June 17, 2014

Andrew Stamp Hearing Officer
Coos County Planning Department
225 N. Adams St.
Coquille OR 97423

Re: Coos County Pacific Connector Gas Pipeline application file number HBCU-13-06

Dear Hearing Officer Stamp:

Please accept the following comments into the record of the Coos County Pacific Connector Gas Pipeline (PCGP) land use application HBCU-13-06. As a citizen who resides in Coos County I have a direct interest in this proceeding in that I live 2 miles from the proposed LNG terminal and the proposed end of the Pacific Connector Gas Pipeline in Coos Bay. I also live in the proposed LNG hazardous impact zone and this application and project will directly impact me and my family due to these potential hazards and the increase in natural gas prices that would be a result of exporting LNG to foreign countries for the benefit of a foreign controlled energy company. The foreign controlled Jordan Cove Energy Project would get the profits and benefits while we citizens in North Bend/Coos Bay and along the pipeline route would be subject to all of the risk and hazards.

This application seeks to alter some of the locations of the pipeline route that were agreed upon with Conditions of Approval in a Coos County land use permit issued in 2012. The Conditions of Approval and Final Decision and Order 10-08-045PL and 12-03-018PL are applicable in this permit proceeding due to the fact this section of pipeline would serve no benefit if the rest of the pipeline did not exist. I would like to ask that the complete prior records of the original and remanded final decision for this complete pipeline project be included in with this proceeding including all final orders and Conditions of Approval. (See Exhibit A)

Detailed pipeline alignment maps for this alternative route were not made available on-line to the public until June 5th. While we appreciate that they were finally made available, many of the new impacted landowners along the Blue Ridge Route Alternative may not have known about these maps since it was almost a week after the hearing had occurred that they were made available. The County Planning Director should have required these before even considering the application for completeness.

It is still not clear why the Coos County Planning Department is charging only $2,500 for this application when the original application had a cost to the applicant of $30,000? (See Exhibit B) It seems that since this is a quasi judicial land use proceeding that the County should be making the applicant conform to the exact same criteria they originally had to follow in order for them to make changes to their already approved Conditional Use Permit (CUP). Allowing the Pacific Connector to be able to file multiple revision applications at such reduced fees makes it harder

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for citizens to be able to participate. Particularly since each revision has to be appealed in separate land use proceeding processes. This clearly biases the process in favor of the applicant and is not in line with the spirit and intent of Oregon Statewide Planning Goal One for Citizens Involvement.

1. Application in violation of Final Decision and Order No. 10-08-045PL, as ratified by Final Decision and Order No. 12-03-018PL, Condition of Approval 25.

The current proposed pipeline is proposed to transmit natural gas to a liquefaction facility located on the North Spit where it would be exported overseas. The original approved CUP permit does not allow for this type of pipeline. Condition #25 states: *(See Exhibit A)*

"25. The conditional use permits approved by this decision shall not be used for the export of liquefied natural gas." (Emphasis added)

On April 16, 2012, the Federal Energy Regulatory Commission vacated the prior Certificate approval that the prior Pacific Connector Land Use CUP decision was based on. *(See Exhibit C)*

The Pacific Connector should have also vacated their Coos County "import only" CUP permit at the same time. **The applicant needs to reapply with a completely new application for the entire pipeline route in the Coastal Zone using the proper purpose and need of the pipeline along with a properly approved and completed Environmental Impact Statement.** FERC has not even issued a Draft Environmental Impact Statement yet for the proposed export project much less issued a Decision. This should have been completed prior to any application being submitted by Pacific Connector. Most of the original 2012 Coos County CUP findings were based on the now vacated FERC EIS and Order. **This should have made the original application and CUP approval no longer valid.** This current pipeline route cannot exist on its own so that would make it not valid either.

CCZLDO SECTION 5.0.350 (B) states:

"An applicant who has received development approval is responsible for complying with all conditions of approval. Failure to comply with such conditions is a violation of this ordinance, and may result in revocation of the approval in accordance with the provisions of Section 1.3.300."

*(Emphasis added)*

2. NEPA Requirements

The National Environmental Policy Act (NEPA) expressly prohibits certain actions while an Environmental Impact Statement (EIS) process is underway. Specifically, until a final record of decision is issued, the Applicant and the Federal Energy Regulatory Commission (FERC) are not
to take any action concerning the proposal which would limit the choice of reasonable alternatives addressed in the EIS.1

If the applicant takes any actions that would tend to bias or influence the ultimate choice amongst reasonable alternatives, FERC has the responsibility to tell the applicant to cease and desist, and may take injunctive measures under NEPA up to and including a refusal to process the application.2

The identification and the objective, un-biased evaluation of alternative ways of meeting the described need for the proposed action is the very heart of the NEPA process. In cases involving a non-federal applicant, FERC must still consider all alternatives that are practical or feasible from a technical and economic standpoint rather than simply desirable from the standpoint of the applicant.3

It is our perception that the Jordan Cove applicant is in the process of violating the NEPA regulations by taking inappropriate actions as indicated by all these land use applications and approval decisions that are being processed prior to the NEPA process being completed.

**Role and Function of an EIS**

NEPA requirements:

*An EIS should “...serve practically as an important contribution to the decisionmaking process and will not be used to rationalize or justify decisions already made”. (40 CFR 1502.5)*

*An EIS “is more than a disclosure document. It shall be used by Federal officials in conjunction with other relevant material to plan actions and make decisions.” (1502.1)*

*An EIS is meant to document how, specifically, environmental considerations were incorporated with economic and technical considerations in all plans and projects (NEPA 102A)*

*An EIS “must be objectively prepared and not slanted to support the choice of the agency’s preferred alternative over the other reasonable and feasible alternatives”. (CEQ 40?, #4c.)*

*An EIS “should be analytic rather than encyclopedic”. (1502.2a)*

Unfortunately, and inadvertently, Coos County and the State of Oregon are giving the appearance of facilitating this malfeasance on the part of FERC by processing the various permits and certifications under their jurisdiction prior to the completion of the EIS process.

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1 CEQ, Regulations for implementing the National Environmental Policy Act, 40 CFR 1500-1508, July 1, 1986, Section 1506.1(a)(2).

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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.

How can Oregonians be expected to objectively evaluate the range of alternatives that would be provided in a valid EIS if, in fact, Coos County and Oregon state agencies have already issued permits and certifications for one of the alternatives beforehand?

In addition, pipelines are subject to oversight and regulation by the Oregon Public Utilities Commission and the U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA) under Title 49, Code of Federal Regulations, Parts 190 to 199. The Department of Transportation's (DOT) Pipeline and Hazardous Material Safety Administration (PHMSA), acting through the Office of Pipeline Safety (OPS), administers the Department’s national regulatory program to assure the safe transportation of natural gas, petroleum, and other hazardous materials by pipeline. OPS develops regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance, and emergency response of pipeline facilities. The applicant must show that their project is in compliance with all these agencies.

3. Coos County Comprehensive Plan and Zoning Land Development Ordinance

The proposed Pacific Connector Gas Pipeline alternative routes will impact Coos County zoning district 20CA, 20RS and the stock slough tributary. This requires that the application decision be subject to the Coos Bay Estuary Management Plan (CBEMP)

CBEMP ZONING DISTRICT:

ZONING DISTRICT: 20-RURAL SHORELANDS

SECTION 4.5.545. Management Objective: This district shall be managed for rural uses along with recreational access. Enhancement of riparian vegetation for water quality, bankline stabilization, and wildlife habitat shall be encouraged, particularly for purposes of salmonid protection. This district contains two designated mitigation sites, U-17(a) and (b), "medium" priority, which shall be protected as required by Policy #22.

SECTION 4.5.546. Uses, Activities and Special Conditions. Table 20-RS sets forth the uses and activities which are permitted, which may be permitted as conditional uses, or which are prohibited in this zoning district. Table 20-RS also sets forth special conditions which may restrict certain uses or activities, or modify the manner in which certain uses or activities may occur. Reference to “policy numbers” refers to Plan Policies set forth in the Coos Bay Estuary Management Plan.

A. Uses:

4. Commercial N
5. Dryland moorage N
6. Industrial and Port facilities N
13. Utilities
   a. Low-intensity P-G
   b. High-intensity N

B. Activities

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1. Stream alteration ACU-S, G
3. Dredged material disposal ACU-S, G
4. Excavation to create new water surface ACU-S, G
5. Fill ACU-S, G
6. Shoreline stabilization
   a. Vegetative P-G
   b. Riprap ACU-S, G
   c. Retaining wall ACU-S, G

GENERAL CONDITIONS (the following conditions apply to all permitted uses and activities):

1. Inventoried resources requiring mandatory protection in this district are subject to Policies #17 and #18.

2. All permitted uses and activities shall be consistent with Policy #23, requiring protection of riparian vegetation.

The following conditions apply to all permitted uses

3. Where "agricultural lands" or "forest lands" occur within this district, as identified in the "Special Considerations Map", uses in these areas shall be limited to those permitted in Policies #28 and #34.

4. Uses in this district are only permitted as stated in Policy #14, "General Policy on Uses within Rural Coastal Shorelands" except as permitted outright, or where findings are made in this Plan, uses are only allowed subject to the findings in this policy.

5. All permitted uses shall be consistent with the respective flood regulations of local governments, as required in Policy #27.

6. On designated mitigation/restoration sites, all uses/activities shall only be permitted subject to the conditions in Policy #22.

7. In rural areas (outside of UGBs) utilities, public facilities and services shall only be provided subject to Policies #49, #50, and #51.

SPECIAL CONDITIONS

Activities:

1. Stream alterations shall be allowed when findings are made which document that the alternations will not negatively impact bankline stabilization or salmonid populations.

3. Disposal of dredged materials from the Coos River and Millicoma River Channels may occur on neighboring farm lands but shall not impact protected wetlands and riparian vegetation (see Policies #19 and #23).

4. Creation of ponds or additional water surfaces shall only be allowed for restoration/resource enhancement or agricultural uses.

5. Fill shall not be allowed in areas of "wet meadow" wetland, as identified on the "Special Considerations Map", except as otherwise allowed in Policy #19.

6b,6c. These activities are only permitted subject to the findings required by Policy #9, "Solutions to Erosion and Flooding Problems".

SECTION 4.5.547. Land Development Standards. The requirements set forth in Table 4.5

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shall govern development in the 20-RS district.
(Emphasis added)

CBEMP Policy #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:

...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 nonresource use.

...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.
(Emphasis added)

There has been no finding of "need" and "consistency" that supports this plan. The Horizontal Directional Drill (HDD) proposed in the 20RS zone could have a hydraulic fracture (i.e frac-out) which would impact also CBEMP Zone 20CA. The Application on page 25 states that the proposed PCGP alternative segment alignment crosses through the 20-CA zoning district. The Applicant’s report on this, "Drilling Fluid Contingency Plan for Horizontal Directional Drilling Operations," (page 3 of report) indicates that, “...Based on the assumptions and interpretation utilized during the modeling process, the evaluation may indicate a high potential (low factor of safety) for hydraulic fracture along the drill path...” (Emphasis added). Any use and activity which could alter the estuary is only to be allowed subject to requirements of CBEMP Policies being met including Policy 5. In this case and Pacific Connector has not followed those requirements. They cannot guarantee that a frac-out would not occur or that drilling muds would not seep into CBEMP Zoning District 20RS and/or 20CA and impact critical Estuarine habitat. On page 6 of their Drilling Fluid Contingency Plan they even state that:

“All three river crossing (Coos, Rogue, and Klamath) proposed for utilizing the HDD method of construction support resident and anadromous fish species including chinook and coho salmon and steelhead trout. Chinook and coho salmon and steelhead trout use these waterways as spawning, rearing, and migration habitats.”

Each of the CBEMP zoning management districts have both “Uses” that are allowed and “Activities” that are allowed in those zoning districts. While a low intensity pipeline structure is allowed in these estuary zoning districts, that does not mean digging a trench or an HDD to bury

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the pipeline would also be allowed. Essentially allowing a pipeline structure in these zones could mean you just placed the pipeline on the top of the tidal muds and/or shorelands. The structure being allowed does not automatically mean the digging of a trench or HDD to bury it would be. THAT IS CLEARLY AN “ACTIVITY” that would occur in those zoning districts that requires a finding of “need” among other things.

CBEMP Policy #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 (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
   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.... (Emphasis added)

CBEMP POLICY #5a Temporary Alterations

I. Local governments shall support as consistent with the Plan: (a) temporary alterations 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. (Emphasis added)
   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.

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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.

(Emphasis added)

Full impacts to all potentially affected waterbodies and rural shorelands and all impacted species connected to those waterbodies and rural shorelands in Coos County should be analyzed by third party independent analyst long before any additional decisions are made with respect to the proposed alternative pipeline routes or before any potential approval is given to the project period. This should include but not be limited to impacts of the project on the threatened Coho salmon (SONCC), the threatened Coho salmon (Oregon Coast ESU), (See Exhibit D) the threatened Green sturgeon (Southern DPS) and any and all marine species, plants, wildlife, people and industries that will impacted by the proposed project’s pipeline alternative routes and their potential impacts on waterbodies. CBEMP Policy 4 and 4a need to be adhered also in this case along with those polices and management objectives noted above.

There has been no independent “Resource Capability Consistency and Impact Assessment.” Pacific Connector has failed to prove that their project is needed and that the pipeline construction in these alternative route areas will not unreasonably interfere with public trust rights. Oregon’s public trust doctrine (PTD) is not of mere academic interest. The doctrine imposes duties on the state as sovereign owner of water, wildlife, and ancillary uplands. In an era of widespread skepticism of government management, the venerable public trust doctrine seems an especially appropriate mechanism to give citizens an opportunity to gain review of government action and inaction threatening unsustainable development of natural resources that are central to the state’s identity, culture, and economy. 4 These public rights in natural resources impose certain duties on the state, such as providing public access, obtaining full market value for private use of public resources, and maintaining PTD resources for future generations.

Cost of Exporting

Exporting natural gas will increase domestic gas prices. This increase in domestic natural gas prices will directly negatively impact citizens in Oregon and the United States and landowners along the pipeline rights of way. It will negatively impact thousands of manufacturing jobs that are in the process of coming back to the U.S. due in part to low natural gas prices.  It will also negatively impact other local and national industries that use natural gas. Eminent domain of Oregon landowner’s private property for the benefit of a foreign controlled “private” corporation with plans to Export LNG would be contrary to the public interest and public trust rights. The negative impacts of exporting are all spelled out in the following attached report, “Drill Here Sell There – The Painful Price of Exporting Natural Gas” 5 (See Exhibit E)

4 Oregon’s Public Trust Doctrine: Public Rights in Waters, Wildlife, and Beaches -
5 “Drill Here Sell There – The Painful Price of Exporting Natural Gas” 3-1-2012
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The state has a duty under the Public Trust Doctrine (PTD) to protect public water resources for public uses consistent with “no-diminishment” trust principles, and statutes may help define when the state has failed to meet its duty and owes compensation to the trust. The Pacific Connector Gas Pipeline has failed to make a finding that the public need for their proposed project “outweighs” the detriment their project would cause to the use and impacts of multiple waterbodies and conservation aquatic zoning districts in Coos County.

Public Service Structures

I challenge whether the proposed pipeline meets the ZLDO definition of “utilities,” considering that it is not a “structure,” as defined in the ZLDO and it would be owned and operated by a “private” foreign controlled energy company.

The term “Utilities” is defined by the CCZLDO as "public service structures" (falling into two categories, low intensity and high intensity). CCZLDO § 2.1.200. It is questionable whether an export pipeline remains a "utility," because the pipeline would no longer provide service to the domestic public. If the pipeline is allowed to change its flow to export it fails to comply with CCZLDO §4.9.450(C). That code provision allows conditional uses for:

Utility facilities necessary for public service, except for the purpose of generating power for public use by sale and transmission towers over 200 feet in height. A facility is necessary if it must be situated in an agricultural zone in order for the service to be provided.

A similar issue arises with regard to Comprehensive Plan Policy #50: Rural Public Services. Policy 50 provides that Coos county shall consider "electrical and gas lines and similar low-intensity facilities and services traditionally enjoyed by rural property owners" as appropriate for all rural parcels. If the pipeline becomes an export line, it would not fit within this allowance. As stated above, an export line does not provide a "service," and certainly not one "traditionally enjoyed by rural property owners."

LCDC administrative rules declare local distribution lines for natural gas are permitted outright. OAR 660-006-0025(3)(c). Additionally, new distribution lines for gas with rights of way up to 50’ or less may be conditionally permitted. OAR 660-006-0025(4). While new electric transmission lines may also be permitted, gas transmission lines are not mentioned.

Resolution of this issue rests in part on determining if the proposed pipeline is a transmission line or a distribution line. The proposed pipeline in this case is 36 inches in diameter with gas pressurized at 1,480 pounds per square inch. The pipeline will transport gas from outside the State of Oregon via a pipeline that enters Oregon at Malin, to Coos Bay, where it will be

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6 Marshall v. Frazier, 81 P.2d 132, 134 (Or. 1938) (explaining that “[t]he question of what is a reasonable compensation for trustees depends largely on the circumstances of each particular case, and can not be properly determined by any inflexible rule” (quoting 26 R.C.L. Trusts, § 258)); 76 AM. JUR. 2D Trusts § 276 (2005) (“Where the trustee makes an unauthorized conversion, transfer, or encumbrance of trust property or funds, the beneficiary of the trust may elect to hold the trustee personally liable and accountable for: this breach of trust.”); id. § 345 (“Misapplication of the trust estate renders the trustee immediately liable for the proceeds or the value of the property misapplied, at the option of the beneficiary.”).
liquefied and pumped into ships for export. These facts demonstrate that the proposed export pipeline equates to a “transmission line” found in ORS 215.276(1)(c), rather than a distribution line:

"Transmission line" means a linear utility facility by which a utility provider transfers the utility product in bulk from a point of origin or generation, or between transfer stations, to the point at which the utility product is transferred to distribution lines for delivery to end users.

Whereas the prior 2012 Decision found that the pipeline would provide natural gas to markets throughout the region this is no longer the case under the current project proposal. The Pacific Connector Gas Pipeline will not serve a single local customer in Coos County or the United States. The proposed export of natural gas has no intended distribution to the domestic public. The Pipeline is not a utility for public service and it is not intended to make a distribution to individual end-use customers in the region. (See Exhibit F) Since the proposed pipeline is not a distribution line and only gas distribution lines are allowed in a Forest zone it is not allowed and the application should be denied. OAR 660-006-0025.

The County has also signed off on this permit prior to the determination needed by the necessary agencies as required by CBEMP Policy 11

#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. (Emphasis added)

Where does the record show any permit coordination, need and consistency findings have been performed by the Planning Department prior to their approval of this permit? How can the Planning Department and citizens make judgments about this project when there is no data? Conditional permits are to be done in coordination with the State Agencies. Where in the record is this coordination? The Application states on page 16 that the “...Pacific Connector will obtain comments from the Oregon Department of Fish and Wildlife (ODFW) for any portion of McCaffree

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the proposed alternative segment alignment which will require removal of riparian vegetation within 50 feet of an estuarine wetland, stream, lake or river proximate to inventoried salmonid spawning and rearing areas subject to special riparian vegetation protection” THIS WAS TO OCCUR “AT THE TIME OF THE PERMIT APPLICATION” NOT AT SOME DISTANT DATE WAY OFF IN THE FUTURE. PCGP has not done this yet. CBEMP policy 4 and 4a clearly spell this out.

CBEMP Policy 4a (V) states:

“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.” (Emphasis added)

4. Public Need and Benefit of Pacific Connector Pipeline Project Lacking

On June 6, 2013, Pacific Connector Gas Pipeline, L.P. (PCGP) filed an application with the Federal Energy Regulatory Commission (FERC) for approval to construct, own and operate a natural gas transmission pipeline in southern Oregon.

PCGP Resource report 1, page 3, under 1.2.2 Need states:

“The primary need for Pacific Connector is to supply approximately 1.02 Bcf/d (1,020,000 Dth/d) of firm transportation service to the Jordan Cove Terminal. The Jordan Cove Terminal, located on the bay side of the North Spit of Coos Bay, is designed to receive, liquefy, store and load LNG onto LNG ships for delivery to export markets...”

Under the Natural Gas Act (NGA), transportation of natural gas for public distribution must be “affected with a public interest.” 15 U.S.C. § 717(a). Under FERC regulations, the applicant must set forth “[t]he facts relied upon” to show that the construction is required by the public convenience and necessity. 18 C.F.R. §157.6(b)(2). Additionally, the applicant must provide “all information necessary to advise the commission fully concerning the operation, sales, service, construction, extension, or acquisition for which a certificate is requested.” 18 C.F.R. 157.5(a). The burden of justification for omitted data rests on the applicant. 18 C.F.R. §157.5(c).

Both the Jordan Cove Energy Project (JCEP) and the PCGP have failed to demonstrate that the proposed facilities are not inconsistent with the public interest as required by applicable regulations. 18 C.F.R. § 153.7(c). The applicant has failed to provide adequate evidence to support the proposition in the applications that the current proposed pipeline route and terminal local and design will have the least adverse impact on local water resources, salmon habitat, forests, and agricultural values. There is significant evidence that the project will negatively impact local farms, fish habitat, water quality and natural resources.

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The Jordan Cove Energy Project L.P. (JCEP) has no experience in the export of LNG and both JCEP and PCGP’s Federal Energy Regulatory Commission (FERC) applications have failed to demonstrate that the proposed facilities will not involve any existing contract(s) between the applicant and a foreign government or person concerning the control of operations or rates for the delivery or receipt of natural gas which may restrict or prevent other United States companies from extending their activities in the same general area. 18 C.F.R. § 153.7(c)iii

JCEP Application to FERC page 4 states:

"...JCEP is a new entrant to the LNG industry and will bear the full economic risk of constructing and operating the Project (without subsidization from, or causing unsubscribed capacity on, existing pipelines). In fact, as the Project will provide a new outlet for North America’s abundant natural gas supplies, it will result in increased utilization of both new and existing pipeline infrastructure."

4.1 Motion to Intervene of Gas Transmission Northwest LLC under FERC PCGP Docket No CP13-492-000 states:

"Gas Transmission Northwest LLC ("GTN")is a "natural-gas company" as defined by the Natural Gas Act, 15 U.S.C. § 717a(6), and is engaged in the business of transporting natural gas in interstate commerce within the jurisdiction of the Commission. As an interstate pipeline serving many of the same markets as the facilities proposed in this proceeding, GTN has a direct and substantial interest in, and may be directly affected by, this proceeding..." ⁷ (Emphasis added)

4.2 Motion to Intervene of Northwest Industrial Gas Users under FERC JCEP Docket No CP13-483-000 states:

"The proposal in this filing could impact NWIGU member companies’ interests. NWIGU member companies purchase substantial quantities of natural gas for use in their facilities, and thus will be directly affected by the outcome of this proceeding..." ⁸ (Emphasis added)

4.3 Motion to Intervene of Southwest Gas Corporation under FERC PCGP Docket No CP13-492-000 states:

"Southwest is a natural gas local distribution company engaged in, inter alia, the intrastate transmission, distribution, and sale of natural gas in certain portions of the states of California, Arizona, and Nevada pursuant to certificates of public convenience and necessity issued by the California Public Utilities Commission, the Arizona Corporation Commission, and the Public Utilities Commission of Nevada. With respect to its northern California and northern Nevada service areas, Southwest relies upon the facilities of Ruby Pipeline L.L.C. (Ruby) for transporting and

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⁸ Motion to Intervene of Northwest Industrial Gas Users under CP13-483-000: http://eLibrary.ferc.gov/edmws/file_list.asp?accession_num=20130618-5008

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delivering supplies of natural gas, which Southwest purchases on a delivered basis, to supply Southwest's northern California and northern Nevada local distribution service areas. Southwest is also dependent upon the facilities of Northwest Pipeline GP (Northwest) for supplies of natural gas, which Northwest delivers to Paiute Pipeline Company for redelivery to Southwest's distribution systems. Southwest is a firm transportation customer of Northwest... 

.... As a customer of both Ruby and Northwest, Southwest buys delivered supplies at Ruby's interconnect with Paiute Pipeline Company and is therefore affected by any change in Ruby's tariff rates. Southwest is also dependent upon Northwest for supplies of natural gas and is subject to the rates that the Commission authorizes Northwest to collect for its transportation of gas. An order in this proceeding may have a direct impact upon Southwest...." 9 (Emphasis added)

4.4 In 2003 and in 1991 Williams (50% owner of the PCGP and proposed builder of the PCGP) was fined the largest civil fines in the history of FERC:

"The Federal Energy Regulatory Commission today approved a settlement that includes a civil penalty of $20 million—the largest in Commission history. The tough penalty stems from anticompetitive practices by Transcontinental Gas Pipe Line Corporation (Transco), a subsidiary of The Williams Companies (Williams)...

... Before today's settlement, the largest civil penalty was $11 million, paid by Transco under a 1991 settlement for, among other things, destroying archaeological sites in Alabama." 10 (Emphasis added)

5. JCEP / PCGP Project - Not Needed for Export According to Industry Analyst Data

In June 2013 Navigant released their updated Outlook for the North American natural gas market, including supply, demand, and prices at key market points. The Navigant Press Release stated among other things that:

"...the real Henry Hub average price will increase at an average rate of 2.9 percent, from $3.66/MMBtu in 2013, to $4.07/MMBtu by 2015, and reach $6.82/MMBtu by 2035"...

