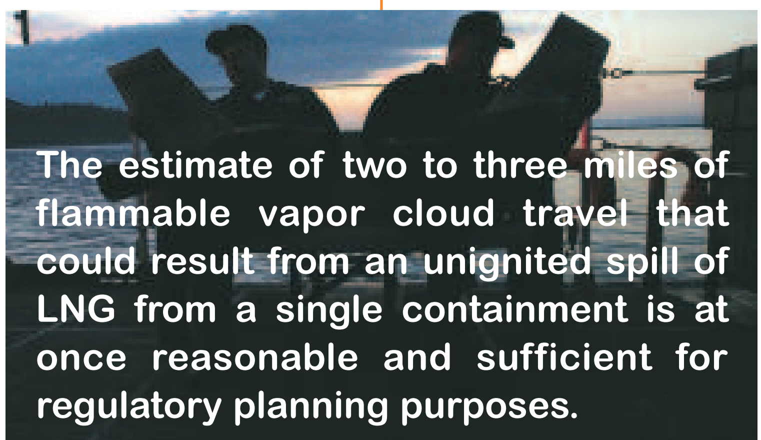
The tragic events of September 11, 2001, changed everything. Watching the World Trade Towers fall sharply focused my research of LNG spills on water. It is understood now that the towers fell because the insulation was knocked off the steel, which could then not withstand the extreme fire exposure. The lesson from this is to understand the consequences of such events, not only in planning for decisions that are within our control, but in planning for events over which we may have little or no control.

LNG experts have learned much over the past three decades and are much better equipped to address the public's questions—just as the public is much better prepared to ask good questions. For space constraints this discussion sidesteps many important issues in the LNG debate; however, it summarizes what is currently known about potential worst-case consequences for public safety of LNG spills onto water.

The description of current LNG knowledge is aided by reference to reports prepared in 2004 by the ABS Shipping Group for the Federal Energy Regulatory Commission[1] and by the Sandia National Laboratory for the Department of Energy.[2] These two reports, which appear to be largely accepted by all of the regulatory agencies involved, emphasize for their analyses one scenario of the consequences of LNG marine spills—spillage onto water of 12,500 m^3 of LNG, which is representative of approximately one half of a single tank on a typical LNG ship. While the Sandia report does provide some consideration of multiple-tank spills, it suggests that such occurrences would not involve more than three tanks at one time. The choice of spillage of only half a tank appears to be the result of the report's consideration of the extreme implausibility of the rapid spillage of the entire tank as an initial result of a terrorist attack. However, limiting discussion to the initial results of a terrorist attack is not necessarily sufficient.

LNG Vapor Cloud Dispersion

My year-long look at the LNG vapor dispersion issue for the Coast Guard produced a report[3] in 1978 that reviewed several predictions by leading authorities of the vapor cloud extent, following spillage of 25,000 m^3 LNG onto water. Those estimates ranged from 0.75 mile to a little over 50 miles. The range was narrowed by showing the errors in reasoning underlying the lowest and highest estimates, but the uncertainty range could not be tightened closer than three to 10 miles.



The estimates, which range between approximately two and three miles, presented in the Sandia and ABS Group reports are endorsable. Note, though, that these estimates are for the spillage of 12,500 m^3 of LNG, half the amount considered in the Coast Guard report produced in 1978. Nonetheless, the estimate of two to three miles of flammable vapor cloud travel that could result from an unignited spill of LNG from a single containment is at once reasonable and sufficient for regulatory planning purposes. Indeed, given the uncertainties involved, the point of diminishing returns has been reached on this scenario for vapor dispersion from a 12,500 m^3 LNG spill on water.

Thermal Radiation from LNG Pool Fires

For thermal radiation from pool fires, the findings of the ABS Group and Sandia reports are also endorsable. Both reports appear to provide estimates of approximately one mile as the distance from a pool fire on a 12,500 m^3 spill on water to which unprotected persons could receive second-degree burns in 30 seconds (based on a thermal flux criterion of 5 KW/m^2). Although this estimate is reasonably representative of the best available estimates of the distance to which the public could be exposed (to this damage criterion), the endorsement is qualified as follows.

First, the use of a thermal flux criterion that would result in second-degree burns in 30 seconds is not necessarily appropriate to ensure public safety, as such exposure essentially ensures that serious burns will occur at that distance to persons who cannot gain shelter within 30 seconds. Aside from questions about the ability of even the most able to gain shelter in such a short time, questions are also raised about the safety of those less able. Lower thermal flux criteria (~1.5 KW/m^2) are prescribed in other national and international regulations designed to provide safe separation distances for the public from fires. Since such lower thermal flux level criteria could increase the distances prescribed in the ABS Group and Sandia reports by as much as one and a half to two times, this end point criteria for ensuring public safety from LNG fires should be reconsidered, especially if the goal is to provide for public safety.

Second, the mathematical modeling methods in the reports that predict the various levels of thermal radiation intensity from a massive LNG pool fire are not on as firm scientific ground as are the methods for predicting vapor cloud dispersion. The vapor cloud question has been more extensively studied to provide data for the models' verification. The physical basis for extrapolation from small-scale experimental data is better understood for vapor dispersion than are the methods in present predictions of thermal radiation extent from pool fires. Sandia and others are considering the need for further large-scale LNG fire testing. Such tests should be conducted with appropriate scientific planning and for the purpose of obtaining experimental data that could be used to verify mathematical modeling methods; this additional testing is advised to provide a better understanding of large LNG fires on water.

However, the Sandia report states that cascading events, resulting either from brittle fracture of structural steel on the ship or failure of the insulation that results in LNG vaporization at rates exceeding the capability of the relief valves, cannot be ruled out. Foamed plastic insulation, widely used on LNG carriers, would be highly susceptible to failure by melting or decomposition. It is a cardinal safety rule that the pressure limits on tanks carrying flammable or reactive materials should not be exceeded, as such excess portends catastrophic rupture of the containment. While the Sandia report concludes that such cascading events would be very unlikely to involve more than three of the five tanks on a typical LNG carrier, the report's optimism in this regard is unexplained. Once cascading failures begin, what would stop the process from resulting in the total loss of all LNG aboard the carrier? More research is required.

Other Hazards

Other hazards associated with spilling LNG onto water include oxygen deprivation, cold-burns, rapid phase transitions, and explosions in confined spaces, as well as the potential for unconfined vapor cloud explosions (UVCEs) if the LNG contains significant heavies. As the hazards of oxygen deprivation and cryogenic burns are not expected to affect the public, they will not be considered further here.

Explosions in confined spaces, either combustion events or events of rapid phase transition, may have the potential for causing secondary damage that could lead to further spillage of LNG. Unconfined vapor cloud explosions cannot be dismissed if the cargo contains significant amounts—perhaps greater than 12 to 18 percent, based on Coast Guard-sponsored tests at China Lake in the 1980s—of gas components heavier than methane. Enrichment in higher boiling point components of LNG remaining on the water can lead to vapor cloud concentrations that pose a UCVE hazard, even if the concentration of liquid initially spilled does not. LNG contact with ship structural steel, rapid phase transitions, and gas explosions in confined spaces on the ship are not expected to pose hazards to the public, except as they may relate to the ship's vulnerability to further damage following the cryogenic cargo spillage onto ship structures, with or without ignition.

Vulnerability Issues

Coast Guard Navigation and Vessel Inspection Circular No. 05-05, "Guidance on Assessing the Suitability of a Waterway for Liquefied Natural Gas (LNG) Marine Traffic," incorporates requirements for a vulnerability assessment that identifies the exposures that might be exploited to ensure the success of an attempted terrorist attack.[4] Two types of vulnerabilities are considered: system and asset. System vulnerabilities consider the ability of the terrorist to successfully launch an attack; asset vulnerabilities consider the physical properties of the target that may influence the likelihood of success of a terrorist attack.

Worst Case?

The hazards of brittle fracture, rapid phase transitions, and explosions in confined ship spaces, as well as cascading events that may result from the extreme fire exposure a ship would experience if a nominal 12,500 m^3 spill on water around the ship was ignited, will require careful consideration. The definition of the worst case event that could be realized as a result of a terrorist attack is likely to hinge on the assessment of the asset vulnerabilities that is required to be considered in NVIC 05-05. This is largely where our unfinished work remains.

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3. Havens, J. A., "Predictability of LNG Vapor Dispersion from Catastrophic Spills onto Water," Report CG-M-09-77, Office of Merchant Marine Safety, USCG HQ, 1978.

4. Navigation and Vessel Inspection Circular No. 05-05, "Guidance on Assessing the Suitability of a Waterway for Liquefied Natural Gas (LNG) Marine Traffic," Commandant, United States Coast Guard, June 2005.

About the author: *Jerry Havens is a chemical engineering professor at the University of Arkansas. He has three decades of experience researching LNG spills onto water.*

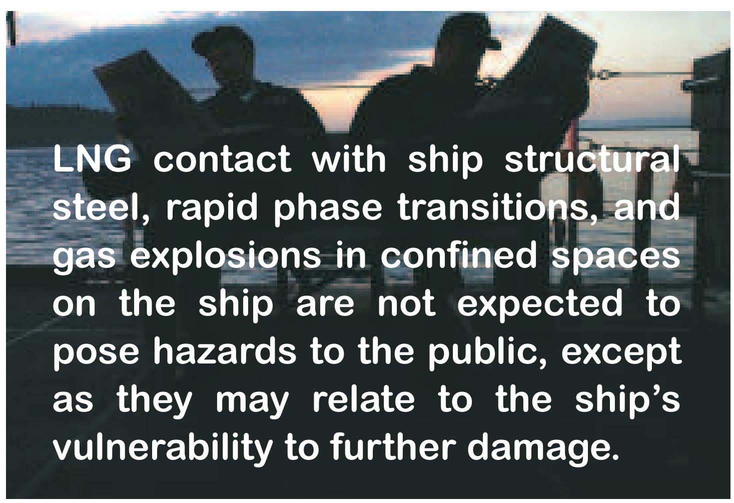

Exhibit 75

https://www.sightline.org/2016/06/03/williams-companies-failed-to-protect-employees-in-plymouth-lng-explosion/

WILLIAMS COMPANIES FAILED TO PROTECT EMPLOYEES IN PLYMOUTH LNG EXPLOSION

The natural gas company eyeing other Northwest projects has a history of unsafe work conditions.

Two employees were inside the compressor building (rear) at the time of the explosion. One sustained severe injuries. by Washington Utilities and Transportation Commission (Used with permission.)

Author: **Tarika Powell**

(@) on June 3, 2016 at 6:30 am

This article is part of the series Fracked Fuel & Petrochemical Projects in the Pacific Northwest

Two years ago, an explosion at a liquefied natural gas (LNG) plant in eastern Washington forced hundreds to evacuate their homes, injured five workers, and caused $69 million in damages. It was one in a string of accidents at The Williams Companies' natural gas facilities that in the last three years has killed five workers and injured at least 120 people.

Through a public records request, Sightline obtained documents from the Washington Department of Labor and Industries (Washington L&I), which conducted an investigation into the safety of employees at the Plymouth plant where the explosion occurred. The agency found that Williams endangered its employees, lacked an adequate emergency response plan, and had deficient safety training. The company's track record—not just in the Northwest, but throughout the US—reveals a pattern of failing to heed safety regulations. It also illustrates why we should not underestimate the fire and explosion hazards of natural gas processing plants such as LNG facilities.

The Williams Plymouth LNG explosion

The explosion happened shortly after 8:00 a.m. on March 31, 2014 at the Plymouth LNG plant in eastern Washington, about 30 miles south of the Tri-Cities, where the company stores natural gas in liquid form in two 14-million-gallon tanks. Natural gas ignited inside the LNG processing equipment, creating a "rolling detonation" that generated a mushroom-shaped cloud and large fire. Members of the public felt the rumble of the explosion up to six miles away, and employees near the explosion were knocked off their feet by its force. Employees saw a ball of fire as large pieces of exploded metal equipment and piping flew by them.

The blast completely fragmented a large piece of the natural gas processing equipment called an adsorber, propelling 250 pounds of debris and shrapnel up to 900 feet away and injuring 5 employees. One employee's injuries were so extensive that a coworker who helped him evacuate the grounds did not initially recognize him. The explosion caused extensive physical damage to buildings and electrical equipment and even bent the BNSF rail line near the perimeter of the facility's property.

Employees saw a ball of fire as large pieces of exploded metal equipment and piping flew by them.

To make matters worse, on the morning of the explosion, plant operators had shut down two safety monitoring systems. Facility operators disabled both the system that detects gas releases and the emergency shutdown system, which is designed to put facility equipment in "safe mode" should the plant experience hazardous conditions.

Shutting down these systems disabled detectors that would have automatically shut down the plant in an emergency. Instead, employees who were trying to flee the site had to locate and manually pull two separate emergency shutdown switches. Shutting down the systems may have also disabled the plant's alarms, which explains why many employees did not hear alarms after the explosion.

The last remaining employees on site were able to successfully engage the emergency shutdown only after realizing that the system had been disabled. While the shutdown stopped at least one gas leak, other leaks continued for more than 24 hours. Shrapnel from the explosion had pierced multiple gas pipes as well as one of the facility's two 90-foot-tall LNG tanks, resulting in a "roaring noise" as pressurized gas escaped from multiple locations on site. Residents within a two-mile radius were evacuated to the local fairgrounds, but not before the smell of gas had spread at least a quarter-mile from the plant.

Employees evacuated to the nearest fire station, but officials in charge of responding to the incident asked three Williams workers to reenter the premises multiple times while gas continued to leak so they could help plug, patch, or stop the leaks by closing valves at the site. The shutdown valves employees used to stop the leaks were 150 to 450 feet from the original explosion and fire, the area with the highest potential for exposure to hazards. While these employees rather selflessly agreed to assist, it was against the law to put them back into the "hot zone," the portion of a hazard site that is immediately dangerous to life and health, because Williams had not given them adequate emergency training.

Fires burn at site of Plymouth LNG explosion. by Washington Utilities and Transportation Commission (Used with permission.)

A disaster months in the making

Notably, plant operators had set the explosion in motion several months earlier, in November 2013, when they closed off the end of a pipeline with plastic and tape rather than proper sealing equipment, a move that allowed an explosive mixture of air and gas to enter the LNG processing system.

Next, system operators, following the company's written procedures, failed to properly purge excess oxygen from the equipment. The procedure for purging oxygen did not meet industry standards, and investigators with the Washington Utilities and Transportation Commission (UTC) later determined that the instruction manual lacked details that were clear enough for employees to follow with consistent and safe results. The Pipeline and Hazardous Materials Safety Administration's safety violation report notes that the company had been using the inadequate oxygen purge procedure for many years.

Williams' deficient safety training compounded this negligence. Federal workplace safety and health standards require Williams to adequately train employees for emergency response before asking them to participate in a real emergency scenario. To ensure their safety, only employees who have been highly trained in hazardous materials emergency response are permitted to enter a hazard site for the purpose of stopping a gas release. Guidance by the National Fire Protection Association and the International Association of Fire Chiefs supports these laws.

Yet Williams failed to adequately train its workers to enter the area of immediate threat, thereby gravely endangering them. On paper, the company's procedures align with workplace safety regulations, stating that only employees who have received advanced training in hazardous materials and emergency response will be sent into a hot zone or participate in an actual emergency response operation. In fact, the employees who were sent into the hot zone had not received the legally required training, so facility managers had a duty to make sure they remained evacuated from the site.

These workers faced many hazards in the hot zone: in addition to the gas leaking from pipes and the LNG storage tank, the facility houses liquid propane and butane tanks that each hold about 3,000 gallons and that are susceptible to expanding vapor explosions in circumstances such as those that followed the Plymouth explosion. The pipeline leak closest to the original explosion abutted a warehouse that gas had most likely entered, and as a 2010 overview of LNG properties and hazards notes, "explosions occur with noticeable frequency from a buildup of natural gas vapors indoors."

In addition to failing to adequately train its employees, Williams did not provide them with the protective clothing and equipment necessary to enter an area containing fire and explosion hazards. Workplace safety laws require that employers provide appropriate protective equipment to any personnel who enter a hazardous site, including a respirator and protective clothing that would cover all parts of the body that could be harmed by the hazard. While firefighters wore full protective gear and respirators, Williams provided only one of the employees with comparable protective equipment to enter the hot zone. Another was only given a flame-resistant shirt and pants, while the third employee was only provided with a flame-resistant shirt.

Washington L&I found that Williams placed its employees in close proximity to gas leaks that were likely to cause injury from a fire or explosion. The state determined that Williams' emergency response plan was not effective in practice because the company only provided limited emergency response training. Further, the agency noted deficiencies in Williams' written health and safety programs. Washington L&I fined Williams $1,000 (later adjusted down to $300) and ordered the company to correct the violations by giving the employees appropriate emergency response and hazardous materials training.

Rocky inspection record at Plymouth LNG

Past inspections at the eastern Washington facility foreshadowed Williams' lack of preparation for fire hazards or natural gas releases. A 2002 inspection by the UTC found fully ten areas of concern at the facility. Some of the fire detectors were too weak to detect hazards more than a couple feet from the equipment, and another was out of alignment with the area it was supposed to monitor. The company's procedures did not require that gas detection systems meet the National Fire Protection Association's minimum LNG fire protection requirements, and plant operators were not able to provide documentation that staff regularly checked the equipment for leaks. Further, the company lacked procedures to minimize the recurrence of safety incidents.

