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**BEFORE COOS COUNTY PLANNING DEPARTMENT**
**HEARINGS OFFICER**

| | |
|---|---|
| In the Matter of the on remand from the Land Use Board of Appeals in *Oregon Shores Conservation Coalition v. Coos County*, 76 OR LUBA 346 (2017 | REM-19-001<br><br>Hearing Statement |

On behalf of Rogue Climate and Jody McCaffree (opponents) supplementing her individual comments. Opponents ask that the record be left open for additional information to be submitted and later for rebuttal.

## A. The Applicant's Request for Remand is untimely

ORS 227.181 requires the applicant to file a request for remand "within 180 days of the effective date of the final order or the final resolution of the judicial review, the city shall deem the application terminated." The final resolution of the judicial review was the date of the Supreme Court's denial of the petition for review. That was August 9, 2018, making the remand application due on February 5, 2019. The applicant's request for remand was not filed until March.

While it appears the applicant and the county believe the triggering date is the date that the appellate judgment entered, opponents challenge that decision. The "decision" of the Supreme Court is the "resolution of the judicial review." A "decision" is defined as:

> (a) "Decision" means a memorandum opinion, an opinion indicating the author or an order denying or dismissing an appeal issued by the Court of Appeals or the Supreme Court. The decision shall state the court's disposition of the judgment being appealed, and may provide for final disposition of the cause. The decision shall designate the prevailing party or parties, state whether a party or parties will be allowed costs and disbursements, and if so, by whom the costs and disbursements will be paid.



Exhibit: 4
Date: 6/10/19

ORS 19.450. The term "resolution" as used in ORS 227.181 is synonymous with the term "disposition" and thus, reliance on the "appellate judgment" date was misplaced.

Moreover, in the context of a denial of supreme court review, the expedited review of land use decisions and given that there are no jurisdictional concerns similar to those at issue with "appeals" from circuit court, there is no policy reason to find that the resolution of judicial review of land use decisions does not occur until the appellate court files the appellate judgment which often occurs 45 or more days after the Supreme Court resolves the petition by denying review.

**B. The county must apply CCZLDO 5.0.500 and deem this application revoked or at least those parts of it that conflict with other subsequently filed and pending applications.**

The policy of CCZLDO 5.0.500 is to cause the permit applicant to choose:

> SECTION 5.0.500 INCONSISTENT APPLICATIONS
> Submission of any application for a land use or land division under this Ordinance which is inconsistent with any previously submitted pending application shall constitute an automatic revocation of the previous pending application to the extent of the inconsistency.

The applicant has filed an Omnibus II application and several applications currently pending resolution before the hearings officer since the Board approved the relevant application. The county must determine if those subsequently filed applications are inconsistent with the project proposed in this application and it has failed to do so. As understood, the project proposed in the application subject to remand, among other things, proposed different locations and different uses related to the gas processing components, including the power generation, and so this analysis must be conducted by the county and findings must be made as to whether the application should be deemed revoked or deemed revoked to the extent of the inconsistency.

**C. There is no public need for this project.**

For the reasons stated in the attached report from McCullough Research, it highly unlikely that this project will be funded because it cannot compete with competitors. If it cannot compete it is not needed. And the applicant knows it has a problem. It has put off significant investment and pushed back the construction dates.

**D. The project will unnecessarily interfere with public trust rights.**

For the reasons suggested in the Division of State Lands April 10, 2019, the applicant has not demonstrated that the project will not interfere with public trust rights.

**E. The permit extensions may not be renewed on remand.**

The applicant attempt to extend four permits which, as understood, were approve in 2013 or 2014. These extensions should be denied for several reasons.

The county should deem the permits to be void pursuant to OAR 660-033-140.[1] The rule states that such permits are void if development has not been initiated within two years. Thus as a matter of law and completely independent from the remand proceedings, the extensions may not be renewed on remand.

The county fails to consider the relevant substantive criteria and should find that the applicant is responsible for the delay.

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[1] The county has consistently applied OAR 660-033-0140 which is incorporated into the acknowledged CCZLDO 5.2.600(1) which implements the rule and is almost identically worded.

OAR 660-033-0140 is entitled "Permit Expiration Dates" and states:

(1) Except as provided for in section (5) of this rule, a discretionary decision, except for a land division, made after the effective date of this division approving a proposed development on agricultural or forest land outside an urban growth boundary under ORS 215.010 to 215.293 and 215.317 to 215.438 or under county legislation or regulation adopted pursuant thereto is void two years from the date of the final decision if the development action is not initiated in that period.