...LNG exports are expected to grow in the U.S. and Canada, reaching 6.8 Bcf/d by 2020." 11 (Emphasis added)

The BP Energy Outlook 2030 that was released in January 2013 also concluded similar statistics:

9 Motion to Intervene of Southwest Gas Corporation under CP13-492-000: http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20130620-5075
11 "Navigant Releases New Data on North American Natural Gas Market Prices" Press Release; June 10th, 2013:
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“North American shale gas production grows by 5.3% p.a. reaching 54 Bcf/d by 2030, more than offsetting the decline of conventional gas production. Supported by shale gas, North America will become a net exporter in 2017, with net exports approaching 8 Bcf/d by 2030...” 12 (Emphasis added)

“Gas trade between regions continues to grow (3.7% p.a. from 2011). Europe remains the largest net importer, and accounts for the largest increment in net imports (18 Bcf/d). Russia remains the largest net exporter – predominantly to Europe.

“LNG contributes an increasing share of trade. LNG production grows by 4.3% p.a., accounting for 15.5% of global gas consumption by 2030. On a regional level, Africa is set to overtake the Middle East to become the largest net LNG exporter in 2028.

“Australia, with a wave of large projects coming on stream from 2014, expands LNG supply by 15 Bcf/d, overtaking Qatar as the largest LNG supplier by 2018 and accounting for 25% of global LNG production by 2030...” 13 (Emphasis added)

These export volumes above have also been confirmed by several additional Navigant Reports that were completed in September for the Jordan Cove Energy Project as a part of their application to the NEB:

**Jordan Cove NEB Appendix D** – Export Impact Assessment – Application for a Gas Export License to the National Energy Board; Gordon Pickering, Navigant; September 201314 – Page 26 states:

“Given this competition, Navigant believes that LNG exports will be more limited for the foreseeable future than the number of applications for LNG export approval might suggest. Our view is that not all LNG export projects will go ahead. In our estimation, export volumes in the 8 Bcfd to 10 Bcfd range from North American seem to be a reasonable estimate of the eventual volume. At these levels, the exports represent only 9 percent - 12 percent of the current market in 2013 and from 6 percent - 8 percent of the North American gas market in 2045.15 At these levels, we believe it is unlikely that even if global gas prices remain high, they will be able to materially affect prices in the North American market.” (Emphasis added)


Page 17 – 18 states:

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15 Report states this was based on the: “Navigant ‘Natural Gas Supply and Demand Market Assessment to 2045’”, Figure 14, page 26. 2013 North American gas production is 85 Bcfd. 6/85=7%; 8/85=9%/ 2045 North American gas production is 130 Bcfd. 6/130=5%; 8/130=6%.

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“It should be noted that Navigant considers the upper end of the volume ranges discussed here for Canadian LNG exports with respect to resource life (i.e., 15 Bcf/d) to be quite high, and unlikely. Navigant’s current view is that the likely development of North American liquefaction capacity for export is in the 8-10 Bcf/d range, with 6-8 Bcf/d from the U.S. and about 2 Bcf/d from Canada, meaning that the scenario of 4.75 Bcf/d of Canadian LNG exports (based on approved projects) should be viewed as a high export assumption.” (Emphasis added)

Page 35 states:

“It is important to recognize that North American LNG exports will occur within a global marketplace, with a supply-demand balance that accounts for international competition. Consequently, it should be expected that only some portion of incremental international LNG liquefaction capacity will be built in North America, and relatedly that only some portion of proposed North American facilities will be built.

... Included in this outlook is “some” LNG export volumes (6.6 Bcf/d from North America) to account for expected increasing global gas on gas competition. Navigant’s current market view has developed to a range of 8 to 10 Bcf/d for North America, and we believe that range of export volumes will likewise be associated with reasonable prices.” (Emphasis added)

According to their own consultant reports, the Jordan Cove Energy LNG Export project and their associated Pacific Connector Gas Pipeline are not needed due to already approved North American LNG Export projects that currently total over 10 Bcf/d as documented further below.

5.1 The order in which the U.S Department of Energy (DOE) is processing proposed LNG Export Projects is below: 17

2.2 Bcf/d - Sabine Pass Liquefaction, LLC – DOE has approved
1.4 Bcf/d - Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC– DOE approved
2.0 Bcf/d - Lake Charles Exports, LLC – DOE approved
1.0 Bcf/d - Dominion Cove Point LNG, LP – DOE approved
.4 Bcf/d - Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC
1.7 Bcf/d - Cameron LNG, LLC

8.7 Bcf/d - Subtotal Bcf/d LNG Export volumes before JCEP approval by the U.S. DOE

.8 – 1.2 Bcf/d - Jordan Cove Energy Project, L.P. (per their application to the DOE)

It should be noted that the total above does not include the prospect of exporting LNG from the Alaska Kenai Plant. The Alaska Department of Natural Resources’ (DNR) requested that ConocoPhillips apply for a new license to export LNG from that terminal which suspended operations in 2012. The Alaska Department of Natural Resources (DNR) has entered into a Memorandum of Understanding (MOU) 18 with the Japan Bank for International Cooperation

16 See studies referenced in footnotes 63 and 64 of Navigant Report
17 Pending Long-Term Applications to Export LNG to Non-FTA Countries - Listed in Order DOE Will Commence Processing http://energy.gov/sites/prod/files/2013/05/f0/Pending%20LT%20LNG%20Export%20Apps%20%285-17-13%29.pdf
18 http://dnr.alaska.gov/commis/priorities/JBIC_DNR_MOU.pdf

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According to a September 11, 2013 press release, JBIC plays a critical role in financing and securing Japan’s LNG imports. The MOU “focuses on opportunities for Japanese companies and JBIC to become involved in resource development projects in Alaska – in particular, a large-volume liquefied natural gas pipeline and export facility.” The Department of Energy (DOE) in April 2014 authorized the shipment of 40 billion cubic feet of gas over two years from the Kenai plant.

5.2 Canadian LNG Export Project Volumes Ahead of Jordan Cove:
- 0.71-1.3 Bcf/d - KM LNG Operating General Partnership – Approved by NEB
- 0.24 Bcf/d - BC LNG Export Co-operative – Approved by NEB
- 3.23 Bcf/d - LNG Canada Development Inc – Approved by NEB
- 2.6 Bcf/d - Pacific Northwest LNG Ltd
- 3.9 Bcf/d - WCC LNG Ltd
- 2.8 Bcf/d - Prince Rupert LNG Exports Limited
- 3 Bcf/d - Woodfire LNG Export Pte. Ltd

Subtotal 13.14 - 14.37 Bcf/d LNG Export volumes before JCEP approval by the NEB in Canada
1.55 Bcf/d – Jordan Cove Energy Project L.P. (per their application to the NEB)

5.4 If one adds up the North American LNG Export Terminal total volumes that have been approved to date, prior to the Jordan Cove Energy Project, those volumes EXCEED industry market analyst projections for LNG Export volumes by 2030. Even if one considers the EIA’s high/rapid LNG Export scenario of 12 Bcf/d phased in at a rate of 3 Bcf/d per year. These volumes would be met long before the Jordan Cove Energy Project:

- 8.7 Bcf/d - U.S. LNG Export volumes in line before Jordan Cove
- +13.14 - 14.37 Bcf/d – Canadian LNG Export volumes in line before Jordan Cove
- =21.84 - 23.07 Bcf/d - Total volume of North America LNG Exports approved before JCEP

SO WHY ARE WE WASTING EVERYONE’S TIME ANALYZING THE JORDAN COVE / PACIFIC CONNECTOR LNG “EXPORT” PROJECT WHEN INDUSTRY DATA DOES NOT SUPPORT IT?

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19 “State Signs Agreement with Major LNG Financier in Japan” – September 11, 2013
http://dnr.alaska.gov/shared/mediareleases/dsp_media_release.cfm?id=1903&title=State%20signs%20agreement%20with%20major%20LNG%20financier%20in%20Japan
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Exporting domestically produced LNG will have a detrimental impact on American manufacturing and industries that rely on and use natural gas. (See Exhibit E) These industries are currently becoming very concerned that any additional export volumes than what have already been approved by the U.S. DOE would be risking thousands of jobs in the manufacturing sector in both the U.S. and Canada. (See Exhibits G & H) On September 18, 2013, the group America’s Energy Advantage, representing the American manufacturing sector, filed a motion to intervene on the next proposed LNG export project that is up for U.S. DOE approval, the Freeport LNG Expansion Export Project. The America’s Energy Advantage press release stated the following:

"...DOE is making decisions that will have far-reaching and potentially irreversible impacts on consumers, our economy, and America's manufacturing renewal based on 30-year-old guidelines for natural gas imports, not exports. No matter where one stands on this issue, surely we can agree that exports and imports are different, and that DOE needs to make rules based on the 21st century, not the 1980s," said Jennifer Diggins, Director, Public Affairs for Nucor Corporation and Chair of AEA.

"We felt the need to file a formal motion because American consumers of natural gas deserve as much say in the process as producers," said Diggins. "All we're saying is that the public interest test is important, and that DOE needs to take a more methodical and legally-based approach to defining what that public interest is. DOE itself conceded that 'the market of the future very likely will not resemble the market of today' in its previous grant applications, but what data are they using to project that future? Nobody knows."

Diggins concluded: "As a result of available and affordable natural gas in the U.S., more than 120 manufacturing projects valued at nearly $110 billion of economic investment have been announced, including thousands of new jobs. Our country cannot afford to lose these job-creating investments or hurt consumers by driving up the cost of utility bills. We have a right to be heard in this debate..."24 (Emphasis added)

7. Detrimental Impacts of Pipeline Construction - Not in the Public Interest or the interest of Protected Species and Essential Habitats.

Pacific Connector is proposing to use the Horizontal Directional Drilling (HDD) method for the crossing of the Coos River (MP 11R). The HDD method involves boring under the Coos River and pulling the pipeline into place through the borehole that has been reamed to accommodate the diameter of the pipeline. This procedure involves three main phases, pilot hole drilling, subsequent reaming passes, and pipe pullback. HDD typically is used for the crossing of major waterbodies (greater than 100 feet wide). Failure rates result in what is known as frac-


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outs where drilling muds are released into the waterbody. Frac-outs occurred with the construction of the Coos County 12-inch pipeline and the impacts to vital marine life and habitat were significant. Photos of the stream damage caused by the 12-inch line can be seen in Exhibit I. Potential releases of drilling fluid bentonite clay can wear down fish gills and impair fish vision making difficulty and predation easy (ODFW quote). Horizontal Directional Drilling has a one in three failure rate. The impacts on fish habitat should this occur would be difficult or impossible to mitigate.

There was no salmon season for fishermen (a vital industry in Coos Bay) in 2006 and 2009 due to poor fish runs. The currently underused twelve-inch gas pipeline that was built in 2003 and which runs from Coos Bay to Roseburg had environmental impacts that were severe and many vital ecological streambeds suffered damage. (See Exhibit I) MasTec, the pipeline builder, and the county sued each other with MasTec agreeing in the end to pay Coos County $8.7 million and dismiss its claims against the county, which totaled $14.5 million. The Sierra Club, along with other environmental groups, filed a separate suit and won a $1.5 million ruling against MasTec which fell well short of the amount that was originally sought by them. Judge Hogan ruled that there had been failure of all parties concerned and that the lack of government oversight was a factor in the low penalty amount he awarded to the plaintiff. I don’t know what became of all the money the environmental groups were awarded in this case but our local environment, citizens and habitats never really come out ahead in these deals. (See Exhibit I)

The Sakhalin II LNG export terminal and pipeline on Sakhalin Island, Russia, was constructed in terrain areas similar to the Southern Oregon coast. The developer Shell Oil Company offered similar unenforceable assurances just like Jordan Cove and Pacific Connector are offering but the final outcome fell far short of their assurances. (See Exhibit K) The environmental degradation from Shell’s LNG project on Sakhalin Island was so bad that even the Russian Government recognized an environmental disaster in the making and stepped in and took over the project. The Pacific Connector should be required to explain how aquaculture and construction activities can co-exist, how the alternative route is superior to other alternative upland routes and how landslides, frac-outs and other hazards will be prevented or mitigated.

Fishing is a vital industry connected to the South Coast Basin, which includes impacts from these streams in Coos County that will be crossed by the Pacific Connector Gas Pipeline’s proposed alternative routes. The Pacific Connector’s pipeline impacts will be counterproductive and in fact detrimental to this industry. This is an important issue to both

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25 Science Direct - “Analysis of wellbore instability in vertical, directional, and horizontal wells using field data” M.A. Mohiuddin, K. Khan, A. Abdulraheem, A. Al-Majed, M.R. Awal; Center for Petroleum and Minerals, Research Institute, King Fahd University of Petroleum and Minerals, Dhahran, Saudi Arabia; Received 18 April 2005; accepted 26 April 2006;

26 SHELL SHAKEDOWN - How the world’s second largest oil company lost control of its $22 billion project on Russia’s Sakhalin Island” By Abraham Lustgarten; FORTUNE Magazine; February 5, 2007; Photographs by Michael Christopher Brown;

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commercial and recreational fishermen on the South Coast of Oregon. In 2005, recreational boaters made 30,996 boat trips in the Coos Bay of which 90% involved fishing.

 Concerns raised by Coos Watershed to FERC on December 4th 2008 are still relevant and apply to the current alternative pipeline routes. If landslides were to occur these same streams and tributaries would be impacted:

Coos Watershed Association:
20081204-5103 FERC PDF (Unofficial) 12/4/2008 4:22:40 PM

...3. Once it crosses the Coos River the proposed pipeline route will traverse lowlands adjacent to Catching Slough and its tributaries (approximately MP 8.25 to MP 18). These areas provide some of the most significant current lowland habitat for coho and Chinook salmon rearing, potential wetland restoration opportunities, and needed riparian restoration to reduce summer stream water temperatures. Of particular importance are Stock Slough (MP 10.1), the crossing in lower Catching Slough (MP 11), and Boone Creek (MP 15.75). All these streams and sloughs are used by coho salmon, and the adjacent riparian areas provide resources for these fish and other aquatic life. Additional information on these resources is found in the recently completed Catching Slough Assessment and Action Plan in the Publications section of our website....”
(Emphasis added)

Construction in riparian areas and along steep slopes increases the risk of erosion and sedimentation in the vitally important Coos Estuary and its tributaries, some of which are listed as water quality limited (i.e., already in violation of state water quality standards). (See Exhibit L) The cumulative environmental impacts of pipeline construction at proposed crossings and upland of waterbodies from the alternative pipeline route locations should all be analyzed and considered. Impacts with building in a FEMA floodzone and the county regulations with regard to building a hazardous facility in those floodzones should all be followed by the PCGP. If PCGP is not able to follow or meet these guidelines that have been established for the protection of the citizens and habitats, the pipeline permit should be denied.

The Coos County 12 inch Pipeline was built in 2003 / 2004. From June of 2009 to June of 2010, close to a quarter of a million dollars was spent by Coos County to fix problems that are still ongoing with that 12-inch line due to construction degradation. What is to prevent this from happening with the Pacific Connector?

Since Policy #14 applies, it is not sufficient to find that the pipeline is a “necessary component” of the approved LNG facility. The county must find that for each rural shoreland management unit impacted by this application, the pipeline cannot be rerouted to non-shoreland areas, urban shoreland areas or shoreland areas committed to nonresource use.

Alternative Pipeline Routes that would have gone towards the North first instead of going directly East along the shoreline of the Coos Bay Estuary were never considered or analyzed by the Pacific Connector as indicated by their map of alternative routes. These alternative routes would have not only avoided impacts to future water dependant industrial development in this area, but also would not have been so impacting to the estuary. (See Exhibit M) By using a

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more northerly route, most of the Pacific Connector’s right of way west of I-5 would cross property owned by Weyerhaeuser Corporation – which has supported the LNG development and has benefited from the sale of its North Spit property. The more northerly route alternatives would also avoid impacts to Rural Residential and EFU lands in Coos County. In addition, the Pacific Trail Pipeline alternative route would be considerably less impacting to the Coos Estuary and Coos County as a whole.

Clearly the management objectives in the CBEMP do not support the Pacific Connector alternative routes nor CBEMP’s Plan Policy #17 which calls for the “Protection of “Major Marshes” and” Significant Wildlife Habitat” in Coastal Shorelands.

8. High Hazard and Landslide Potential with Alternative Pipeline Route

PCGP Application states that they will use an HDD method to install the pipeline under the Coos River. They reference their Resource Report 2 but not their Resource Report 10. The Coos Crossing of the Alternative Route is very close to the proposed Landowner Blue Ride Alternative Route that has been proposed by several landowners. The reasons that these Blue Ridge Route alternatives were not chosen previously was due to the steep terrain and potential for landslides.

The former May 2009 FERC Final EIS stated on page 3-72 the following:

“Because there are questions about safety and buildability along the alternative routes, we do not believe that either the Blue Ridge Route Variation or the Amended Blue Ridge Alternative Route are clearly environmentally superior, and do not recommend either.”

(See Exhibit N)

Pacific Connector Gas Pipeline Project Resource Report 10 – page 29 states the following: (See Exhibit O)

“Along the Landowner Amended Route, additional areas of potential rapidly moving landslides would be crossed on the slopes immediately south of MP 9.45 and north of Echo Valley (Section 29, T. 25 S., R. 12 W.) as well as on the steep slopes on the north side of the Coos River (NE/4 Section 29, T. 25 S., R. 12 W.). The location of the Coos River crossing on the Landowner Amended Route would also likely be infeasible for an HDD because of the topographic conditions on the north side of the river. The narrow floodplain and steep slopes, approximately 300 feet from the edge of Millicoma Highway on the north side of the river, would limit the necessary HDD setback to allow acceptable geometric requirements and proper workspace layout for a large-diameter pipeline. At this crossing location, a wet open-cut river crossing method would be required since a conventional bore would be infeasible because of the excessive length (greater than 700 feet) to cross the river and the roads on eitherside of the river (Millicoma Highway and Coos River Road).

27 The Oregon Department of Geology and Mineral Industries (DOGAMI), in cooperation with other agencies, produced a map of Potential Rapidly Moving Landslide Hazards in Western Oregon (Hofmeister et al., 2002).
For these reasons, Pacific Connector concluded that the current proposed route is the environmentally preferred route that will have the least impact on local land area residents and allow for safe and efficient pipeline construction and operation.”
(Emphasis added)

Landslides

In December of 2006 a section of Willanch Road sank 8 feet in North Bend due to heavy rains causing difficulties for road crews and motorists. A picture of the slide out can be seen to your right. This is a common occurrence on the South Coast of Oregon every year as winter storms blanket the area bringing high winds, rain and high surf. High winds earlier in December of this same year blew down trees and knocked out power. Waves and ocean conditions were so bad that port entrances were closed. At the height of the storm, 110,000 customers, mostly along Oregon’s coast, were out of power. The outages were the result of broken wires from falling trees and tree limbs. Area rivers reached flood stage and some Coos County roads were closed due to flooding, high winds and downed trees. A chip truck blew over on U.S. Highway 101 just south of Port Orford. The truck sprawled across both lanes of traffic and closed the highway for several hours. ODOT closed Hwy 101, the main coastal highway to high-profile vehicles, such as recreational vehicles, trucks and vans, throughout the windstorm. Even after the storm had passed the weather service issued a high surf warning informing area residents to, “stay out of the surf zone as these large swells will result in large breaking waves in excess of 30 feet along the shoreline.”

What is PCGP’s emergency response plan in the event of a landslide? In the event of a 100 year or 500 year flood? In the event of a tsunami? Such a plan would need to address the entire life of the Project. The Pacific Connector Pipeline currently has no Emergency Response Plan in rural areas. IF THERE IS A PLAN WHERE IS IT?

In addition, alternative pipeline routes that would take the pipeline up through Weyerhaeuser Corp lands, by taking the pipeline route north and/or directly east from Coos Bay over mostly Weyerhaeuser lands to the Williams Grants Pass Lateral, would be far better than the current suggested alternative routes through rural residential and EFU zoned lands South of Coos Bay. (See Exhibit M) Weyerhaeuser is supportive of the Jordan Cove / Pacific Connector project and this alternative would put many residents and farm lands in Coos County out of harms way. The current route does not meet the management objectives for EFU zoned lands in Coos County, since this alternative was not considered.

Forest Impacts

The Pacific Connector Pipeline will be built by the Williams Pipeline Company. Large sections of the Pacific Connector Gas Pipeline cut through forested areas. As we have explained above,

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28 “Rains create all types of hazards” The World Newspaper, Dec 28th 2006

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gas transmission lines are not allowed in Forest Zones. This could be due in part because of the fact that in rural areas thinner pipe is used and that puts the pipe at greater risk of a hazardous fire or accident occurring. Seneca Jones Timber Company explained in recent comments submitted to the Douglas County Planning Dept all the issues and detriment that would occur to their business due to the proposed Pacific Connector gas transmission pipeline going through their timberlands. (See Exhibit P) Forest fires from a pipeline accident along with secondary fires and impacts need to be fully evaluated and considered. Many areas this pipeline will go through are not easily accessible so Emergency Response and complications due to difficult terrain need to all be taken into account before permits of any kind are issued. **Who will monitor that Emergency Response measures needed to protect rural Oregon and Oregonians is sufficient?** Who will pay should a forest fire develop as a result of a mishap with the proposed pipeline? Our Rural fire departments do not have the ability (ie; equipment, manpower) to fight with any significance a Pacific Connector Gas Pipeline fire. Will fire suits be provided for all the residents in the zones of concern that are at risk? The Pacific Connector should have an approved Emergency Response, Hazard Prevention, Mitigation and Compensation plan that is in compliance with the Statewide Planning Goals and has had oversight and review by the public and various local, state and federal public agencies, including our rural Fire Departments and the Oregon Department of Energy. Just stating non-binding promises on paper is not sufficient.

I think it should be obvious that PCGP will not be in compliance with ZLDO 4.8.400.B; OAR 660-006-0025 (5)(b) as the proposed use will significantly increase fire hazard and significantly increase fire suppression costs and significantly increase risks to fire suppression personnel in the area. (See Exhibits Q & R)

**Earthquake and Tsunami**

According to a November 2009 report by the Oregon Department of Transportation (ODOT), hundreds of Oregon bridges remain vulnerable to earthquake damage. ODOT has begun a study to define the magnitude of the problem by evaluating the vulnerability of state highway bridges in western Oregon. ODOT estimates they’ll need $3 billion to prepare Oregon’s bridges to withstand a major earthquake along the coast, far more money than they have.

Without such repairs, a 9.0 temblor would leave U.S. Highway 101 impassable and state highways 38 and 42 in disrepair. There may be no way to access the pipeline block valves if need be.

Oregon Revised Statutes 455.446 to 455.449 prohibits construction of certain facilities and structures in tsunami inundation and earthquake zones. An August 1, 2013, news

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report that was issued by the Oregon State University clearly spells out the fact that the Jordan Cove facility would be located in an area on the Southern Oregon coast that may be the most vulnerable to a Cascadia Subduction mega quake and tsunami event based on recurrence frequency. 31 (See Exhibit S)

According to the report, the evidence 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 because it is not a matter of “if” but “when.”

“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.

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 last known great earthquake in the northwest was in 1700, just over 300 years ago. In 1700, geologists say, a quake with an estimated magnitude of 9.0 struck, touching off waves that hit both Japan and the West Coast. The 1700 Cascadia Subduction Earthquake caused extensive land level changes of subsidence and emergence. Between earthquakes, when the oceanic and continental plates are locked, internal stress stored by the interacting plates slowly deforms the land, pushing it upward and inland. When the locked plates slip, the toe of the subduction zone moves seaward and up, and the uplifted land drops to a lower position.

State estimates are that in low-lying vulnerable areas such as Oregon’s Seaside or Washington’s Aberdeen, tsunami waves could wipe out entire towns.

For the sake of the thousands of people who are at risk in the Coos Bay area we ask the Coos County Commission and Hearing Officer to require such an independent review before considering approval of this permit for these alternative pipeline routes in order to Export natural gas.

31 13-Year Cascadia Study Complete – And Earthquake Risk Looms Large


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The rules and guidelines spelled out in the Coos County Comprehensive Plan 5.11 need to be followed along with State Goal #7(3 – b), local county plans should prohibit the siting of essential facilities, major structures, hazardous facilities and special occupancy structures, as defined in the state building code (ORS 455.447(1) (a)(b)(c) and (e)), in identified hazard areas, where the risk to public safety cannot be mitigated. Natural hazards for purposes of this goal are: floods (coastal and riverine), landslides, earthquakes and related hazards, tsunamis, coastal erosion, and wildfires. Local governments may identify and plan for other natural hazards.

What happens if the Pipeline Company files for Chapter 11? Is the county prepared to fix a larger and even more devastating pipeline mess than what they have had to deal with on the 12-inch line? The pipeline company should be made to put up a bond that would cover any worse case scenario involving the PCGP pipeline, including decommissioning of the pipe.

9. Project Impacts on local Communities

PCGP Resource Report 5 filed with FERC, page 26 states:

"Potential impacts from worker influx could include temporary increases in demands placed on short-term housing and public services. Workers would use local transportation networks, creating a short-term increase in traffic along specific routes."

PCGP Resource Report 5, page 27 states:

Operation of the PCGP Project is expected to require five permanent employees (operations technicians). These employees and their families would reside in the project area.....

.... Construction of the pipeline would involve an average monthly workforce of 1,400 workers with a projected peak of 1,844 workers in the middle of the second construction season. Operation of the proposed pipeline would require five permanent employees.