A V-shaped ice formation develops above the puncture on Plymouth LNG tank while pipe (lower left) spews LNG and gas vapor. By Washington Utilities and Transportation Commission (Used with permission.)

In other failings, a 2007 inspection by the UTC noted that for at least two years, Williams technicians had not correctly read the output for one of the cathodic protection devices, which help prevent leaks by monitoring corrosion in metal structures such as liquid gas storage tanks and pipes. They hadn't done so because the technicians themselves were confused about the configuration of the equipment.

In 2008, the UTC issued a violation to facility operators because they did not inspect and test fire control systems within six-month intervals, as required by federal LNG standards. Two of Williams' senior officials at the plant were "surprised that there was no grace period in the code" that allowed them to exceed the six-month minimum requirement for testing fire equipment.

Company's workplace safety problems have triggered federal probes

The Williams Companies is a natural gas corporation with hundreds of miles of pipeline in the western states and along the Atlantic coast. The company was set to build 232 miles of pipeline through Oregon for the Jordan Cove LNG export project, which federal regulators rejected in March 2016, and 85 miles of pipeline for the proposed Oregon LNG export facility, which developers withdrew from consideration in April 2016.

Both federal and state agencies have fined the company on numerous occasions for poor operations of natural gas plants and pipelines, but in the past three years, an alarming number of explosions and fires have broken out at The Williams Companies' natural gas and petrochemicals facilities, suggesting a pattern of recklessness that reaches far beyond Plymouth.

For example, a flash fire at one of the company's natural gas compression facilities injured fifteen people in New Jersey in May 2013. That same month, a Pennsylvania gas compressor station caught fire with eleven employees on site. In June 2013, an explosion at a Louisiana olefins plant killed two workers and injured more than 100 others. Then in October 2013, another explosion killed three contractors at a different Louisiana facility. A month after the March 2014 explosion at Plymouth LNG, an explosion at a Williams gas gathering facility in a small Wyoming town forced residents to evacuate.

The Occupational Safety and Health Administration found that the company failed in its responsibility to find and fix safety violations and ensure the safety of workers at its Louisiana olefins plant. The string of accidents also triggered the US Chemical Safety

Board to initiate a federal probe into Williams' safety practices. That investigation has been slow-going.

Williams resumes business as usual in Washington

Williams failed to properly train and equip its employees for emergency response, and it did not adequately coordinate with local first responders so that they could address the hazard without endangering employees. The company's failure increased the dangers of the hazard not only for employees and first responders, but also for the broader community.

There is reason to worry The Williams Companies will continue to shirk safety standards.

After paying a very small fine for its actions, Williams has moved forward. The company has now completed all the repairs necessary to resume full operations at Plymouth, and it is slated to build the pipeline for a proposed methanol facility at the Port of Kalama, Washington. But the company's record, along with ongoing investigations into the company's practices by Washington L&I and the UTC, demonstrate there is reason to worry The Williams Companies will continue to shirk safety standards—potentially endangering Williams' employees and nearby communities once again.
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Exhibit 76

CBEMP POLICIES

POLICIES:

- **#1 Estuary Classification**

The Coos Bay Estuary is recognized as a "Deep-Draft Development Estuary" by the local governments, which is consistent with the overall Oregon Estuary Classification (OAR 660-17-000, as amended). Further, the Estuary Management Plan's allowed uses and activities are, and must remain, consistent with the "Deep-Draft Development" classification and the estuarine management unit requirements of Goal #16.

This strategy recognizes the development mandates of LCDC Goal #16.

- **#2 General Schedule of Permitted Uses and General Use Priorities**

Local government shall restrict estuarine development and/or alteration so it is equal to, or less intensive, than uses and activities that are allowed, or may be allowed pursuant to LCDC Goal #16 and the Oregon Administrative Rule classifying Oregon Estuaries (OAR 600-17-000 as amended 6/81).

I. Local government's determination regarding estuarine management unit designation as well as respective uses and activities permitted reflect priorities for estuarine uses and activities necessary to:

1. Ensure compatibility with the requirement of LCDC Goal #16 and the administrative rule classifying Oregon Estuaries (OAR 600-17-00) as amended 6/81).
2. Maintain the integrity of the estuarine ecosystem. This shall be implemented by limiting uses and activities within Natural, Conservation and Development Estuarine Management Units so that such uses and activities are not more intensive than those following.

MANAGEMENT UNIT: NATURAL

A. Uses and Activities listed below may be allowed in Natural Management Units (LCDC Goal #16) without special assessment of the resource capabilities of the area, but subject to special conditions and other policies set forth elsewhere in this Plan. Note: existing man-made features may be retained, maintained and protected if existing on October 7, 1977.

1. Undeveloped low-intensity, water-dependent recreation
2. Research and educational observations
3. Navigational aids (such as beacons and buoys)
4. Passive restoration measures
5. Protection of habitat, nutrient, fish, wildlife and aesthetic
6. Bridge crossings
7. Cultural, historical and archaeological resources
8. Research and educational observation structures
9. Dredging necessary for on-site maintenance of existing functional tidegates and associated drainage channels

B. Uses and Activities listed below MAY be allowed in Natural Management Units when it is established that such are consistent with the resource capabilities of the area and the purpose of the management units (LCDC Goal #16) (pursuant to "Linkage" and "Goal Exception" findings in this Plan) but also subject to special conditions and other policies set forth elsewhere in this Plan.

1. Aquaculture which does not involve dredge or fill or other estuarine alteration other than incidental dredging for harvest of benthic species or removable in-water structures such as stakes or racks (commercial, not archaeological stakes or racks) - is subject to Policy #4a.
2. Communication facilities
3. Active restoration of fish and wildlife habitat or water quality and estuarine enhancement
4. Riprap (see Policy #9)
5. Placement of low-water bridge (see Policy #6)
6. Boat ramps for public use where no dredging or fill for navigational access is needed
7. Installation of tidegates in existing functional dikes
8. Temporary alterations
9. Pipelines, cables and utility crossings, including incidental dredging necessary for their installation
10. Bridge crossing support structures and dredging necessary for their installation

MANAGEMENT UNIT: CONSERVATION

A. Uses and Activities listed below may be allowed in Conservation Management Units (LCDC Goal #16) without special assessment of the resource capabilities of the area, but subject to special conditions and other policies set forth elsewhere in this Plan.

1. All uses permitted outright in Natural Management Unit (except for "temporary alterations")

B. Uses and Activities listed below MAY be allowed in Conservation Management Units when it is established that such are consistent with the resource capabilities of the area and the purpose of the management units (LCDC Goal #16) (pursuant to "Linkage" and "Goal Exception" findings in this Plan) but also subject to special conditions and other policies set forth elsewhere in this Plan.

1. High intensity, water-dependent recreation including boat ramps, marinas and new dredging for boat ramps and marinas
2. Minor navigational improvements
3. Mining and mineral extraction, including dredging necessary for mineral extraction
4. Water-dependent uses requiring occupation of the water surface by means other than fill
5. Waste water/storm water discharge meeting state and federal water quality

standards
6. Temporary alterations
7. Aquaculture requiring dredge or fill or other alteration of the estuary
8. Active restoration for purposes other than those listed in A-1 above

MANAGEMENT UNIT : DEVELOPMENT

A. Uses and Activities listed below may be allowed in Development Management Units (LCDC Goal #16) without special assessment of the resource capabilities of the area, but subject to special conditions and other policies set forth elsewhere in this Plan.

1. Water-dependent commercial and industrial uses
2. Navigation and water-dependent commercial enterprises and activities
3. Water transport channels where dredging may be necessary
4. Dredge or fill as allowed elsewhere in Goal #16 (see special "dredge" or "fill" policy)
5. Navigational structures other than those permitted in Natural and Conservation Management Units
6. Marinas
7. Water storage areas where needed for products in, or resulting from, industries, commerce, and recreation
8. Flow-lane disposal of dredge material monitored to assure that estuarine sedimentation is consistent with the resource capabilities and purposes of affected Natural and Conservation Management Units
9. Energy production where quantities of water are necessary to produce energy directly.
10. Water-borne transportation, which requires water access for transportation, receipt/shipment of goods, or is necessary to support water-borne transportation (examples, moorage fueling servicing of watercraft, ships, boats, and terminal and transfer facilities).

B. Uses and Activities listed below MAY be allowed in Development Management Units when it is established that such are consistent with the purposes of this management unit and adjacent shorelands designated suitable for water-dependent uses or designated for waterfront redevelopment (pursuant to "Linkage" and "Goal Exception" findings to the Plan) but also subject to special conditions and other policies set forth elsewhere in this Plan.

1. Water-related and nondependent, nonrelated uses not requiring dredge or fill
2. Undeveloped low-intensity, water-dependent recreation
3. Mining and mineral extraction
4. All activities allowed in Natural and Conservation Management Units

This strategy is based on the recognition that the "Use and Activity Matrices" set forth as policy elsewhere in this Plan conform with and shall be maintained in compliance with the "Priority of Uses" and other "use" requirements of Goal #16. Unless otherwise noted in respective "Use and Activity Matrices", the "resource capability assessments" called for in Goal #16 have been conducted, and uses subject to these findings are thus allowed by this Plan, subject only to Policies and Special Conditions set forth herein.

II. This strategy recognizes that the Plan's estuarine management unit designations, and permitted uses and activities are based upon and establish general priorities for the use of estuarine resources.

These general use priorities (from highest to lowest) are:

a. Uses which maintain the integrity of the estuarine ecosystem;
b. Water-dependent uses requiring estuarine location, as consistent with the overall Oregon Estuarine Classification;
c. Water-related uses which do not degrade or reduce the natural estuarine resources and values; and
d. Non-dependent, non-related uses which do not alter, reduce or degrade the estuarine resources and values.

- **#3 Use of "Coos Bay Estuary Special Considerations Map" as the Basis for Special Policies Implementation**

Local governments shall use the "Coos Bay Estuary Special Considerations Map" as the basis for implementing the special protection.

I. The "Coos Bay Estuary Special Considerations Map" which is a series of color mylar overlays, shall delineate the general boundaries (plan inventory maps contain more precise boundary locations) of the following specific areas covered by the Coos Bay Estuary Management Plan:

a. Coos Bay Estuary Coastal Shorelands Boundary;
b. Sensitive Beach and Dune Areas:

   i. areas unsuitable for development,
   ii. areas with limited development suitability;

c. Floodplain Hazard Areas;
d. Agricultural Lands Designated for Exclusive Farm Use, and "Wet Meadow" Wetlands;
e. Coastal Historical and Archaeological Sites;
f. Urban Growth Boundaries (UGBs);
g. Priority Dredged Material Disposal and Mitigation/Restoration Sites;
h. Significant Wildlife Habitat and Major Marshes;
i. Forest Lands.

The "Special Considerations Map" is NOT a substitute for the detailed spatial information presented on the Coos Bay Estuary Management Plan's inventory maps. The "Special Considerations Map" is merely an INDEX GUIDE designed as a zoning counter implementation tool that indicates when special policy considerations apply in a GENERAL area, thereby, requiring inspection of the DETAILED Plan Inventory maps. The "Special Considerations Map" must and shall at all times accurately reflect the detail presented on the inventory maps (but at a more general scale).

II. Specific Plan provisions set forth elsewhere as Policy and relating to the above-listed

considerations shall be used in conjunction with the "Special Considerations Map"; such Plan provisions include requirements set forth in " Unit Management Objectives", "Allowed Uses and Activities in Management Units", and the following specific "Functional" Policies set forth below:

- #13 Over-all Use Priorities within Coastal Shorelands
- #14 General Policies on Uses within Rural Coastal Shorelands
- #15 Land Divisions within Rural Shorelands
- #16 Protection of Sites Suitable for Water-Dependent Uses (within UGBs) and Special Allowance for New Non-water-Dependent Uses in "Urban Water-Dependent (UW)"
- #16a Urban Unincorporated Communities Use Standards
- #17 Protection of "Major Marshes" and "Significant Wildlife Habitat" in Coastal Shorelands
- #18 Protection of Historical and Archaeological Sites within Coastal Shorelands
- #19 Management of "Wet-Meadow" Wetlands within Coastal Shorelands
- #20 Dredged Material Disposal Sites
- #20a Dredged material Disposal Guidelines
- #20b Priority for In-Bay Disposal Sites
- #21 Mitigation and Restoration Sites
- #22 Mitigation Sites: Protection Against Pre-emptory Uses
- #23 Riparian Vegetation and Streambank Protection
- #25 Waste Water/Storm Water Discharge
- #27 Floodplain Protection within Coastal Shorelands
- #28 Recognition of LCDC Goal #3 (Agricultural Lands) Requirements for Rural Lands within the Coastal Shorelands Boundary
- #29 Restricting Actions in Beach and Dune Areas that are "Unsuitable for Development"
- #30 Restricting Actions in Beach and Dune Areas with "Limited Development Suitability" and Special Consideration for Sensitive Beach and Dune Resources
- #31 Reserved
- #34 Recognition of LCDC Goal #4 (Forest Lands) Requirements for Rural Lands within the Coastal Shorelands Boundary

All other plan provisions - including "Management Objectives" and "Allowed Uses and Activities in Management Units" -- are SUBORDINATE to the special "functional" policies listed above, unless a goal exception has been taken for the intended use.

This strategy recognizes that the "Special Considerations Map" is an official policy component of the plan, and it provides a mechanism for site-specific application of special management Policies.

- **#4 Resource Capability Consistency and Impact Assessment**

I. Local government concludes that all proposed actions (approved in this Plan) which would potentially alter the integrity of the estuarine ecosystem have been based upon a full consideration of the impacts of the proposed alteration. Except for the following uses and activities:

a. Natural Management Units
   - ~ Aquaculture
   - ~ Log storage
   - ~ Bridge Crossings

b. Conservation Management Units
   - ~ High-intensity water-dependent recreation
   - ~ Aquaculture
   - ~ New or expanded log storage
   - ~ Log storage dredging
   - ~ Dike maintenance dredging
   - ~ Minor navigational improvements requiring dredging or fill
   - ~ Bulkheading
   - ~ Water intake or withdrawal and effluent discharge
   - ~ Riprap

c. Development Management Units
   - ~ Aquaculture
   - ~ New or expanded log storage
   - ~ Mining and mineral extraction
   - ~ Water-related and non-dependent, non-related uses not requiring fill
   - ~ Dredging
   - ~ Bulkheading (except for Aquatic Units #3DA, #5DA and #6DA)
   - ~ Fill
   - ~ In-water structures
   - ~ Flow-lane disposal of dredged material and other activities which could affect the estuary's physical processes or biological resources
   - ~ Application of pesticides

d. Any other uses and activities which require the resource capability consistency test as a condition within a particular management unit.

For uses and activities requiring the resource capabilities test, a special condition is noted in the applicable management unit uses/activities matrix. A determination of consistency with resource capability and the purposes of the management unit shall be based on the following:

i. A description of resources identified in the plan inventory;
ii. An evaluation of impacts on those resources by the proposed use (see Impact Assessment procedure, below);
iii. A determination of whether the proposed use or activity is consistent with

the resource capabilities of the area, or that the resources of the area are able to assimilate the use and activity and their effects and continue to function in a manner to protect significant wildlife habitats, natural biological productivity, and values for scientific research and education.

Where the impact assessment requirement (of Goal #16 Implementation Requirements #1) has not been satisfied in this Plan for certain uses or activities (i.e., those identified above), then such uses or activities shall not be permitted until findings demonstrate the public's need and gain which would warrant any modification or loss to the estuarine ecosystem, based upon a clear presentation of the impacts of the proposed alteration, as implemented in Policy #4a.

III. An impact assessment need not be lengthy or complex, but it should give reviewers an overview of the impacts to be expected. It may include information on:

a. the type and extent of alterations expected;
b. the type of resource(s) affected;
c. the expected extent of impacts of the proposed alteration on water quality and other physical characteristics of the estuary, living resources, recreation and aesthetic use, navigation and other existing and potential uses of the estuary; and
d. the methods which could be employed to avoid or minimize adverse impacts.

This policy is based on the recognition that the need for and cumulative effects of estuarine developments were fully addressed during the preparation of this Plan and may be mitigated by the imposition, as necessary, of conditions through the administrative conditional use process.

- **#4a Deferral of (I) Resource Capability Consistency Findings, and (II) Resource Impact Assessments**

Local government shall defer, until the time of permit application, findings regarding consistency of the uses/activities listed in Policy #4 with the resource capabilities of the particular management unit.

Additionally, the impact assessment requirement for those uses/activities as specified in Policy #4 shall be performed concurrently with resource capability findings above at the time of permit application.

I. This strategy shall be implemented through an Administrative Conditional Use process that includes local cooperation with the appropriate state agencies:

a. Where aquaculture is proposed as a use, local government shall notify the Oregon Department of Fish & Wildlife (ODFW) and Department of Agriculture in writing of the request, with a map of the proposed site;

b. Where log storage dredging is proposed as an activity local government shall notify the Oregon Department of Environmental Quality (DEQ) in writing of the request, together with a map of the proposed site.