(2) A county may grant one extension period of up to 12 months if:

(a) An applicant makes a written request for an extension of the development approval period;

(b) The request is submitted to the county prior to the expiration of the approval period;

(c) The applicant states reasons that prevented the applicant from beginning or continuing development within the approval period; and

(d) The county determines that the applicant was unable to begin or continue development during the approval period for reasons for which the applicant was not responsible.

(3) Approval of an extension granted under this rule is an administrative decision, is not a land use decision as described in ORS 197.015 and is not subject to appeal as a land use decision.

(4) Additional one-year extensions may be authorized where applicable criteria for the decision have not changed.

Moreover, the applicable criteria has changed and thus the extensions are not allowed under the rule. Since 2014, the following relevant comprehensive map and code changes, among others, were adopted.[2]

> Section 5.0.175 Application Made by Transportation Agencies, Utilities or Entities was adopted. (AM-14-10 & AM-14-11 (2015). The provision requires the applicant for a pipeline permit to demonstrate that they have the private right of property acquisition pursuant to ORS Chapter 35 before filing an application without landowner consent.
>
> Coos County Planning Amendments to CCZLDO. (AM-15-03 Exclusive Farm Use / Forest) and (AM-15-04 Hazards) (July 2015). The provisions require, among other things, a qualified geologist or civil engineer to report that the structure can or cannot be safely constructed at the proposed site. Volume 1, Part 1, Section 5.11. Paragraphs 4 (i) and (ii). They require the county to "take reasonable measures to protect life and property to the fullest extent, from the impact of a local source Cascadia tsunami." Volume 1, Part 1, Section 5.11. Paragraphs 5 (ii). They adopt hazards overlay zones among all of the zones in the county related to: Wildfire, Landslides, Liquefaction, Earthquake and Tsunami. Final Hazard Ordinance No.15-05-005PL and approved Hazard Maps.
>
> Coos County Planning Text Amendments to CCZLDO / Hazard maps. (AM-16-01) (2017). The provisions adopt and implement the comprehensive plan amendments referenced above and purports to only apply to all unincorporated areas of the Coos County outside of the Coos Bay Estuary Management Plan and the Coquille River Estuary Management Plan.

See Landslide Hazard map adopted under AM-15-04 http://www.co.coos.or.us/Portals/0/Planning/AM-15-04/2%20-%20Landslide%20Hazard%20Areas%20-%208%20Apr%202015.pdf; and Wildfire Hazard map adopted under AM-15-04: http://www.co.coos.or.us/Portals/0/Planning/AM-15-04/6%20-%20Wildfire%20Hazard%20Areas%20-%208%20Apr%202015.pdf; and the AM16-001 amendment here: http://www.co.coos.or.us/Portals/0/Planning/AM-16-01/AM-16-001%20signed%20order.pdf?ver=2017-05-05-132330-287

The extensions may not should not be approved on remand.

/s/ Tonia Moro
Tonia Moro
Attorney for Opponents

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[2] Other amendments that should be considered as adopting new criteria include the Flood Plain Amendments adopted in AM-14-01, the legislative amendments adopted in AM-12-04.

IN THE SUPREME COURT OF THE STATE OF OREGON

OREGON SHORES CONSERVATION COALITION,
Petitioner below,

and

DEB EVANS, RON SCHAAF, ROGUE CLIMATE, HANNAH SOHL, and JODY MCCAFFREE,
Petitioners,
Petitioners on Review,

and

JOHN CLARKE, et al.,
Intervenors-Petitioners below,

v.

COOS COUNTY and JORDAN COVE ENERGY PROJECT, L. P.,
Respondents,
Respondents on Review.

Court of Appeals
A166596

S065974

**ORDER DENYING REVIEW**

Upon consideration by the court.

The court has considered the petition for review and orders that it be denied.

MARTHA L. WALTERS
CHIEF JUSTICE, SUPREME COURT
8/9/2018 10:00 AM

c: Nathaniel Greenhalgh-Johnson
Tonia Louise Moro
Seth J King

jr

# McCullough Research

Robert F. McCullough, Jr.
Principal

Date: June 5, 2019

To: McCullough Research Clients

From: Robert McCullough
Michael Weisdorf
Eric Shierman

Subject: The Questionable Economics of Jordan Cove LNG Terminal

A decade ago, one member of Oregon's congressional delegation asked us for a review of the Jordan Cove LNG import terminal proposed for Coos Bay.[1,2] The analysis was not difficult. The price of LNG exported to Japan from Alaska is reported in both Japan and Alaska. These prices were higher than the increasing amounts of natural gas appearing on the market from Alberta and Wyoming. Clearly, Jordan Cove was not a competitive solution for the import of LNG.