PCGP Resource Report 5, page 31 states:

"Pipeline construction could temporarily affect the availability and cost of short-term housing in the project area, but no significant or sustained impacts on local housing markets are expected to occur. At the present time, it is not possible to predict the communities in which construction workers would stay while employed on the PCGP Project as lodging locations would be influenced by individual worker preferences for lodging attributes such as quality of accommodations, rental rates, and commuting time to worksites." (Emphasis added)

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It is not possible to predict the communities in which construction workers would stay while employed on the PCGP project because many of these rural areas have NO PLACES FOR WORKERS TO STAY. Decision makers should not be fooled into believing that this project will have no impacts when thousands of workers will be descending on rural sparsely populated areas and communities where impacts will be nothing short of devastating to these areas and the residents living there. Many rural areas along the pipeline route depend on small business, recreation and tourism and could end up with severely crippling economic impacts that would be difficult to recover from as a result of the construction and easements of the PCGP. Coos County would suffer the aftermath of unemployment that follows temporary employment in large-scale construction works. **The 5 permanent employees PCGP will hire in no way justifies the proposed project’s benefits over its destructive impacts in Southern Oregon.**

PCGP Resource Report 5, page 32 states:

"... Construction of the PCGP Project could result in localized temporary impacts on police, fire, and medical services."

PCGP Project impacts on police, fire, and medical services will not be positive. Many rural areas lack sufficient police, fire and medical services as it is. If the pipeline was to have an incident after being built it would be extremely difficult to even get to the fire much less be able to put it out. If the predicted Cascadia subduction earthquake and tsunami was to occur it might well be impossible. **Rural land owners along the pipeline route would be placed at an incredible risk along with our Southern Oregon forest.** Some rural areas have no real fire protection currently. *(See Exhibit Q)* PCGP’s idea of giving rural volunteer fire departments a book with phone numbers is not a sufficient Emergency Response plan nor is it sufficient rural fire protection.

The Pacific Connector Gas Pipeline is projecting an ad valorem tax of approximately $2 to $3 million a year to each of the 4 counties the pipeline would traverse, but this would not compensate for the losses suffered by property owners forced by eminent domain to accommodate the pipeline. Those property owners would not be allowed to build or develop anything in the easement area, thus lowering their property values and decreasing the amount of property tax collected by the counties.

**10. Pipeline Safety and Security**

Onshore natural gas pipelines can leak or rupture, causing significant harm. In May 2005, a natural gas pipeline near Hallsville, Texas exploded, sending a fireball 500 feet in the air.\(^{34}\) In 2007 natural gas pipelines were sabotaged in Mexico. Flames from the fires could be seen for six miles and explosions could be felt up to 12 miles away.\(^{35}\) More recently, a September 9, 2010, blast of a Pacific Gas and Electric Company (PG&E) natural gas pipeline that exploded underneath a suburb south of San Francisco left eight people dead, injured more than 50 and destroyed or damaged more than 100 homes. Internal PG&E memos, which have come to light

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\(^{34}\) Associated Press, "Explosion reported in Northeast Texas", May 13, 2005

\(^{35}\) Associated Press, "Explosions strike Mexico Gas Pipelines", September 10, 2007
in connection with legal proceedings resulting from the San Bruno explosion, reveal that PG&E engineers told company executives years before the blast that major cuts in pipeline safety spending could endanger the public safety. A division of the California Public Utilities Commission recommended on May 6, 2013, that the agency levy a $2.25-billion penalty against Pacific Gas and Electric Company for the deadly 2010 explosion.\textsuperscript{36} Pipeline accidents occur all the time. \textbf{There is just no way to guarantee safety.} On April 23, 2014, a small town in southwest Wyoming was evacuated after an explosion and fire occurred at a natural gas processing facility and major national pipeline hub.\textsuperscript{37}

The Williams Company who will be responsible for building and maintaining the Pacific Connector Gas Pipeline has a terrible safety record. Landowners along the route would be living with this hazard and risk. The proposed Pacific Connector Gas Pipeline (PCGP) is an approximately 232 mile, 36-inch high-pressure gas pipeline that will operate at 1,480 pounds per square inch (PSI) pressure with a delivery capacity of around 1 billion cubic feet a day. A pipeline of this size operating at this amount of pressure would have a hazard area radius of \textbf{approximately 1,000 ft out from the center of the pipe (2,000 feet across)} according to industry C-FER guidelines.\textsuperscript{38} Many homes along the route would be located in the pipeline’s hazard zone including landowners who do not have the pipeline crossing their property directly and who may not even know they are living in a proposed pipeline hazard area. \textit{(See Exhibit R)} The Pacific Connector plans on using thinner pipe in these rural areas throughout Oregon which will place citizens, forest and waterbodies at an even a more increased risk.

\textbf{11. Williams and Pipeline Safety - Not wanted in anyone’s backyard}

- On Monday, March 31, 2014, a blast at the Williams Northwest Pipeline plant in the town of Plymouth, along the Columbia River, also punctured a liquefied natural gas storage tank. Flames shot up into the air at least a hundred feet high. There were worries of a much larger explosion due to the close proximity of the LNG storage tanks. Deputies went door to door throughout the town of Plymouth evacuating about 200 residents \textbf{in a 2-mile radius}.\textsuperscript{39}

- On Thursday, \textbf{June 13, 2013}, an explosion at the Williams Companies Inc. plant in the Ascension Parish town of Geismar La., killed two workers and injured dozens of others. More than 300 people were evacuated from the site. The fire broke out in the morning hours of June 13\textsuperscript{th} at the plant, which the company’s website says puts out about 1.3 billion pounds of ethylene

\textsuperscript{36} Los Angeles Times, \textit{“Record $2.25-billion fine recommended in San Bruno explosion”} May 6, 2013, by Kate Mather: \url{http://articles.latimes.com/2013/may/06/local/la-me-In-san-bruno-explosion-20130506}


\textsuperscript{38a} \textit{A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines} – Topical Report Prepared by Mark J. Stephens – C-FER Technologies; For the Gas Research Institute – Contract $174; October 2000; GRI-00/0189; \url{http://www.crrs.ucsb.edu/courses/ChE124%202011/R7-Fire%20hazard%20for%20gas%20pipelines.pdf}


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and 90 million pounds of polymer grade propylene a year. The cause of the blast wasn’t immediately known, but the FBI had ruled out terrorism.40

* On May 30, 2013, according to the Natural Gas Watch, Williams (Transco), the natural gas company proposing to build a massive, new natural gas pipeline through wetlands and recreation areas in coastal New York City, asked federal regulators for an exemption to existing wildlife protection laws to “harass” a range of marine life during the pipeline’s construction.41

* On May 14, 2013, an explosion touched off a fire at a natural gas compressor facility owned by the Williams Co in New Milford, Pennsylvania, sending flames shooting high into the night sky. No one was injured in the explosion and subsequent fire. Williams has a lengthy history of pipeline safety violations according to documents obtained by Natural Gas Watch and this incident represents the second explosion at a Williams-owned facility in Pennsylvania’s Susquehanna County in 14 months.42

* On March 23, 2013, a major natural gas gathering pipeline owned and operated by the Williams Companies ruptured in West Virginia, according to media reports, the accident occurred just days after the company rejected safety recommendations from the U.S. Army Corps of Engineers in connection with controversial new natural gas pipeline of similar diameter proposed for New York City. Natural gas gathering pipelines move methane from the wells in the gas fields to processing facilities, where it is then moved downstream via natural gas transmission lines. Natural gas gathering lines operate essentially unregulated by federal agencies.43

* On April 9, 2012, the Natural Gas Watch reported the following about the Williams Co. lengthy record of pipeline safety violations and about a leak that had occurred in a Williams’ natural gas pipeline:

> "The Williams Transco natural gas pipeline, an 11,000 mile pipeline that runs from the Gulf Coast to markets on the eastern seaboard, sprung a leak in Bergen County, New Jersey, according to a recent media report (dated April 4, 2012). The leak in a 36-inch-diameter section of the pipeline represents the second incident calling in to question the pipeline’s integrity in less than a month. A natural gas compressor station owned and operated by Williams, which pumps pressurized natural gas obtained from hydraulic fracturing wells in Pennsylvania through the Transco pipeline, exploded last week. The Williams Co., which is already operating under a federal Corrective Action Order in connection with a massive natural gas pipeline explosion in Alabama last year, has a

40 “2nd victim dies after blast at La. chemical plant” (AP) By Littice Bacon-Blood—Jun 14, 2013: http://bigstory.ap.org/article/2nd-victim-dies-after-blast-la-chemical-plant


42 This Week In Natural Gas Leaks and Explosions — May 27, 2013: http://www.naturalgaswatch.org/?p=2046


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lengthy record of pipeline safety violations, according to documents obtained by NaturalGasWatch.org." 44 (Emphasis added)

* On March 29, 2012, Williams Partners L.P., was the owner/operator of the natural gas compressor station that exploded in northeastern Pennsylvania. Williams has a history of serious natural gas pipeline safety violations. The federal Pipeline and Hazardous Material Safety Administration (PHMSA) issued a Corrective Action Order to Williams Partners on Dec. 6, 2011, in connection with a massive natural gas explosion that occurred in Marengo County, Alabama, on Dec. 3, 2011, on the company’s Transco pipeline. The facility that exploded in Pennsylvania fed pressurized natural gas into the Transco pipeline.45

* On March 5, 2012, Williams Partners subsidiary, the Transcontinental Gas Pipeline Co. LLC, was fined $50,000 by PHMSA for failure to follow its own, internal policies related to controlling external corrosion in natural gas pipelines running through the New York City borough of Staten Island.45

* On June 24, 2011, Williams Partners subsidiary, the Transcontinental Gas Pipeline Co. LLC, was fined $23,800 by PHMSA for failure to conduct annual inspections of natural gas compressor stations in Texas and Louisiana.45

* On Sept 14th, 2008, a 36-inch Williams’ pipeline exploded in Appomattox County, VA. The fireball demolished two houses and blistered the siding on homes 400 yards away. Flames shot in the air in excess of 300 feet and five people were injured in the blast. The aftermath of the explosion left a 15-foot crater in the ground.46 Twenty-three families were evacuated.

The Appomattox rupture was caused by corrosion of the 53-year-old pipeline, which had been inspected three months earlier by a "smart pig," a computerized scanning device that travels through a pipeline searching for dings, dents or corrosion, but had not yet been repaired. Transco’s owner, the Williams Cos., paid the U.S. Transportation Department a $952,000 fine, replaced 2,500 feet of the pipeline, "smart pigged" all of its pipelines in Virginia and performed pressurized water tests to validate the repairs.47

Law360 out of New York reported on August 18, 2009:

“The second largest proposed penalty this year has been a $952,000 fine against Williams Gas Pipeline-Transco for a spill in September near Appomattox, Va. Five

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44 This Week In Natural Gas Leaks and Explosions – April 9, 2012: http://www.naturalgaswatch.org/?p=1332 and
46 “Some Appomattox residents return home after explosion” September 14, 2008: www.newsadvance.com
46 “Nearby pipelines still working after Appomattox explosion”, September 16, 2008: www.newsadvance.com

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people were sent to the hospital, and several homes were damaged or destroyed from an ensuing fire."

The Pipeline Safety Trust from 1986 through 2008 showed 11 non-public injuries and $43 million in damages along the entire length of that William’s Transco line. Most of the failures were caused by material defects, corrosion or outside forces.

- On August 10, 2007, it was reported that 27 horses were found dead near a gas leak of the Northwest Pipeline, which is one of the Williams Companies pipelines. Company personnel discovered the dead horses on the ranch while conducting routine maintenance checks on the 24-inch pipeline that runs underground. The dead horses were found 300 to 400 yards from where the leak was suspected.

- On November 11, 2006, a report indicated that a 300- to 400-foot section of the Williams Northwest natural gas pipeline had dropped into the Toutle River near Castle Rock when the river bank gave way. The exposed pipe did not rupture but Cowlitz County emergency crews established a 300-foot perimeter around the exposed pipe due to the potential of the pipeline rupturing which would have caused a significant explosion and fire. The pipeline is part of a 4,000-mile-long pipeline that carries fuel to Washington, Oregon, Idaho, Wyoming, Utah and Colorado.

- A report in 2003 gives more examples of the jaded history of the Williams Co and their pipeline safety record.

"...In June 1999, a pipeline explosion in a park in Bellingham killed three young people, and triggered an intensive investigation into pipeline safety and operating regulations. Following that, the Washington Utilities and Transportation Commission launched an investigation into the pipeline inspection and testing record of the companies operating in Washington State. Williams came out nearly at the bottom of the list, having inspected only 17% of its system and tested a mere 11%.

...Dec 13, 2003. For the second time in six month, Williams' Northwest Pipeline (which runs from Sumas to Mexico) ruptured, releasing gas for three hours before it could be stopped.

The federal government has ordered a natural-gas supplier to shut down one of its two pipelines that run through Whatcom County, saying continued operation of the line would be hazardous to people, property and the environment.

49 "27 horses found dead near gas leak" By Sven Berg for the Times-News, Posted Friday, August 10, 2007: http://magicvalley.com/news/local/horses-found-dead-near-gas-leak/article_b32b16a5-c560-5ace-a0ae-00ed345b357f.html

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The Office of Pipeline Safety on Thursday ordered Northwest Pipeline, a division of the Oklahoma-based Williams Cos. Inc. natural-gas drilling and transportation company, to idle the 26-inch line. The company must demonstrate the 47-year-old line is safe or replace certain segments before it begins operating the line again.\(^{2}\)

\textbf{May 1, 2003.} Williams' same Northwest Pipeline ruptured dramatically

The company's natural-gas artery burst with a roar on May 1 near Lake Tapps, sparking evacuations at a school, a supermarket and about 40 homes. Inspectors later identified the cause as "stress corrosion cracking."

After repairs were made to the line near Lake Tapps in May, inspectors ordered the company to reduce the line's gas pressure 20 percent to 632 pounds per square inch.\(^{3}\)

The Washington Utilities and Transportation Commission documents a series of earlier incidents on Williams Northwest Pipeline (4):

\textbf{Feb 26, 1999.} near Stevenson, the 22 inch pipeline failed.

\textbf{Jan 3, 1998.} a weld defect located on a fitting caused the 22 inch pipeline to rupture at a location east of Pendleton, Oregon

\textbf{Jun 28, 1997.} human error caused a valve to leak near Woodinville

\textbf{Feb 9, 1997.} near Kalama , the 26 inch pipeline failed.

\textbf{Feb 8, 1997.} near Everson, the 26 inch pipeline failed

The line has a history of problems that includes a February 1997 explosion just east of Everson. That incident didn't result in injuries, but the explosion shattered windows and damaged homes in the area. Flames could be seen for miles.\(^{2}\)

\textbf{Mar 6, 1995.} near Castle Rock, the 26 inch pipeline failed.

\textbf{1994.} A lateral line on the same system near Oregon City, Ore., failed 22 times during tests

\textbf{1992.} Stress corrosion cracking caused the Williams line to fail during tests in 1992.\(^{52}\)

\textbf{Conclusion}

The amount of gas that would be flowing through the Pacific Connector for export is more than the entire state of Oregon uses in a day. The pipeline will require a 95 foot clear-cut corridor that will permanently scar and alter hundreds of miles of Oregon lands, much of this is private land and timberland that will be permanently stripped bare. The JCEP and PCGP project would place

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\(^{52}\) Williams and Pipeline Safety - Not wanted in anyone's backyard - December 21, 2003; Arthur Caldicott, Cobble Hill; GSX Concerned Citizens Coalition: \textcolor{blue}{http://www.swalk.com/WilliamsNotWantedInAnyonesBackyard.html}

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thousands of Oregon citizens unnecessarily in a hazard zone and will place private land owners at risk of losing rights to their private property by Eminent Domain. Natural gas pipelines that are already operating in the same vicinity as the proposed PCGP are currently only operating at a fraction of their proposed capacity. It makes no sense whatsoever to add yet another natural gas pipeline in these same general areas.

FERC vacated their December 17, 2009, Order authorizing the Jordan Cove Energy “LNG Import” Project and the related Pacific Connector Gas Pipeline and I have attached the FERC news release noting that Order Vacation. (See Exhibit C) The once approved Jordan Cove Import terminal that the original Coos County Pacific Connector Gas Pipeline ruling was based on is no longer relevant and the Pacific Connector has no Certification of Approval currently under the Natural Gas Act. A pipeline used for importing gas does not have the same “public need” and environmental footprint as a pipeline that is used for exporting fracked gas for the benefit and profits of the foreign controlled Jordan Cove Energy Project. The gas Jordan Cove would be obtaining for export would be coming from different North American supply basins, and in this case from the controversial use of hydraulic fracturing. The gas flowing in the pipeline would thus have different levels of the various gasses and contaminants that are the result of the Shale basin hydraulic fracturing process. Those processes in and of themselves are not in the public interest as a new report entitled, “Fracking by the Numbers,”63 confirms. See Exhibit T for an executive summary of this report.

The proposed Jordan Cove LNG Export Project would be building a gas processing facility that would clean out all these gas impurities coming from the shale hydraulic fracturing processed gas before they would be able to liquefy the gas for export. The proposed gas processing and liquefaction facility was not needed or a part of the prior “LNG Import” proposal as the gas would have been already liquefied in processes that would have occurred at a supplying Export terminal located overseas. Some of these additional impurities that will be coming in the pipeline can be very hard and corrosive on pipes and as I have already clearly shown above, Williams does a very poor job of maintain their pipelines. These additional extra contaminants in the pipeline would mean a higher risk of failure to every area the Pacific Connector Gas Pipeline crosses. It also puts a lot more contaminants into the air in the vicinity of the proposed Jordan Cove LNG Export facility and at the compressor and meter stations along the pipeline route. Some of these particulate contaminants would be carried by the wind into the nearby waterbodies and across the bay where thousands of citizens live, work and recreate.

The Pacific Connector Gas Pipeline has not provided evidence or made a finding that the export of natural gas is in the public interest. They have failed to demonstrate that the public need for the project “outweighs” the detriment to the use of the shorelands and waterbodies that will be negatively impacted by the proposed project’s alternative route as the CBEMP requires. They have failed to analyze ALL potential alternative pipeline route possibilities. There has been no findings of Need and/or Consistency as required prior to the County’s approval of the permit. The project cannot be considered a public utility

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since it provides no service to the public. Natural Gas Transmission lines are not allowed in Forest zones. The application should have been denied.

In addition, there is no public benefit in increasing domestic natural gas prices; There is no public benefit in a 95 + foot clear-cut through our forestlands and waterbodies; There is no public benefit in the use of eminent domain for the profit of a “private” foreign energy company; There is no public benefit in citizens living in the extreme hazard zones of the proposed PCGP and the JCEP LNG Export terminal; There is no public benefit to all the Bay closures that will occur due to the safety and security zones of transiting LNG tanker ships; There is no public benefit to the loss of fish, marine and wildlife habitat due to the destructive nature of pipeline construction projected to impact 400 waterbodies in Southern Oregon; There is no public benefit to the negative impacts of this project on tourism, recreation, fishing, farming, timber harvesting, ranching, crabbing, clamming, oyster harvesting, property values and use, real-estate, local air travel, transportation, noise, air and water pollution; There is no public benefit in the loss of thousands of manufacturing jobs in America and also local jobs in timber, ranching, farming, fishing and recreation; There is no public benefit in the detrimental impacts from hydraulic fracturing that will be used in order to obtain the gas supply. The project’s proposed transmission export pipeline violates Condition of Approval #25, it can no longer be considered a public utility and is not allowed in forest zones.

Exporting LNG out of Coos Bay would be for the sole benefit and “interest” of the foreign owned and controlled Jordan Cove Energy Project whose own country understands fully when LNG projects are contrary to the Public Interest and Public Trust. (See Exhibit U) The Pacific Connector has not proven their case in order to justify this application or these alternative routes. They have not provided enough information for their application to be considered complete. There are also multiple pipeline route alternatives that would be far less environmentally impacting than these they are considering. The HBCU-13-06 application is not complete, it is not in the public interest nor is it allowed as proposed. It should be rejected.

Sincerely,

Jody McCaffree

Jody McCaffree

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Exhibit A: Conditions of Approval of Coos County Final Decision and Order 10-08-045PL and 12-03-018PL for the Pacific Connector Gas Pipeline.

Exhibit B: Coversheets of Pacific Connector 2010 original Coos County land use application and the current HBCU-13-06 application.


Exhibit D: The World – “Study: Coho still at risk of extinction”; May 26, 2010; By Jeff Barnard -AP Environmental Writer; The World


Exhibit F: Jordan Cove Application to the National Energy Board in Canada “Appendix B” showing their intended export volumes at the Jordan Cove facility.


Exhibit I: Photos of Impacts from Coos County 12-inch Pipeline Construction – 2003/2004


Exhibit K: Photos of Impacts of the Natural Gas pipeline for Shells’ Sakhalin II LNG Export project in Russia

Exhibit M: Suggested Coos Bay Pipeline Route Alternatives for the Pacific Connector Pipeline Project


Exhibit P: October 9, 2013 letter from Seneca Jones Timber Company to Douglas County Planning Department concerning impacts to their forest lands from the proposed Pacific Connector Gas Pipeline Project.


Exhibit U: Letter from Canadian House of Commons Concerning their opposition to the proposed Passamaquoddy Bay LNG terminal.
Exhibit A
BOARD OF COMMISSIONERS  
COUNTY OF COOS  
STATE OF OREGON  

IN THE MATTER OF CONSOLIDATED  
CONDITIONAL USE APPLICATIONS HBCU-10-01 SUBMITTED BY PACIFIC CONNECTOR  
GAS PIPELINE  
FINAL DECISION AND ORDER NO. 10-08-045PL  

WHEREAS, on Pacific Connector Gas Pipeline filed consolidated permit applications to develop 49.72 miles of gas pipeline and associated facilities on property described in Exhibit "B" of this Order; and  

WHEREAS, on March 2, 2010, pursuant to its authority under CCZLOD §5.0.600, the Board of Commissioners (Board) voted to: (1) call up the applications; and (2) appoint a Hearings Officer to conduct the initial public hearing for the applications and then make a recommendation to the Board. On April 5, 2010, the Board appointed Andrew H. Stamp to serve as the Hearings Officer.  

WHEREAS, on May 20, 2010, Hearings Officer Stamp conducted a public hearing on this matter and at the conclusion of the hearing the record was held open for 21 days to accept additional written evidence to rebut evidence presented at the hearing, followed by a 7-day period for accepting surrebuttal testimony, followed by a 7-day period for the applicant to submit final written argument.  

WHEREAS, on July 16, 2010, Hearings Officer Stamp issued his Analysis, Conclusions and Recommendations to the Board to approve the applications subject to the imposition of conditions.  

Order 10-08-045PL
WHEREAS, on August 3, 2010, at 1:30 p.m., the Board met to deliberate on the matter and made a tentative decision to accept the Hearings Officer's recommended approval subject to amended findings and conditions:

NOW, THEREFORE, the Board adopts the Findings of Fact; Conclusions of Law and Final Decision attached hereto labeled Exhibit "A" and incorporated into this order herein.

ADOPTED this 8th day of September 2010.

BOARD OF COMMISSIONERS

[Signatures]

COMMISSIONER

[Signatures]

COMMISSIONER

[Signatures]

COMMISSIONER

ATTEST:

[Signatures]

Recording Secretary

APPROVED AS TO FORM:

[Signatures]

Office of Legal Counsel

Order 10-08-045PL
"Prior to issuance of a zoning compliance letter for the project, the applicant shall file a bond, surety, irrevocable letter of credit, cash or other security deposit agreement in the amount of 120% of the estimated cost of necessary improvements to bring County road facilities impacted by pipeline construction back to current or better condition. After five (5) years, the security shall either be forfeited to the County if the applicant does not complete required improvements or be refunded to the applicant if applicant has completed required improvements or there are no improvements to complete."

The Board finds that this modified condition addresses this issue.

III. CONCLUSION

For the above stated reasons, and after consideration of the applicable law and all argument and evidence in the record, the Board finds that the applicant has met its burden of proof to demonstrate that the applications satisfy all applicable approval standards and criteria, or that those standards or criteria can be satisfied through the imposition of conditions of approval. Accordingly, the Board hereby approves the application, subject to the following conditions of approval, which are authorized by Section 5.2.800 of the CCZLDO:

A. Staff Proposed Conditions Of Approval

1. Intentionally deleted.

2. To minimize impacts to wells and groundwater, the applicant must comply with the Groundwater Supply Monitoring and Mitigation Plan approved by the federal Office of Energy Projects within FERC, including without limitation, provisions requiring: (a) subject to landowner consent, testing and sampling groundwater supply wells for both yield and water quality; and (b) as needed, implementing site-specific measures to mitigate adverse impacts on the yield or quality of groundwater supply.

3. The facility will be designed, constructed, operated and maintained in accordance with U. S. Department of Transportation requirements.

4. The pipeline will be rerouted, where feasible, in order to avoid impacts to the property identified on Drawing No. 3430.33-X-9007. (MP 13.8 to MP 14.4). If requested, the applicant shall work with affected property owners within the pipeline's alignment to make "minor field realignments per landowner needs and requirements which do not affect other landowners or sensitive environmental areas such as wetlands" pursuant to FERC Order Condition #6 in order to avoid or minimize impacts to structures or the owner's use of the property."

5. The proceedings for the condemnation of such lands shall be the same as that provided in ORS chapter 35, provided that any award shall include, but shall not be limited to, damages
for destruction of forest growth, premature cutting of timber, diminution in value to remaining timber caused by increased harvesting costs, and loss of product value due to blow-downs. Whatever incremental costs and value losses to timber lands can be identified and demonstrated to result from the granting of the pipeline easement will be reflected in the company’s appraisal of damages payable to the owner. Therefore, the landowner should not experience any uncompensated logging or access costs. [See ORS 772.210(4) and Report entitled Forest Practices and Economic Issues related to Proposed Pacific Connector Gas Pipeline, by Dallas C. Hemphill, ACF, CF, PE., dated June 17, 2010, at p. 5.]