II. Within twenty (20) days of receipt of the notification, the state agency shall submit in writing to the local government a statement as to whether the proposed use/activity will:

a. Be consistent with the resource capabilities of the management unit or,

b. If determined not to be consistent, whether the proposal can be made consistent through imposition of conditions on the permit.

III. The appropriate state agency shall also perform the impact assessment required in Policy #4. If no statement is received from the state agency by the expiration of the twenty (20) day period, local government shall:

a. Presume consistency of the proposal with the resource capabilities of the management unit; and

b. Make findings appropriate to that presumption; and

c. Perform the assessment of impacts required by Policy #4.

IV. For all other uses/activities specified above, local government shall:

a. Determine through appropriate findings whether the proposed use/activity is consistent with the resource capabilities of the management unit, and

b. Perform the assessment of impacts required by Policy #4.

V. This strategy recognizes:

a. That resource capability consistency findings and impact assessments as required by LCDC Goal #16 can only be made for the uses specified above at the time of permit application, and

b. That the specified state agencies have expertise appropriate to assist local government in making the required finding and assessments.

This strategy is based upon the recognition that the need for and cumulative effects of estuarine developments were fully addressed during development of this Plan and that no additional findings are required to meet Implementation Requirement #1 of Goal #16.

- **#5 Estuarine Fill and Removal**

I. Local government shall support dredge and/or fill only if such activities are allowed in the respective management unit, and:

a. The activity is required for navigation or other water-dependent use that require an estuarine location or in the case of fills for non-water-dependent uses, is needed for a public use and would satisfy a public need that outweighs harm to navigation, fishing and recreation, as per ORS 541.625(4) and an exception has been taken in this Plan to allow such fill;

b. A need (ie., a substantial public benefit) is demonstrated and the use or alteration does not unreasonably interfere with public trust rights;

c. No feasible alternative upland locations exist; and

d. Adverse impacts are minimized.

e. Effects may be mitigated by creation, restoration or enhancement of another area to ensure that the integrity of the estuarine ecosystem is maintained;

f. The activity is consistent with the objectives of the Estuarine Resources Goal and with other requirements of state and federal law, specifically the conditions in ORS 541.615 and Section 404 of the Federal Water Pollution Control Act (P.L.92-500).

II. Other uses and activities which could alter the estuary shall only be allowed if the requirements in (b), (c), and (d) are met.

Identification and minimization of adverse impacts as required in "d" above shall follow the procedure set forth in Policy #4.

As required by Goal #16, only dredging necessary for on-site maintenance of existing functional tidegates, associated drainage channels and bridge crossing support structures is permitted in Natural and Conservation Management Units (applies to 11-NA,18A-CA, 20-CA, 30-CA, 31-NA and 38-CA). Dredging necessary for the installation of new bridge crossing support structures is permitted in Conservation Management Units and may be allowed in Natural Management Units where consistent with the resource capabilities of the area and the purposes of the management unit.

In the Conservation Management Unit, new dredging for boat ramps and marinas, aquaculture requiring dredge or fill or other alteration of the estuary, and dredging necessary for mineral extraction may be allowed where consistent with the resource capabilities of the area and the purposes of the management unit.

This strategy shall be implemented by the preparation of findings by local government documenting that such proposed actions are consistent with the Comprehensive Plan, and with the above criteria "a", "b", "c", "d", "e" and "f"; however, where goal exceptions are included within this Plan, the findings in the exception shall be sufficient to satisfy above criteria "a" through "d". Identification and minimization of adverse impacts as required in "e" above shall follow the procedure set forth in Policy #4a. The findings shall be developed in response to a "request for comment" by the Division of State Lands (DSL), which shall seek local government's determination regarding the appropriateness of a permit to allow the proposed action.

"Significant" as used in "other significant reduction or degradation of natural estuarine values", shall be determined by: a) the U.S. Army Corps of Engineers through its Section 10.404 permit processes; or b) the Department of

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Environmental Quality (DEQ) for approvals of new aquatic log storage areas only; or c) the Department of Fish and Wildlife (ODFW) for new aquaculture proposals only.

This strategy recognizes that Goal #16 limits dredging, fill and other estuarine degradation in order to protect the integrity of the estuary.

- **#5a Temporary Alterations**

I. Local governments shall support as consistent with the Plan: (a) <u>temporary alterations</u> to the estuary, in Natural and Conservation Management Units provided it is consistent with the resource capabilities of the management units. Management unit in Development Management Units temporary alterations which are defined in the definition section of the plan are allowed provided they are consistent with purpose of the Development Management Unit. b) alterations necessary for federally authorized Corps of Engineers projects, such as access to dredge material disposal sites by barge or pipeline or staging areas, or dredging for jetty maintenance.

II. Further, the actions specified above shall only be allowed provided that:

a. The temporary alteration is consistent with the resource capabilities of the area (see Policy #4);
b. Findings satisfying the impact minimization criterion of Policy #5 are made for actions involving dredge, fill or other significant temporary reduction or degradation of estuarine values;
c. The affected area is restored to its previous condition by removal of the fill or other structures, or by filling of dredged areas (passive restoration may be used for dredged areas, if this is shown to be effective); and
d. The maximum duration of the temporary alteration is three years, subject to annual permit renewal, and restoration measures are undertaken at the completion of the project within the life of the permit.

Mitigation shall not be required by this Plan for such temporary alterations.

This Policy shall be implemented through the administrative conditional use process and through local review and comment on state and federal permit applications.

This Policy is based on the recognition that temporary estuarine fill and habitat alterations are frequently legitimate actions when in conjunction with jetty repair and other important economic activities. It is not uncommon for projects to need staging areas and access that require temporary alteration to habitat that is otherwise protected by this Plan.

- **#5b Dredging to Repair Existing Functional Dikes & Tidegates**

Dredging to repair and maintain existing functional tidegates shall be permitted in Units 11-NA, 18A-CA, 20-CA, 30-CA, 31-NA and 38-CA. Dredging (limited to subtidal areas only) shall also be permitted in these units for repair of dikes where breaching has occurred or is in imminent danger of occurring.

Dredging for routine repair and maintenance of existing functional dikes shall only be permitted in Units 21-CA (Catching Slough), 30-CA (Central Isthmus Slough), and 38-CA (Coalbank Slough) limited to subtidal areas, and only in cases where the alternative of using upland fill material is not reasonably available. The upland fill alternative shall be used if a source of suitable material is available on the landowner's property and access to the dike is feasible for heavy equipment, taking into account soil conditions and road access.

In disposal of material from channel maintenance dredging on Coos River and log storage area maintenance dredging on Isthmus Slough and at Unit 18A-CA (Cooston Channel), first consideration shall be given to side-casting materials onto adjacent agricultural lands for dike repair/maintenance.

This policy shall not override the protection of "high priority" mitigation sites U-30(b) and U-32(b) on Catching Slough from pre-emptive uses by Policy #22.

This policy shall be implemented through the state/federal waterway permit review and comment process, and through a local administrative review process that includes an evaluation of the availability and suitability of alternative sources of material. Local government shall recommend imposition of a condition on state and federal waterway permits to require that any dredging authorized to repair and maintain tidegates or dikes shall be limited to the minimum necessary to restore the functional operation of the tidegate or dike.

I. This policy is based on the recognition:

   a. There is no alternative to dredging for tidegate maintenance or for emergency repair of dikes breached by erosion;
   b. Dredging for routine dike repair maintenance may be necessary if suitable material such as upland fill is not reasonably available, or if access to the dike is not possible for heavy equipment due to wet ground conditions;
   c. Maintenance and repair of dikes and tidegates is necessary to maintain productive farm land in Coos County and has been a historical farm management practice in the area for over half a century; and
   d. Any required dredging must be restricted to subtidal areas to minimize adverse impacts to aquatic habitat that might otherwise result.

- **#5c New and Expanded Log Storage**

Where otherwise listed as an allowable use within the respective management unit, new or expanded log storage shall be reviewed and approved by the Department of Environmental Quality in accordance with DEQ's Log Handling Implementation Program which shall include a determination of whether the use is consistent with the resource capabilities of the area and purposes of the estuarine management unit and consistent with Policy #5 regarding other significant reductions or degradation of estuarine natural values.

This strategy recognizes the technical expertise of Department of Environmental Quality regarding resource capabilities.

- **#5d Research and Educational Observation Structures**

I. Local government shall support research and educational observation structures, if:

   a. such activities are allowed in the respective management unit, and
   b. the activity is required for research and educational purposes.

This policy shall be implemented through the Administrative Conditional Use review criteria, which is through local review.

II. Further, where listed as allowable, a "temporary" Research and Educational Observation Structure shall be treated as "temporary" in nature and shall comply with Policy 5a(II).

This strategy recognizes that Goal #16 provides for research and educational observation structures, strictly for the purposes of scientific research or education .

- **#6 Fill in Conservation and Natural Estuarine Management Units**

I. Local government may allow fill activities in Conservation management units only if listed as an "allowable" use within a respective unit and then only as part of the following use or activity:

   a. Maintenance and protection of man-made structures existing as of October 7, 1977;
   b. Active restoration if a public need is demonstrated;
   c. Low water bridges if:
      1. An estuarine location is required;
      2. Within the estuary, there are no alternative locations such as in a development management unit; and
      3. Adverse impacts are minimized as much as feasible.
   d. Support structures if:
      1. The findings of "c" above are made; and
      2. Consistent with the resource capabilities of the area and purposes of the management unit.
   e. Aquaculture, high-intensity water-dependent recreation and minor

navigational improvements if:

1. The findings of "d" above are made; and
2. No alternative upland locations exist for the portion of the use requiring fill.

f. Flood and erosion control structures if:

1. Required to protect a water-dependent use as otherwise allowed in "d" above; and

2. Land use management practices and non-structural solutions are inadequate to protect the use.

Further, local government may allow riprap activities in Natural Management Units to a very limited extent where necessary for erosion control to protect (a) uses existing as of 10-7-77; (b) unique natural resource and historical and archaeological values, or; (c) public facilities.

This strategy shall be implemented through estuarine "Use and Activity" matrices set forth in this Plan, and through local review and comment on state and federal permit applications for such projects.

This strategy recognizes the general objectives of LCDC Goal #16 and #17. (June, 1981)

- **#7 Maintenance Dredging of Authorized Channel**

Local government shall support maintenance dredging of all authorized navigation channels.

This strategy recognizes that there are persistent problems with buildup of sediment which interferes with navigation.

- **#8 Estuarine Mitigation Requirements**

Local government recognizes that mitigation shall be required when estuarine dredge or fill activities are permitted in inter-tidal or tidal marsh areas. The effects shall be mitigated by creation, restoration or enhancement of another area to ensure that the integrity of the estuarine ecosystem is maintained as required by ORS 196.830 (renumbered in 1989). However, mitigation shall not be required for projects which the Division of State Lands determined met the criteria of ORS 196.830(3).

This strategy shall be implemented through procedures established by the Division of State Lands, and as consistent with ORS 196.830 and other mitigation/restoration policies set forth in this Plan.

This strategy recognizes the authority of the Director of the Division of State Lands in administering the statutes regarding mitigation.

- **#9 Solutions to Erosion and Flooding Problems**

Local government shall prefer nonstructural solutions to problems of erosion and flooding to structural solutions. Where shown to be necessary, water and erosion control structures such as jetties, bulkheads, seawalls and similar protective structures and fill whether located in the waterways or on shorelands above ordinary high water mark shall be designed to minimize adverse impacts on water currents, erosion and accretion patterns.

I. Further, where listed as an "allowable" activity within the respective management units, riprap may be allowed in Development Management Units upon findings that:

   a. Land use management practices and nonstructural solutions are inadequate; and
   b. Adverse impacts on water currents, erosion and accretion patterns are minimized; and
   c. It is consistent with the Development management unit requirements of the Estuarine Resources Goal.

II. Further, where listed as an "allowable" activity within respective management units, riprap shall only be allowed in Conservation Aquatic (CA) units upon findings that:

   a. Land use management practices and nonstructural solutions are inadequate; and
   b. Adverse impacts on water currents, erosion and accretion patterns are minimized; and
   c. Riprap is consistent with the resource capabilities of the area and the purposes of maintaining Conservation management units.

III. Further, where listed as an "allowable" activity within respective management units, riprap shall only be allowed in Natural Aquatic (NA) units upon findings that:

   a. There is a need to protect from erosion: uses existing as of October 7, 1977, unique natural resources and historic archaeological values, or public facilities;
   b. Land use management practices and nonstructural solutions are inadequate;
   c. It is consistent with the natural management unit as set forth in this Plan and required by Goal #16; and
   d. Adverse impacts on water currents, erosion and accretion patterns and estuarine organisms and their habitat are minimized.

Implementation of this strategy shall occur through local review of and comment on state and federal permit applications for such projects.

This strategy is based on the recognition that nonstructural solutions are often more cost-effective as corrective measures, but that carefully designed structural solutions are occasionally necessary. The strategy also recognizes LCDC Goal #16 and #17 requirements and the Oregon Administrative Rule classifying Oregon estuaries (OAR 660-17-000 as amended June, 1981).

- **#10 Proliferation of Single-Purpose Docks and Piers**

Local government shall act to restrict the proliferation of individual single-purpose docks and piers, when such are allowed within respective management units.

I. This strategy shall be implemented:

a. By preparation of findings by local government in response to a "request for comment" by the Division of State Lands (which shall seek local government's determination regarding the appropriateness of a permit to allow the proposed dock or pier) which documents that:

1. The size and shape of the proposed dock or pier shall be limited to that required for the intended use; and
2. Alternatives to docks and piers (such as mooring buoys, dryland storage, and launching ramps) have been investigated and considered; and

b. By encouraging community facilities common to several uses and interests by:

1. Satisfying community needs for docks and moorage facilities in this Plan; and
2. Encouraging easements to facilitate multi-ownership.

This strategy recognizes the requirements of Goal #16 and the environmental benefits of multi-purpose and multi-ownership docks and moorage facilities.

- **#11 Authority of Other Agencies**

Local government shall recognize the authority of the following agencies and their programs for managing land and water resources:

~ The Oregon Forest Practices Act and Administrative Rules for forest lands as defined in ORS 527.620(1991) to 527.730 and Forest Lands Goal;

~ The nonpoint source discharge water quality program administered by the Department of Environmental Quality (DEQ) under Section 208 of the Federal Water Quality Act as amended in 1972 (PL 92-500);

~ The Fill and Removal Permit Program administered by the Division of State Lands (DSL) under ORS 196.800-196.880 (renumbered 1989); and

~ The programs of the State Soil and Water Conservation Commission and local districts and the Soil Conservation Service and the Agricultural Lands Goal.

This strategy recognizes there are several agencies with authority over coastal waters, and that their management programs should be used rather than developing new or duplicate management techniques or controls, especially as related to existing programs functioning to maintain water quality and minimize man-induced sedimentation.

This strategy shall be implemented through the permit coordination with ODFW and the Army Corps of engineers prior to County sign-off on permits.

- **#12 Removal of Old Pilings and Snags**

Local governments shall support removal of pilings, sunken logs, snags and other obstructions, and accumulations of debris from the Coos Bay Estuary, where "minor navigational improvement" is listed as an allowable use or activity within all management units, except where identified as needed for habitat.

This strategy recognizes that the Coos Bay Estuary contains a number of disused pilings, snags, other obstructions and accumulations which may interfere with navigation and which can adversely affect habitat and increase erosion hazard.

This strategy shall be implemented through the permit coordination with ODFW and the Army Corps of Engineers prior to County sign-off on permits.

- **#13 Overall Use Priorities within Coastal Shorelands**

I. Local government shall maintain the following priorities for the overall use of coastal shorelands (from highest to lowest):

  a. Promote uses which maintain the integrity of estuaries and coastal waters;
  b. Provide for water-dependent uses;
  c. Provide for water-related uses;
  d. Provide for nondependent, nonrelated uses which retain flexibility of future use and do not prematurely or inalterably commit shorelands to more intensive uses;
  e. Provide for development, including nondependent, nonrelated uses, in urban areas compatible with existing or committed uses;
  f. Permit nondependent, nonrelated uses which cause a permanent or long-term change in the features of coastal shorelands only upon a demonstration of public need.

In addition, priority uses for flood hazard and floodplain areas outside of incorporated cities shall include agriculture, forestry, recreation and open space.

This strategy recognizes that the Coos Bay Estuary Management Plan's shoreland designations, and permitted uses and activities are based upon and establish general priorities for the use of coastal shoreland resources.