Jordan Cove's owners gradually realized that the new technologies of oil and natural gas made the import proposal uneconomic and changed the direction of LNG to a proposed export terminal in 2012.[3]

However, there are a number of good reasons to question whether this is a good location and a good project design. First, the supplies for Jordan Cove are taken from the Malin hub in southern Oregon. This puts the terminal at a six-hundred-mile disadvantage in transportation costs. Second, the announced costs of the terminal are high by market standards – significantly higher than its competitors. Third, the technology of Jordan Cove – using natural gas as opposed to electricity for compression – makes it less efficient than its competitors in British Columbia or the Gulf Coast.

Our analysis indicates that Jordan Cove will have a significant cost disadvantage compared to its competitors – approximately 25%. We also calculate the chance of Jordan Cove reaching operation is only one third.

[1] McCullough Research. *Memo on LNG Pricing.* April 8, 2008.
[2] LNG refers to Liquified Natural Gas. LNG is a liquid when maintained at 260 degrees (F) below zero.
[3] Jonathan Thompson. "A pipeline built years ago may start to export Rocky Mountain gas to Asia." *High Country News*, April 14, 2014. https://www.hcn.org/blogs/goat/how-a-little-noticed-pipeline-might-make-natural-gas-exports-possible

Jordan Cove is currently at the pre-FID stage in its development. FID is an industry term standing for "Final Investment Decision". The FID is a critical decision that initiates actual financing and construction. The justification for proceeding to FID usually depends on two different analyses:

1. Is the location and facility likely to succeed given the past history of feed gas and ultimate markets?
2. How competitive is this specific facility compared to its peers?

The price differential between feed gas at the production site and delivered LNG at the destination market forms the economic basis for the decision to invest in LNG export projects. The chart in Figure 1 below shows the price history for Platts JKM (Japan/Korea Marker) price index, the global market with the highest price premium, as well as the price of Canadian feed gas at the AECO hub, which in recent years has traded at the lowest prices in North America.[4]

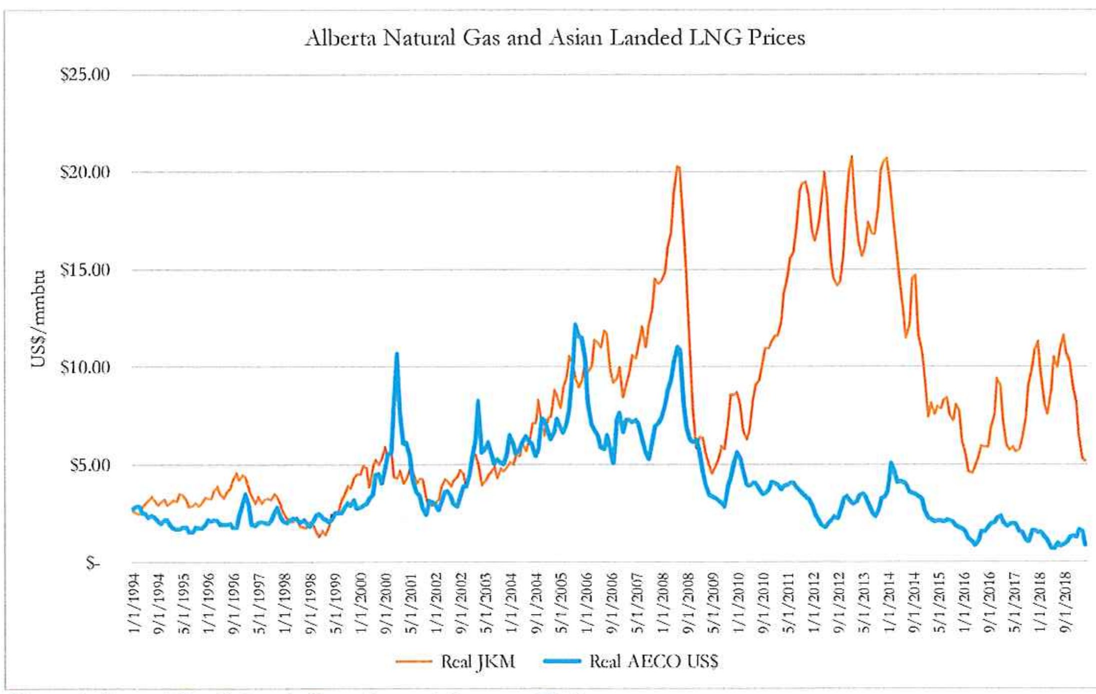


*Figure 1: Natural Gas Prices in Canadian and Japanese Markets*

[4] "Platts JKM™ is the Liquefied Natural Gas (LNG) benchmark price assessment for spot physical cargoes. It is referenced in spot deals, tenders and short-, medium- and long-term contracts both in Northeast Asia and globally." https://www.spglobal.com/platts/en/our-methodology/price-assessments/natural-gas/jkmt-japan-korea-marker-gas-price-assessments