6. Pacific Connector shall not begin construction and/or use its proposed facilities, including related ancillary areas for staging, storage, temporary work areas, and new or to-be-improved access roads until:

   Pacific Connector files with the Secretary remaining cultural resource survey reports and requested revisions, necessary site evaluation reports, and required avoidance/treatment plans;

   Pacific Connector file with the Secretary comments on the reports and plans from [SHPO], appropriate land management agencies, and interested Indian tribes;
   The [ACHP] has been afforded an opportunity to comment, and a Memorandum of Agreement has been executed; and

   The Commission staff reviews and the Director of OEP approves the cultural resource reports and plans, and notifies Jordan Cove and Pacific Connector in writing that treatment plans/mitigation measures (including archaeological data recovery) may be implemented and/or construction may proceed.”

1. **Pre-Construction**

7. Intentionally deleted.

8. To protect residences and structures, evidence of compliance with FERC’s Certificate Order, Condition #43 must be provided prior to issuance of zoning clearance.

9. Coos River Highway is part of the State Highway system, under the authority and control of the Oregon Transportation Commission. Evidence that the applicant has the appropriate state authorization to cross Coos River Highway shall be provided to the Planning Department prior to zoning clearance authorizing construction activity.

10. Temporary closure of any county facility shall be coordinated with the County Roadmaster. Evidence of Roadmaster approval and coordination of any detour(s) shall be provided to the County Planning Department.

11. Each county facility crossing will require a utility permit from the County Road Department. Construction plan showing pullouts and permits for work within the right-of-way for monitoring sites will also require Roadmaster approval.

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12. An analysis of construction impacts shall be provided to the County Roadmaster, which will include a pavement analysis. The analysis must identify the current condition of County facilities and include a determination of the project’s impact to the system and the steps that will be necessary to bring back to current or better condition. Prior to issuance of a zoning compliance letter for the project, the applicant shall file a bond, surety, irrevocable letter of credit, cash or other security deposit agreement in the amount of 120% of the estimated cost of necessary improvements to bring County road facilities impacted by pipeline construction back to current or better condition. After five (5) years, the security shall either be forfeited to the County if the applicant does not complete required improvements or be refunded to the applicant if applicant has completed required improvements or there are no improvements to complete.

13. Should any part of the project involve permanent structural streambank stabilization (i.e. riprap), the applicant must contact the Planning Department for a determination of the appropriate review, if any.

14. All necessary federal, state and local permits must be obtained prior to commencement of construction, including any required NPDES 1200-c permits. Prior to the commencement of construction activities, Pacific Connector shall provide the County with a copy of the “Notice to Proceed” issued by FERC. [See Letter from Mark Whitlow, dated June 24, 2010, at p. 52.]

15. Floodplain certification is required for “other development” as provided in CCZLDO 4.6.230 occurring in a FEMA flood hazard area. The applicant must coordinate with the County Planning Department.

16. Intentionally deleted.

17. The pipeline operator shall maintain an emergency response plan in compliance with 49 CFR 192.615.

2. Construction

18. Riparian vegetation removal shall be the minimum necessary for construction and maintenance of the pipeline, and shall comply with all FERC requirements for wetland and waterbody protection and mitigation both during and after construction. The applicant shall restore riparian vegetation 25 feet from the streambanks on either side of waterbodies on private lands where riparian vegetation existed prior to construction, consistent with the applicant’s ECRP.

19. Prior to construction, the applicant shall be required to undertake the sampling and analysis set forth in the Sediment Analysis Protocol (SAP) in order to ensure that there will be no adverse water quality impacts from digging the trench for the pipeline across Haynes Inlet.

3. Post-Construction

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20. Evidence shall be provided to demonstrate that all temporary construction and staging areas have been abandoned and that those areas that were forested prior to construction have been replanted, consistent with the requirements of this approval, the FERC Order, and the applicant's ECRP.

21. Evidence shall be provided to demonstrate that all temporary construction and staging areas have been abandoned and that those areas have been replanted, re-vegetated and restored to their pre-construction agricultural use, consistent with the requirements of this approval, the FERC Order, and the applicant's ECRP.

22. In order to minimize cost to forestry operations, the applicant agrees to accept requests from persons conducting commercial logging operations seeking permission to cross the pipeline at locations not pre-determined to be “hard crossing” locations. Permission shall be granted for a reasonable number of requests unless the proposed crossing locations cannot be accommodated due to technical or engineering feasibility-related reasons. Where feasible, the pipeline operator will design for off-highway loading at crossings, in order to permit the haulage of heavy equipment. If technically feasible, persons conducting commercial logging operations shall, upon written request, be allowed to access small isolated stands of timber by swinging logs over the pipeline with a shovel parked stationary over the pipeline, subject to the requirement that, if determined by the applicant to be necessary, the use of a mat or pad is used to protect the pipe. The pipeline operator will determine the need for additional fill or a structure at each proposed hard, and shall either install the crossing at its expense or reimburse the timber operator/landowner for the actual reasonable cost of installing the crossing. [See Report entitled Forest Practices and Economic Issues related to Proposed Pacific Connector Gas Pipeline, by Dallas C. Hemphill, ACF, CF, PE., dated June 17, 2010, at p. 1.]

23. The pipeline operator will conduct routine vegetation maintenance clearing on the 30-foot strip every 3-5 years. [See Report entitled Forest Practices and Economic Issues related to Proposed Pacific Connector Gas Pipeline, by Dallas C. Hemphill, ACF, CF, PE., dated June 17, 2010, at p. 3.]

24. In order to discourage ATV/OHV use of the pipeline corridor, the applicant shall work with landowners on a case-by-case basis to reduce ATV/OHV impacts via the use of dirt and rock berms, log barriers, fences, signs, and locked gates, and similar means. Such barriers placed in key locations (i.e. in locations where access to the pipeline would otherwise be convenient for the public) would be an effective means to deter ATV/OHV use.

B. Applicant's Proposed Conditions Of Approval

1. Environmental

1. Intentionally deleted.

2. Intentionally deleted.
3. Intentionally deleted.

4. The applicant shall submit a final version of the Noxious Weed Plan to the county prior to construction in order to address concerns raised regarding invasive species in farm and forest lands.

5. The applicant shall employ weed control and monitoring methods consistent with the Weed Control and Monitoring sections of the ECRP. The applicant shall not use aerial herbicide applications.

6. Fill and removal activities in Coos Bay shall be conducted between October 1 and February 15, unless otherwise modified or agreed to by the Oregon Department of Fish and Wildlife.

7. The authorized work in Haynes Inlet shall be conducted in compliance with the required U.S. Army Corps of Engineers Section 404 Permit and OR DEQ’s 401 Water Quality Certification and 402 NPDES permits, which will mandate turbidity standards, monitoring requirements, and reporting procedures.

8. Petroleum products, chemicals, fresh cement, sandblasted material and chipped paint or other deleterious waste materials shall not be allowed to enter waters of the state. No wood treated with leachable preservatives shall be placed in the waterway. Machinery refueling is to occur off-site or in a confined designated area to prevent spillage into waters of the state. Project-related spills into water of the state or onto land with a potential to enter waters of the state shall be reported to the Oregon Emergency Response System at 800-452-0311.

9. For dredging activity conducted by clamshell bucket, activity shall be positioned from a floating crane or top-of-bank position. In the closed position, the bucket shall be sealed so as to minimize sediment re-suspension.

10. If any archaeological resources and/or artifacts are uncovered during excavation, all construction activity shall immediately cease. The State Historic Preservation Office shall be contacted (phone: 503-986-0674).

11. When listed species are present, the permit holder must comply with the federal Endangered Species Act. If previously unknown listed species are encountered during the project, the permit holder shall contact the appropriate agency as soon as possible.

12. The permittee shall immediately report any fish that are observed to be entrained by operations in Coos Bay to the OR Department of Fish and Wildlife (ODFW) at (541) 888-5515.

13. Pacific Connector will comply with all federal and state requirements during the fire season that mandate the amount of water required on the right-of-way for adequate fire suppression during timber removal and construction activities.
2. Safety


15. The pipeline operator shall conduct public education in compliance with 49 CFR 192.616 to enable customers, the public, appropriate government organizations, and persons engaged in excavation related activities to recognize a gas pipeline emergency for the purpose of reporting it to the gas pipeline operator. Such public education shall include a "call before you dig" component.

16. The pipeline operator shall comply with any and all other applicable regulations pertaining to natural gas pipeline safety, regardless of whether such regulations are specifically listed in these conditions.

17. The pipeline operator shall provide annual training opportunities to emergency response personnel, including fire personnel, associated with local fire departments and districts that may be involved in an emergency response to an incident on the Pacific Connector pipeline. The pipeline operator shall ensure that any public roads, bridges, private roads and driveways constructed in conjunction with the project provide adequate access for fire fighting equipment to access the pipeline and its ancillary facilities.

18. The pipeline operator shall respond to inquiries from the public regarding the location of the pipeline (i.e., so called "locate requests").

19. At least six (6) months' prior to delivery of any gas to the Jordan Cove Energy Project LNG import terminal, the applicant shall: (1) submit a project-specific Public Safety Response Manual to the County, and (2) in order to comply with federal safety regulations, coordinate with local emergency response groups. As detailed in Section 4.12.10 of the FEIS, Pacific Connector will meet with local responders, including fire departments, to review plans and communicate specifics about the pipeline. If requested, Pacific Connector will also participate in any emergency simulation exercises and provide feedback to the emergency responders.

3. Landowner

20. (a) This approval shall not become effective as to any affected property until the Applicant has acquired ownership of an easement or other interest in the property necessary for construction of the pipeline, and obtains either: (i) the signature of all owners of the property consenting to the application, or (ii) an order of a court in condemnation of the property interest required for the pipeline that operates to obviate the need for consent of owners of property other than the applicant. In the alternative, should this condition 20(a) be deemed insufficient on appeal to satisfy applicable code requirements, the applicant shall instead be subject to the alternative condition 20(b) immediately below.
20. (b) In the alternative to the above condition 20(a), in the event that condition 20(a) is deemed invalid on appeal, this approval shall not become effective as to any affected property until the applicant has acquired an ownership interest in the property and the signatures of all owners of the property consenting to the land use application for development of the pipeline, unless the signature requirement of CCZLDO 5.0.150 is preempted or otherwise invalid under another provision of law including without limitation federal statutes, regulations, or the United States Constitution.

21. The permanent pipeline right-of-way shall be no wider than 50 feet.

22. Intentionally deleted.

23. The applicant shall be responsible for restoring, as nearly as possible, to its former condition any agricultural land and associated improvements that are damaged or otherwise disturbed by the siting, maintenance, repair or reconstruction of the utility facility.

4. Historical, Cultural and Archaeological

24. At least 90 days prior to issuance of a zoning compliance letter under CCZLDO Section 3.1.200, the County Planning Department shall make initial contact with the affected Tribe(s) regarding the determination of whether any archaeological sites exist within the area proposed for development, consistent with the provisions of CCZLDO Section 3.2.700. Once the Tribe(s) have commented or failed to timely comment under the provisions of CCZLDO Section 3.2.700, the County shall take one of the following actions: (1) if no adverse impacts to cultural, historical or archaeological resources have been identified, the County may approve and issue the requested zoning compliance letter and related development proposal; (2) if the Tribe(s) and the applicant reach agreement regarding the measures needed to protect the identified resources, the development can be approved with 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 County Board of 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 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. For purposes of this condition, the public hearing shall be subject to the provisions of Section 5.8.200 of the CCZLDO with the Board of Commissioners serving as the Hearings Body.

5. Miscellaneous

25. The conditional use permits approved by this decision shall not be used for the export of liquefied natural gas.

Approved this 8th day of September, 2010.

Final Decision of Coos County Board of Commissioners
BEFORE THE BOARD OF COMMISSIONERS
OF THE COUNTY OF COOS, OREGON

In the Matter of LUBA Remand of Pacific
Connector Gas Pipeline, L.P. REM-10-01
HBCU-10-01

) )

FINAL DECISION AND ORDER
NO. 12-03-018PL

Whereas on September 8, 2010, the Coos County Board of Commissioners adopted Final
Decision and Order No. 10-08-045PL, approving Pacific Connector’s application in county file
#HBCU-10-01 to develop 49.72 miles of interstate natural gas pipeline and associated facilities
connecting the Jordan Cove LNG terminal to the pipeline segment in adjacent Douglas County.

Whereas the opponents appealed the County’s decision to the Land Use Board of
Appeals (“LUBA”). On March 29, 2010, LUBA remanded the decision for further consideration
of two issues: (1) a procedural issue related to property owner consents under LDO 5.0.150; and
(2) potential impacts to Olympia oysters in Haynes Inlet under the two applicable CBEMP
Management Objectives.

Whereas Pacific Connector submitted a written request for a remand hearing on May 12,
2011. On June 7, 2011, the Board concluded that no additional evidence was required to address
the issue regarding property owner consents. However, the Board determined that the Olympia
oyster issue could not be fully resolved without an evidentiary hearing, and appointed a hearings
officer to hold a de novo evidentiary hearing on remand, with the scope of the hearing limited to
the second issue identified by LUBA regarding potential impacts on Olympia oysters.

Whereas Hearings Officer Andrew Stamp conducted a public hearing on September 21,
2011, and held the record open for additional evidence and argument until December 15, 2011.
The hearings officer issued his decision on January 30, 2010, recommending that the Board
approve the application on remand with conditions, and rejecting the opponents’ arguments that
the applicable CBEMP Management Objectives were not satisfied.

Whereas the County Planning Director provided the Board with a staff report dated
February 15, 2012, which provides two substantive recommendations: (1) revised language for
Condition of Approval #20 regarding property owner consents under LDO 5.0.150, as required
by LUBA’s opinion under Assignment of Error Two; and (2) proposed findings addressing a
procedural issue identified by the hearings officer in his decision regarding authorization of
witnesses to testify under LDO 5.7.300(4).

Whereas on March 13, 2012, the Board met to review the hearings officer’s
recommendation “on the record,” without accepting additional evidence or argument from the
parties, and to deliberate regarding: (1) whether to accept, reject, or modify the hearings
officer’s recommendation, and (2) whether to accept, reject, or modify the revised findings and
conditions provided by staff.
WHEREAS, at the conclusion of the March 13, 2012 meeting the Board reached a
decision to adopt the hearings officer’s recommendation, with the modifications provided in the
February 15, 2012 staff report regarding compliance with LDO 5.7.300(4). The Board finds that
the applicant has addressed the remand issues and that all applicable approval criteria are met
with the suggested new conditions of approval. The Board finds that staff’s suggested revisions
to Condition 20 address Assignment of Error Two. The Board hereby adopts the hearings
officer’s recommendation, as modified and attached as Attachment “A,” as its own approval
findings, along with the attached conditions of approval. All other findings and conditions of
approval in Order No. 10-08-045PL adopted September 8, 2010, remain in full force and effect,
except as modified herein.

ADOPTED this 13th day of March, 2012.

BOARD OF COMMISSIONERS

[Signatures]

COMMISSIONER

[Signatures]

COMMISSIONER

[Signatures]

COMMISSIONER

ATTEST:

[Signature]

Recording Secretary

APPROVED AS TO FORM:

[Signature]

Office of County Counsel

Final Decision & Order 12-03-018PL

- 2 -
FINDINGS OF FACT, CONCLUSIONS OF LAW, AND FINAL DECISION
OF THE COOS COUNTY BOARD OF COMMISSIONERS
ON REMAND FROM LUBA

PACIFIC CONNECTOR GAS PIPELINE PROPOSAL
COOS COUNTY, OREGON

FILE NO. REM-10-01
PCGP REMAND – CONDITIONS OF APPROVAL

Property Owner Signatures amended Condition 20

No. 20. This approval shall not become effective as to any affected property in Coos County until the Applicant has acquired ownership of an easement or other interest in all properties necessary for construction of the pipeline, and/or obtains the signatures of all owners of the affected property consenting to the application for development of the pipeline in Coos County. Prior to this decision becoming effective, the County shall provide notice and opportunity for a hearing regarding compliance with this condition of approval and the property owner signature requirement. County staff shall make an Administrative Decision addressing compliance with this condition of approval and LDO 5.0.150, as applied in this decision, for all properties where the pipeline will be located. The County shall provide notice of the Administrative Decision as provided in LDO 5.0.900(B) and shall also provide such notice to all persons requesting notice. For purposes of this condition, the public hearing shall be subject to the procedures of LDO 5.8.200 with the Board of Commissioners serving as the Hearings Body

CONDITIONS ON REMAND

Oyster Mitigation Plan

No 1. The applicant shall comply with the terms and conditions of the applicant's proposed Olympia oyster mitigation plan prepared by Bob Ellis of Ellis Ecological Services, Inc. dated October 7, 2011 (the "Mitigation Plan"), as supplemented and modified by the following mitigation measures:

a) The applicant's compliance with the Mitigation Plan will be administered through permits pursuant to the Clean Water Act Section 404 by the Army Corps of Engineers (Corps), pursuant to Section 401 of the Clean Water Act by the Oregon Department of Environmental Quality (DEQ), and pursuant to Oregon's Removal-Fill Law (ORS 196.795-990) by the Oregon Department of State Lands (DSL). These permitting agencies will be provided with copies of the Mitigation Plan, as modified by this condition, and approval of the permits issued by the Corps, DEQ and DSL may, as appropriate, incorporate the terms of the Mitigation Plan.

b) As part of the state permitting process for the pipeline discussed in subsection (a) above, the applicant shall consult with ODFW and OIMB on the specific details regarding how best to accomplish the actual amount and placement of Pacific oyster shells addressed in Section 4.2.1 of the Mitigation Plan in order to ensure success of the
project, including ideal depth and breadth of coverage of new hard substrate, specific methods for dispersal (e.g., bagged vs. loose), and best locations for placement of substrate within the pipeline right of way.

c) Unless modified under the direction of ODFW during the consultation described above, the applicant will establish appropriate baseline conditions for the Olympia oyster mitigation effort in Haynes Inlet using the following guidelines for a before-after control impact study design in order to ensure that any impacts to Olympia oysters are insignificant or de minimis:

i. The "Before" conditions shall be determined by field surveys of the distribution, abundance, status, and condition of existing Olympia oysters: (a) within the "Impact Area," i.e., the 250-foot pipeline right of way within the intertidal portion of Haynes Inlet; and (b) within an appropriate "Control Area" in another portion of Coos Bay that will not experience any influence from construction of the pipeline. The precise location of the Control Area will be selected in consultation with ODFW.

ii. The surveys of the Control and Impact Areas shall be conducted immediately prior to construction of the pipeline (Before), and repeated annually over a period of five years following construction of the pipeline (After) to encompass the lifespan of individual Olympia oysters.

d) Monitoring of the "Relocation Area" shall be undertaken as described in Section 4.3 of the Mitigation Plan.

No. 2. In-Water Work Periods

(a) If the applicant’s mitigation plan is approved by other regulatory agencies, the dispersal of Pacific oyster shells within the pipeline right of way will be effectuated either in late July or early August following the construction season.

(b) Based on the potential for the larval settlement peak in October, the applicant should not be allowed to conduct dredging operations between Milepost 2.6 to MP 3.2 during the month of October, unless otherwise modified or agreed to by the Oregon Department of Fish and Wildlife.

No. 3. Turbidity

The applicant must comply with all DEQ regulations and requirements regarding turbidity. The applicant shall employ turbidity curtains and/or other appropriate control measures to assure that turbidity does not exceed the levels specified in the applicant’s DEQ water quality permit.
Exhibit B
Coos County Planning Department
Conditional Use Application

Please place a check mark on the appropriate type of review that has been requested.

☒ Administrative Conditional Use ☐ Hearings Body Conditional Use
☐ Site Plan Review ☐ Variance

An **incomplete** application **will not** be processed. Applicant is responsible for completing the form. Attach additional sheets to answer questions if needed.

A. **Applicant:**

Name: Pacific Connector Gas Pipeline, LP  Attn: Rodney Gregory
Address: 72909 NE Redmond-Fall City Rd.
City: Redmond State: WA Zip Code: 98053

B. **Owner: SEE ATTACHED OWNER AND PROPERTY LIST.**

Name: Telephone:
Address: Telephone:
City: State: Zip Code:

C. **As applicant, I am (check one):**

☐ The owner of the property;
☐ The purchaser of the property under a duly executed written contract who has the written consent of the vendor to make such application (consent form attached).
☐ A lessee in possession of the property who has written consent of the owner to make such application (consent form attached).
☒ The agent of any of the foregoing who states on the application that he/she is the duly authorized agent and who submits evidence of being duly authorized in writing by his principal (consent form attached).

D. **Description of Property: SEE ATTACHED OWNER AND PROPERTY LIST.**

Township ______ Range _______ Section _______ Tax Lot _________

Tax Account ____________ Lot Size _______ Zoning District _______

Updated 11/09
Please place a check mark on the appropriate type of review that has been requested.

- [ ] Administrative Review
- [ ] Site Plan Review
- [X] Hearings Body Review
- [ ] Variance

An **incomplete** application will **not** be processed. Applicant is responsible for completing the form and addressing all criteria. Attach additional sheets to answer questions if needed. Please indicate not applicable on any portion of the application that does not apply to your request.

**A. Applicant:**

Name: Pacific Connector Gas Pipeline, L.P.  
Address: c/o Perkins Coie LLP, Attn: Mark D. Whilow, 1120 NW Couch Street, 10th Floor  
City: Portland  
Telephone: 503.727.2073

**B. Owner:** See Attached Owner and Property List

Name:  
Address:  
City:  
Telephone:  
State:  
Zip Code:

**C. As applicant, I am (check one): Please provide documentation.**

- [ ] The owner of the property (shown on deed of record);
- [ ] The purchaser of the property under a duly executed written contract who has the written consent of the vendor to make such application (consent form attached);
- [ ] A lessee in possession of the property who has written consent of the owner to make such application (consent form attached);
- [ ] The agent of any of the foregoing who states on the application that he/she is the duly authorized agent and who submits evidence of being duly authorized in writing by his principal (consent form attached).

**D. Description of Property:** See Attached Owner and Property List

Township ______ Range ______ Section ______ Tax Lot ______

Tax Account ______ Lot Size ______ Zoning District ______

Updated 2013
Exhibit C
FERC Vacates Order Authorizing Jordan Cove LNG Project

The Federal Energy Regulatory Commission (FERC) today vacated, without prejudice, an order authorizing Jordan Cove Energy Project, L.P., to site, construct and operate a liquefied natural gas (LNG) import terminal in Coos County, Oregon, and the related Pacific Connector pipeline from the terminal to a point near the Oregon/California border.

Jordan Cove had notified FERC on Feb. 29, 2012, that due to current market conditions it no longer intends to implement a Dec. 17, 2009, authorization to construct and operate an import terminal. In the same filing, Jordan Cove sought pre-filing status to explore the feasibility of a liquefaction export project that would be built and operated at the same site. FERC granted that status (Docket No. PF12-7-000).

FERC is not changing its longstanding policy of allowing the market to determine which gas infrastructure projects go forward, once the Commission has determined that a project would not result in substantial adverse impacts. But as Jordan Cove no longer intends to import LNG, the Commission is vacating that authorization. Jordan Cove may submit a new application to construct and/or operate facilities to import natural gas if it determines there is a market need for import service in the future.

Further, FERC said that Jordan Cove’s pre-filing application for export authorization will be considered on its merits in that proceeding.

In light of these actions, FERC dismissed as moot requests for rehearing.

Commissioner Philip Moeller dissented on today’s order.

R-12-14

(30)

Updated: April 16, 2012
Exhibit D
Study: Coho still at risk of extinction

By Jeff Barnard, AP Environmental Writer | Posted: Wednesday, May 26, 2010

GRANTS PASS -- Oregon coastal coho salmon remain at moderate risk of extinction from the continued decline of habitat in the rivers where it begins and ends its life, and should stay on the threatened species list, federal biologists said Tuesday.

The review released Tuesday by NOAA Fisheries Service was prompted by the settlement of a lawsuit brought by Douglas County, the most timber-dependent county in Oregon. The public has 60 days to comment before a final decision is made.

The case was the latest in a series of lawsuits that has made the Oregon coastal coho the most litigated fish in the Northwest, going on and off the threatened species list since first being proposed for protection in 1993.

"There weren't any surprises in this review," said NOAA Fisheries biologist Garth Griffin. "It's really the same issues and topics we've been talking about with Oregon coastal coho for 15 years."

Coastal coho were once the bread and butter of Oregon's commercial salmon fleet, but populations dropped precipitously in the early 1990s due to overfishing, misguided hatchery practices and destruction of freshwater habitat.

They spawn and spend the first year of their lives primarily in rivers running out of the Coast Range through private forest and farm lands.

Fishing is still allowed for hatchery coho and limited numbers of wild fish.

The review found that overfishing has been reigned in, and fewer hatchery fish are being released to compete with wild fish, resulting in improved returns. But rivers continue to decline from logging, farming and urban development, particularly on private land. Habitat was better on federal land where logging has been cut back to protect fish and wildlife.

The reviewers added that stream restoration projects are helping but are outpaced by the habitat destruction still happening.

An upturn in ocean conditions that has produced plentiful food has helped sustain coho, but freshwater habitat may not be in good enough shape to get them through the next downturn, the review found.

The review team members said they were "particularly concerned" that global warming would make it even tougher for salmon by warming and changing both the ocean and streams.

Mary Scurlock, policy director for the conservation group Pacific Rivers Council, said the findings pointed out the need to further control logging, farming and urban development on private lands.

"We have made more progress in hatchery reforms than we have in changing our forest practices to meet the needs of coho recovery," she said.

Douglas County Commissioner Doug Robertson did not immediately return a phone call for comment. Conservationists first proposed Oregon coastal coho for Endangered Species Act protection in 1993, and NOAA Fisheries tentatively agreed.

Hoping to avoid a dramatic decline in logging on private lands at the same time logging on federal lands was being cut back, then-Gov. John Kitzhaber launched an effort to promote voluntary habitat protection.