- **#14 General Policy on Uses within Rural Coastal Shorelands**

I. Coos County shall manage its rural areas within the "Coos Bay Coastal

Shorelands Boundary" by allowing only the following uses in rural shoreland areas, as prescribed in the management units of this Plan, except for areas where mandatory protection is prescribed by LCDC Goal #17 and CBEMP Policies #17 and #18:

a. Farm uses as provided in ORS 215.203;
b. Propagation and harvesting of forest products;
c. Private and public water-dependent recreation developments;
d. Aquaculture;
e. Water-dependent commercial and industrial uses, water-related uses, and other uses only upon a finding by the Board of Commissioners or its designee that such uses satisfy a need which cannot be accommodated on uplands or shorelands in urban and urbanizable areas or in rural areas built upon or irrevocably committed to non-resource use.
f. Single-family residences on lots, parcels, or units of land existing on January 1, 1977, when it is established that:

    1. The dwelling is in conjunction with a permitted farm or forest use, or
    2. The dwelling is in a documented "committed" area, or
    3. The dwelling has been justified through a goal exception; and
    4. Such uses do not conflict with the resource preservation and protection policies established elsewhere in this Plan;

g. Any other uses, including non-farm uses and non-forest uses, provided that the Board of Commissioners or its designee determines that such uses satisfy a need which cannot be accommodated at other upland locations or in urban or urbanizable areas. In addition, the above uses shall only be permitted upon a finding that such uses do not otherwise conflict with the resource preservation and protection policies established elsewhere in this Plan.

This strategy recognizes (1) that Coos County's rural shorelands are a valuable resource and accordingly merit special consideration, and (2) that LCDC Goal #17 places strict limitations on land divisions within coastal shorelands. This strategy further recognizes that rural uses "a through "g" above, are allowed because of need and consistency findings documented in the "factual base" that supports this Plan.

- **#15 Land Divisions within Rural Shorelands**

Coos County shall permit subdivisions, major and minor partitions within the Coos Bay Coastal Shorelands Boundary in rural areas only upon a finding by the County: 1. that the new land divisions have been justified through a goal exception; 2. that the new land divisions fulfill a need that cannot otherwise be accommodated in uplands in urban and urbanizable areas, or other upland locations; and 3. that such land divisions would not otherwise conflict with the resource preservation and protection policies established elsewhere in this Plan.

This strategy shall be implemented through provisions in ordinance measures that require the above findings to be made: (1) prior to the approval of the preliminary plat of a subdivision or major partition; or (2) prior to the approval of minor partition.

This strategy recognizes: (1) Coos County's rural shorelands area is a valuable resource and accordingly merits special consideration; and (2) that LCDC Goal #17 places strict limitations on land divisions within coastal shorelands.

- **#16 Protection of Sites Suitable for Water-Dependent Uses and Special Allowance for new Non-Water-Dependent Uses in "Urban Water-Dependent (UW) Units"**

Local government shall protect shorelands in the following areas that are suitable for water-dependent uses, for water-dependent commercial, recreational and industrial uses.

a. Urban or urbanizable areas;
b. Rural areas built upon or irrevocably committed to non-resource use; and

c. Any unincorporated community subject to OAR Chapter 660, Division 022 (Unincorporated Communities).

This strategy is implemented through the Estuary Plan, which provides for water-dependent uses within areas that are designated as Urban Water-Dependent (UW) management units.

I. Minimum acreage. The minimum amount of shorelands to be protected shall be equivalent to the following combination of factors:

   a. Acreage of estuarine shorelands that are currently being used for water-dependent uses; and
   b. Acreage of estuarine shorelands that at any time were used for water-dependent uses and still possess structures or facilities that provide or provided water-dependent uses with access to the adjacent coastal water body. Examples of such structures or facilities include wharves, piers, docks, mooring piling, boat ramps, water intake or discharge structures and navigational aids.

II. Suitability. The shoreland area within the estuary designated to provide the minimum amount of protected shorelands shall be suitable for water-dependent uses. At a minimum such water-dependent shoreland areas shall possess, or be capable of possessing, structures or facilities that provide water-dependent uses with physical access to the adjacent coastal water body. The designation of such areas shall comply with applicable Statewide Planning Goals.

III. Permissible Non-Water-Dependent Uses. Unless otherwise allowed through an Exception, new non-water-dependent uses which may be permitted in "Urban Water-dependent (UW)" management units are a temporary use which involves minimal capital investment and no permanent structures, or a use in conjunction with and incidental and subordinate to a water-dependent use. Such new non-water-dependent uses may be allowed only if the

following findings are made, prior to permitting such uses:

1. Temporary use involving minimal capital investment and no permanent structures:

    a. The proposed use or activity is temporary in nature (such as storage, etc.); and
    b. The proposed use would not pre-empt the ultimate use of the property for water-dependent uses; and
    c. The site is committed to long-term water-dependent use or development by the landowner.

2. Use in conjunction with and incidental and subordinate to a water-dependent use:

    a. Such non-water-dependent uses shall be constructed at the same time as or after the water-dependent use of the site is established, and must be carried out together with the water-dependent use.
    b. The ratio of the square footage of ground-level indoor floor space plus outdoor acreage distributed between the non-water-dependent uses and the water-dependent uses at the site shall not exceed one to three (non-water-dependent to water-dependent).
    c. Such non-water-dependent uses shall not interfere with the conduct of the water-dependent use.

This policy shall be implemented through provisions in ordinance measures that require an administrative conditional use application be filed and approved, and the above findings be made prior to the establishing of the proposed uses or activities.

- **#16a Minimum Protected Acreage Required for County Estuarine Shorelands**

Coos County designates as water-dependent shorelands any shorelands with the Coos Bay Estuary whose total acreage is equal to or greater than the minimum acreage of water-dependent shorelands calculated for the Coos Bay Estuary by combining the inventories of Coos County and the City of North Bend.

The following chart shows acreages that were available and zoned for water-dependent use and acreages that were required to be protected by DLCD for each jurisdiction on the Coos Bay Estuary.

Acreage Available and Zoned for Water-Dependent Use and Acreage to be Protected for Water-Dependent Use on the Coos Bay Estuary			
Jurisdiction	***Acreage Available and Zoned for Water-Dependent Use***	***Acreage to be Protected for Water-Dependent Use***	***Date of Data***

Unincorporated Coos County	1440.50 acres	496.52 acres	January 1, 2000
City of North Bend	5.42 acres	96.33 acres	2006 data as amended
Combined Inventory for the Coos Bay Estuary on an Estuary-wide Basis for Unincorporated Coos County and the City of North Bend	1445.92 acres	592.85 acres	September 27, 2006
*City of Coos Bay	106.89 acres	76.18 acres	January 1, 2000

*City of Coos Bay chose not to participate in combining the City's water-dependent acreage

Use of the acreage in the Combined Inventory for the Coos Bay Estuary on and Estuary-Wide Basis shown in the chart entitled, *Acreage Available and Zoned for Water-Dependent Use and Acreage to be Protected for Water-Dependent Use on the Coos Bay Estuary* will be coordinated by Coos County.

Any proposal to utilize unincorporated acreage to supply inventory for the City of North Bend from the unincorporated Coos County Acreage Available and Zoned for Water-Dependent Use in the chart entitled *Acreage Available and Zoned for Water-Dependent Use and Acreage to be Protected for Water-Dependent Use on the Coos Bay Estuary* will be subject to amendments of the Coos County Plan Inventory Document, Volume II, Part, 1 Plan Policy 16a.

- **#16b Rural, Urban, and Unincorporated Communities Use Standards**

I. Commercial and Industrial uses in Unincorporated Communities and on Rural Lands shall be consistent with OAR 660-022-0030. Commercial and industrial uses shall comply with building square footage requirements set forth in OAR 660-022-0030(10) and (11). New commercial structures authorized outside of a UCB or UGB shall not exceed 3,500 square feet of floor area. New industrial structures located outside of a UCB or UGB shall not exceed 35,000 square feet of floor area, unless:

   a. The industrial use involves the primary processing of raw material(s) produced in the area or from ocean resources; or
   b. The industrial use is located on an abandoned or diminished mill site as defined by statute; or
   c. The industrial use is located in an area where an exception to Goal 14 has been taken; or
   d. As authorized by Goals 3 and/or 4.

This policy shall be implemented through ordinance measures. Implementation shall occur as identified under specific zoning district standards. (04-04-005PL 9/1/04)

II. It must be demonstrated through findings that the proposed use will not:

   a. adversely affect agricultural and forest operations, and

b. interfere with the efficient functioning of urban growth boundaries.

III. The following are development standards for proposed commercial or industrial structures to be located on parcels which are abutting exclusive farm use or forest zoned properties:

a. All structures, except fences, shall be setback a minimum of thirty-five (35) feet from any road right-of-way centerline, or five (5) feet from any right-of-way centerline, whichever is greater; and
b. All structures being sited on parcels abutting exclusive farm use (EFU) or forest (F) zoned parcels, property owner(s)/applicant(s) shall acknowledge and file in the deed records of Coos County, a "Farm or Forest" Practices Management Covenant. The covenant shall be recorded in the deed records of the county prior to the County issuing a zoning compliance letter.

- **#17 Protection of "Major Marshes" and "Significant Wildlife Habitat" in Coastal Shorelands**

Local governments shall protect from development, major marshes and significant wildlife habitat, coastal headlands, and exceptional aesthetic resources located within the Coos Bay Coastal Shorelands Boundary, except where exceptions allow otherwise.

I. Local government shall protect:

a. "Major marshes" to include areas identified in the Goal #17, "Linkage Matrix", and the Shoreland Values Inventory map; and
b. "Significant wildlife habitats" to include those areas identified on the "Shoreland Values Inventory" map; and
c. “Coastal headlands”; and
d. “Exceptional aesthetic resources” where the quality is primarily derived from or related to the association with coastal water areas.

II. This strategy shall be implemented through:

a. Plan designations, and use and activity matrices set forth elsewhere in this Plan that
limit uses in these special areas to those that are consistent with protection of natural values; and
b. Through use of the Special Considerations Map, which identified such special areas and restricts uses and activities therein to uses that are consistent with the protection of natural values. Such uses may include propagation and selective harvesting of forest products consistent with the Oregon Forest Practices Act, grazing, harvesting wild crops, and low-intensity water-dependent recreation.
c. Contacting Oregon Department of Fish and Wildlife for review and comment on the proposed development within the area of the 5b or 5c bird sites.

This strategy recognizes that special protective consideration must be given to key resources in coastal shorelands over and above the protection afforded such resources elsewhere in this Plan.

- **#18 Protection of Historical, Cultural and Archaeological Sites**

Local government shall provide protection to historical, cultural and archaeological sites and shall continue to refrain from widespread dissemination of site-specific information about identified archaeological sites.

I. This strategy shall be implemented by requiring review of all development proposals involving a cultural, archaeological or historical site, to determine whether the project as proposed would protect the cultural, archaeological and historical values of the site.

II. The development proposal, when submitted shall include a Site Plan Application, showing, at a minimum, all areas proposed for excavation, clearing and construction. Within three (3) working days of receipt of the development proposal, the local government shall notify the Coquille Indian Tribe and Coos, Siuslaw, Lower Umpqua Tribe(s) in writing, together with a copy of the Site Plan Application. The Tribe(s) shall have the right to submit a written statement to the local government within thirty (30) days of receipt of such notification, stating whether the project as proposed would protect the cultural, historical and archaeological values of the site, or if not, whether the project could be modified by appropriate measures to protect those values.

"Appropriate measures" may include, but shall not be limited to the following:

a. Retaining the prehistoric and/or historic structure in situ or moving it intact to another site; or
b. Paving over the site without disturbance of any human remains or cultural objects upon the written consent of the Tribe(s); or
c. Clustering development so as to avoid disturbing the site; or
d. Setting the site aside for non-impacting activities, such as storage; or
e. If permitted pursuant to the substantive and procedural requirements of ORS 97.750, contracting with a qualified archaeologist to excavate the site and remove any cultural objects and human remains, reinterring the human remains at the developer's expense; or
f. Using civil means to ensure adequate protection of the resources, such as acquisition of easements, public dedications, or transfer of title.

If a previously unknown or unrecorded archaeological site is encountered in the development process, the above measures shall still apply. Land development activities, which violate the intent of this strategy shall be subject to penalties prescribed in ORS 97.990.

III. Upon receipt of the statement by the Tribe(s), or upon expiration of the Tribe(s) thirty day response period, the local government shall conduct an administrative review of the Site Plan Application and shall:

a. Approve the development proposal if no adverse impacts have been identified, as long as consistent with other portions of this plan, or

b. Approve the development proposal subject to appropriate measures agreed upon by the landowner and the Tribe(s), as well as any additional measures deemed necessary by the local government to protect the cultural, historical and archaeological values of the site. If the property owner and the Tribe(s) cannot agree on the appropriate measures, then the governing body shall hold a quasi-judicial hearing to resolve the dispute. The hearing shall be a public hearing at which the governing body shall determine by preponderance of evidence whether the development project may be allowed to proceed, subject to any modifications deemed necessary by the governing body to protect the cultural, historical and archaeological values of the site.

IV. Through the "overlay concept" of this policy and the Special Considerations Map, unless an exception has been taken, no uses other than propagation and selective harvesting of forest products consistent with the Oregon Forest Practices Act, grazing, harvesting wild crops, and low intensity water-dependent recreation shall be allowed unless such uses are consistent with the protection of the cultural, historical and archaeological values, or unless appropriate measures have been taken to protect the historic and archaeological values of the site.

This strategy recognizes that protection of cultural, historical and archaeological sites is not only a community's social responsibility; it is also legally required by ORS 97.745. It also recognizes that cultural, historical and archaeological sites are non-renewable cultural resources.

- **#19 Management of "Wet-Meadow" Wetlands within Coastal Shorelands**

I. Coos County shall protect for agricultural purposes those rural areas defined as "wet-meadow" wetlands by the U.S. Fish and Wildlife Service but currently in agricultural use or with agricultural soils and not otherwise designated as "significant wildlife habitats" or major marshes", unless an Exception allows otherwise. Permitted uses and activities in these areas shall include farm use and any drainage activities which are necessary to improve agricultural production. Filling of these areas, however, shall not be permitted so as to retain these areas as wildlife habitats during periods of seasonal flooding and high water tables, with the following exceptions:

a. For transportation corridors where an exception has been taken to Goal #3 (Agricultural Lands); or

b. For agricultural buildings, where no alternative sites exist on the applicant's property; or

c. Minor improvements for which there is no practical alternative; or

d. Where no fill permit is required under Section 404 of the Water Pollution Control Act; or

e. For priority dredged material disposal sites designated by this Plan for protection from pre-emptory uses.

Any activity or use requires notification of Division of State Lands, with their comments

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received prior to the issuance of any permits.

II. This policy shall be implemented by designating these lands as "Agricultural Lands" on the Special Considerations Map and by making findings in response to a request for comment by the Division of State Lands (DSL), which show whether the proposed action is consistent with the Comprehensive Plan:

a. That protection of these areas for agricultural use is necessary to ensure the continuation of the local agricultural economy;
b. That improved drainage is necessary to maintain or enhance productivity by establishing preferred forage types;
c. That the present system of agricultural use in the Coos Bay area is compatible with wildlife habitat values, because the land is used for agriculture during the season when the land is dry and therefore not suitable as wetland habitat, and provides habitat areas for wildfowl during the flooding season when the land is unsuitable for most agricultural uses; and
d. That these habitat values will be maintained provided filling is not permitted.

- **#20 Dredged Material Disposal Sites**

Local government shall support the stockpiling and disposal of dredged materials on sites specifically designated in Plan Provisions, Volume II, Part 1, Section 6, Table 6.1, and also shown on the "Special Considerations Map". Ocean disposal is currently the primary disposal method chosen by those who need disposal sites. The dredge material disposal designated sites on the list provided on Table 6.1, has decreased because the ocean has become the primary disposal method, the in-land DMD sites have diminished and those which have remained on the DMD list are sites which may be utilized in the future and not be cost-prohibitive. Consistent with the "Use/Activity" matrices, designated disposal sites shall be managed so as to prevent new uses and activities which could prevent the sites' ultimate use for dredge material disposal. A designated site may otherwise only be released for some other use upon a finding that a suitable substitute upland site or ocean dumping is available to provide for that need. Sites may only be released through a Plan Amendment. Upland dredged material disposal shall be permitted elsewhere (consistent with the "Use/Activity" matrices) as needed for new dredging (when permitted), maintenance dredging of existing functional facilities, minor navigational improvements or drainage improvements, provided riparian vegetation and fresh-water wetlands are not affected. For any in-water (including intertidal or subtidal estuarine areas) disposal permit requests, this strategy shall be implemented by the preparation of findings by local government consistent with Policy #5 (Estuarine Fill and Removal) and Policy #20c (Intertidal Dredged Material Disposal). Where a site is not designated for dredged material disposal, but is used for the disposal of dredged material, the amount of material disposed shall be considered as a capacity credit toward the total identified dredged material disposal capacity requirement.

I. This policy shall be implemented by:

a. Designating "Selected Dredge Material Disposal Sites" on the "Special Considerations Map"; and
b. Implementing an administrative review process (to preclude pre-emptory

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uses) that allows uses otherwise permitted by this Plan but proposed within an area designated as a "Selected DMD" site only upon satisfying all of the following criteria:

1. The proposed use will not entail substantial structural or capital improvements (such as roads, permanent buildings and nontemporary waterand sewer connections); and
2. The proposed use must not require any major alteration of the site that would affect drainage or reduce the usable volume of the site (such as extensive site grading/excavation or elevation from fill); and
3. The proposed use must not require site changes that would prevent the expeditions conversion of the site to estuarine habitat.

c. Local government's review of and comment on applicable state and federal waterway permit applications for dike/tidegate and drainage ditch actions.