NOAA Fisheries endorsed the plan and decided coastal coho didn't need protection in 1997.

With one lawsuit after the other, coastal coho went on and off the threatened species list until 2008, the latest time NOAA Fisheries agreed to protect the fish.
Exhibit E
DRILL HERE
SELL THERE
PAY MORE

THE PAINFUL PRICE OF EXPORTING NATURAL GAS

This report has not been officially adopted by the Committee on Natural Resources and may not necessarily reflect the views of its Members.
Executive Summary

The United States faces a critical decision about whether to export natural gas following the rapid expansion of domestic production in recent years. The Department of Energy has already approved one export application and is currently considering eight others. If these applications are approved and the companies export at full capacity, the United States could soon be exporting more than 20 percent of current consumption. The Energy Information Administration has estimated that exporting even less natural gas than what is currently under consideration could raise domestic prices 24 to 54 percent, which would substantially increase energy bills for American consumers and could potentially have catastrophic impacts on U.S. manufacturing.

In a February 24th letter to Massachusetts Congressman Edward J. Markey, Department of Energy (DOE) official Christopher Smith made clear that no additional export permits will be approved by the Department at least until an additional evaluation of the macroeconomic impact of these prospective exports is completed and reviewed by DOE this spring. This decision represents an important deliberative step that ensures deeper consideration will be given to the ramifications of energy exporting.

In examining energy markets and the impacts of higher natural gas prices, the House Natural Resources Democratic Staff found that:

- Unlike the oil market, natural gas prices are not determined on a global market. Natural gas prices in Europe and Asia are 3 to 7 times higher than in the United States. This provides the American economy with a competitive advantage in the manufacture of energy-intensive goods.

- From 2000 to 2008, the price of natural gas rose more than 400 percent, and was a major contributor to the U.S. manufacturing sector losing 3.7 million jobs. While larger macroeconomic forces were also at work during this period, it is clear that the cost of natural gas for industries like steel, plastics, chemicals, paper, glass, fertilizer, cement, and refining is a very significant determinant in whether facilities are sited domestically or overseas. Keeping American natural gas resources in America and keeping prices low will support a more diversified domestic economy and provide greater domestic job benefits than pursuing an export strategy.

- Keeping natural gas resources at home will allow greater amounts of natural gas to be used in the domestic electric power and transportation sectors. Greater natural gas utilization in these sectors could lead directly to a 1.2 million barrel per day reduction in

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1 Included as an appendix to this report.
foreign oil imports and a 9 percent reduction in coal consumption by 2035, which would measurably enhance America's national, economic, and environmental security.

Legislation introduced by Rep. Markey would prevent companies from exporting natural gas extracted from public lands (H.R. 4025) and would place a moratorium on the Federal Energy Regulatory Commission approving the siting and development of LNG export terminals before 2025, except under special circumstances (H.R. 4024).
Background

On June 10, 2003, the Chairman of the Federal Reserve Board, Alan Greenspan, testified before the House Energy and Commerce Committee that rising natural gas prices were harming domestic manufacturers and that large numbers of liquefied natural gas (LNG) terminals were needed to import more natural gas and stabilize prices. He said:

*The updrift and volatility of the spot price for gas have put significant segments of the North American gas-using industry in a weakened competitive position. ... The perceived tightening of long-term demand-supply balances is beginning to price some industrial demand out of the market. ... Access to world natural gas supplies will require a major expansion of LNG terminal import capacity. ... As the technology of LNG liquefaction and shipping has improved, and as safety considerations have lessened, a major expansion of U.S. import capability appears to be under way. These movements bode well for widespread natural gas availability in North America in the years ahead.*

Chairman Greenspan was half right. Since natural gas is both the primary fuel source for the industrial sector and a primary feedstock for the production of plastics, chemicals, fertilizers, and many other products, low-price natural gas is essential to our industrial competitiveness. The increase in natural gas prices of more than 400 percent between 2000 and 2008 significantly undermined American industrial competitiveness and was a major factor in the loss of 3.7 million manufacturing jobs during that time.

But Chairman Greenspan turned out to be wrong about our need to import large amounts of LNG. Subsequent discoveries of domestic shale gas deposits and advances in horizontal drilling and hydraulic fracturing techniques, have led to expanded domestic gas reserves and production and the lowest well-head prices in 10 years. Of the nearly 50 LNG import terminals that have been certified for construction, only 12 facilities were ultimately built. And of this 6.95 trillion cubic feet (Tcf) of LNG import capacity, only 0.35 Tcf of natural gas was actually

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4 The well-head price is the price charged by the producer for petroleum or natural gas without transportation costs. See [http://www.merriam-webster.com/dictionary/wellhead+price#](http://www.merriam-webster.com/dictionary/wellhead+price#)


imported in 2011, a utilization rate of 5 percent.\textsuperscript{7} Several of these import terminals are now mothballed entirely and their owners are looking to turn them into LNG export terminals.\textsuperscript{8}

**The Natural Gas Market Today**

Natural gas production in the United States reached a historical high in November 2011, when producers withdrew an average of 82.7 billion cubic feet per day, 18 percent higher than five years earlier.\textsuperscript{9} This expansion in domestic natural gas supplies has led to a reduction in domestic prices. Even while consumption of natural gas has been increasing, the average wellhead price has stayed below $5 per million cubic feet (Mcf) for more than two years. Shale gas now accounts for more than a third of total U.S. gas resources.\textsuperscript{10} The Energy Information Administration (EIA) estimates that shale gas will provide 49 percent of total U.S. natural gas supply by 2035, up from 23 percent in 2010.\textsuperscript{11} Net imports now represent 10 percent of total U.S. consumption, the lowest proportion since 1993, and this share is expected to continue to shrink.

Unlike oil, natural gas prices are not set on a global market. Natural gas cannot currently be moved cheaply in volumes great enough to efficiently link low-cost producing regions with high-demand regions. With massive deployment of expensive infrastructure—international natural gas pipelines, special cryogenic LNG tankers, liquefaction equipment—regional natural prices would converge to a global price in the same way that global oil prices have emerged. However, like the oil market, a global natural gas market could be manipulated by nations, national companies, and cartels in the same way that the Organization of Petroleum Exporting Countries (OPEC) now manipulates the global oil market.

Regional variation in natural gas prices is considerable, as seen in Figure 1. For example, natural gas prices are six to seven times higher in Asia than they are in the United States. Prices are more than three times higher throughout most of Europe. The regional nature of the natural gas market clearly benefits American consumers and businesses.

\textsuperscript{8} Energy Information Administration, U.S. Natural Gas Imports by Point of Entry, available at http://www.eia.gov/dnav/ng/ng_move_poe1_a_EPG0_IML_Mmcf_a.htm
The Department of Energy Considers Export Permits

Export Applications Pour In

As a result of high domestic natural gas production and higher prices in foreign markets, several companies have submitted applications to the Department of Energy over the past year seeking permits to export domestically produced natural gas. Most of these applications are planning to use LNG terminals that were originally built for importing. Existing terminals can be seen in Figure 2.
DOE has already approved a plan from a Cheniere Energy subsidiary, Sabine Pass Liquefaction, to export LNG through a terminal originally built for importing the fuel. This export facility, which is still at least four years away from becoming operational, has booked major deals to export American natural gas to Indian and Korean markets and, in total, has long-term agreements in place to export 89 percent of its approved capacity.\(^{12}\) DOE is now considering eight other LNG export applications. If all nine export applications are approved and this export capacity is fully utilized, the companies would export an amount equal to 20.6 percent of current U.S. consumption, according to data provided by DOE to Democratic staff on the House Natural Resources Committee.

After the Sabine Pass approval in May of 2011 and the subsequent rush of new applicants, DOE commissioned the EIA and a private contractor to undertake separate studies on the cumulative impacts of pending natural gas export applications. DOE has since committed to withhold approval of the pending export applications until these studies are completed. EIA released its study in January, finding that domestic natural gas prices could rise more than 50 percent if exports take off (see summary below). The second study is scheduled to be completed this spring.

Roles and Authorities

Section 3(a) of the Natural Gas Act of 1938 defines the process for DOE’s reviews of most LNG export applications. In particular, the Secretary of Energy must approve an export application “unless after opportunity for hearing, [the Secretary] finds that the proposed exportation... will not be consistent with the public interest.” Thus, there is “a rebuttable presumption that a proposed export of natural gas is in the public interest,” according to DOE. This presumption must be overcome for DOE to deny an export application. For export approvals, DOE may also attach terms or conditions that it considers necessary to protect the public interest.

The Energy Policy Act of 1992 amended the Natural Gas Act to further limit DOE’s ability to deny natural gas export applications. Specifically, DOE must approve applications to export natural gas to the 15 countries that have free trade agreements (FTAs) with the United States covering natural gas.¹³ Such applications are automatically deemed in the public interest, and DOE cannot add any terms or conditions to approvals.

In addition to DOE authorization to export LNG, companies must receive authorization from the Federal Energy Regulatory Commission (FERC) for the actual siting and development of LNG projects, as specified under Section 3 of the Natural Gas Act.⁴ FERC is also the lead agency responsible for the preparation of the analysis and decisions required under National Environmental Policy Act for the approval of new facilities, including tanker operation, marine facilities, and terminal construction and operation, environmental and cultural impacts.¹⁵

The Energy Information Administration Study

If DOE approves the pending applications and exports rise as expected, domestic natural gas prices could increase 24 to 54 percent, depending on recoverable shale resources and how quickly exports are ramped up, according to the EIA’s January report.¹⁶ About three-quarters of the increased natural gas production needed to satisfy such export demand would come from shale sources, according to an EIA export scenario. That would require a dramatic expansion of hydraulic fracturing, or “fracking,” which is necessary to access these resources.

Higher prices are also expected to substantially reduce U.S. demand for natural gas. Around 30 to 40 percent of natural gas export demand would be met through reduced domestic consumption, not increased production, according to EIA. Consequently, EIA projects that dirty

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¹³ These countries are Australia, Bahrain, Canada, Chile, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Peru, and Singapore. Three other countries, South Korea, Colombia, and Panama, will soon join this club when their Senate-ratified trade agreements take effect.


coal-fired power generation will rise in the United States to make up for the expected decline in natural gas-fired electricity generation.

**Energy Department Responds to Markey Letter**

Rep. Markey, Ranking Member on the House Natural Resources Committee, wrote to Energy Secretary Steven Chu in January asking about the consequences of exporting greater amounts of natural gas, including the consequences for prices, manufacturing and economic growth, energy security, and the environment.

Deputy Assistant Secretary Christopher Smith responded on behalf of Secretary Chu. This response, delivered February 24th, noted that DOE has already approved the export of 10.93 billion cubic feet of natural gas per day (Bcf/d) to countries with free trade agreements with the United States. The EIA report looked at export scenarios associated with the approval of additional exports to counties without free trade agreements. The second report by the private contractor is still being completed, but Smith wrote that it would provide important information about the macroeconomic consequences resulting from EIA’s export scenarios, including:

- Consequences for domestic energy consumption, production, and prices;
- Effects on gross domestic product, job creation, and balance of trade; and
- Impacts on U.S. manufacturers, especially energy intensive industries.

Smith made clear that DOE would not approve the pending export applications until this study is finished and DOE has considered the findings. “We are mindful of the need for prompt action in each of the non-FTA LNG export proceedings before us,” Smith wrote. “We are equally mindful that a sound evidentiary record is essential to reach a reasoned decision in these proceedings. As such, DOE will not issue a final order addressing the pending applications to export LNG to non-FTA countries until the full study has been completed and the Department has had an opportunity to review the results.”

**Economic Ramifications of Exporting**

The United States currently enjoys affordable natural gas that benefits consumers and also provides us with a competitive advantage that is felt up and down the U.S. economy. Affordable natural gas keeps energy prices low for consumers that rely on natural gas for heating, cooking, and electricity. Increasing those energy costs on American consumers and businesses by exporting would have a direct impact on their disposable income and reduce their purchasing power.

Industrial and manufacturing facilities are the largest consumers of natural gas in the United States—ahead of the electricity, commercial, and residential sectors—and would be especially hard hit. These facilities may require natural gas not only as a primary energy source

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\(^{17}\) DOE now has pending or approved permits for exports to FTA countries totaling 12.51 Bcf/d. DOE LNG docket available at: http://fossil.energy.gov/programs/gasregulation/LNG_Summary_Table_2-25-12_2.pdf
but also use it as a physical input into product. In some sectors, like fertilizers and chemicals, natural gas can constitute 80 to 90 percent of the cost of production. For businesses like these, the cost of energy may be the number one determining factor in whether to site production in the United States and employ American workers or whether to move production overseas.

In the past, high natural gas prices have had a disastrous effect on U.S. manufacturing. From 2000 to 2008, the price of natural gas rose more than 400 percent, and was a major contributor to the U.S. manufacturing sector losing 3.7 million jobs.\(^{18}\) Other variables were certainly relevant to this undermining of manufacturing competitiveness as well, including the 2001 recession in the global trend of moving manufacturing to countries with lower labor costs. However, for energy intensive industries—like aluminum, steel, plastics, chemicals, paper, glass, fertilizer, food processing, cement, and refining—the cost of energy is a far greater share of production costs than labor and a more significant determinant in facility siting.

The experiences of some specific energy-intensive industries below illustrate the dangers that natural gas exporting could have on sectors of the U.S. economy.

**Fertilizer Industry**

An important use of natural gas is as a feedstock in fertilizer production. In this process, natural gas is used to produce ammonia, which has a high nitrogen content, and the ammonia becomes the primary component of nitrogen fertilizers. It takes 33,500 cubic feet of natural gas to manufacture 1 ton of anhydrous ammonia fertilizer.\(^{19}\) As a result, natural gas can account for up to 90 percent of the cost to produce ammonia fertilizer.\(^{20}\)

The fertilizer sector is the largest industrial consumer of natural gas in the United States, consuming 60 percent of U.S. industrial demand.\(^{21}\) The period between 2000 and 2006 was a devastating one for the U.S. fertilizer industry, as seen in Figure 3. Domestic ammonia fertilizer production declined 44 percent, and more than a third of all U.S. fertilizer production capacity shuttered. At the same time, imports skyrocketed 115 percent.\(^{22}\)

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\(^{18}\) Dow Jones Industrial Average Basic Chart, Yahoo! Finance, available at http://finance.yahoo.com/q/bc?s=%5EDJ&l=my&l=en&z=1&q=l&c=

\(^{19}\) Eddie Funderberg, *Why are Natural Gas Prices So High?*, available at http://www.noble.org/ag/soils/nitrogenprices/index.htm


The harm to the U.S. economy and domestic jobs was not limited to merely the fertilizer industry. The cost of buying fertilizer to farmers rose 130 percent between 2000 and 2006, from $227 per ton to $521. Farmers get especially squeezed with higher fertilizer costs because they are often times unable to pass along higher fertilizer costs in what they charge for their commodity crops. According to the U.S. Department of Agriculture, “With lower crop prices, high fertilizer prices would place downward pressure on farmers’ net returns. Farms with higher than average fertilizer costs, a greater need to use fertilizers on the crops they grow, and/or a limited ability to either move away from fertilizer-intensive crops or substitute other inputs will be especially vulnerable if fertilizer prices increase once again.”

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With U.S. natural gas prices at 10-year lows, fertilizer production is coming back to the United States, albeit slowly. Over the past two years, several facilities have returned to production and a series of large expansions are under consideration:

- Oklahoma-based LSB Industries reopened its Pryor, Oklahoma ammonia facility in 2009 and two smaller units at Pryor will restart soon as well.

- Orascom Construction has purchased and reopened a large ammonia plant in Beaumont, Texas. The company announced earlier this year that “Low natural gas prices in the U.S. were a deciding factor in the company's decision to acquire and rehabilitate the plant.”

- PCS Corporation is in the process of reopening its large plant in Geismar, Louisiana with an online target in the third quarter this year. It is also considering expansions at its Lima, Ohio and Augusta, Georgia plants.

- CF Industries has reopened portions of its giant Donaldsonville, Louisiana, facility in the past two years and has purchased an additional facility. The company announced last year that it plans to invest $1 billion to $1.5 billion over the next four years to expand its production capacity for ammonia and other products.

For farmers waiting to see a drop in fertilizer prices, this new domestic production cannot come online fast enough. Even though U.S. natural gas prices have fallen to 10-year lows, fertilizer prices remain high because the United States now imports more than half of its fertilizer. Imported fertilizer comes from regions which do not have the low natural gas prices that the United States is currently enjoying, increasing the prices for farmers.

**Chemicals and Plastics Industry**

Chemical manufacturers rely on natural gas for 58 percent of their fuel and natural gas liquids for 58 percent of their feedstock. Natural gas constitutes upwards of 80 percent of the total cost to produce plastic. The high natural gas prices the U.S. chemical and plastics industry faced throughout much of the last decade significantly eroded the U.S. chemicals industry’s competitive position. As detailed in Figure 4, the U.S. chemical industry was essentially wiped out as an export sector between 1997 and 2006, as net exports fell from $16.8 billion annually to $218 million. Of the largest 120 chemical plants being built around the world in 2005, exactly one was located in the United States. According to the U.S. Commerce Department, “The

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25 Stephanie Seay, Platts, *Low gas costs may not be enough to spur large fertilizer expansion*, available at [http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/3915346](http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/3915346)


27 PowerPoint presentation “Manufacturing Competitiveness and Jobs Depend Upon Affordable and Reliable Electricity and Natural Gas,” Industrial Energy Consumers of America, February 2012.
increase in U.S. natural gas prices has helped reduce and even eliminate in some recent years the United States’ trade surplus in bulk chemicals.²⁸

Figure 4. U.S. Trade Balance for Chemicals (not including pharmaceuticals)


Appearing before the Select Committee on Energy Independence and Global Warming in 2008, the Dow Chemical Company’s Vice President for Energy, Rich Wells, testified to the difficulties that the domestic chemical industry was facing. Dow had shut down dozens of uncompetitive U.S. plants in the previous decade as natural gas prices had skyrocketed. They were investing preferentially in the Middle East and other parts of the world where energy costs were lower. Wells explained that it was cheaper for chemical companies to move their manufacturing to where energy is cheap than to move cheap energy to their manufacturing.²⁹

Once again, like the fertilizer sector, low domestic natural gas prices are driving a resurgence in the domestic chemical industry. According to the American Chemistry Council, “A new competitive advantage has already emerged for U.S. petrochemical producers.”³⁰ Dow has

announced it will increase key chemical processing capability along the Gulf Coast by 20 to 30 percent over the next two to three years. The American Chemistry Council estimates that if natural gas-based feedstock prices stay low and supply expands, the U.S. chemical industry is projected to invest $49 billion in new plants and equipment in the United States in the coming years and spur the creation of more than 400,000 jobs across the U.S. economy. Such investments would generate $44 billion in new federal, state, and local tax revenue over the next decade.\textsuperscript{31} Low-priced natural gas is the key to unlocking these economic benefits.

\textit{Steel Industry}

The domestic steel sector’s fuel reliance is split mostly between natural gas, electricity, and coal-derived coke, and the sector’s natural gas consumption makes up 4 percent of U.S. industrial natural gas use.\textsuperscript{32} The steel industry is highly energy-intensive with very tight margins, and small changes in energy prices can have a significant impact on the cost of downstream manufactured goods like automobiles, construction equipment, and wind turbines. Recycled steel is especially energy intensive, and energy can account for 25 percent or more of the cost of production.\textsuperscript{33}

Integrated steelmakers, which produce steel from raw iron ore, use natural gas as the primary energy source for the reheating and rolling procedures at the end of the steelmaking process. Recent low natural gas prices have allowed companies to replace costly and dirty coal-derived coke with natural gas, which has become a far more cost-effective way of melting iron ore. U.S. Steel estimates that with natural gas prices around what they are today, substituting natural gas for coal-derived coke translates to savings of $7 per ton of steel.\textsuperscript{34} A $1 per million BTU increase in the price of natural gas would increase costs by more than $100 million for U.S. Steel, based on current gas usage and steel production levels.

Another American steel producer, Nucor, has utilized low natural gas prices to build new “direct reduced iron” facilities,\textsuperscript{35} which combine natural gas with iron ore pellets to create a steady feedstock for the company’s electric arc furnaces. This is a growing technology that now accounts for more than 60 percent of steel production in the United States. Low natural gas prices are critical to operating these types of facilities. Seven years ago, as U.S. natural gas prices

\textsuperscript{31} Id.
\textsuperscript{32} American Iron and Steel Institute, \textit{2010 Annual Statistical Report}, Table 37
\textsuperscript{33} PowerPoint presentation “Manufacturing Competitiveness and Jobs Depend Upon Affordable and Reliable Electricity and Natural Gas,” Industrial Energy Consumers of America, February 2012.
were much higher than today, Nucor relocated a facility to Trinidad in order to take advantage of "a low cost supply of natural gas."\textsuperscript{36}

**Conclusion**

If we keep natural gas here at home, and keep prices low, we will accelerate the transition away from coal and foreign oil, making U.S. energy consumption not only cheaper, but cleaner and more secure.

Natural gas could eventually overtake coal as America’s primary source of electricity. In just the last six years, coal’s share of the U.S. electricity market has dropped from 50 percent to 43 percent, with natural gas displacing most of this production, along with wind. At the same time, buses and commercial fleet vehicles, which consume large amounts of fuel, are increasingly powered by natural gas instead of gasoline. “Replacing 3.5 million of these heavy vehicles with natural gas vehicles by 2035 would save more than 1.2 million barrels of oil per day compared to business as usual, which is more than we imported from either Venezuela or Saudi Arabia in 2009,” according to a report by the Center for American Progress.\textsuperscript{37}

Using more natural gas for electricity and transportation is expected to drive up U.S. demand by 18 percent by 2035 under current policies and commitments, “causing coal demand to drop by around 9% and oil demand by around 6%,” according to the International Energy Agency.\textsuperscript{38} This transition away from coal and foreign oil, however, could be slowed or jeopardized if we undermine our affordable domestic natural gas supply by exporting it to foreign markets.

To address these concerns Rep. Ed Markey has introduced two bills to stop natural gas from being exported. H.R. 4025 would prevent oil and gas companies from exporting natural gas extracted from public lands, and H.R. 4024 would place a moratorium on the Federal Energy Regulatory Commission approving the siting and development of LNG export terminals until 2025, except under special circumstances. Markey also offered a floor amendment to H.R. 3408, the so-called PIONEERS Act, that would have stopped the exporting of natural gas extracted from the public lands and waters opened up by the bill. That amendment failed by a vote of 173 to 254.

Instead of starting with a presumption in favor of exports, they should be evaluated against the following goals for American energy policy:

1. Keep energy affordable for American consumers;
2. Grow U.S. manufacturing and support its competitive position in the global economy;
3. Reduce America’s dependence on foreign oil; and


4. Reduce dangerous environmental pollution.

These goals are now being advanced because natural gas supplies are abundant; prices are cheaper here than abroad; and natural gas is becoming more economical than dirtier coal and imported oil. If we keep natural gas here, these benefits will continue. If we export it abroad, we will undermine each goal.
Exhibit F
NATIONAL ENERGY BOARD

IN THE MATTER OF the National Energy Board Act, RSC 1985, c N-7, as amended;

AND IN THE MATTER OF an application by Jordan Cove LNG L.P. for a licence pursuant to section 117 of the National Energy Board Act authorizing the export of gas.

To: Secretary
National Energy Board
444 Seventh Avenue SW
Calgary, AB
T2P 0X8

APPLICATION

SEPTEMBER 9, 2013
Appendix B

Export Volumes

Illustrative Volume Build-up⁽¹⁾

<table>
<thead>
<tr>
<th>Year and Quarter⁽²⁾</th>
<th>Natural Gas Export Volumes⁽³⁾ (Bcf)</th>
<th>Including 15% Tolerance (Bcf)</th>
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<td>Year 2 Average/Year</td>
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<td>Year 3 Average/Year</td>
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<td>Year 4-25 Average/Year</td>
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</tbody>
</table>

¹This table is an illustrative build-up of natural gas export quantities from Canada to the United States for the Jordan Cove LNG Export facility.

²The year and quarter is the date from first natural gas export and does not correspond to calendar quarters. It is anticipated that a Licence would be in effect from 2019-2044.

³Natural Gas Export Volumes includes natural gas requirements for pipeline fuel and losses and power generation. The volume build-up assumes a commissioning period of 6 months with trains 1-4 being available for commercial operations after this time. Trains 5 and 6 will be commissioned and available for commercial operations during year 3 of the anticipated Licence.
Press Release – September 18, 2013

America's Energy Advantage Files LNG Export Motion, Seeks Rulemaking on Public Interest Test

~Says DOE's Standards for Reviewing LNG Export Applications "Appear to be in Flux"

PR Newswire

WASHINGTON, Sept. 18, 2013 /PRNewswire/ -- In a major new development in the debate over LNG exports, America's Energy Advantage (AEA) today filed a formal motion to intervene in the Department of Energy's (DOE) proceeding for the Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC (together "FLEX") export application (FE Docket No. 11-161-LNG). DOE is currently reviewing the application, which if authorized would raise the cumulative volume of authorized exports of LNG to 8.31 Bcf/d, which would go beyond the "low export scenario" level identified in a NERA report DOE used to grant three previous LNG export applications.

AEA is seeking a more formal rulemaking process based on current data and assessments of today's supply and demand environment, and noted that current applications are being granted based on guidelines developed for gas imports in the 1980s. AEA's motion also indicates that the legal standards that DOE used to analyze the public interest in two previous grant applications were not "adequate, appropriate, or sustainable." See AEA's motion here: http://www.americasenergyadvantage.org/AEA-Comment.