II. This strategy recognizes that sites designated in the Comprehensive Plan reflect the following key environmental considerations required by LCDC Goal #16:

a. Disposal of dredged material in upland or ocean waters was given general preference in the overall site selection process;

b. Disposal of dredged material in estuary waters is permitted in this Plan only when such disposal is consistent with state and federal law;
c. Selected DMD sites must be protected from pre-emptory uses.

- **#20a Dredged Material Disposal Guidelines**

Future dredged material disposal should be carried out in accordance with the guidelines outlined in Volume II, Part I, Section 6.2 of the Plan, which relate to: drainage diversion, sediment quality and turbidity, timing of disposal, land surface use, revegetation, toxic materials, land use outfalls and influent discharge points, water quality and removal of material from approved upland sites. Future land use shall be governed by the uses/activities permitted and the Management Objective in that management unit. Additional guidelines contained in the "Special Considerations" section of the individual site fieldsheets (see Inventory and Factual Base, Volume II, Part 2, Section 7, Appendix 'A') provide site-specific information on the procedures that should be followed.

These guidelines are intended to indicate the type of conditions that federal and state agencies are likely to impose on dredged material disposal permits, which shall be the primary means of implementation. Local government shall implement this policy by review and comment on permit applications.

This policy recognizes that disposal permit conditions are imposed at the discretion of the permitting agency, and should not be set down as mandatory requirements in the Plan, but simply as guidelines.

- **#20b Priority for In-Bay Subtidal Disposal Sites**

I. In-bay disposal site "G" (Coos Head) also known as Aquatic Unit 67A-DA, is the first priority in-bay subtidal disposal site, but shall be used only:

a. During rough bar conditions when ocean disposal is not feasible; or
b. In conjunction with maintenance dredging of the Charleston marina complex.

II. In-bay site "8.4" shall be used only when site "F" is inaccessible because of severe weather conditions and/or dredging above R.M. 6.

This policy shall be implemented by state and federal issuance of dredged material disposal permits.

This policy recognizes that there are limitations on the acceptable use of in-bay placement of dredged materials.

#20c <u>Intertidal Dredged Material Disposal</u>

Local government shall prohibit dredged material disposal in intertidal or tidal marsh areas except where such disposal is part of an approved fill project.

This strategy shall be implemented through operation of the waterway permit process as a response to a "request for comment" from the Division of State Lands and U. S. Army Corps of Engineers.

This strategy recognizes that upland disposal and ocean disposal are alternatives to intertidal disposal.

- **#20d DMD Planning Period**

Local government recognizes that the Comprehensive Plan does not provide adequate information of dredged material disposal (DMD) sites. Updating information and strategies will occur during the County’s period review.

This strategy shall be implemented through review of DMD needs during periodic review, and through statistical monitoring of DMD fills by the Army Corps of Engineers and Oregon International Port of Coos Bay.

- **#21 Mitigation and Restoration Sites**

Local government shall support mitigation and restoration actions on the sites specifically designated in this Plan (See Plan Inventory, Section 8, Special Mitigation/Restoration Element). However, mitigation and restoration actions shall not necessarily be limited to the identified sites, but may occur in other areas with suitable potential as permitted in the "Uses/Activities" matrices and subject to Policy #8, Mitigation Requirements. Local government shall also cooperate with the Oregon Department of Fish and Wildlife (ODFW) and the Division of State Lands (DSL) to form a "mitigation bank" pursuant to ORS 196.600-655 and 196.830 (renumbered 1989).

This strategy is based upon the recognition of the need for identification of areas to be used to fulfill the mitigation requirements of Goal #17 and this Plan.

- **#22 Mitigation Sites: Protection Against Pre-emptory Uses**

Consistent with permitted uses and activities:

~ "High Priority" designated mitigation sites shall be protected from any new uses or activities which could pre-empt their ultimate use for this purpose.

~ "Medium Priority" designated mitigation sites shall also be protected from uses which would pre-empt their ultimate use for this purpose.

However, repair of existing dikes or tidegates and improvement of existing drainage ditches is permitted, with the understanding that the permitting authority (Division of State Lands) overrides the provisions of Policy #38. Wetland restoration actions designed to answer specific research questions about wetland mitigation and/or restoration processes and techniques, may be permitted upon approval by Division of States Lands, and as prescribed by the uses and activities table in this Plan.

~ "Low Priority" designated mitigation sites are not permanently protected by the Plan. They are intended to be a supplementary inventory of potential sites that could be used at the initiative of the landowner. Pre-emptory uses shall be allowed on these sites, otherwise consistent with uses and activities permitted by the Plan. Any change in priority rating shall require a Plan Amendment.

Except as provided above for research of wetland restoration and mitigation processes and techniques, repair of existing dikes, tidegates and improvement of existing drainage ditches, "high" and "medium" priority mitigation sites shall be protected from uses and activities which would pre-empt their ultimate use for mitigation.

I. This policy shall be implemented by:

   a. Designating "high" and "medium" priority mitigation sites on the Special Considerations Map; and
   b. Implementing an administrative review process that allows uses otherwise permitted by this Plan but proposed within an area designated as a "high" or "medium" priority mitigation site only upon satisfying the following criteria:

      1. The proposed use must not entail substantial structural or capital improvements (such as roads, permanent buildings or nontemporary water and sewer connections); and
      2. The proposed use must not require any major alteration of the site that would affect drainage or reduce the usable volume of the site (such as extensive site grading/excavation or elevation from fill); and
      3. The proposed use must not require site changes that would prevent

the expeditious conversion of the site to estuarine habitat; or

4. For proposed wetland restoration research projects in "medium" priority mitigation sites the following must be submitted:

   i. A written approval of the project, from Division of States Lands, and
   ii. A description of the proposed research, resource enhancement and benefits expected to result from the restoration research project.

c. Local government's review and comment on state and federal waterway permit applications for dike/tidegate and drainage ditch actions.

This policy recognizes that potential mitigation sites must be protected from pre-emptory uses. However, "low priority" sites are not necessarily appropriate for mitigation use and are furthermore in plentiful supply. It further recognizes, that future availability of "medium priority" sites will not be pre-empted by repair of existing dikes, tidegates and drainage ditches or otherwise allowed by this policy. This insures the continuation of agricultural production until such time as sites may be required for mitigation. This policy also recognizes that research activities designed to gain further understanding of wetland, restoration and mitigation processes and techniques are needed. The consideration of "medium priority" mitigation sites for this purpose will facilitate future identification and successful use of mitigation sites (OR 95-11-010PL 1/24/96).

- **#22a Acquisition or Protection of Mitigation/Restoration and Dredged Material Disposal Sites**

Local government shall actively promote the acquisition or protection of mitigation/restoration or dredged material disposal sites through purchase of fee title easements or development rights, property exchange or other similar methods, in addition to mitigation banking, as necessary to meet development needs on the estuary. They shall also investigate such methods of site protection as "limited term freeze" and "open space taxation" or other means of tax reduction.

This policy recognizes that purchase of an interest in a site is often necessary to afford a higher degree of protection than zoning can provide.

- **#22b Limiting Dredge and Fill as Estuarine Restoration**

I. Local government shall support estuarine dredge or fill actions as estuarine restoration (pursuant to LCDC Goal #16) only when such restoration will meet the requirements of administrative rules adopted by the Division of State Lands and only upon findings which demonstrate the following:

   a. Factual assessment of the nature and extent of the estuarine resource believed to have existed at the proposed restoration site at some time in the past; and
   b. Factual assessment of how the estuarine resource at the site was lost; and
   c. Comparison of the resource enhancement expected to result from the

proposed restoration project, together with a determination that the proposed project will, in fact, probably restore all or some of the resource values lost at the site; and

d. The fill/removal findings at ORS 196.

This policy shall be implemented by an administrative conditional use review process and response to requests for comments by the Division of State Lands and Corps of Engineers regarding state or federal waterway permits.

This policy recognizes that not all estuarine dredge or fill actions may be considered estuarine restoration pursuant to LCDC Goal #16.

- **#23 Riparian Vegetation and Streambank Protection**

I. Local government shall strive to maintain riparian vegetation within the shorelands of the estuary, and when appropriate, restore or enhance it, as consistent with water-dependent uses. Local government shall also encourage use of tax incentives to encourage maintenance of riparian vegetation, pursuant to ORS 308.792 - 308.803.

Appropriate provisions for riparian vegetation are set forth in the CCZLDO Section 3.2.180 (OR 92-05-009PL).

II. Local government shall encourage streambank stabilization for the purpose of controlling streambank erosion along the estuary, subject to other policies concerning structural and non-structural stabilization measures.

This strategy shall be implemented by Oregon Department of Transportation (ODOT) and local government where erosion threatens roads. Otherwise, individual landowners in cooperation with the Oregon International Port of Coos Bay, and Coos Soil and Water Conservation District, Watershed Councils, Division of State Lands and Oregon Department of Fish & Wildlife shall be responsible for bank protection.

This strategy recognizes that the banks of the estuary, particularly the Coos and Millicoma Rivers are susceptible to erosion and have threatened valuable farm land, roads and other structures.

- **#24 Special Forest Protective Regulations in Coastal Shorelands**

Local government shall urge the Oregon Department of Forestry to recognize the unique and special values provided by coastal shorelands when developing standards and policies to regulate uses of forest lands within coastal shorelands.

This strategy recognizes LCDC Goal #17 "Implementation Requirement #1" and the need for protection and maintenance of special shoreland values and forest uses especially for natural shorelands and riparian vegetation.

- **#25 Waste/Storm Water Discharge**

Local government recognizes that Waste /storm water discharge must meet state and federal water quality standards prior to issuance of any permits by the county.

I. Local government shall support Waste/Storm Water discharge, if such activity is allowed in the respective management unit and:

   a. The activity is required for waste/storm water discharge; and,
   b. The activity is consistent with the resource capabilities of the area (see Policy #4); and,
   c. Findings must be made satisfying the impact minimization criterion of Policy #5.

This policy shall be implemented through the conditional use process and through local review and comment on state and federal permit applications.

This strategy recognizes that Goal #16 provides for Waste/Storm Water discharge; and, recognizes the technical expertise of Department of Environmental Quality regarding resource capabilities.

- **#26 Agricultural Drainage Facilities**

Local government shall cooperate with Coos Soil and Water Conservation District, local drainage districts and individual landowners in their efforts to obtain permits and funding for drainage projects. These projects shall include both improvement and maintenance of existing functional dikes, tidegates and drainage ditches and construction of new drainage facilities. Areas to be drained may include "wet meadow" areas (see Policy #19) currently in agricultural use or with agricultural soils, not otherwise designated as "significant wildlife habitat" or "major marshes", subject to Policy #17. Local government shall also encourage the formation and expansion of local drainage districts.

The purpose of this strategy is to reduce damage to economically valuable forage crops, by controlling flooding of saltwater, and by alleviating ponding of flood water and high water tables that cause serious drainage problems for farmers.

This strategy recognizes that flooding is a particular problem of the Coos Bay area lowlands and that forage crop quality can be improved, and grazing seasons lengthened by effective drainage facilities. It further recognizes that drainage districts are effective for local control and financing of agricultural drainage.

- **#27 Floodplain Protection within Coastal Shorelands**

The respective flood regulations of local government set forth requirements for uses and activities in identified flood areas; these shall be recognized as implementing ordinances of this Plan.

This strategy recognizes the potential for property damage that could result from flooding of the estuary.

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- **#28** **Recognition of LCDC Goal #3 (Agricultural Lands) Requirements for Rural Lands within the Coastal Shorelands Boundary**

Unless otherwise allowed through an Exception, Coos County shall manage all rural lands designated within the Coastal Shorelands Boundary as being suitable for "Exclusive Farm Use" (EFU) designation consistent with the “Agricultural Use Requirements” of ORS 215. Allowed uses are listed in Appendix 1, of the Zoning and Land Development Ordinance.

This policy shall be implemented by using the Special Considerations Map (Policy #3) to identify EFU-suitable areas, and to abide by the prescriptive use and activity requirements of ORS 215 in lieu of other management alternatives otherwise allowed for properties within the "EFU-overlay" set forth on the Special Considerations Map, and except where otherwise allowed by exceptions for needed housing and industrial sites.

The "EFU" zoned land within the Coastal Shorelands Boundary shall be designated as "Other Aggregate Sites" inventories by this Plan pursuant to ORS 215.298(2). These sites shall be inventoried as "1B" resources in accordance with OAR 660-16-000(5)(b). Coos County will re-evaluate these inventoried sites pursuant to the requirements of said rule at, or before, County's periodic review of the Comprehensive Plan (OR 92-08-013PL 10/28/92).

- **#28a** **RESERVED**

- **#29** **Restricting Actions in Beach and Dune Areas that are "Unsuitable for Development"**

Unless otherwise allowed through an exception, Coos County shall prohibit residential development, and commercial and industrial buildings within areas designated as "Beach and Dune Areas Unsuitable for Development" on the Coos Bay Estuary Special Considerations Map.

I. Further, Coos County shall permit other developments in these areas only:

a. When specific findings have been made which consider:

1. Type of use proposed and the adverse effects it might have on the site and adjacent areas; and
2. Temporary and permanent stabilization programs and planned maintenance of new and existing vegetation; and
3. Methods for protecting the surrounding area from any adverse effects of the development; and
4. Hazards to life, public and private property, and the natural environment which may be caused by the proposed use; and
5. Whether drawdown of groundwater would lead to loss of stabilizing vegetation, loss of water quality, or intrusion of saltwater into water supplies; and

b. When it is demonstrated that the proposed development:

1. Is adequately protected from any geologic hazards, wind erosion, undercutting, ocean flooding and storm waves; or is of minimal value; and
2. Is designed to minimize adverse environmental effects; and

c. When specific findings have been made where breaching of foredunes is contemplated, that:

1. The breaching and restoration after breaching is consistent with sound principles of conservation, and either;
2. The breaching is necessary to replenish sand supply in interdune areas, or;
3. The beaching is done on a temporary basis in an emergency (e.g., fire control, cleaning up oil spills, draining farm lands, and alleviating flood hazards).

II. This policy shall be implemented through:

a. Review of the Coos Bay Estuary Special Considerations Map when development is proposed in these areas; and
b. An administrative conditional use process where findings are developed based upon a site investigation report submitted by the developer which addresses the considerations set forth above.

III. This policy recognizes that:

a. The "Special Considerations Map" category of "Beach and Dune Areas Unsuitable for Development" includes the following dune forms:

1. beaches
2. active foredunes
3. other foredunes which are conditionally stable and that are subject to ocean undercutting or wave overtopping, and

4. interdune areas (deflation plains) that are subject to ocean flooding;

b. The measures prescribed in this policy are specifically required by LCDC Goal #18 for the above-referenced dune forms; and that
c. It is important to ensure that development in sensitive beach and dune areas is compatible with or can be made compatible with, the fragile and hazardous conditions common to such areas.

- **#30 Restricting Actions in Beach and Dune Areas with "Limited Development Suitability" and Special Consideration for Sensitive Beach and Dune Resources (moved from Policy #31)**

I. Coos County shall permit development within areas designated as "Beach and

Dune Areas with Limited Development Suitability" on the Coos Bay Estuary Special Considerations Map only upon the establishment of findings that shall include at least:

a. The type of use proposed and the adverse effects it might have on the site and adjacent areas;
b. Temporary and permanent stabilization programs and the planned maintenance of new and existing vegetation;
c. Methods for protecting the surrounding area from any adverse effects of the development; and
d. Hazards to life, public and private property, and the natural environment which may be caused by the proposed use; and
e. Whether drawdown of groundwater would lead to loss of stabilizing vegetation, loss of water quality, or intrusion of saltwater into water supplies.

Implementation shall occur through an administrative conditional use process which shall include submission of a site investigation report by the developer that addresses the five considerations above.

II. This policy recognizes that:

a. The Special Considerations Map category of "Beach and Dune Areas with Limited Development Suitability" includes all dune forms except older stabilized dunes, active foredunes, conditionally stabilized foredunes that are subject to ocean undercutting or wave overtopping, and interdune areas (deflation plains) subject to ocean flooding;
b. The measures prescribed in this policy are specifically required by LCDC Goal #18 for the above-referenced dune forms, and that
c. It is important to ensure that development in sensitive beach and dune areas is compatible with, or can be made compatible with, the fragile and hazardous conditions common to beach and dune areas.

III. Permits for beachfront protective structures shall be issued only where development existed on January 1, 1977 (see Section 3. Definitions for "development"). Criteria for review of all shore and beachfront protective structures shall provide that:

a. Visual impacts are minimized;
b. Necessary access to the beach is maintained;
c. Negative impacts on adjacent property are minimized; and
d. Long-term or recurring costs to the public are avoided.

IV. Local government shall cooperate with state and federal agencies in regulating the following actions in beach and dune areas by sending notification of Administrative Conditional Use decision:

a. Destruction of desirable vegetation (including inadvertent destruction by moisture loss or root damage),

b. The exposure of stable and conditionally stable areas to erosion,
c. Construction of shore structures which modify current or wave patterns leading to beach erosion, and
d. Any other development actions with potential adverse impacts.