"DOE is making decisions that will have far-reaching and potentially irreversible impacts on consumers, our economy, and America's manufacturing renewal based on 30-year-old guidelines for natural gas imports, not exports. No matter where one stands on this issue, surely we can agree that exports and imports are different, and that DOE needs to make rules based on the 21st century, not the 1980s," said Jennifer Diggins, Director, Public Affairs for Nucor Corporation and Chair of AEA.

"We felt the need to file a formal motion because American consumers of natural gas deserve as much say in the process as producers," said Diggins. "All we're saying is that the public interest test is important, and that DOE needs to take a more methodical and legally-based approach to defining what that public interest is. DOE itself conceded that 'the market of the future very likely will not resemble the market of today' in its previous grant applications, but what data are they using to project that future? Nobody knows."

Diggins concluded: "As a result of available and affordable natural gas in the U.S., more than 120 manufacturing projects valued at nearly $110 billion of economic investment have been announced, including thousands of new jobs. Our country cannot afford to lose these job-creating investments or hurt consumers by driving up the cost of utility bills. We have a right to be heard in this debate."
AEA submitted today's motion following DOE's failure in recently issued export authorizations to apply reasonable standards for assessing the public interest as required by the NGA. As AEA stressed in its motion: "It is not enough for DOE to summarily refer to the public interest, vaguely acknowledge that conditions may change, and imply that these changed conditions could possibly affect pending and future proceedings or retroactively affect previously granted authorizations. The development of an LNG export industry in the United States has widespread consequences affecting all segments of the American public interest, including the economy, the environment, public policy, international relations and the quality of life for American citizens."

**About America's Energy Advantage**

America's Energy Advantage, Inc. is a 501(c)(6) not for profit organization that is dedicated to educating the American public about the growth in American manufacturing that has been made possible by our country's abundant and affordable supply of natural gas.

SOURCE America’s Energy Advantage

[Emphasis has been added]
Gas users warn LNG exports may impact Canada’s domestic supply

JEFF LEWIS | Sept 03 2013 |

CALGARY - Dow Chemical Co. and other big manufacturers are bringing their fight over unfettered natural gas exports in the United States to Canada.

With some 14 billion cubic feet a day of proposed export capacity on tap for the British Columbia coast, an Alberta-based trade group representing Dow’s Canadian arm, Nova Chemicals Corp. and other large gas users is calling for a comprehensive study into the potential impacts of liquefied natural gas projects on prices and future supplies of the heating fuel.

Concern over access to natural gas comes as Canada’s energy watchdog asks export hopefuls ExxonMobil Corp., Britain’s IG Group Plc and Malaysia’s Petronas to reassess forecasts for Canadian demand out to 2050. The companies are seeking permission to export a combined 10 billion cubic feet of gas per day – Equivalent to 75% of Canada’s daily gas production in 2012 – from separate projects on the B.C. coast.

The moves may throw up new roadblocks to obtaining export permits, frustrating an expected construction boom in B.C. and political promises of billions of new government revenue.

“It is plain to see on the surface of this issue that an unconstrained approach to issuing export licenses for serving LNG markets has the potential to exceed the current total production of” Western Canada, Greig Sproule, executive director of the Industrial Gas Consumers Association of Alberta, said in an emailed statement.

“Although one may assume that not all of these projects (or any of them) will proceed, the [National Energy Board] should not make this assumption when issuing licenses.”

IGCAA, in a submission filed this week with the board, said it is counting on B.C. shale gas to meet future industrial demand in Alberta. Member companies are concerned about the impact an export permit sought by Petronas may have on future gas supplies for domestic use, throughputs and tolls on existing pipelines on the Alberta system, the group said.

The complaint mirrors objections raised by Midland, Mich.-based Dow in the U.S. The chemical maker, through an advocacy group called America’s Energy Advantage, has waged a protracted battle over LNG exports against companies such as Exxon.

Dow, which runs a sprawling petrochemical complex northeast of Edmonton, argues such proposals undermine the benefits of the U.S. shale boom. Exxon and others have accused the chemical maker of protectionism.
Gas used by oil sands companies and petrochemical plants in Alberta is growing at a "significant" pace, the IGCAA said.

By 2020, the oil sands alone could burn roughly three bcf/d, up from about 1.2 bcf/d today, according to Ziff Energy Group.

IGCAA members, who include energy giants Suncor Energy Inc. and Syncrude Canada Ltd., today burn roughly 1.3 bcf/d and purchase another 0.65 bcf/d in the market, the trade group said. Shell, by comparison, has approval to export up to 3.2 bcf/d from its LNG Canada project at Kitimat.

Mr. Sproule said the industry alliance is not proposing a moratorium on new export licenses. Rather, it is worried a "one-off approach" to assessing applications could mask the aggregate impacts on price and future supplies of the heating fuel.

Canadian chemical companies have also expressed concern that existing export orders could limit their access to petroleum liquids such as propane, butane and ethane, according to an Aug. 27 letter filed with the NEB by the Chemistry Industry Association of Canada. Member companies including Dow and DuPont use ethane, a natural gas byproduct, in Alberta petrochemical plants.

Canada has welcomed LNG projects with open arms in recent years, doling out coveted export authorizations for a raft of proposals amid an aggressive corporate and government push to find new markets for the fuel.

Those plans appear to be testing limits set by the NEB, which judges applications against several criteria, including forecast Canadian demand. The board, in separate information requests sent last week to BG, Exxon and Petronas, has told the companies to conduct a "sensitivity analysis" assessing Canadian gas needs.

It wants Exxon, for example, to run numbers assuming Canada’s yearly demand grows at a faster clip than levels forecast in its export application, adding 20% to corporate estimates.

The increase is a "drop in the bucket" relative to Canada’s technically recoverable resource base and is unlikely to affect the permitting process, a person familiar with the board’s thinking said.

The board "recognizes that not all the projects are going to go that are applied for," the person said. "I would hope that they’re not going to pick winners and losers."

Spokesmen for BG and Imperial Oil Ltd. declined to comment on the IGCAA submission or the demand analysis. A Dow spokesman did not respond to messages seeking comment.
Exhibit I
There was no salmon season for fishermen (a vital industry in Coos Bay) in 2006 or 2009 due to poor fish runs. The currently underused twelve-inch gas pipeline that was built in 2003 and which runs from Coos Bay to Roseburg had environmental impacts that were severe and many vital ecological streambeds suffered damage. Mastec, the pipeline builder was ordered to pay 1.5 million in penalties. This was far short of the actual damage caused and the amount sought by plaintiffs. Judge Hogan ruled that there had been failure of all parties concerned and that the lack of government oversight was a factor in the low penalty amount he awarded to the plaintiff.

*Photos shown above show environmental impacts of the Coos County Pipeline built in 2003 from Coos Bay to the Williams Lateral In Roseburg.*
Exhibit J
Federal court fines Coos pipeline builder

The World
Tuesday, February 24, 2009

EUGENE (AP) — MasTec Inc., the contractor fired not long after being hired to build a natural gas pipeline from Roseburg to Coquille, has been ordered to pay $1.5 million in penalties. The money will go to the U.S. Treasury because of damage caused to pristine streams and rivers.

Government agencies from the feds on down to Coos County had a hand in the debacle, too.

U.S. District Judge Michael Hogan, who issued the order, also found that government agencies provided inadequate oversight of the $51 million project. But, though the contractor violated the Clean Water Act, the judge said there did not appear to be serious environmental harm.

A MasTec attorney declined comment about the ruling Monday.

The project was dogged with problems since the summer of 2003, when work began on the 60-mile long, 12-inch pipeline. Crews contaminated streambeds with drilling spoils, threatening fish habitat. Regulators later discovered project managers had not taken adequate steps to protect hillsides from erosion. That led to even more sediment in fish spawning grounds.

Coos County terminated its contract with the Coral Gables, Fla.-based company in April 2004. An Oregon company finished the project.

Residents and environmental groups complained early and often about the project, contending the state Department of Environmental Quality, the U.S. Army Corps of Engineers and Coos County were lax in oversight of a project that crossed sensitive terrain, including many parcels of private property.

Officials initially maintained the project was on track and that state and federal clean water laws were being followed. But as contrary evidence piled up, legal battles ensued.

MasTec and the county sued each other in a case settled last year.

Then the Sierra Club, along with other environmental groups, filed suit in the case Hogan settled this week.

The $1.5 million fine fell well short of the amount sought by the plaintiffs. Their case was based in part on assertions the company had saved $6 million by avoiding its Clean Water Act obligations. Hogan, however, wrote that MasTec lost $9.23 million on the project.

The lack of government oversight was another factor Hogan used in determining the size of the penalty.

"In this case, there was a failure of all parties concerned," Hogan wrote.
Exhibit K
LNG UPLAND IMPACTS
Shell's Sakhalin II LNG pipeline 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.
Exhibit L
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<td>847.15</td>
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<td>Major</td>
<td>E2EMPN, E1UBL, E2USN, E1UBL</td>
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<td>192.21</td>
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<td>ESP013</td>
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<td>10.13</td>
<td>BSP090</td>
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<td>R2UBHC</td>
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<td>Fecal Coliform/Year-Round - Cat. 5</td>
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<tr>
<td>Stock Slough</td>
<td>10.14, 10.15, 10.21</td>
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<td>145.23</td>
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<td>Fecal Coliform/Year-Round - Cat. 5</td>
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<td>Fecal Coliform/Year-Round - Cat. 5</td>
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<td>Fecal Coliform/Year-Round - Cat. 5</td>
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<td>R2UBHC</td>
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<td>Fecal Coliform/Year-Round - Cat. 5</td>
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<td>Tri to Catching Slough</td>
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<td>R2UBHC</td>
<td>Perennial</td>
<td>F</td>
<td>Fecal Coliform/Year-Round - Cat. 5</td>
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<td>R2UBHC</td>
<td>Perennial</td>
<td>F</td>
<td>Fecal Coliform/Year-Round - Cat. 5</td>
<td></td>
</tr>
</tbody>
</table>

Appendix G – Water Resources and Wetlands
Exhibit M
Alternative Pacific Connector Pipeline Route

Jordan Cove Energy Project
Alternative Pacific Connector Pipeline Route #2

Jordan Cove
Energy Project
Jordan Cove Energy Project
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.

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
- Diameter 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 »
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 N
Final Environmental Impact Statement

JORDAN COVE ENERGY AND PACIFIC CONNECTOR GAS PIPELINE PROJECT

Jordan Cove Energy Project, L.P. Docket Nos. CP07-444-000
Pacific Connector Gas Pipeline, L.P. CP07-441-000

FERC/EIS – 0223F

Federal Energy Regulatory Commission
Office of Energy Projects
Washington, DC 20426

Cooperating Agencies
USDA Forest Service, Pacific Northwest Region
Department of the Army, Corps of Engineers, Portland District
US Environmental Protection Agency, Region 10
US Department of Homeland Security Coast Guard, Portland
US Department of Transportation Pipeline and Hazardous Materials Safety Administration
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
Douglas County, Oregon

May 2009
We approve of the new proposed pipeline between MPs 0.0 and 11.36 (Route WC-1A-2A). None of the other route variations we analyzed in the Coos Bay area appear to be environmentally superior to the new proposed route. However, to ensure that impacts on resources are minimized to the extent possible, we recommend that:

- Pacific Connector should continue to consult with the Port and potentially affected oyster growers regarding measures that should be implemented during pipeline installation in Coos Bay to minimize impacts on Port activities and oyster raising. The results of this consultation should be filed with the Secretary prior to pipeline construction.

The Coos Watershed Association, in a letter to the FERC dated December 4, 2008, commenting on the draft EIS, indicated concerns about Route Variation WC-1A. This variation would cross Kentuck, Wilanch, Catching, and Stock Sloughs, and Boone Creek, which the Association claims are of value to coho salmon. The route down Lilienthal Creek would cross the Brunschmid Wetland Reserve Project, which has an easement held by the USDA Farm Services Agency. These concerns would also apply to the currently proposed route because Variation WC-1A and the proposed route share the same location at the crossings of these waterbodies and wetlands. Each of the other pipeline route variations evaluated in the Coos Bay area would also potentially affect salmon as a result of in-water construction within Coos Bay or other waterbody crossings, therefore potential impact on salmon could not be avoided by using one of the other Coos Bay alternative routes. Members of the Waterbody Crossing Methodologies Subgroup of the Federal and State Task Force on ESA-related issues for the Project appeared to favor Route Variation WC-1A over the in-water route, for the reason that variation WC-1A (and also the proposed route) would reduce the length of pipeline within aquatic habitat.

We address impacts on waterbodies and wetlands in section 4.3 of this final EIS. Pacific Connector intends to use a bore to cross under both Kentuck and Catching Sloughs, thus avoiding direct impacts on those waterbodies and the fish species that may inhabit those streams. We believe that measures proposed by Pacific Connector for construction and restoration within wetlands would adequately minimize impacts on wetlands along Lilienthal Creek and the Brunschmid Wetland Reserve Project. However, we have recommended in section 4.3 that Pacific Connector work with the Coos Watershed Association and the USDA Farm Services Agency during finalization of design plans to ensure that impacts on the Wetland Reserve Project and adjacent wetlands are properly mitigated. We address impacts to federally listed salmon in section 4.6, and outline measures that would be used to avoid, reduce, or mitigate those impacts.

3.4.2.2 MPs 9 to 22 - Blue Ridge Route Variations

In filings made on October 4, 2007, both Fred Messerle & Sons, Inc. (Messerle) and the Coos County Sheep Company proposed what they called the Blue Ridge Alternative Route between about MPs 9 and 22 (figure 3.4-3). They contend that this route, shifting the pipeline further east, would place the pipeline over tracts mainly owned by the federal government and large timber companies. They state that their alternative route would be further removed from the Coos Bay estuary, and farther away from areas that would be more likely to be developed in the future for residential and commercial purposes. Their suggested route alternative would mostly follow ridgelines. They claim that their alternative route would only have one waterbody crossing, of Steinnon Creek, and would avoid crossings of Catching and Stock Sloughs, and
Boone Creek, Catching Creek, and Cunningham Creek along the proposed route. Pacific Connector believes that the alternative route would cross five waterbodies. The variation would be about 0.8 mile shorter than the corresponding segment of the proposed route.

In a November 21, 2007 filing, responding to a November 2, 2007 data request from the FERC, Pacific Connector provided the results of its desktop comparison of the Blue Ridge Route Variation with the September 2007 proposed route between about MPs 9 and 22. Pacific Connector contends that there are constructability issues along the Blue Ridge Route Variation, as two areas susceptible to landslides were identified with LiDAR. The proposed route would follow the exiting BPA powerline corridor for 5.9 miles, while the Blue Ridge Route Variation would follow a one-lane asphalt road for 4.1 miles. Pacific Connector believes it would have to install its pipeline in Blue Ridge Road along the route variation, resulting in traffic delays due to road closures, potentially impacting residences along the route, limiting access for timber extraction and recreational activities in the area, and increasing expenses related to rebuilding the road after pipeline installation. Pacific Connector is also concerned that the Blue Ridge Route Variation would follow Razor Back Ridge Top, requiring slow and expensive stave-pipe construction techniques that could add a year to the installation schedule, with limited access for construction vehicles, limited turn around space, and limited work space.

In a November 29, 2008 letter to the FERC, Laurie and Richard Potts supported the finding in the draft EIS that the proposed route was environmentally preferable to the Blue Ridge Variation. They point out that the Blue Ridge Route Variation was promoted by Messerle to avoid impacts on his property. The variation merely shifts the burden of the pipeline route onto other landowners. Potts state that Blue Ridge is narrow, with steep drop offs, and residents driving along Blue Ridge Road have to use pullouts to avoid oncoming traffic. They are concerned about safety and buildability issues if the pipeline was rerouted along the road.

A December 1, 2008 letter to the FERC from Mark Sheldon of Coos Bay argued in favor of the Blue Ridge Route Variation because it would affect fewer landowners (by two) and cross fewer creeks (by two) in comparison to the proposed route. Messerle, in a December 1, 2008 letter, proposed the use on an Amended Blue Ridge Alternative Route between about MP 9.2 along Route Alternative WC-1A and MP 21.6. Messerle claims this new alternative route would avoid the wetland habitat restoration project on the Brunschmid property, avoid potential cultural resources at Grave Yard Point, eliminate crossings of Stock Slough and Catching Slough, and instead move the pipeline to a route within the Vogel Creek drainage. Messerle asserts that the new alternative route would reduce the length of the pipeline and reduce impacts on private property by increasing the distance crossing BLM land. The Coos Watershed Association, in a December 4, 2008 letter commenting on the draft EIS, requested a more thorough analysis of the Amended Blue Ridge Alternative Route. In a December 29, 2008 data request, we asked Pacific Connector to provide the results of a desk-top environmental analysis of the Amended Blue Ridge, and additional information was filed on January 21, 2009. Figure 3-4-3 illustrates the proposed route, Messerle’s October 2007 Blue Ridge Route Variation, and his December 2008 Amended Blue Ridge Alternative Route. Table 3.4.2.2-1 compares environmental elements between the proposed route, Blue Ridge Route Variation, and Amended Blue Ridge Alternative Route. The proposed route would be longest, and affect the most landowners, while the Amended Blue Ridge Alternative Route would be 2.2 miles shorter and affect 18 fewer tracts. The proposed route would maximize following existing rights-of-way, and would cross less steep terrain.
TABLE 3.4.2.2-1

Comparison of Pacific Connector's Proposed Route and Blue Ridge Route Variation and Amended Blue Ridge Variation (MP 9.45 to 21.6) a,b,c,d

<table>
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<tr>
<th>Impact/Issue</th>
<th>Proposed Route</th>
<th>Blue Ridge Variation</th>
<th>Landowner Amended Blue Ridge Variation</th>
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<tr>
<td>Individual Land Tracts</td>
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<td>40</td>
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<td>Total Length (miles) b/</td>
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<td>Parallel/Adjoining Existing Disturbances (miles) c/</td>
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<tr>
<td>In-Road Lay – Paved (Asphalt) – Rebuild road post-construction (miles)</td>
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<td>4.1 d/</td>
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<td>HDD</td>
<td>HDD</td>
<td>HDD – not feasible e/</td>
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<td>Creek/Ditch Crossings f/</td>
<td>60 f/</td>
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<td>17 f/</td>
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<td>Concrete Weight Coating of Pipe Required (miles) i/</td>
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a/ To provide a common comparison of all routes, the routes begin at MP 9.45 of the proposed route.
b/ Lengths measured using ArcMap GIS Software.
c/ The proposed route would parallel 5.9 miles of BPA rights-of-way, whereas both variations would follow 4.1 miles of single-lane paved road as noted in Footnote 4.
d/ 4.1 miles ridge top construction is within & above a light-duty single-lane paved road; 0.50 mile of which is populated on both sides of the road.
e/ Potential Coos River HDD not feasible on Landowner Amended route because of steep slopes and lack of suitable HDD entry or exit point on north side of the Coos River.
f/ Based on Pacific Connector's wetland and waterbody surveys conducted by Jones and Stokes on the Proposed Route and from Pacific Northwest Hydrography Framework Clearinghouse (PNHFC) data layers (http://hydro.nrc.gov) for the variations. The Proposed Route includes 12-ditches, 11-intermittent waterbodies and 37-perennial waterbodies.
g/ Only 4 access points in 9.5 miles ridge top - Extended In/Out Travel Time for all operations along ridge top easement means short work production days.
h/ 4.5 miles razorback ridge top - extremely narrow, limited work space, limited access, limited turnaround space available.
i/ Based on Pacific Connector's wetland and waterbody surveys conducted by Jones and Stokes on the Proposed Route and NWI mapping on the variations where wetland and waterbody surveys have not been completed.

Pacific Connector identified additional areas of potentially rapidly moving landslides on slopes immediately south of MP 9.45 and north of Echo Valley, as well as on the slopes on the north side of the Coos River along the Amended Blue Ridge Alternative Route. Pacific Connector also believes that an HDD under the Coos River would not be possible along the Amended Blue Ridge Alternative Route because of the topographic conditions on the north side of the river. Therefore, a wet open-cut crossing would be required.

Because there are questions about safety and buildability along the alternative routes, we do not believe that either the Blue Ridge Route Variation or the Amended Blue Ridge Alternative Route are clearly environmentally superior, and do not recommend either. While the proposed route would follow more existing rights-of-way and less steep terrain, the alternative routes would encounter difficult construction conditions, landslide areas, access issues, and most likely result in delays for users of Blue Ridge Road. While any of the routes would cross streams that...
provide habitat for salmon, we are concerned about increased impacts caused by an open-cut crossing of the Coos River along the Amended Blue Ridge Alternative Route. The desk-top analysis is adequate to support our finding that the proposed route is environmentally preferable, and we do not agree that on-the-ground surveys of the alternatives routes or additional analyses are necessary.

3.4.2.3 MP$s 36 to 39 - Big Creek/Spirit Mountain Route Variations

On December 9, 2007, the BLM Coos Bay District requested that the FERC analyze three potential alternative routes between about MP 36 to 39 to avoid newly identified habitat for MAMU nesting sites. In a December 14, 2007 data request, the FERC asked Pacific Connector to provide desktop data comparing the suggested alternative routes (northern, southern, and intermediate variations) with the corresponding segment of proposed route (figure 3.4-4 and table 3.4.2.3-1).

The northern route variation would leave the proposed route just east of MP 36, heading northeast towards Spirit Mountain, following in a part an existing road or trail for about 1.5 miles, then rejoining the proposed route just east of MP 38. This variation would be about 0.5 mile longer than the corresponding segment of proposed route. The route variation would transverse rugged topography with steep slide-slopes (greater than 50 percent) and cross several waterbodies. The geologic hazard evaluation determined that this variation is not a reasonable alternative due to the high risk of landslides and construction difficulties on the steep slide-slopes.

The southern route variation would head southeast from the proposed route east of MP 36, crossing Big Creek, following existing roads or trails for about 1.3 miles, and rejoining the proposed route just east of an existing quarry east of MP 39. This variation would be about 0.33 mile longer than the corresponding segment of proposed route. It would require less clearing of mature forest, and would cross an area with more regenerating forest. This variation would cross Big Creek, which would be avoided by the proposed route. It would also cross tribal lands associated with the Coquille Forest that would be avoided by the corresponding segment of proposed route.

The intermediate route variation would roughly follow the first mile of the southern variation, but then turn north and rejoin the proposed route near MP 38.1. This variation was eliminated from further evaluation because it would require crossing unstable slopes composed of a landslide complex mapped and described in the Geologic Hazards Report submitted with the Pacific Connector's FERC application. This alternative would also cross Big Creek, which would be avoided by the corresponding segment of proposed route.
Exhibit O
### Alternatives Analysis

<table>
<thead>
<tr>
<th></th>
<th>2009 FEIS Route (MPs)</th>
<th>WRP Avoidance Alternative 1</th>
<th>Proposed Route (Environmentally Preferred)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length of waterbody crossings (feet)</td>
<td>763&lt;sup&gt;4&lt;/sup&gt;</td>
<td>754&lt;sup&gt;3&lt;/sup&gt;</td>
<td>750&lt;sup&gt;3&lt;/sup&gt;</td>
</tr>
<tr>
<td>Number of wetlands crossed</td>
<td>6&lt;sup&gt;4&lt;/sup&gt;</td>
<td>6&lt;sup&gt;5&lt;/sup&gt;</td>
<td>3&lt;sup&gt;5&lt;/sup&gt;</td>
</tr>
<tr>
<td>Length of wetland crossings (feet)</td>
<td>5,902&lt;sup&gt;4&lt;/sup&gt;</td>
<td>4,417&lt;sup&gt;5&lt;/sup&gt;</td>
<td>6,687&lt;sup&gt;5&lt;/sup&gt;</td>
</tr>
<tr>
<td>Agricultural lands affected (miles)</td>
<td>0.33&lt;sup&gt;6&lt;/sup&gt;</td>
<td>0.33&lt;sup&gt;6&lt;/sup&gt;</td>
<td>1.19&lt;sup&gt;6&lt;/sup&gt;</td>
</tr>
<tr>
<td>Evergreen Forest (acres construction right-of-way)</td>
<td>3.81</td>
<td>7.67</td>
<td>13.66</td>
</tr>
<tr>
<td>Regenerating forest clearing (acres construction right-of-way)&lt;sup&gt;7&lt;/sup&gt;</td>
<td>7.16</td>
<td>7.49</td>
<td>14.66</td>
</tr>
</tbody>
</table>

| Habitat for threatened or endangered species | Coos River Southern DPS Green Sturgeon River - HDD | Directly affects Known bald eagle nest<sup>8</sup> Coos River Southern DPS Green Sturgeon River - HDD | Coos River Southern DPS Green Sturgeon River - HDD |
| Number of previously recorded cultural resources | 1 | 1 | 1 |
| Number of newly identified cultural resources<sup>9</sup> | 0 | 0 | 0 |
| Miles of right-of-way parallel or adjacent to existing rights-of-way (percent of alternative length) | 0.84 (29.5 percent) | 0.76 (27.1 percent) | 0.50 (17.2 percent) |

<sup>1</sup> Mileage length cannot be calculated by subtracting milepost ranges because of engineering station equations included in route segment between MP 9.41R to 12.39R.<br><sup>2</sup> Acres of permanent easement calculated based on crossing length on private and federal timber lands. Pacific Connector proposes a 50-foot permanent easement on federal lands and a 50-foot permanent easement on private timber lands.<br><sup>3</sup> From aerial photo review and review of Pacific Northwest Hydrography Framework Clearinghouse data layers (http://hydro.reo.gov/).<br><sup>4</sup> Based on field surveys (see Tablo 2A-3 in Appendix 2A to Resource Report 2). Note, some waterbody crossing lengths are included in the wetland crossings length (waterbody/ditches not separated out of extensive wetlands)<br><sup>5</sup> Based on NWI mapping. Waterbodies/ditches not separated out of extensive wetlands.<br><sup>6</sup> Agricultural lands are associated with the Coos River Floodplain and included wetland pastures and hayfields.<br><sup>7</sup> Includes recent clear-cut forests.<br><sup>8</sup> ORBIC - Oregon Biodiversity Information Center Data, Institute for Natural Resources, Portland State University 2012. Nest site confirmed during PCGP October 2012 over-flight route investigation.<br><sup>9</sup> Surveys incomplete.

### 10.6.3 Blue Ridge Route Variation MPs 9.0 to 21.6

On October 4, 2007, both Fred Messerle & Sons, Inc. (Messerle) and the Coos County Sheep Company proposed the 'Blue Ridge Alternative Route' to FERC between MPs 9 and 22 (see Figure 10.6-3). They indicated that shifting the pipeline route to the east would place the pipeline over tracts mainly owned by the federal government and large timber companies. They stated that the alternative route would be further removed from the Coos Bay estuary and away from areas that
would more likely be developed in the future for residential and commercial purposes. The suggested route alternative mostly followed ridgelines. They claimed that the alternative would only cross one waterbody, Steinhorn Creek, and would avoid crossings of Catching and Stock Sloughs, Boone Creek, Catching Creek, and Cunningham Creek, which were crossed along the proposed route. Pacific Connector determined that the alternative would cross five waterbodies but would be about 0.8 mile shorter than the corresponding segment of the proposed route.

In a November 21, 2007 filing, responding to a November 2, 2007 FERC Data Request, Pacific Connector provided the results of a desktop comparison of the Blue Ridge Route with the 2007 proposed route between MPs 8.9 and 21.6. Pacific Connector evaluated the route from a constructability, pipeline integrity, and land impact perspective. Using LIDAR, two Rapidly Moving Landslides (RMLs) were identified along the Blue Ridge Route as well as several constructability issues related to narrow ridge-top construction, limited access, limited workspace, and potential logistical problems in providing access to area residents. In addition, residential development is anticipated along portions of Blue Ridge Road, a one-lane asphalt road, which the Blue Ridge Route followed for approximately 4.1 miles.

In a November 29, 2008 letter to FERC, Laurie and Richard Potts supported the finding in the Draft EIS that the proposed route was environmentally preferable to the Blue Ridge Route. They pointed out that the Blue Ridge Route Variation was promoted by Messerle to avoid impacts to his property and that the variation merely shifted the burden to other landowners. The Potts stated that Blue Ridge is narrow, with steep drop-offs, and residents driving along Blue Ridge Road must use pullouts to avoid oncoming traffic. They were concerned about safety and constructability if the pipeline was rerouted along the road.

In a December 1, 2008 letter to FERC, Mark Sheldon of Coos Bay argued in favor of the Blue Ridge Route Variation because it would affect fewer landowners (by two) and cross fewer creeks (by two) in comparison to the proposed route. Fred Messerle & Sons, Inc. suggested an 'Amended Blue Ridge Alternative Route' in a December 1, 2008 comment letter between about MPs 9.2 and 21.6 (shown as 'Landowner Amended Route' on Figure 10.6-3). Messerle claimed that the amended alternative route would avoid the wetland habitat restoration project on the Brunschmid property, avoid potential cultural resources at Graveyard Point, eliminate crossings of Stock Slough and Catching Slough, and move the pipeline within the Vogel Creek drainage. Messerle also indicated that the amended alternative route would reduce the length of the pipeline and reduce impacts on private property by increasing the distance crossing BLM-managed lands. The Coos Watershed Association, in a December 4, 2008 letter commenting on the Draft EIS, requested a more thorough analysis of the Amended Blue Ridge Alternative Route/Landowner Amended Route.

In response to a December 29, 2008 FERC Data Request to analyze the Amended Blue Ridge Route, Pacific Connector filed additional information on January 21, 2009 (see Table 10.6-3), comparing the proposed route, the Blue Ridge Alternative, and the Amended Blue Ridge Alternative. The comparison is based on a common beginning and ending location along the proposed route. The proposed route would be the longest, and affect the most landowners, while the Amended Blue Ridge Alternative Route would be 2.2 miles shorter and affect 18 fewer tracts. The proposed route would maximize following existing rights-of-way and would cross less steep terrain.
In the January 21, 2009 response to FERC, Pacific Connector concluded that although both the landowner suggested and amended routes are shorter than the proposed route, constructability, pipeline integrity, and land impact issues (previously noted by Pacific Connector and described in the DEIS (FERC, 2008)) associated with the Blue Ridge Route Variation prevented Pacific Connector from considering these suggested routes further. The area along the narrow "razor" ridge line on Blue Ridge Road, specifically in Sections 4 and 10, T. 26 S., R. 12 W. is especially problematic where residences are located on either side of the route (as noted in the Potts' DEIS comment letter). Pacific Connector agrees that this portion of the route renders it likely unconstructable. Full-time traffic control along Blue Ridge Road would be required for timber and construction activities during construction. These road restrictions could potentially limit any commercial timber removal in the area, recreation, and residential access at times. If either of the proposed alternates were approved, the construction window for this section of the pipeline would change from "Clear and Construct in Year 1" to "Clear in Year 1" and "Construct in Year 2," which would increase the amount of disturbance in the area by stretching the work over a two-year construction window. The extended construction window would be required to accomplish the in-road and steep terrain pipeline installation.

Along the Landowner Amended Route, additional areas of potential rapidly moving landslides² would be crossed on the slopes immediately south of MP 9.45 and north of Echo Valley (Section 29, T. 25 S., R. 12 W.) as well as on the steep slopes on the north side of the Coos River (NE/4 Section 29, T. 25 S., R. 12 W.). The location of the Coos River crossing on the Landowner Amended Route would also likely be infeasible for an HDD because of the topographic conditions on the north side of the river. The narrow floodplain and steep slopes, approximately 300 feet from the edge of Millicoma Highway on the north side of the river, would limit the necessary HDD setback to allow acceptable geometric requirements and proper workspace layout for a large-diameter pipeline. At this crossing location, a wet open-cut river crossing method would be required since a conventional bore would be infeasible because of the excessive length (greater than 700 feet) to cross the river and the roads on either side of the river (Millicoma Highway and Coos River Road).

For these reasons, Pacific Connector concluded that the current proposed route is the environmentally preferred route that will have the least impact on local land area residents and allow for safe and efficient pipeline construction and operation.

<table>
<thead>
<tr>
<th>Impact/Issue</th>
<th>Proposed Route</th>
<th>Blue Ridge Variation</th>
<th>Landowner Amended Blue Ridge Variation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Individual Land Tracts</td>
<td>58</td>
<td>48</td>
<td>40</td>
</tr>
<tr>
<td>Total Length (miles)</td>
<td>15.63</td>
<td>14.63</td>
<td>13.63</td>
</tr>
<tr>
<td>Parallel/Adjoining Existing Disturbances (miles)</td>
<td>6.85</td>
<td>5.05</td>
<td>4.22</td>
</tr>
<tr>
<td>Timbered Land (miles)</td>
<td>10.63</td>
<td>10.73</td>
<td>10.75</td>
</tr>
<tr>
<td>In-Road Lay – Dirt (Gravel) – Rebuild road post-construction (miles)</td>
<td>1.07</td>
<td>1.17</td>
<td>0.69</td>
</tr>
<tr>
<td>In-Road Lay – Paved (Asphalt) – Rebuild road post-construction (miles)</td>
<td>None</td>
<td>4.1 df</td>
<td>4.1 df</td>
</tr>
</tbody>
</table>

² The Oregon Department of Geology and Mineral Industries (DOGAMI), in cooperation with other agencies, produced a map of Potential Rapidly Moving Landslide Hazards in Western Oregon (Hofmeister et al., 2002).
### Impact Issues

<table>
<thead>
<tr>
<th>Impact Issue</th>
<th>Proposed Route</th>
<th>Blue Ridge Variation</th>
<th>Landowner Amended Blue Ridge Variation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Road Closure During Construction – Flaggers, Traffic Control &amp; Detours (miles)</td>
<td>None</td>
<td>4.1 d/</td>
<td>4.1 d/</td>
</tr>
<tr>
<td>River Crossings</td>
<td>HDD</td>
<td>HDD</td>
<td>HDD – not feasible g/</td>
</tr>
<tr>
<td>Creek/Ditch Crossings /</td>
<td>60 g/</td>
<td>12 g/</td>
<td>17 h/</td>
</tr>
<tr>
<td>Slough Crossing – Dry Open Cut</td>
<td>1</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Slough Crossing – Bore (feet)</td>
<td>400</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>Unpaved Road Crossings – Cut</td>
<td>33</td>
<td>20-33</td>
<td>20-25</td>
</tr>
<tr>
<td>Paved Road Crossings – Cut</td>
<td>7</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>Steep Up &amp; Down Slopes – Tie-Off Equipment, etc., (miles)</td>
<td>1.1</td>
<td>1.2</td>
<td>1.3</td>
</tr>
<tr>
<td>Narrow Ridge Top Construction – Only access is along easement (miles)</td>
<td>None</td>
<td>9.5 h/</td>
<td>9.5 h/</td>
</tr>
<tr>
<td>Razor – Back Ridge Top Construction – Stove-pipe, Sections, End haul, etc., (miles)</td>
<td>None</td>
<td>4.5 h/</td>
<td>4.5 h/</td>
</tr>
<tr>
<td>Concrete Weight Coating of Pipe Required (miles) d/</td>
<td>1.58</td>
<td>1.08</td>
<td>0.93</td>
</tr>
<tr>
<td>Work off Hardwood Mats/Dewater Ditch, etc. (miles) (g)</td>
<td>1.58</td>
<td>1.08</td>
<td>0.93</td>
</tr>
</tbody>
</table>

**Note:**
- d/ To provide a common comparison of all routes, the routes begin at MP 9.45 of the proposed route.
- h/ Lengths measured using ArcMap GIS Software.
- g/ The proposed route would parallel 5.9 miles of BPA rights-of-way, whereas both variations would follow 4.1 miles of single-lane paved road as noted in Footnote 4.
- f/ 4.1 miles ridge top construction is within & above a light-duty single-lane paved road; 0.50 mile of which is populated on both sides of the road.
- e/ Potential Coos River HDD not feasible on Landowner Amended route because of steep slopes and lack of suitable HDD entry or exit point on north side of the Coos River.
- f/ Based on Pacific Connector’s wetland and waterbody surveys conducted by Jones and Stokes on the proposed route and from Pacific Northwest Hydrography Framework Clearinghouse (PNHFC) data layers (http://hydro.rea.gov) for the variations. The proposed route includes 12-ditches, 11-intermittent waterbodies and 37-perennial waterbodies.
- g/ Only 4 access points in 9.5 miles ridge top - Extended In/Out Travel Time for all operations along ridge top easement means short work production days.
- h/ 4.5 miles razorback ridge top - extremely narrow, limited work space, limited access, limited turnaround space available.

**10.6.4 Big Creek/Spirit Mountain Route Variations MP 36 to 39**

On December 9, 2007, the BLM Coos Bay District requested that FERC analyze three potential alternative routes between MP 36.14 and 39.15 in an effort to avoid impacts to occupied Marbled Murrelet stands and old growth forest stands. The ‘Intermediate’ route was eliminated (as described below) based on geologic issues. In a response to a December 14, 2007 data request, Pacific Connector utilized existing geographic spatial resource data, topographic maps, and recent aerial photography to provide comparison information for the other two routes (see Table 10.6-4).

**Table 10.6-4**

<table>
<thead>
<tr>
<th>Alternatives Analysis</th>
<th>Proposed Alignment (MPs 36.14 - 39.15)</th>
<th>BLM Northern Variation T8S, R10W, Sec. 21, 22, 27, 28 &amp; 29</th>
<th>BLM Southern Variation T8S, R10W, Sec. 26, 27, 28, 29, 33 &amp; 34</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length (miles)</td>
<td>2.75 1</td>
<td>3.20</td>
<td>3.08</td>
</tr>
<tr>
<td>Construction right-of-way (acres)</td>
<td>31.67</td>
<td>38.85</td>
<td>35.47</td>
</tr>
<tr>
<td>Temporary extra work areas (TEWA) (acres)</td>
<td>21.46</td>
<td>Not designed. Estimated to require more temporary extra work areas than the proposed route because of increased length, length of steep side slope and steep slope</td>
<td>Not designed. Estimated to require more temporary extra work areas than the proposed route because of increased length, length of steep side slope and increased number of</td>
</tr>
</tbody>
</table>

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30
Exhibit P
October 9, 2013

Mr. Stuart Cowie  
Douglas County Planning Department  
Douglas County Courthouse  
Room 216  
Roseburg, OR 97470

Re: PACIFIC CONNECTOR GAS PIPELINE MAJOR AMENDMENT - P/D 09-045  
Previously Approved Conditional Use Permit & Utility Facility Necessary for Public Service

Dear Mr. Cowie:

We are in receipt of your recent notice regarding Pacific Connector Gas Pipeline’s (PCGP) request for a Major Amendment to a previously approved Conditional Use Permit in Douglas County's Coastal Zone Management Area and appreciate the opportunity to comment. The proposed pipeline will cross Seneca Jones Timber Company’s (SJTC) ownership across two tax lots (1000 and 1100) in Section 10, Township 29 South, Range 8 West. The zoning designation on SJTC’s property is Timberland Resource property.

SJTC has maintained a presence in Douglas County for over 20 years, through the management of our timberland base, largely located in Douglas County, Oregon. The above referenced tract is just one of many of SJTC forest properties negatively impacted by the PCGP project. We manage our timberland base on a sustained yield basis by local foresters and employees who make Douglas County their home. The lumber generated from our forests is essential as a supply source for our milling operations and our ability to stay in business benefiting Douglas County.

SJTC attended the public hearing in 2009 regarding PCGP’s request for the original conditional use permit to allow construction of a new gas pipeline in Douglas County's Coastal Zone Management Area. Since that time, it appears that PCGP has failed to exercise the use stated in the original conditional use permit. The Douglas County Land Use and Development Ordinance (Article 39, Section 3.39.200) provides that a conditional use permit will become invalid without special action if the permit is not exercised within two (2) years of the date of approval, or the use approved by the conditional use permit is discontinued for any reason for one (1) continuous year or more. More importantly, PCGP has substantially altered the intent of the conditional use permit by suggesting and requesting an export facility rather than an import facility. Given the inability to meet the timeframes outlined in code and the substantial modifications to the request, a new conditional use permit application appears warranted, rather than a major amendment. As a subscriber to the information PCGP supplies to FERC, significant new and updated information is now available that was either unavailable or unknown in 2009.

As defined in the Douglas County Land Use and Development Ordinance (Article 2 Section 3.2.000) the purpose of establishing Farm Forest Land is to insure, conserve and retain these lands for forest resource uses, protecting such land from nonresource use and conflicts. As part of the conditions for approval of a conditional use permit, we require assurance that the
utility pipeline will be compatible and not interfere with accepted resource management practices. Another primary aspect to consider in approving this conditional use permit request is that placement of the utility pipeline will not:

- Force a significant change in or significantly increase the cost of accepted forest practices on our lands (Article 2 Section 3.2.150(1)),
- Increase the fire hazard and/or resultant fire suppression costs (Article 2 Section 3.2.150(2)), and
- Significantly increase risks to fire suppression personnel (Article 2 Section 3.2.150(2)).

Our initial contact with PCGP representatives began in March, 2006. Seven years later, despite numerous meetings, we are no closer to reaching an agreement to utilize our property than we were back in 2006. Although PCGP indicates they can adequately compensate our loss; our facilities need fiber rather than cash to operate on a long-term continual basis without negative economic impacts. We have yet to receive any assurances in writing that PCGP will adequately finance or mitigate our increased costs and loss of productive timber growing ground. On May 9, 2013, potential solutions to mitigate the impacts to our timberland base, were specifically denied by PCGP. PCGP seems to have a "one size fits all approach" to dealing with landowners, while we manage our property utilizing a "site specific" philosophy to address unique aspects. Some of our concerns include:

- Gas pipelines located on timberland properties require atypical harvest methods, as characteristically the gas pipeline is located on the same ridge line in which a forest landowner wants to place its equipment or construct access routes. Topographical features can limit the number of viable equipment sites, in some cases, only one location may be available and/or feasible. Employment of these atypical harvest methods increase costs and reduce revenues.
- Avoiding the spread of invasive plants, such as scotchbroom, and the treatment and control of these species. PCGP admits that routine vegetation mowing or clearing over the full width of the permanent right-of-way in uplands shall not be done more frequently than every three years.
- The maintenance of forest roads that provide access to the pipeline and PCGP's willingness to assist in this effort.
- Preventing recreational traffic from utilizing the gas pipeline right-of-ways.
- Loss in timber value as a result of harvesting at less than optimal periods to allow for construction of pipeline.
- Loss of plantable land to allow for a minimum of 30' wide corridors through existing land.
- Removal of slash and debris generated from construction.
- Increased risk of fire to adjacent forestland and necessary response for immediate suppression. Catastrophic wildfires clearly demonstrate that scorching of subsoils can occur to depths as much as three feet, along with retainage of significant temperatures in these soils. To suppress fire, generally the utilization of heavy equipment digs and turns over soils to distribute the heat contained in the soil. Placement of a gas pipeline will impede these normal suppression efforts. The intensity of thermal radiation may
Letter to Stuart Cowie  
October 9, 2013  
Page Three

entirely block a firefighter's ability to approach the area for suppression purposes or employ use of conventional firefighting equipment. As the Oregon Department of Forestry is responsible for the initial attack on forest fires, Douglas County may want to seek input, guidance for mitigation, and concurrence with the placement of this additional fire risk potentially located on private forest lands.

- Gas pipelines located in an unpopulated forested area may allow PCGP to utilize reduced construction standards. Given the high pressure content of these lines, pipeline construction standards through forest land property should match urban construction standards and covered with soil as deeply as possible to prevent and minimize possible pipeline breach/ruptures due to heavy equipment operation or other natural phenomena in order to protect our valuable timberland resource.

- Studies are suggesting that the transmission and storage of natural gas can result in possible methane emissions through potential leaks, as well as compressor stations located along the pipeline. Gas leaks are invisible, loosely regulated and often are difficult to find. The EPA website shows that fugitive emissions from underground pipelines make up over 50% of methane emissions in the distribution sector, which can vary based on pipeline use, material and age. Long term corrosion of pipe steel may also occur when exposed to ground water. Methane emission is a greenhouse gas and we would ask that Douglas County seek assurance that PCGP quantify and address these emissions in the Coastal Zone Management Area, should Douglas County deem this as a concern, now or in the future.

Although, FERC provided a certificate of necessity for an import facility, PCGP has yet to provide adequate evidence to FERC to meet all the requirements necessary for a certificate of necessity for an export facility. Without a certificate of necessity, FERC has yet to release an absolute finding that this utility project is for the public good. It may be premature to determine the outcome of this conditional use permit until FERC determines its decision on the certificate of necessity.

The Douglas County Land Use and Development Ordinance references the public in applying rules and provisions that apply to utility installations. Will the Planning Commission apply this definition specifically to the residents of Douglas County or is this term broader in scope. Certainly, as an export facility, rather than an import facility, Douglas County must weigh the long-term benefits to the local citizens and the Douglas County public. In 2009, one of the important aspects that PCGP reportedly could deliver was the ability to supply new and existing commercial energy customers access to natural gas which would provide long-term economic benefits directly to Douglas County. Recent submittals to FERC do not explore this possibility and if it is important to Douglas County citizens as a whole, we would recommend a written document to that effect prior to conditional use approval.

Douglas County addresses many local residents concerns regarding the siting standards for wireless utility and communication facility siting (Article 39 Section 3.39.150). The siting of an underground gas pipeline of this magnitude should also have similar provisions to ensure that the structure is located safely on stable ground and will not exceed local resources to safeguard our community assets and resources that make Douglas County a great place to live. According to information PCGP supplied to FERC, the placement of the pipeline impacts
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over 500 acres of high erosion potential land, a significant portion of which lies in Douglas County.

Lastly, we would suggest that Douglas County consider requiring a bond from the applicant to ensure compliance with any conditions imposed should Douglas County ultimately approve this application.

Despite our significant concerns, we continue to maintain a willingness to work with PCGP on several alternatives, seeking a letter of agreement to ensure that these concerns be addressed at an early juncture. *Article 2 Section 2.120(1)(a)*, places the burden of proof on the applicant to ensure compliance with the timberland resource goals.

SJTC remains supportive of projects that benefit the local community. Certainly, we would support a pipeline project that both addresses our concerns and is compatible with the permitted uses in the Timberlands Resources zone. At this juncture, we do not agree that PCGP has met its delineated burden of proof either with Douglas County or with FERC.

We appreciate the opportunity to comment and urge that the application now before you not be approved as we clearly disagree with the applicant's statement that the pipeline is a subsurface utility that will have no impact on either passive or active forestry operations after construction. We would like to reserve the opportunity to appear and be heard at the upcoming hearing on October 17, 2013 at 7:00 p.m., in any event, we trust our comments will be incorporated into the official record.

Sincerely

Monica Jelden  
Real Properties Coordinator

cc: T. Payne  
S. Weber  
R. Re  
D. Riddle  
T. Reiss  
D. Robertson
Exhibit Q
A question of fire protection

Some rural areas lack ways to fight structure fires

December 31, 2008 12:00 am  •  By Jessica Musicar, Staff Writer

When the home of fellow Allegany residents went up in a blaze around midnight Monday, Howard Edwards grabbed his water pump. He rushed to protect neighboring houses.

He remained at the home up the West Fork of the Millicoma River for more than three hours. Firefighters from the Coos Forest Protective Association arrived and stayed 45 minutes to ensure a fire wouldn't erupt in nearby trees. They and the home owners could only watch as the house at 67520 West Fork Millicoma Road burned.

Neighbors said the owners of the 1,672 square-foot home, Robert Yesser and Jane Cross, are staying at the Red Lion Hotel in Coos Bay. The pair declined assistance from the American Red Cross and was unavailable before press time.

The state will not investigate the cause of the fire, said Bob Wright, a supervising deputy for the Office of the State Fire Marshal.

He said he learned of the fire the evening it occurred and contacted the Coos Bay Fire Department, because it was the closest fire agency to the scene. But he has not been to the site and the state will not investigate the fire unless home owners request it.

CFPA's firefighters aren't trained nor equipped to battle structure fires. Nor could other local fire department have done any better — there aren't any. The house and many others in Allegany aren't included in any city or rural fire protection districts.

"It's a way of life. That's what you take with where you live," Edwards said on Tuesday, adding he is aware CFPA's hands are tied. "They're not going to touch anything unless its burning trees.

"They wouldn't let anybody die. But they have to go along with their bylaws."

Even if Coos Bay fire trucks had responded, it wouldn't have made much of a difference, said Fire Chief Stan Gibson. It would have taken too long to get there to save the structure and if they had gone, the city of Coos Bay would've been stuck with the bill.

"We would have been closest but there is no way we would have responded, because they are not paying for the service. They don't belong to the taxing district," Gibson said.

It's a somewhat hazardous yet not uncommon situation for people residing in rural areas.
“For people who live outside of a fire district they may be saving money on their taxes. However they are paying increased costs for their homeowner’s insurance and receive no protection,” Gibson said.

CFPA is responsible only for wildfire protection in a district covering 1.5 million acres of private, county, state and Bureau of Land Management lands in Coos, Curry and Western Douglas counties.

Nils Storksen, the unit forester for CFPA’s Coos Bay office, said the association doesn’t fight structure fires because staff members are only trained for wildland fire suppression. They haven’t been trained to handle burning buildings.

“Even our fire trucks that we use, they don’t meet specifications required for safety standards,” Storksen said. “They don’t hold enough water. They don’t pump enough water. All in all, wildland and structure fire, they are totally different arenas.”

Rich Hoover, the State Fire Marshal’s public information officer, said residents in unprotected areas throughout the state do have an option. They can work together to start their own fire district. It just takes money, manpower and possibly a tax base.

“They just have to realize that if they want to form a district there will be some cost associated with that,” Hoover said.

He described another rural community in Central Oregon that faced the same problem. Residents founded the Three Rivers Rural Fire Protection District in June.

“I just think they thought protection was a good idea,” Hoover said. “They didn’t want to be unprotected.”

Art Klingsporn, the chief of Three Rivers Rural Fire Protection District, said they raised money and passed a ballot measure to get the district started. Its directors also signed a mutual aid agreement for extra protection. Now, if a fire threatens the area, other fire agencies can lend a hand.

“We wanted help,” he said.

Although Allegany remains without fire protection, the issue of a fire district has been brought up.

A 30-plus year resident of Allegany, Edwards said locals discussed it some time ago.

“I’m sure after this there might be a lot more conversation,” he said. “It wouldn’t be a bad idea but you’ve got to have everyone involved.”
Exhibit R
(C-FER hazard info begins on page 110. Graph is on page 112)

SPECIAL REPORT 281

Transmission Pipelines and Land Use
A Risk-Informed Approach

Committee for Pipelines and Public Safety:
Scoping Study on the Feasibility of Developing
Risk-Informed Land Use Guidance near
Existing and Future Transmission Pipelines

TRANSPORTATION RESEARCH BOARD
OF THE NATIONAL ACADEMIES

Transportation Research Board
Washington, D.C.
2004
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THE NATIONAL ACADEMIES
Advisers to the Nation on Science, Engineering, and Medicine

The National Academy of Sciences is a private, nonprofit, self-perpetuating society of distinguished scholars engaged in scientific and engineering research, dedicated to the furtherance of science and technology and to their use for the general welfare. On the authority of the charter granted to it by the Congress in 1863, the Academy has a mandate that requires it to advise the federal government on scientific and technical matters. Dr. Bruce M. Alberts is president of the National Academy of Sciences.