- **#30a Future Update of Site Plan Review Procedure**

During the first plan review and update, The County shall amend the Coos Bay Estuary Ordinance to include more detailed procedures for site investigations and standards for development in limited suitability areas, consistent with those provisions adopted for the balance of the County (Volume I).

- **#31 RESERVED**

- **#32 Boat Ramps**

Local government shall encourage the provision of new boat ramps, and the repair and improvement of existing boat ramps, and facilities in areas designated to allow that use.

This strategy recognizes the need for facilities to accommodate recreational boating access.

- **#33 Water-Based Recreation**

Local governments support increased use of the Coos Bay estuary for water-based recreation.

- **#34 Recognition of LCDC Goal #4 (Forest Lands) Requirements for Forest Lands within the Coastal Shorelands Boundary**

Unless otherwise allowed through an Exception, Coos County shall manage all rural lands designated on the Special Considerations Map as "Forest Lands" within the Coastal Shorelands Boundary consistent with the "Forest Uses" requirements of LCDC Goal #4. Allowed uses are listed in Appendix 3 of the Zoning and Land Development Ordinance.

Where the County's Comprehensive Plan identified major marshes, significant wildlife habitat and riparian vegetation on coastal shorelands subject to forest operations governed by the Forest Practices Act, the Forest Practice program and rules of the Department of Forestry shall be carried out in such a manner as to protect and maintain the special shoreland values of the major marshes, significant wildlife habitat areas, and forest uses especially for natural shorelands and riparian vegetation.

This policy shall be implemented by using the Special Considerations Map (Policy #3) to identify "Forest Lands", and to abide by the prescriptive use and activity requirements of LCDC Goal #4 in lieu of other management alternatives otherwise allowed for properties within the "Forest Lands-Overlay" set forth on the Special Considerations Map, and except where otherwise allowed by Exception for needed housing and industrial sites.

This policy recognizes that the requirements of LCDC Goal #4 are equal and not subordinate to other management requirements of this Plan for "Forest Lands" located within the Coastal Shorelands Boundary.

- **#34a Forest Practices Act**

Where the County's Comprehensive Plan identified major marshes, significant wildlife habitat and riparian vegetation on coastal shorelands subject to forest operations governed by the Forest Practices Act, the Forest Practice program and rules of the Department of Forestry shall be carried out in such a manner as to protect the natural values of the major marshes, and significant wildlife habitat areas, and to maintain riparian vegetation.

This policy recognizes the special requirements of Goal #17 that must be implemented through the Oregon Department of forestry and the Forest Practices Act.

- **#34b Future Update of Policy #34**

During the plan review and update, Policy #34 and its implementing provisions shall be reviewed and amended if necessary, to insure consistency with Volume I, Part 1 of the Coos County Comprehensive Plan, and its implementing ordinance.

- **#35 Plan Implementation**

I. Coos County's on-going land use and community development planning process shall utilize the Planning Commission as its citizen involvement for public consideration of the following:

a. Identification of new planning problems and issues;
b. Collection and analysis of inventories and other pertinent factual information;
c. Evaluation of alternative courses of action and ultimate policy choices; and
d. Recommendation of policy directives, based upon consideration of the County's social, economic, energy and environmental needs.

This strategy is based upon the recognition that Coos County's public planning process is essential to producing rational land use and community development policies which are the basis of this Comprehensive Plan, and which must be the basis for future Plan revisions and modifications.

This Plan includes coordination between the cities of Coos Bay and North Bend through a cooperative agreement which ensures the exchange of information and the maintenance of an adequate supply of specifically zoned and developable lands in the Bay Area.

This strategy is based on the recognition that the zoning map, zoning and land development ordinances are simply implementation tools which carry out the expressed policies and intent of the Plan.

- **#36 Plan Update**

Coos County shall: a) conduct a formal review of this the Plan, including inventory and factual base and implementing measures to determine if any revision is needed; b) shall base its review upon re-examination of data, problems and issues; c) shall issue a public statement as to whether any revision is needed; d) shall coordinate with other jurisdictions which are included within the Coos Bay Estuary and its shorelands; and e) shall incorporate public input into its decision.

Coos County may rely on the formal "Periodic Review " process of this Plan to satisfy the requirements of this policy.

This strategy is based on the recognition that a formal periodic review is necessary to keep this Plan current with local situations and events which may change from time-to-time and reduce the Plan's ability to effectively and appropriately guide growth of the Coos Bay Estuary and its shorelands.

Coos County shall approve minor revisions/amendments to its Comprehensive Plan when justified. Minor revisions/amendments are smaller in scope than major revisions/amendments, and generally include, but are not limited to changes in uses and activities allowed and changes in standards and conditions.

The County shall undertake special studies and projects deemed beneficial and/or necessary to the community, to keep key inventories current which are the factual basis of this Plan. This policy shall be implemented through Planning efforts to keep a statistical data base on Coos County's changing socio-economic characteristics (including, but not limited to, population and housing data, employment statistics, traffic counts, agricultural production, etc). The County encourages agency cooperation in providing relevant new data as it is published.

This policy recognizes the necessity of keeping key planning information current, and further, that County efforts to do so would be largely limited to collecting and analyzing data compiled initially by other agencies. Further, the policy recognizes that special projects (ie., neighborhood traffic studies) may be necessary to help resolve unanticipated small- scale community problems.

The policy recognizes: a. the Planning Department may conduct the necessary research or contract with a consultant (if dollars are available); b. the County may continue with a skeletal long-range planning staff necessary to provide technical support in efforts to maintain and update the Plan; and c. state funds might be available to help defray the local costs of such activities.

- **#37 County Plan Revisions and Amendments (do not apply to provisions affecting City Management Units): Public Hearing Procedure**

Coos County shall exercise due process in considering amendments to this Plan. Public hearing procedures set forth in the Coos County Zoning and Land Development Ordinance (CCZLDO) Section 5.7 (OR 92-05-009PL).

- **#38 Grandfathering of Existing Nonconforming Uses and Structures**

Coos County shall permit the continuation of legally established existing uses and structures (located outside incorporated city limits) that do not conform to the provisions of this Plan and its implementing ordinances.

I. This policy shall be implemented by:

   a. following the provision about non-conforming uses legally required by ORS 215.130, and ORS 215.215 and which regulate and allow the continued existence of nonconforming uses, and the alteration and expansion of such uses; and
   b. more specific implementing ordinance measures.

- **#39 Citizen Involvement**

The Citizen Involvement Program presented in Volume I, Part 1, Section 5.1 of the Coos County Comprehensive Plan shall be regarded as the Citizen Involvement Program for the Coos Bay Estuary Management Plan.

- **#40 RESERVED**

- **#41 Maintenance of Inventories and Factual Base**

The Board of Commissioners shall instruct the County Planning Commission to undertake special studies and projects deemed beneficial to the community, and/or necessary to keep current certain key inventories that are the factual basis of this Plan as funding is provided for such purposes by the Board of Commissioners.

This policy shall be implemented through on-going Planning Commission efforts to keep a statistical data base on Coos County's changing socio-economic characteristics including, but not limited to, population and housing data, employment statistics, traffic counts, agricultural production, etc. The County shall welcome agency cooperation in providing relevant new data as it is published.

This policy recognizes the necessity of keeping key planning information current, and further, that County efforts to do so would be largely limited to collecting and analyzing data compiled initially by other agencies. Further, the policy recognizes that special projects like neighborhood traffic studies may be necessary to help resolve unanticipated small-scale community problems.

Further, The policy recognizes: (1) that the Planning Director may assist the Planning Commission in conducting necessary research as ordered; (2) that the County may wish to continue a skeletal long-range planning staff as necessary to provide technical support in efforts to maintain and update the Plan; and (3) that state funds will likely be available to help defray the local costs of such activities.

- **#42 Special Allowance for Accessory Housing**

I. Local government may allow dwellings as an "Accessory Use" to any of the following legally established uses:

   a. Agriculture, as otherwise consistent with Policy #28
   b. Airports
   c. Aquaculture
   d. Commercial
   e. Dryland moorage/Marinas
   f. Industrial and Port Facilities
   g. Log Storage and Sorting yard
   h. Mining and Mineral Extraction
   i. High-Intensity Recreation
   j. Solid Waste Disposal
   k. Timber Farming/Harvesting, as otherwise consistent with Policy #34
   l. High-Intensity Utilities

II. Accessory dwellings shall only be allowed when findings document that:

   a. The dwelling is for a watchman or caretaker that needs to reside on-premise; and
   b. That the primary purpose of the dwelling is not to provide rental housing.

This policy shall be implemented through ordinance measures.

This policy recognizes the need for flexibility in allowing watchman and caretaker dwellings in conjunction with certain commercial, industrial and other uses.

- **#43 Interpretation of Coastal Shorelands Boundary**

When a proposed development is in the immediate vicinity of the Coastal Shorelands Boundary (CSB) and when such proposed development relies on a precise interpretation of the CSB, local government shall establish the precise location of the CSB using the seven criteria specified in Goal #17 (Coastal Shorelands). Establishment of the exact location may require an on-site inspection. If the location of the CSB, as shown on the Plan maps or Coastal Shorelands Inventory map is subsequently found to be inaccurate or misleading, the Planning Director shall make the appropriate determination and minor adjustments to the maps.

I. This policy recognizes:

   a. The precise location of the Coastal Shorelands Boundary may be critical for certain types of actions (e.g., land divisions), and
   b. Certain features such as riparian vegetation cannot be mapped with complete accuracy at the scale of 1"=800'.

- **#44 Planned Unit Development or Density Transfer Development on Parcels which are partially within the Coastal Shorelands Boundary**

This policy shall apply only to Coastal Shorelands within the unincorporated areas. Where a parcel lies partially within the Coastal Shorelands Boundary (CSB), Coos County shall consider the portion within the CSB to be part of the total acreage for the purposes of Planned Unit Developments, Recreational Planned Unit Developments and Density Transfer Developments provided that no new parcels are thereby created within the CSB in rural areas.

This policy recognizes that while land divisions are restricted within rural shorelands, this does not preclude the transfer of certain development rights to the portions of a parcel upland from the CSB.

- **#45 RESERVED**

- **#46 Exemption for Subtidal Disposal of Dredged Materials in Conjunction with Deep-Draft Channel Maintenance Dredging**

Local government shall exempt certain deep-draft channel maintenance dredging actions of the U.S. Army Corps of Engineers from the requirements of dredge/fill policies and use/activity matrices of this Plan, to the effect that the Corps shall be allowed, subject to a finding that adverse impacts have been minimized as much as feasible to dispose of dredged materials resulting from main channel maintenance dredging by placing the material within subtidal areas adjacent to the main channel which have historically been used for this purpose (see Deep-Draft Navigational Unit).

This policy shall be implemented through review and comment on state waterway project permit reviews and federal public notices of application for permit and through ordinance provisions implementing this Plan.

I. This strategy recognizes that:

a. Placement of dredged materials at selected locations alongside the main channel of Coos Bay increases the velocity and enhances the natural scouring effect of the flow, and thus reduces future maintenance dredging costs;
b. Goal #16 requires identified Development management units to include subtidal areas for in-water disposal of dredged material;
c. Areas historically used for this purpose do not qualify as a "Natural or Conservation" management unit because they have been "partially altered" and are needed for development purposes;
d. The purpose and thrust of this policy shall be reviewed at the next Plan update, since the policy is an expedient suggested by resource agency representatives at a 1/25/84 agency coordination meeting sponsored by the Department of Land Conservation and Development. Further review is expected to suggest lateral expansion of the boundaries of management segment "DDNC-DA" into adjacent subtidal areas.

- **#46a Flow-Lane Disposal of Dredged Material Allowed in Development Aquatic Management Units**

I. Flow-lane disposal of dredged materials shall be permitted in the deep-draft navigation channel adjacent to In-bay Site "G" provided that administrative conditional use findings establish that:

a. Such disposal is consistent with the purposes of the affected development aquatic management unit; and
b. Any approval shall be conditioned upon the requirement that the flow-lane "project applicant", shall monitor the flow-lane project to assure that estuarine sedimentation resulting from the project is consistent with the resource capabilities and purposes of any natural or conservation management units affected by the flow-lane disposal.

A report regarding (b) above, shall be provided to the Coos County Planning Department upon completion of the project, or during the project, if the project applicant or County have reason to believe unacceptable impacts may be occurring as a result of the project. The Planning Department shall review the report to assure compliance with this policy. If impacts are deemed unacceptable, the project may be ordered ceased, or redesigned, or a decision made to not reauthorize the project at future dredging cycles.

This policy is based on provisions for uses in Development Management Units pursuant to LCDC Goal #16.

- **#47 Environmental Quality**

The Coos Bay Estuary Management Plan and Implementing Ordinance shall comply with the Department of Environmental Quality (DEQ) regulations regarding air, water quality and noise source standards that are established as law.

- **#48 Weak Foundation Soils**

The State Department of Commerce, Building Codes Division (pursuant to the authority vested in it by Section 2905 of the State Structural Specialty Code) shall require an engineered foundation or other appropriate safeguard deemed necessary to protect life and property in areas of weak foundation soils.

This strategy recognizes it is the responsibility of the State of Oregon Department of Commerce, Building Codes Division to determine, based on field investigations, whether safeguards are necessary to minimize potential risks. The general level of detail used in mapping areas known as weak foundation soils is not of sufficient scale to mandate specific safeguards prior to a field investigation by the Building Codes Division.

- **#49 Rural Residential Public Services**

Coos County shall provide opportunities to its citizens for a rural residential living experience, where the minimum rural public services necessary to support such development are defined as police (sheriff) protection, public education (but not necessarily a rural facility), and fire protection (either through membership in a rural fire protection district or through appropriate on-site fire precaution measures for each dwelling).

Implementation shall be based on the procedures outlined in the County's Rural Housing State Goal Exception.

I. This strategy is based on the recognition:

   a. that physical and financial problems associated with public services in Coos Bay and North Bend present severe constraints to the systems' ability to provide urban level services, and
   b. that rural housing is an appropriate and needed means for meeting housing needs of Coos County's citizens.

- **#50 Rural Public Services**

Coos County shall consider on-site wells and springs as the appropriate level of water service for farm and forest parcels in unincorporated areas and on-site DEQ-approved sewage disposal facilities as the appropriate sanitation method for such parcels, except as specifically provided otherwise by Public Facilities and Services Plan Policies #49, and #51. Further, Coos County shall consider the following facilities and services appropriate for all rural parcels: fire districts, school districts, road districts, telephone lines, electrical and gas lines, and similar, low-intensity facilities and services traditionally enjoyed by rural property owners.

This strategy recognizes that LCDC Goal #11 requires the County to limit rural facilities and services.

- **#51 Public Services Extension**

I. Coos County shall permit the extension of existing public sewer and water systems to areas outside urban growth boundaries (UGBs) and unincorporated community boundaries (UCB's) or the establishment of new water systems outside UGB's and UCB's where such service is solely for:

   a. development of designated industrial sites;
   b. development of "recreational" planned unit developments (PUDs);
   c. curing documented health hazards;
   d. providing domestic water to an approved exception for a rural residential area;
   e. development of "abandoned or diminished mill sites" as defined in ORS 197.719(1) and designated industrial land that is contiguous to the mill site.

II. This strategy shall be implemented by requiring:

   a. that those requesting service extensions pay for the costs of such extension; and
   b. that the services and facilities be extended solely for the purposes expressed above, and not for the purpose (expressed or implied) of justifying further expansion into other rural areas; and
   c. that the service provider is capable of extending services; and
   d. prohibiting hook-ups to sewer and water lines that pass through resource lands as allowed by "I, a through d" above; except, that hook-ups shall be allowed for uses covered under "II, a through d" above.

   e. That the service allowed by "e" above is authorized in accordance with ORS 197.719.

- **#52 RESERVED**

- **#53 Shoreland Dwellings on Forest Lands**

Coos County may conditionally permit, within forest lands inside the Coos Bay Shorelands Boundary, a single family dwelling, provided the proposed dwelling meets one of the requirements found in the Zoning and Land Development Ordinance Section 4.8.500.

This policy shall be implemented through the administrative conditional use process and Appendix 3 of the Zoning and Land Development Ordinance.

- **#54 Forest Dwelling Conflict Minimization**

Coos County shall require all owners of forest land within the shorelands boundary requesting a single family dwelling to site the dwelling so as to minimize the conflicts with forest practices on adjacent and nearby lands.

This policy shall be implemented by the imposition, as necessary, of conditions through the administrative conditional use process to achieve this requirement. See the Review Standards and Special Development Conditions in Appendix 3 of the Zoning and Land Development Ordinance.

- **#55 Recreation Planning**

Coos County shall strive to increase recreational opportunities and facilities in proportion to population growth consistent with the guidelines established by the Statewide Comprehensive Outdoor Recreation Plan (see the Recreation Inventory and Assessment).