The National Academy of Engineering was established in 1964, under the charter of the National Academy of Sciences, as a parallel organization of outstanding engineers. It is autonomous in its administration and in the selection of its members, sharing with the National Academy of Sciences the responsibility for advising the federal government. The National Academy of Engineering also sponsors engineering programs aimed at meeting national needs, encourages education and research, and recognizes the superior achievements of engineers. Dr. William A. Wulf is president of the National Academy of Engineering.

The Institute of Medicine was established in 1970 by the National Academy of Sciences to secure the services of eminent members of appropriate professions in the examination of policy matters pertaining to the health of the public. The Institute acts under the responsibility given to the National Academy of Sciences by its congressional charter to be an adviser to the federal government and, on its own initiative, to identify issues of medical care, research, and education. Dr. Harvey V. Fineberg is president of the Institute of Medicine.

The National Research Council was organized by the National Academy of Sciences in 1916 to associate the broad community of science and technology with the Academy's purposes of furthering knowledge and advising the federal government. Functioning in accordance with general policies determined by the Academy, the Council has become the principal operating agency of both the National Academy of Sciences and the National Academy of Engineering in providing services to the government, the public, and the scientific and engineering communities. The Council is administered jointly by both the Academies and the Institute of Medicine. Dr. Bruce M. Alberts and Dr. William A. Wulf are chair and vice chair, respectively, of the National Research Council.

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APPENDIX D

Risk Assessment Techniques in the Pipeline Industry

During the past two decades, emphasis on pipeline safety has shifted from response to prevention of accidents. Preventive actions have included greater levels of inspection, involvement of the public through communications, and prospective analysis of the dangers presented by pipelines. Pipeline companies also began to use various risk assessment techniques, including hazard and operability (HAZOP) analysis, fault tree analysis, scenario-based analysis, and indexing methods. Most analyses focus on specific factors affecting the probability of pipeline failure (e.g., internal corrosion, external corrosion, pipeline loading) or on the consequences of rupture (such as heat intensity, thermal impact radius, depth of cover). Some of these analyses focus on specific pipeline system components, while a few attempt to take component interdependencies into account. Some of the more commonly used techniques are described below.

The pipeline risk assessment and management approaches that have been published to date, regardless of the methodology used to obtain the probabilities and consequences of processes and events leading to risk, emphasize the calculation of a risk number (i.e., a mathematical product of probability and consequence). Although this calculation allows a quantitative comparison of the effect of different factors on pipeline safety, it is not adequate to define risk to the public. As outlined in Chapter 3, such a risk is better characterized in terms of the three questions posed (known in risk assessment as the risk triplet).

Recently, the U.S. Department of Transportation’s Office of Pipeline Safety (OPS) implemented a new regulatory approach—the Integrity Management Program—that establishes new testing, repair, and mitigation requirements for transmission pipelines and requires pipeline companies to use a risk-based approach for pipeline safety. Under the
program, liquid and natural gas pipeline operators, as a first step, will be
required to perform risk assessments on each of their pipeline segments
in high-consequence areas. Inspections will be performed by the use of
in-line inspection tools, analysis of operating and maintenance records,
and direct examination of pipe in selected areas. Risk criteria have been
considered in other countries, including societal risk due to land use near
pipelines (IGE 2001; Committee for the Prevention of Disasters 1999).

CURRENT APPROACH TO RISK ASSESSMENT
IN THE PIPELINE INDUSTRY

Risk assessment is the process of identifying, describing, and analyzing
risk with the following elements:

• Recognition or identification of a hazard or potential adverse event,
  perhaps with definition of accident scenarios in which the hazards are
  realized or experienced;
• Analysis of the mechanisms by which an event can occur and the
  mechanisms by which the event can create loss;
• Analysis of the consequences of an adverse event as a function of various
  factors of design or circumstance; and
• Estimation of the likelihood of the sequences of events that lead to the
  consequences.

According to Muhlbauser (1999), because the risk of pipeline failure is
sensitive to unmeasurable or unknowable initial conditions, risk efforts
are often not attempts to predict how many failures will occur or where
the next failure will occur. Instead, efforts are designed to systematically
and objectively capture everything that is known and use the information
to make better decisions.

Risk assessments can guide pipeline operators to make decisions and
take precautions that allow the risks to be minimized or avoided entirely.
Risk management is a systematic focusing of limited resources on those
activities and conditions with the greatest potential for reducing risk. In
risk management, decision makers take the results from risk assessments
and use them to prioritize risk reduction actions. Risk controls can in-
volve measures both to prevent adverse events and to mitigate their mag-
nitude. One reduces the likelihood; the other reduces the severity of impact. Another step in risk management is the monitoring of performance to determine whether risk control measures are effective. The process can be repeated to further address and reduce overall risk.

The first step in defining risk is to identify a potential hazard or dangerous situation and describe the mechanisms by which the hazard can cause harm to people, property, and the environment. Risk is then analyzed for each hazard or hazard scenario. In terms that can be analyzed, risk is defined as the product of (a) severity of impact and (b) the likelihood of impact from an adverse event. The severity of impact, often called consequences, can be expressed in human terms such as fatalities or injuries or some other metric such as dollars lost. The likelihood of occurrence of an adverse event can be estimated with a variety of methods, ranging from prior experience with the frequency of occurrence, perhaps using statistical data of similar events, to computations based on mathematical models. Likelihood can also be determined by examining the probability of the adverse event occurring in a Bayesian sense, a prior perception of probability.

The example of automobile travel can clarify the concepts. The consequences of an automobile crash can be damage to the car and injury or death to the driver or passengers. More than 40,000 Americans are killed in automobile crashes each year, and several hundred thousand more are injured. Fender benders and other minor crashes are even more frequent. From these data, the risk for large automobiles or small, local streets or Interstate highways, fender bender or serious crashes can be quantified. If a person never rides in an automobile, the risk of death, injury, or damage to one’s personal property is zero, except as a nonmotorist (e.g., pedestrian, bicyclist). By similar reasoning, a person who makes a living traveling in automobiles is more likely to experience harm than a person who rides occasionally, even given the differences in driving skill. The difference in the likelihood of experiencing harm is a concept known as exposure. The greater the exposure, the higher the risk.

Data on pipeline incidents are collected and analyzed by OPS for each reportable safety incident. These data provide the number of incidents that result in death, injury, or significant property damage. They also provide the general causes of these incidents, including damage by out-
side force, corrosion, construction defects, operator error, natural forces such as ground movement, and many other categories. At some level of aggregation, the data can be used to determine, or quantify, the risk from various types and sizes of pipelines. On the basis of this experience, one can begin to identify factors that determine risk.

The principle of exposure can be applied to pipelines as well. For an individual who seldom crosses or comes near a pipeline right-of-way—a person who has little exposure—the risk is minimal, while people who live, work, or congregate near pipelines have greater exposure. Exposure is a function of time near a pipeline and effective distance. Exposure to the potential dangers of a pipeline leak or rupture is the result of proximity to the pipeline, natural or man-made barriers, and the mobility of people near the pipeline. People pursuing activities on or near the pipeline that can cause damage to the pipeline have the greatest exposure.

SCENARIO-BASED RISK ASSESSMENT

This category of risk assessment includes a number of methods: HAZOP studies, scenario-based fault tree/event tree analysis, and so forth. These techniques are useful for examining specific situations, and often they are used with other techniques.

HAZOP Technique

In the HAZOP study approach, all possible failure modes are examined, but it is very time-consuming and costly. HAZOP analysis is used in the preliminary safety assessment of new systems or modifications of existing systems. A HAZOP analysis involves a detailed examination of pipeline system components to determine the outcome if a specific component does not function as it is designed to (within its normal parameters). Each parameter (e.g., pressure or flow rate) is examined to identify potential changes in the system that are based on changes in the component parameter.

Fault Tree Analysis

In scenario-based fault tree analysis, the sequence of events is traced backwards from a failure. This technique uses most probable or most severe
pipeline failure scenarios, and then resulting damage is estimated and mitigation responses and prevention strategies are developed.

Fault tree analysis is a method of risk identification and scenario building in which the outcome of an event is traced backward to all possible causes (Mc² Management Consulting 2004). It is a probabilistic top-down analysis that is used to assess the likelihood of occurrence of an undesired system-level event (e.g., a release of product, an explosion), and it can be used to quantify the risk associated with resulting safety hazards. Factors or combinations of factors that could cause the event are put in a structured logic diagram (which takes interdependencies in components into account). The network branches from the outcome event to individual factors (e.g., failure of pump, failure of switch, no response from operator) in a treelike structure. [Additional information is given by Mc² Management Consulting (2004), IsographDirect (2004), and Sandia National Laboratories (2004).]

Fault tree analysis can include such factors as natural disasters, human activity, and other externally induced causes. The method can also be used to establish cost-effective troubleshooting procedures based on the factors that are most likely to cause a failure.

Other Probabilistic Risk Assessment Techniques

While fault tree analyses are better suited to examine systems in which the failures of components or processes can be described in terms of pass/fail outcomes (a binary description), they are not ideal for systems in which the processes are not discrete and the outcomes cannot be described simply as pass or fail. (Typically, these are natural events.) Other probabilistic risk assessment techniques have been developed that can consider a range of outcomes of individual processes in a scenario.

An example of scenario-based risk assessment models is the PIPESAFE model (Acton et al. 1998).

INDEX MODELS

Index models use customized algorithms to conduct pipeline risk assessment. There are a variety of index models, including Muhlbauser's
Risk Assessment Methodology, Consequence Modeling (the C-FER method), and the PipeView Risk Model.

Muhlbauer’s Risk Assessment Methodology

Muhlbauer (1996, x) believes that “data on pipeline failures are still insufficient to perform a thorough risk assessment using purely statistical concepts” and that an assessment using probabilistic theory is not required because the probabilities used in the assessment are of questionable benefit.

A hazard, according to Muhlbauer, is a characteristic that provides the potential for loss; it cannot be changed. Risk is the probability of an event that causes a loss and the magnitude of that loss, and therefore actions can be taken to affect the risk. Thus, when risk changes, the hazard may remain unchanged. Risk can change continuously; conditions along a pipeline are usually changing, and as they change, the risk also changes.

Risk is defined by answering three questions:

- What can go wrong (every possible failure must be identified)?
- How likely is it to go wrong?
- What are the consequences?

In this technique, numerical values are assigned to conditions on the pipeline system that contribute to risk. The score, which reflects the importance of an item relative to other items, is determined from a combination of statistical failure data and operator experience. As do all techniques, this model has a number of assumptions:

- All hazards are independent and additive.
- The worst-case condition is assigned for the pipeline section.
- All point values are relative, not absolute.
- The relative importance of each item is based on expert judgment; it is subjective.
- Only risks to the public are considered, not risks to pipeline operators or contractors.

In Muhlbauer’s basic risk assessment model, data gathered from records and operator interviews are used to establish an index for each category of pipeline failure initiator (i.e., what can go wrong and the as-
sociated likelihood): (a) third-party damage, (b) corrosion, (c) design, and (d) incorrect operations. These four indexes score the probability and importance of all factors that increase or decrease the risk of a pipeline failure. The indexes are summed. The last portion of the assessment addresses the potential hazards, their probabilities of occurring, and their consequences. The consequence factor begins at the point of pipeline failure, called the leak impact factor. The leak impact factor is the sum of the product hazards divided by the dispersion factor.

This basic model can be expanded to include other modules such as the cost of service interruption, distribution systems, offshore pipelines, environment, failure adjustment, leak history adjustment, sabotage, and stress.

Consequence Model (C-FER Model)

C-FER Technologies developed a model that examines isometric thermal radiation distances to determine a burn radius and a 1 percent fatality radius from a natural gas pipeline break. An assumption of this model is that risk can be expressed as the product of failure probability and failure consequences, and reliability is the complement of failure probability. Probability of failure and consequence calculations are conducted by using two C-FER software programs—PIRAMID, which is used to optimize maintenance and inspection decisions, and PRISM, which is used to conduct pipeline reliability analyses (Zimmerman et al. 2002). The model incorporates three factors: a fire model that relates the gas release to the intensity of the heat, a model that provides an estimate of the amount of gas being released as a function of time, and a heat intensity threshold. The model can be used to determine a zone of impact for a pipeline fire. The equation used in the model relates the diameter and operating pressure of a pipeline to the size of the affected areas, assuming a worst-case failure event (Stephens 2000). The model can also be used to determine how the intensity of heat changes with the distance from the fire. From the model, “circles” around a pipeline fire that have equal levels of thermal radiation can be calculated. (In fact, the distance of equal thermal radiation from a pipeline fire may not be circular, depending on the nature of the gas discharge, obstructions of the jet of
flowing gas, and delays in ignition. For example, the gas coming out of a ruptured pipe may be discharged in a particular direction or upward from the surface depending on the direction of the jet of flowing gas.

C-FER calculates the degree of harm to people due to thermal radiation by using a model that relates the potential for burn injury or fatality to the thermal load received. A 30-second exposure time is assumed for people exposed to the fire in the open. In this interval, it is assumed that an exposed person will remain in fixed position for between 1 and 5 seconds (presumably to understand what is happening and react) and then run at 5 miles per hour in the direction of shelter. It is further assumed that a person would find a sheltered location within 200 feet of his or her initial position. It is offered that the heat flux that will cause burn injury is between 1,000 and 2,000 Btu/h/ft² (3.2 and 6.3 kW/m²), depending on the burn injury criterion (e.g., time to blister). The threshold level of heat flux for fatal injury is determined when the chance of mortality is 1 percent; that is, 1 in 100 people directly exposed to this thermal load would not be expected to survive. This heat flux is calculated to be 5,000 Btu/h/ft² (15.8 kW/m²).

C-FER also calculates a lower bound reliability curve based on the probability of a fatality or injury of an individual standing on the centerline of a pipeline. The third calculation is the cumulative frequency of casualties along the length of a pipeline system, called the FN curve. [See Harris and Acton (2001) for more information on these calculations.]

C-FER models the thermal load on wooden structures leading to ignition and fire. One calculation shows that 5,000 Btu/h/ft² (15.8 kW/m²) would correspond to ignition in the presence of a flame source in approximately 20 minutes. It calculates that spontaneous ignition at this level of thermal radiation would not occur.

On the basis of these thermal radiation levels, C-FER calculates the radius of a hazard area as a function of pipeline size (diameter) and operating pressure. The graph of hazard area radius versus maximum operating pressure is shown in Figure D-1. A 36-inch-diameter pipeline operating at a maximum pressure of 1,000 pounds per square inch would have a hazard area radius of 750 to 800 feet. A 6-inch-diameter pipeline operating at less than 500 pounds per square inch would have a hazard area radius of less than 100 feet.
FIGURE D-1 Proposed hazard area radius as a function of line diameter and pressure. (SOURCE: Stephens 2000.)

By using the approach in C-FER’s report, it would be possible to calculate hazard area distances for a variety of hazard scenarios involving more hardened structures and different accident scenarios.

PipeView Risk

PipeView Risk is a pipeline risk assessment program that assists pipeline operators in evaluating the current condition of their pipelines and identifying sections of higher risk in order to prioritize maintenance programs (Kiefner & Associates and M. J. Harden Associates 2004). PipeView Risk uses a relative risk ranking model. The analyses are performed by evaluating the physical pipeline attributes (e.g., diameter, grade, and wall thickness) in an algorithm that models the relationship between them. PipeView Risk is designed to be geographic information system (GIS) compatible by starting with an Integrated Spatial Analysis Techniques
(ISAT) database—a family of applications that integrate information from many sources including GIS; the Global Positioning System; pipeline maps; and other operating, monitoring, and maintenance data. The ISAT project was begun at the Gas Research Institute in the mid-1990s.

SUMMARY

A number of risk assessment methods are being used by the pipeline industry to prioritize risk mitigation actions. Regulatory agencies in the United States and abroad have developed risk-based regulations and criteria for safe operation of pipelines. While the risk assessment methodologies in use allow scarce resources to be focused on mitigation of the highest-risk items by emphasizing a single risk number, they do not adequately characterize all the dimensions of risk. A broader characterization of risk, as outlined in Chapter 3, will enable state and local policy makers, with input from stakeholders, to make land use decisions in a systematic manner.

REFERENCES


Exhibit S
13-year Cascadia study complete – and earthquake risk looms large

Media Contact: Mark Floyd, 541-737-0788
Source: Chris Goldfinger, 541-737-5214
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."

Contact Info
News and Research Communications Oregon State University 416 Kerr Administration Bldg. Corvallis, Oregon 97331 541-737-4611
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Exhibit T
Fracking by the Numbers

Key Impacts of Dirty Drilling at the State and National Level

Written by:

Elizabeth Ridlington
Frontier Group

John Rumpler
Environment America Research & Policy Center

October 2013
Executive Summary

Over the past decade, the oil and gas industry has fused two technologies—hydraulic fracturing and horizontal drilling—in a highly polluting effort to unlock oil and gas in underground rock formations across the United States.

As fracking expands rapidly across the country, there are a growing number of documented cases of drinking water contamination and illness among nearby residents. Yet it has often been difficult for the public to grasp the scale and scope of these other fracking threats. Fracking is already underway in 17 states, with more than 80,000 wells drilled or permitted since 2005. Moreover, the oil and gas industry is aggressively seeking to expand fracking to new states—from New York to California to North Carolina—and to areas that provide drinking water to millions of Americans.

This report seeks to quantify some of the key impacts of fracking to date—including the production of toxic wastewater, water use, chemicals use, air pollution, land damage and global warming emissions.

To protect our states and our children, states should halt fracking.

Toxic wastewater: Fracking produces enormous volumes of toxic wastewater—often containing cancer-causing and even radioactive material. Once brought to the surface, this toxic waste poses hazards for drinking water, air quality and public safety:

- Fracking wells nationwide produced an estimated 280 billion gallons of wastewater in 2012.
- This toxic wastewater often contains cancer-causing and even radioactive materials, and has contaminated drinking water sources from Pennsylvania to New Mexico.
- Scientists have linked underground injection of wastewater to earthquakes.
- In New Mexico alone, waste pits from all oil and gas drilling have contaminated groundwater on more than 400 occasions.

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<th>Table ES-1. National Environmental and Public Health Impacts of Fracking</th>
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<td><strong>Fracking Wells since 2005</strong></td>
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<td><strong>Toxic Wastewater Produced in 2012 (billion gallons)</strong></td>
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<td><strong>Water Used since 2005 (billion gallons)</strong></td>
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<td><strong>Chemicals Used since 2005 (billion gallons)</strong></td>
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<td><strong>Air Pollution in One Year (tons)</strong></td>
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<td><strong>Global Warming Pollution since 2005 (million metric tons CO₂-equivalent)</strong></td>
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<td><strong>Land Directly Damaged since 2005 (acres)</strong></td>
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Water use: Fracking requires huge volumes of water for each well.

- Fracking operations have used at least 250 billion gallons of water since 2005. (See Table ES-2.)

- While most industrial uses of water return it to the water cycle for further use, fracking converts clean water into toxic wastewater, much of which must then be permanently disposed of, taking billions of gallons out of the water supply annually.

- Farmers are particularly impacted by fracking water use as they compete with the deep-pocketed oil and gas industry for water, especially in drought-stricken regions of the country.

Chemical use: Fracking uses a wide range of chemicals, many of them toxic.

- Operators have hauled more than 2 billion gallons of chemicals to thousands of fracking sites around the country.

- In addition to other health threats, many of these chemicals have the potential to cause cancer.

- These toxics can enter drinking water supplies from leaks and spills, through well blowouts, and through the failure of disposal wells receiving fracking wastewater.

Air pollution: Fracking-related activities release thousands of tons of health-threatening air pollution.

- Nationally, fracking released 450,000 tons of pollutants into the air that can have immediate health impacts.

- Air pollution from fracking contributes to the formation of ozone “smog,” which reduces lung function among healthy people, triggers asthma attacks, and has been linked to increases in school absences, hospital visits and premature death. Other air pollutants from fracking and the fossil-fuel-fired machinery used in fracking have been linked to cancer and other serious health effects.

Global warming pollution: Fracking produces significant volumes of global warming pollution.

- Methane, which is a global warming pollutant 25 times more powerful than carbon dioxide, is released at multiple steps during fracking, including during hydraulic fracturing and well completion, and in the processing and transport of gas to end users.

- Global warming emissions from completion of fracking wells since 2005 total an estimated 100 million metric tons of carbon dioxide equivalent.

Damage to our natural heritage: Well pads, new access roads, pipelines and other infrastructure turn forests and rural landscapes into industrial zones.

- Infrastructure to support fracking has damaged 360,000 acres of land for drilling sites, roads and pipelines since 2005.

- Forests and farmland have been replaced by well pads, roads, pipelines and other gas infrastructure, resulting in the loss of wildlife habitat and fragmentation of remaining wild areas.

### Table ES-2. Water Used for Fracking, Selected States

<table>
<thead>
<tr>
<th>State</th>
<th>Total Water Used since 2005 (billion gallons)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arkansas</td>
<td>26</td>
</tr>
<tr>
<td>Colorado</td>
<td>26</td>
</tr>
<tr>
<td>New Mexico</td>
<td>1.3</td>
</tr>
<tr>
<td>North Dakota</td>
<td>12</td>
</tr>
<tr>
<td>Ohio</td>
<td>1.4</td>
</tr>
<tr>
<td>Pennsylvania</td>
<td>30</td>
</tr>
<tr>
<td>Texas</td>
<td>110</td>
</tr>
<tr>
<td>West Virginia</td>
<td>17</td>
</tr>
</tbody>
</table>
In Colorado, fracking has already damaged 57,000 acres of land, equal to one-third of the acreage in the state's park system.

The oil and gas industry is seeking to bring fracking into our national forests, around several of our national parks, and in watersheds that supply drinking water to millions of Americans.

Fracking has additional impacts not quantified here—including contamination of residential water wells by fracking fluids and methane leaks; vehicle and workplace accidents, earthquakes and other public safety risks; and economic and social damage including ruined roads and damage to nearby farms.

To address the environmental and public health threats from fracking across the nation:

- States should prohibit fracking. Given the scale and severity of fracking's myriad impacts, constructing a regulatory regime sufficient to protect the environment and public health from dirty drilling—much less enforcing such safeguards at more than 80,000 wells, plus processing and waste disposal sites across the country—seems implausible. In states where fracking is already underway, an immediate moratorium is in order. In all other states, banning fracking is the prudent and necessary course to protect the environment and public health.

- Given the drilling damage that state officials have allowed fracking to incur thus far, at a minimum, federal policymakers must step in and close the loopholes exempting fracking from key provisions of our nation’s environmental laws.

- Federal officials should also protect America’s natural heritage by keeping fracking away from our national parks, national forests, and sources of drinking water for millions of Americans.

- To ensure that the oil and gas industry—rather than taxpayers, communities or families—pays the costs of fracking damage, policymakers should require robust financial assurance from fracking operators at every well site.

- More complete data on fracking should be collected and made available to the public, enabling us to understand the full extent of the harm that fracking causes to our environment and health.

Defining “Fracking”

In this report, when we refer to the impacts of “fracking,” we include impacts resulting from all of the activities needed to bring a shale gas or oil well into production using high-volume hydraulic fracturing (fracturing operations that use at least 100,000 gallons of water), to operate that well, and to deliver the gas or oil produced from that well to market. The oil and gas industry often uses a more restrictive definition of “fracking” that includes only the actual moment in the extraction process when rock is fractured—a definition that obscures the broad changes to environmental, health and community conditions that result from the use of fracking in oil and gas extraction.
Exhibit U
Mr. Jon Wellinghoff, Chair  
Federal Energy Regulatory Commission  
888 First Street NE, Room 1A  
Washington, D.C. 20426

Dear Mr. Wellinghoff,

I wish to state, for your official record, my opposition to Liquefied Natural Gas development, terminals and traffic in Passamaquoddy Bay. This was the public position of my predecessor – the Honourable Greg Thompson – and it continues to be the policy of the Government of Canada as articulated by the Right Honourable Stephen Harper, Prime Minister of Canada. Our Government believes this is an important local issue for residents and an international one for Canada.

An LNG terminal on the Maine coast of Passamaquoddy Bay along with resulting tanker traffic through the environmentally sensitive waterways of Head Harbour Passage and Passamaquoddy Bay ignores obvious risks, navigational hazards and public safety. The Government of Canada – as long ago as 1976 – determined that this area was the least acceptable for tanker operation because of the value of the fisheries, other aquatic resources and the navigational risk. Other factors against this proposal include the risk of strong tidal currents, pollution, no safe anchorage and danger from high winds.

Our Government maintains the right to control and regulate the use of Head Harbour Passage. This waterway – between Deer Island and Campobello – is internal waters of Canada by virtue of historic title. Our Government’s long standing opposition to any LNG project in Passamaquoddy Bay is also based on concerns regarding navigational safety, environmental and other impacts that such projects could have on Canada. Because of the nature of the shared waters of Passamaquoddy Bay beyond Head Harbour Passage, Canada’s cooperation is required
to ensure safe passage. That cooperation has not been forthcoming and it should not be expected.

As a Member of Parliament on the government benches, I can state categorically that Canada’s position remains unchanged. We will continue to use all diplomatic and legal options to defend our interests, which is to reject the passage of LNG tankers through Head Harbour Passage. As such, proponents of any LNG projects in Passamaquoddy Bay should not expect these projects to go forward.

Finally, I want to recognize the work of citizens on both sides of the Canada-U.S. border who have been involved on this important issue for many years. I will be working closely with concerned residents as we continue to work for the environmental integrity of Head Harbour Passage and Passamaquoddy Bay.

Yours truly,

John Williamson, M.P.
New Brunswick Southwest