I. This strategy shall be implemented by:

a. striving to implement where economically feasible, the capital priorities established by the County Parks Advisory Board, as approved by the Board of Commissioners; and
b. encouraging applications for "recreational" PUD's;
c. requiring open space standards in new PUDs/subdivisions;
d. cooperating with state/federal agencies involved in developing recreation facilities; and
e. structuring implementing ordinance measures to permit a variety of small-scale recreational developments.

II. This strategy is based on the recognition:

a. that future generations have the right to at least an equal level of the recreational opportunities currently available to County residents, but also, that financial constraints limit opportunities, and
b. that compliance with the Statewide Comprehensive Outdoor Recreation Plan Action Program will become one of the primary requirements for project eligibility under the new open project selection system for the distribution of land and water conservation fund grants.

- **#56 Recreational Boating Facility Planning**

Coos County shall actively cooperate with state and federal agencies in identifying and establishing recreational boating facilities, including boat ramps.

Implementation shall occur by cooperating with such agencies as the State Marine Board, the State Department of Fish and Wildlife, the U.S. Heritage, Conservation and Recreation Service, etc.

This strategy is based on the recognition that fulfillment of the need for public boating facilities requires sharing and coordinating of responsibility between state and local agencies.

- **#57 Recreational Planned Unit Developments**

Coos County shall conditionally permit the establishment of "Recreational Planned Unit Development" (Recreational PUD) within specific land areas of the County.

I. Implementing ordinance measures shall prescribe at a minimum, the following criteria to identify qualifying sites:

   a. the area proposed as a Recreational PUD shall contain a minimum of 80 contiguous acres in private ownership;
   b. the area proposed as a Recreational PUD contains or is adjacent to, a significant natural resource that has value for recreational purposes (such as an estuary, waterfall, lake, or dune formation).

II. Implementing ordinance measures shall also prescribe at a minimum, the following criteria to review qualifying sites:

   a. a portion of the total land area within the Recreational PUD shall be conserved as open space to provide sufficient area for active and passive outdoor recreational activities. Such open space shall not be developed except for active and passive recreational activities, nonmotorized vehicle or pedestrian trails, hazard control structures, and vegetative alteration such as golf courses and landscaped grounds; and
   b. clustering of intensive or built-up uses shall be encouraged to provide maximum retention of open space and to provide sufficient access to the recreational resource; and
   c. residential densities for "owner's-primary-dwelling-unit" housing shall not exceed the densities prescribed by the underlying zones(s); and
   d. "Recreational" dwelling units within a Recreational PUD may be individually owned, and occupied year-round, such as, through time-sharing or other concepts; but shall be designed and generally used as "vacation homes" and "second homes" rather than as the owner's primary dwelling;

   e. implementing ordinance measures shall be designed to create flexibility in approving residential density for recreational dwellings. The following general standards shall be employed as the basis for decisions on the residential density of recreational dwellings, that is appropriate for each specific Recreational PUD:

      1. the minimum number of recreational dwelling units proposed shall not be less than the number of owner-occupied dwelling units permitted within the area of the Recreational PUD; to ensure that the development is designed to encourage tourist visitation; and
      2. substantial increases in the ratio of recreational dwelling units to owner-occupied dwelling units shall be strongly encouraged, and are to be used as an incentive for the developer:

i. to conserve additional open space above the minimum required by the implementing ordinance and
ii. to provide recreational amenities of significant public beach access; and
iii. to provide cultural amenities, a value to the local economy that promote the concept of a "destination-resort" such as a convention center and commercial uses.

III. This strategy is based on the recognition:

a. that Recreational Planned Unit Developments will help meet an identified need for local recreational opportunities; and
b. that Recreational PUDs can provide significant diversification of the local economy by increasing the attraction of tourists to the County; and
c. that the flexible density provision for recreational dwellings, offers necessary incentives to stimulate the development of destination resort complexes; and
d. that this strategy and the applicable "Shorelands and Dunes" strategies provide complementary protection of significant open space and natural resource areas.

- **#58 Goal #5 Coordination for Coastal Recreation Trails**

Coos County shall continue to cooperate with the Parks and Recreation Division of the Oregon Department of Transportation (ODOT) to assure coordination in addressing Goal #5 requirements of OAR 660-16-000, should site-specific routes for coastal recreation trails be proposed in the County.

- **#59 Commercial and Industrial Land Supply**

Coos County shall continuously plan for and maintain an adequate supply of commercial and industrial land, recognizing that a readily available supply of such land is the basis for a sound economic development program.

- **#60 Coos, Curry, Douglas Business Development Corporation (CCD-BDC)**

Coos County as an active participating member of the CCD-Business Development Corporation (CCD-BDC), shall sanction and support the economic development efforts of that regional organization, recognizing that regional problems are best resolved by a cooperative regional economic development program.

- **#61 Economic Program Development Committee**

Coos County shall support the regional economic goals and objectives periodically adopted by the Coos County Overall Economic Development Program Committee, recognizing that these regional strategies constitute a coordinated program targeted at resolving impediments to the area's economic development potential as identified by the CCD-BDC.

- **#62 Adequacy of Urban Commercial Land Supply**

Coos County shall ensure that adequate urban commercial land is designated within cities and urban growth areas as necessary to meet future needs for urban commercial uses.

I. This strategy shall be implemented in two ways:

a. Through coordinated urban growth boundary negotiations with cities; and
b. Through use of the "Controlled Development" designation as a complementary device to the "Commercial" designation.

II. This strategy is based on the recognition:

a. That Coos County has coordination responsibilities; and
b. That the Controlled Development designation is necessary and appropriate to guide land use decisions in certain urban growth areas that are experiencing a conversion of land in residential areas to commercial use.

- **#63 Adequate and Available Housing**

Coos County shall provide zoning for adequate buildable lands and shall encourage the availability of adequate numbers of housing units for future housing needs, at price ranges and rent levels which are commensurate with the financial capabilities of Coos County households.

I. This strategy shall be implemented:

a. through appropriate Comprehensive Plan map and zoning designations, as appropriately determined to meet housing and estimates established in this Plan's inventory and assessment; and
b. through cooperation by Coos County, Coos-Curry Housing Authority (CCHA) and Southwestern Oregon Community Action in their efforts to develop housing assistance programs for people with low and moderate incomes.

II. This strategy recognizes:

a. the lead role of CCHA in housing assistance planning; and
b. each city's responsibility for assessing housing needs within its urban growth boundary (UGB); and

c. the county's responsibility for assessing housing needs within all other unincorporated areas and for coordinating the UGB housing assessments of each city.

- **#64 Variety in Housing Locations**

Coos County shall encourage the availability of a wide variety of housing locations in urban and rural areas.

For urban and urbanizable areas, this strategy shall be implemented through urban growth management agreements and appropriate coordinated land use designations. For rural areas, this strategy shall be implemented through appropriate land use designations for acreage homesites as selected and justified in the County's rural housing exception.

This strategy recognizes that the selected urban and rural locations are necessary to provide flexibility in housing location.

- **#65 Manufactured Dwelling/Mobile Homes**

I. Coos County shall structure its implementing zoning ordinance such that it:

a. permits mobile homes,
b. permits mobile homes and clustering of dwellings under a Planned Unit Development concept in most residential zones;
c. permits multiple family dwellings in selected locations within urban growth boundaries (UGBs); and
d. permits multiple family dwellings outside UGBs when part of a Recreational Planned Unit Development.

This strategy recognizes that such flexibility of housing type provides greater choice and enhanced ability to meet the housing needs of the citizens of Coos County.

- **#66 Housing Density**

Coos County shall structure its implementing ordinance so that it allows increasing density for (from lowest to highest) acreage homesites, rural centers, and UGAs.

- **#67 Rights Leasing for Energy Exploration**

Coos County shall encourage coal, oil and gas exploration and recovery by entertaining proposals for leasing the oil, coal, and gas mineral rights held by Coos County.

This strategy recognizes that Coos County is in a position to promote development of its energy resources by encouraging exploration and recovery operations on lands believed to have non-renewable energy resources and on which Coos County maintains an ownership interest.

- **#68 Small-Scale Hydroelectric Power Generation**

I. Coos County shall ensure that its implementing ordinances promote the conservation of energy, based upon sound economic principles, by considering utilization of the following techniques as incentives:

a. lot size, dimension and siting controls;
b. building height, bulk and surface area;
c. density of uses, particularly housing;
d. availability of light, wind, water, and air.

In addition, alternate energy devices (such as wind energy towers) shall be conditionally permitted to exceed the maximum height limitation of its particular zone if found to be visually compatible with the immediate neighborhood.

This strategy recognizes that implementing ordinances can provide incentives in development to promote energy conservation.

- **#69 RESERVED**

- **#70 Miscellaneous Provisions of Goals #8, #9, #10 and #13**

Coos County hereby adopts by reference all language in Coos County Comprehensive Plan, Volume I, Part 1 (Plan Provisions) and Part 2 (Inventories & Factual Base) pertaining to LCDC Goals #8, #9, #10 and #13.

This policy recognizes that certain provisions and inventory information prepared for the "Balance of County" Comprehensive Plan is applicable to the Coos Bay Estuary and Shorelands and that the information and provisions are necessary and sufficient to comply with the requirements of LCDC Goals #8, #9, #10 and #13.

- **#71 RESERVED**

- **#72 RESERVED**

- **#73 RESERVED**

Jan – Dilley – 1223 Winsor Ave – North Bend – OR - PH: 541 756-4802 – janyce.dilley@frontier.com

RECEIVED
APR 25 2019
BY:

April 25, 2019

Coos Bay Planning Commission

RE: 187-18-000153-PLNG-01

Dear Commissioners,

With a small part of an enormous dredge and fill project, you have been tasked to approve an application for one section in a vacuum of info. Yet your section is the most consequential since it will increase the flow into the bay. Thereby, it will affect the salinity of the bay and estuary and all living creatures and plants within, including the significant but dwindling eelgrass.

For you to do this highly responsible task requires examination of the larger part of this project before a Hearing Officer at Coos County Planning Department (AM 18-011). You will find significant argument against this project and the lack of response by the Applicant and you can follow to the county's conclusion. Please go to CC Application file AM 18-011 at:

http://www.co.coos.or.us/Departments/Planning/PlanningDepartment-Applications2018.aspx

Even if the county does not have the wisdom to recognize the premature and invalid sequencing of applications, you may follow the lead of the Department of State Lands (DSL) who must approve all the dredging, Coos Bay City and County plus North Bend. Following, I include DSL's letter of April 10th deeming the application incomplete and strongly urging the Applicant to review and answer the concerns of public comment, of which you have received much the same. I hope you will find DSL's determination useful in your review.

Respectfully submitted,

Jan Dilley

Kate Brown, Governor **Oregon** **Department of State Lands** 775 Summer Street NE,
Suite 100 Salem, OR 97301-1279 (503) 986-5200 FAX (503) 378-4844 www.oregon.gov/dsl **State Land Board** Kate Brown Governor Bev Clarno Secretary of State Tobias Read State Treasurer

April 10, 2019
RL600/60697
JORDAN COVE ENERGY PROJECT, L.P.
ATTN DERIK VOWELS
111 SW 5TH AVE, STE. 1100
PORTLAND OR 97204
Re: DSL Removal-Fill Permit Application No. 60697-RF
Jordan Cove Energy Project, Multiple Counties
Dear Mr. Vowels:
The Oregon Department of State Lands' (Department) 60-day public review period has closed for the above-referenced permit application. Public comments submitted and other investigative work by the Department have raised various issues for which the Department needs additional information.

Overview of Decision Process and Need for Additional Information

Specific applicable portions of the Department's Oregon Administrative Rules (OAR) in the narrative below in order to help Jordan Cove Energy Project, L.P. (Jordan Cove) understand the Department's permit decision process and why the additional information is needed.
OAR 141-085-0550 addresses the level of documentation used by the Department to make decisions:

• Section (4) provides that "The applicant is responsible for providing sufficient detail in the application to enable the Department to render the necessary determinations and decisions. The level of documentation may vary depending upon the degree of adverse impacts, level of public interest and other factors that increase the complexity of the project."
• Section (7) provides that "The Department may request additional information necessary to make an informed decision on whether or not to issue the authorization."

The Department analyzes a proposed project using the factors and determination criteria set forth in Oregon Revised Statute (ORS) 196.825 and OAR 141-085-0565. The applicant bears the burden of providing the Department with all information necessary for the Department to consider the factors and make the determinations.
• Section (1) of the OAR provides that "The Department will evaluate the information provided in the application, conduct its own investigation, and consider the comments submitted during the public review process to determine whether or not to issue an individual removal-fill permit."

• Section (2) of the OAR provides that "The Department may consider only standards and criteria in effect on the date the Department receives the complete application or renewal request." This application was deemed complete for public review and comment on

December 6, 2018. OAR 141 Division 85 contains the standards and criteria that will be considered throughout the review of this application.

• Section (3) of the OAR provides that "The Department will issue a permit if it determines the project described in the application:
(a) Has independent utility;
(b) Is consistent with the protection, conservation and best use of the water resources of this state as specified in ORS 196.600 to 196.990, and
(c) Would not unreasonably interfere with the paramount policy of this state to preserve the use of its waters for navigation, fishing and public recreation."

• Section (4) of the OAR provides that "In determining whether to issue a permit, the Department will consider all of the following:
(a) The public need for the proposed fill or removal and the social, economic or other public benefits likely to result from the proposed fill or removal. When the applicant for a permit is a public body, the Department may accept and rely upon the public body's findings as to local public need and local public benefit;
(b) The economic cost to the public if the proposed fill or removal is not accomplished;
(c) The availability of alternatives to the project for which the fill or removal is proposed;
(d) The availability of alternative sites for the proposed fill or removal;
(e) Whether the proposed fill or removal conforms to sound policies of conservation and would not interfere with public health and safety;
(f) Whether the proposed fill or removal is in conformance with existing public uses of the waters and with uses designated for adjacent land in an acknowledged comprehensive plan and land use regulations;
(g) Whether the proposed fill or removal is compatible with the acknowledged comprehensive plan and land use regulations for the area where the proposed fill or removal is to take place or can be conditioned on a future local approval to meet this criterion;
(h) Whether the proposed fill or removal is for stream bank protection; and
(i) Whether the applicant has provided all practicable mitigation to reduce the adverse effects of the proposed fill or removal in the manner set forth in ORS 196.600."

• Section (5) of the OAR provides that "The Department will issue a permit only upon the Department's determination that a fill or removal project is consistent with the protection, conservation and best use of the water resources of this state and would not unreasonably interfere with the preservation of the use of the waters of this state for navigation, fishing and public recreation. The Department will analyze a proposed project using the criteria set forth in the determinations and considerations in sections (3) and (4) above (OAR 141-085-0565). The applicant bears the burden of providing the Department with all information necessary to make this determination."

Summary of Substantive Public Comments

DSL has reviewed all the comments received concerning Jordan Cove application for a removal-fill permit. The Department's summary of the substantive comments (below) is not exhaustive. Jordan Cove should review and address the substantive comments that relate directly to the proposed removal and fill or that relate to the potential impacts of the proposed removal and fill. All substantive comments received are provided here.
Jordan Cove failed to demonstrate the project is in the public interest, Jordan Cove failed to demonstrate a public need. (ORS 196.825(3)(a)): Comments received on this topic

stressed that the Department must affirmatively determine that the project would address a public need consistent with *Citizens for Resp. Devel. In the Dalles v. Walmart* 295 Or App 310 (2018). With a privately-sponsored project of this scale and complexity, the Department must consider public need in a transparent and comprehensive analysis that weighs all the relevant impacts and alleged benefits of the project.

Jordan Cove failed to demonstrate the project is consistent with the protection, conservation, and best use of Oregon's waters. (ORS 196.825(1)(a)): Commenters are concerned that the project would likely do unnecessary harm and damage to water quality in Oregon and suggest the applicants have failed to demonstrate that the project is consistent with the protection, conservation and best use of the water resources of this state. The proposed project will likely impair designated beneficial uses, threatening drinking water supplies and fish habitat. It will also likely further degrade stream segments in which water quality is already impaired for temperature, dissolved oxygen, pH, turbidity, mercury, and sedimentation.

The project does not conform to sound policies of conservation and will likely interfere with public health and safety (ORS 196.825(3)(e)): The Department received comments with concerns that the applicant has failed to demonstrate that the project will not interfere with public health and safety. Potential risks to public health and safety include natural hazards, such as floods, tsunamis, wildfires, landslides, and earthquakes, identified under Statewide Planning Goal 7. The potential for high-flow events that expose the pipeline or inadvertent drilling fluid releases (frac-outs) during construction at proposed stream crossings may result in increased risks to public health and safety. Failure at any of the major waterbody crossings claiming avoidance by using either Hydraulic Directional Drill (HDD) method, conventional bore or direct pipe method would have detrimental impacts to waters of the state and potentially contaminate state waters. Several risks to public health and safety were raised during public review that need to be addressed by the applicant, such as the list provided below. Please address these adverse impacts of this project:

- An accidental explosion of a fully loaded Liquefied Natural Gas (LNG) ship or at the terminal, including the worst-case scenario for the immediate area;
- How are the Federal Aviation Administration (FAA) presumed hazard determinations being addressed by Jordan Cove;
- Tsunami risks increasing from the project dredging activities;
- Improper facility siting, Society for International Gas Tanker and Terminal Operators (SIGTTO) standards not followed (i.e., on the outside bend of the navigation channel, near other terminal users, near population centers);
- Impacts on municipal drinking water sources, private wells, irrigation sources and agricultural uses;
- Increased wildfire risks as construction season coincides with the in-water work period which also coincides with fire season; and
- Impacts of massive scale clearing and grubbing with pipeline installation on water quality, land stability, erosion and turbidity of doing these activities during the rainy winter seasons, all water flows downhill.

The project would interfere with navigation, fishing, and public recreation: Comments received on this topic addressed that the Department must conduct a weighing of the public benefits of the project against interference with factors including navigation, fishing, and public recreation (See *Citizens for Resp. Devel. In the Dalles v. Walmart,* 295 Or App 310 (2018)). As part of this weighing of public benefits, the Oregon Legislature has clearly demonstrated that it

is the State's "paramount policy" to preserve Oregon waters for navigation, fishing, and public recreation. ORS 196.825(1).
The comments indicate that the applicant has failed to demonstrate that the project will not unreasonably interfere with navigation, fishing, and public recreation in this application. Potential conflicts include but are not limited to:
- Crabbing, fishing and all types of recreational uses in and around Coos Bay;
- Safe bar passage issues/LNG tanker bar crossings only at high tides conflict with recreational fishers and the commercial fleets that also cross the bar at high slack tides for safety reasons should be evaluated;
- Exclusion zones required around LNG tankers while the LNG tanker is in transit will impact the recreating public crabbing via the ring method. This is reportedly the most common recreational crabbing method in Coos Bay. High slack tides are optimum for crabbing and if an LNG tanker must transit only at high tides, given the security and exclusion zones, there is interference with existing recreational uses within Coos Bay; and
- Impacts on the commercial fisheries uses of Coos Bay and adjacent ocean resources.

Jordan Cove failed to demonstrate independent utility (OAR 141-085-0565(3)(a)):
Commenters assert that the project is connected to the Coos Bay Channel Modification (CBCM) Project. The applicant would be the primary benefactor from the proposed widening and deepening of the federal navigation channel as part of the CBCM project or similar efforts to expand the navigation channel. Further, there are serious questions about the feasibility of LNG vessels transiting the federal navigation channel under the dredging currently proposed as part of this application. Oregon Department of Fish and Wildlife (ODFW) contends that the Jordan Cove Energy Project and Port of Coos Bay Channel Modification project are connected actions and should be evaluated that way. The applicant has failed to demonstrate that the project has independent utility as required under OAR 141-085-0565(3)(a).
Jordan Cove failed to demonstrate a comprehensive analysis of alternatives to the project (OAR 141-085-0550(5), ORS 196.825(3)(c) and (d)): Commenters outline that the applicant has failed to demonstrate a comprehensive analysis of alternatives to the project, and therefore, the Department does not have the information to consider the availability of alternatives both for the project and for proposed fill and removal sites. Also, the Department was not able to determine that the project is the practicable alternative with the least adverse impacts on state water resources. Comments detail that through a flawed, overly-narrow purpose and need statement, the resulting biased alternative analysis prevents the Department from considering a reasonable range of alternatives to the project.
Navigation Reliability Improvements (NRI) Dredging: Comments indicate that there is no documented need for the 590,000 cubic yards to dredge the four corners outside the existing Federal Navigation Channel (FNC). Comments also state that Jordan Cove can export 99.5% of the anticipated annual output of the LNG facility (7.8 million tons) without the NRI dredging, which leaves the question, is there a 'need' to excavate 590,000 cubic yards of material for a nominal gain in transport capacity to allow Jordan Cove to travel at higher wind speeds than the current channel configuration could safely allow. Comments further suggest this minor economic benefit to only Jordan Cove does not equate to a 'need' to impact trust resources of the State of Oregon. The adverse impacts are understated or not explained in terms of the salinity impacts and hydrologic changes that will result from widening the existing navigational channel. The potential tsunami run-up impacts are not well explained either, nor are any hydrodynamic changes that would likely result or any analysis on potential increases to bank erosion adjacent to the proposed NRI channel improvements. The need should be substantiated, and a robust alternatives analysis prepared to address these issues and justify

the dimensions and depths needed with supporting documentation in the form of simulation modelling showing that the current channel is insufficient for Jordan Cove.

Pile Dike-Rock Apron: Comments raised concerns that no alternatives were presented regarding the proposed 6,500 cubic yards (cy) of rock riprap proposed to protect the existing pile dike against erosion from the slip and access channel location, depth and dimensions. With no alternatives presented on the dimensions or design alignment of the slip and access channel, no reasonable range of alternatives can be considered. There is no discussion on impact avoidance, minimization, and/or mitigation to offset any adverse impacts to waters of the state. Please address:

- Why 6,500 cy?
- Why not more?
- Why not less?
- Why any at all?

Dredged Material Disposal (DMD) transfer of materials to APCO 1 & 2 from the NRI dredging: Comments received raised the following questions, please answer:

- How will the rock be excavated and transferred to the DMD site? Vague alternatives analysis presented, leaves more questions than answers.
- What types of equipment will be used to excavate the NRI's?
- Which works best in what type of materials (bedrock, rock, sand or silts), which has least environmental impacts depending on the material encountered?
- How will the rock be dredged? Different equipment?
- Can rock be transferred to a DMD site via slurry line as the application states? Inadequate discussion on alternatives, leaving the details to the contractor is insufficient.

Slip and Access Channel: Comments raised the concern of a lack of discernable alternative analysis for the precise dimensions and location of the slip and access channel. The slip and access channel are designed for a ship class of 217,000 cubic meters, yet the Coast Guard Waterway Suitability Analysis recommends allowing ships no larger than 148,000 cubic meters. Please answer the following questions and concerns:

- Why design a slip to accommodate a ship class that is not currently allowed nor physically capable of navigating into Coos Bay given the constraints of the Coos Bay bar and currently authorized limitations of the federal navigation channel?
- The application claims the stated depth needed for the slip and access channel is to maintain 'underkeel clearance' while an LNG ship is at dock. This is misleading as an LNG ship can only safely navigate the current channel at a high tide advantage, above 6ft tides to get through the channel to the slip before the tide recedes which would strand the vessel if it is not safely docked in the slip. Any LNG ship, 148,000 cubic meter class ship, would not be able to transit Coos Bay except periods of high tide, there would be no way for a ship to exit the slip at any lower tidal elevation as the ships draft would exceed navigational depth of the channel which could pose huge safety concern in the event of a tsunami.
- Water quality concerns from the 'sump effect' of having the proposed 45ft Mean Low Low Water (MLLW) deep slip and access adjacent to and on the outside bend of the 37ft MLLW navigation channel need to be addressed.
- What are the sedimentation impacts, salinity impacts, temperature and dissolved oxygen impacts that would likely result from a deep-water pocket created for the slip?

Questions were raised over whether the access channel dimensions can change, as no alternatives discussion exists, it is just one option, take it or leave it. Any reduction in the size of the slip or access channel would reduce water impacts and reduce the required mitigation. Any reduction in size or depth would also reduce adverse impacts associated with this project. The need should be substantiated, and a robust alternatives analysis prepared to address these issues.

DMD Alternatives: Commenters would also like to know why Jordan Cove will move 300,000 cubic yards of sand to the Kentuck site when other alternatives exist that would have less impact than transferring a line all the way across Coos Bay to Kentuck slough. The log spiral bay could accommodate more than 300,000 cubic yards, it is much closer to the dredge sites and would have significantly less impacts than the Kentuck proposal, yet it is dismissed. Please explain more thoroughly the alternatives that were considered and why those alternatives were dismissed within the greater DMD plan.

APCO DMD Site: Commenters have concerns over the capacity of the APCO site. Does this site have the capacity for the initial dredging and maintenance dredging over the lifespan of this project? Commenters also have site stabilization and liquefaction concerns over a mountain of sand piled up adjacent to Coos Bay in an earthquake and tsunami zone. There is safety, engineering, project feasibility, and water resources concerns that must all be addressed.

The project does not conform with existing land use laws (ORS 196.825(3)(g)):
Commenters indicate that the applicant has failed to demonstrate that the project conforms with existing land uses designated in the applicable comprehensive plan and land use regulations. They also mentioned that the applicant has failed to provide the Department with the information necessary to make the determinations required by ORS 196.825(3)(g) that the applicant's proposed fill or removal is compatible with the requirements of the comprehensive plan and land use regulations for the area in which it will take place. Current, up-to-date Land Use Consistency Statements are required for all parts of this project in all jurisdictions with an explanation of the current status, pending or resolved local issues, processes, or appeals status.

Further, commenters are concerned the applicant has failed to obtain land use permits for the project in Coos Bay. Because of the reasons adopted by the Land Use Board of Appeals (LUBA) in remanding the prior land use application are directly related to the inconsistency of the proposed dredge and fill in wetlands and in the Coos Bay Estuary with the Coos Bay Estuary Management Plan, the project cannot be conditioned on a future land use approval to meet this criterion.

In January 2019, the Douglas County Circuit Court Judge reversed the Douglas County extensions from December 2016 and 2017 that approved the Pacific Connector Gas Pipeline as a conditional use. Because the pipeline will require a new application for conditional use permit and utility facility necessary for public service, the applicant has not met its burden to demonstrate to the Department that the project conforms to Douglas County's acknowledged comprehensive plan and land use regulations.

The comments received indicate that the applicant has not met their burden to demonstrate to the Department that the project conforms to Jackson County's acknowledged comprehensive plan and land use regulations.

Insufficient Mitigation-Kentuck Compensatory Wetland Mitigation (CWM) Site: Concerns were raised about the lack of a discernable alternative analysis on many components of the Kentuck mitigation proposal to see what alternatives were considered and on what basis were rejected. The mitigation proposal itself is the largest wetland impact in this project proposal. Please answer the following questions:

- Why import 300,000 cubic yards of sand?
- Why not more or less materials?
- Why not use more suitable materials native to the area?
- Why sand vs. native cohesive clay soils for use as fill?
- What are the alternatives to move the sand to the site?
- Why were upland routes dismissed without reasonable justification? o Trucking the materials is a viable option with no impact to waters of the state.

- What other mitigation sites or options have you looked at addressing the following concern?
- The Kentuck site is already a freshwater wetland and has increased its functions in the past 10 years to the point that the current mitigation strategy might be inappropriate to offset functional losses. Please answer these questions as well: o Why is the dike so big, long, and wide?

o Why is there no justification given to support dimensions of the proposed dike?

o Why are there no alternatives are presented to evaluate the adverse effects of the dike and mitigation strategy?

o Address the landowner concerns regarding the Kentuck Mitigation proposal and the Saltwater Intrusion impacts on adjacent lands.

o Further address the concerns of flooding and impacting agricultural activities and existing farm uses.

o Why is the pipeline proposed under a proposed mitigation site?

o Where is the avoidance and/or impact minimization, especially given that each impact reduces the overall size of the mitigation project, therefore diminishing its potential function and values? Concerns were raised about the suitability of having a pipeline under the mitigation site that is supposed to be protected in perpetuity.

Insufficient Mitigation-Eelgrass CWM Site: Comments raised concerns about the lack of a discernable alternative analysis on many components of the eelgrass mitigation proposal. The CWM citing was found not to be in-kind or in proximity mitigation which would replace similar lost functions and values of the impact site. Disturbing existing mudflats and adjacent eelgrass beds is likely to have additional adverse impacts from construction. The proposal is inconsistent with ODFW Habitat Mitigation Policy. Alternatives should be considered, in consultation with ODFW, that favor impact avoidance to adjacent high value habitats (mudflats and adjacent eelgrass beds) and seek out appropriate in-kind, in proximity mitigation. The project impacts are to eelgrass beds adjacent to deep water habitats, while the proposed mitigation is near the airport runway and in shallow water habitats a considerable distance from deep water habitats. There are likely unforeseen FAA issues with the proximity of the mitigation site to the airport runway, this should be explored in detail with the FAA. The location of the eelgrass CWM site is situated in a portion of the Coos Bay Estuary classified as "52-Natural Aquatic" in the Coos Bay Estuary Management Plan where dredging is not allowed. This issue needs to be clarified by Coos County with respect to land use consistency.

Insufficient Mitigation-Stream Impacts: Comments assert that the project will impact many waterways' beneficial uses, water quantity and quality will be further impaired from construction of this project. Potential impacts include but are not limited to increased water temperatures, dissolved water oxygen, turbidity, etc. from riparian shade removal in 303(d) listed waterways and other waters. Disruption of fluvial processes, increased erosion and downstream sedimentation and turbidity from construction activities, impacts on spawning and rearing habitats, impacts on fish migration and passage.

Many people have raised concerns that Federal Energy Regulatory Commission (FERC) procedures are vague and will not provide assurances that water quality/quantity standards will be protected. Stream risk analysis, alternative ways to avoid and minimize impacts for each water crossing are not possible on properties with denied access. How are any reasonable alternatives considered if access is denied and unattainable without a FERC Order granting condemnation authority? Alternatives are not fully explored or explained to avoid and minimize impacts at every opportunity.

ODFW Habitat Mitigation Policy Inconsistencies: Commenters expressed that the applicants should work with ODFW to appropriately categorize each wetland and waterway impact from start to end along the proposed pipeline route. Once the appropriate habitat category has been assigned in agreement with ODFW, appropriate mitigation can be discussed based on resources impacted. Currently, temporary impacts mitigation is insufficient and inconsistent with the ODFW Habitat Mitigation Policy for streams and wetlands crossed by the pipeline.

Fish Passage-Coastal Zone Management Act (CZMA) and Non-CZMA Streams: Comments expressed concern that fish passage has not been addressed by the applicant. According to ODFW, applications for fish passage have not been submitted and this is critical to the Department for impact analysis determinations yet to be made. Fish passage applications may need to include a contingency method for crossing each waterway. For instance, if any of the HDD's fail, what is next, certainly not open trench, wet cut methods that are not currently being evaluated as alternative crossing methods under consideration.

Wetland Delineations/Concurrence: Public comments point out that some of the wetland delineation reports have either expired or are about to expire, see C4, C5, C9 and C10 of the application.

Additional Information Requested by the Department

Delineation-status for JCEP/PCGP: To allow adequate review time of the wetland delineation report in order to meet the decision deadline, please submit the following data requests by the dates requested.

1) By April 17, 2019: GIS shape files of the new routes and re-routes so DSL can finish the initial review and provide any additional review comments in time to address this summer (involving additional field work, if needed);

2) End of April 2019: Responses to the initial delineation review questions and delineation maps (prototype subset of each map series for completeness review);

3) June 7, 2019: Responses to GIS review questions;

4) Last week of June 2019: Site visits (possible); and

5) August 9, 2019: Everything due: responses to all remaining requests for information based on site visits, GIS review responses and follow-up review requests, all final delineation maps, and all supporting materials for the concurrence.

Bonding Requirements: Prior to any permit issuance, a performance bond should be negotiated and put in place for the Eelgrass and Kentuck CWM projects. Bonds are required for non-public agencies that have permanent impacts greater than 0.2 acre. Proposed financial instruments need to demonstrate consistency with OAR 141-085-0700.

Administrative Protections Required for Eelgrass and Kentuck CWM projects: Administrative protection instruments need to demonstrate consistency with OAR 141-085-0695.
Oregon Department of State Lands, Land Management Issues: Any proposed uses or activities on, over, or under state owned lands requires Department proprietary authorizations.
Extensive Comments-Detailed response requested. The Department requests that the applicant respond to all substantive comments. Certain commenters provided extensive, detailed comments. The Department would like to call these comments to the applicant's attention to ensure that the applicant has time to sufficiently address them.

- Mike Graybill;
- Jan Hodder;
- Rich Nawa, KS Wild;
- Stacey Detwiler, Rogue Riverkeepers;
- Jared Margolis, Center for Biological Diversity;
- Jodi McCaffree, Citizens Against LNG;
- Walsh and Weathers, League of Womens Voters;
- Wim De Vriend;
- The Klamath Tribes, Dawn Winalski;
- Tonia Moro, Atty for McLaughlin, Deb Evans and Ron Schaaf;
- Regna Merritt, Oregon Physicians for Societal Responsibility;
- Oregon Women's Land Trust;
- Sarah Reif, ODFW;
- Margaret Corvi, CTLUSI;
- Deb Evans and Ron Schaaf;
- Maya Watts; and
- Steve Miller.

All comments received during the public review of this application were previously provided to Jordan Cove by the Department via Dropbox and should be responded to as well. Please submit any responses to the Department and copy the commenting party if contact information was provided.
The Department asks that any responses be submitted in writing within 25 days of the date of this letter to allow adequate time for review prior to making a permit decision. If Jordan Cove wishes to provide a response that will take more than 25 days to prepare, please inform me as soon as possible of the anticipated submittal date.
The Department will make a permit decision on your application by September 20, 2019, unless Jordan Cove requests to extend that deadline. Please call me at (503) 986-5282 if you have any questions.
Sincerely,
Robert Lobdell
Aquatic Resource Coordinator
Aquatic Resource Management
RL:jar:amf