A number of LNG export projects were proposed, planned, invested in, and built in the years following the 2011 Tohoku earthquake and resultant nuclear accidents at Fukushima Daiichi. During this period, all of Japan's nuclear reactors were taken offline, and large quantities of LNG were imported to replace the lost megawatts of electric power, causing the large increase seen in the JKM price marker. As nuclear plants begin to come back online in Japan, and the global LNG supply has expanded, the premium prices at JKM have begun to fall back in line with other natural gas markets around the world. Although Japan, with little to no gas supplies of its own, will continue to import gas from other markets, it seems unlikely that the large price premium observed from 2011-2016 will be a permanent feature of this market, which currently trades below $6/MMBtu.

The price of LNG in Japan has dropped markedly in the last six months, and even more dramatically in the last 3 years.[5] The following chart in Figure 2 shows the spread between JKM LNG and the Henry Hub index price of North American natural gas.


*Figure 2: Recent JKM Price Changes*

Beyond just the costs of feed gas itself, the costs of building, maintaining and operating an LNG export terminal must be recovered from the sale of LNG in the export market. The Jordan Cove Energy Project proposes to operate as a tolling model, providing liquefaction,

[5] *LNG Daily*, S&P Global Platts. https://www.spglobal.com/platts/en/products-services/lng/lng-daily

storage, and transport services to buyers of natural gas, who will pay a tolling fee per unit (MMBTU) based on the costs involved.[6]

Reviewing the materials submitted to FERC by the applicant allows us to calculate the tolling fee that would be needed to fully recover the costs of the project. Similar data is available for the British Columbia LNG terminal that received its FID last year. LNG Canada, sited at Kitimat, British Columbia, is larger than Jordan Cove, closer to inexpensive Alberta natural gas, and has better technology.[7]

The industry leader in North America is Cheniere Energy.[8] They have massive projects already in operation and plan an additional 30 MTPA to come into operation in the near future. Their data is contained in many sources and is generally subject to SEC rules on reporting.

The following table compares the three projects:

| | Jordan Cove | LNG Canada | Cheniere |
|---|---|---|---|
| Output (MTPA) | 7.8 | 14 | 31.5 |
| Pipeline Cost (Billion $) | $ 2.46 | $ 4.77 | |
| LNG Project Cost (Billion $) | $ 7.30 | $ 10.77 | $ 30.00 |
| Required Profit Margin for FID (Billion $) | $ 0.98 | $ 1.55 | $ 3.00 |
| Total (Billion $) | $ 12.05 | $ 19.18 | $ 33.00 |
| Per MTPA | $ 1.54 | $ 1.37 | $ 1.05 |
| Annualized/MTPA @ 10% Real RoR | $0.16 | $0.15 | $0.11 |
| Annualized/MMBTU | $3.33 | $2.95 | $2.26 |
| O&M | $ 0.05 | $ 0.04 | $ 0.02 |
| O&M/MMBTU | $0.94 | $0.83 | $0.32 |
| Natural Gas Basis Differential ($/MMBTU) | ($0.07) | ($0.64) | $0.00 |
| Required Margin @ FID | $4.27 | $3.78 | $2.58 |
| Transportation to Asia ($/MMBTU) | $0.87 | $0.87 | $1.50 |
| **Required Margin at Asian Market** | **$5.07** | **$4.01** | **$4.08** |

*Table 1: Comparison of Jordan Cove, LNG Canada, and Cheniere*

[6] "Tolling" is an industry term that indicates that natural gas suppliers can bring natural gas to the LNG facility and have it compressed into liquified natural gas and delivered to the final market. The facility operator does not own the product at any point.

[7] Compression of natural gas into a liquid can be done by electricity or natural gas. Electricity is less expensive and more reliable. Jordan Cove's competitors are using electricity. Jordan Cove is using natural gas.

[8] Cheniere Energy, once an importer of LNG to its Sabine Pass, LA terminal, became the first Gulf Coast LNG exporter in early 2016. https://www.cheniere.com/terminals/lng/

The calculation of the minimum tolling fee that an LNG project can charge and make an acceptable project starts with the proposed output in millions of metric tons per annum. The pipeline cost from existing natural gas hubs to the project is added in the second line.

The cost per MMBTU (Millions of British Thermal Units) is derived by dividing the cost per MTPA by the BTU content of a metric ton of LNG.

Annual O&M costs are assumed to be 3% of the total project cost. Cheniere has a lower O&M cost available from its financial reports and financial presentations.

The basis differential for natural gas supplies is discussed below. Put simply, natural gas costs less at the well head – Alberta or Texas/Louisiana – than it does at the end of the pipeline.

The required profit margin is assumed to be 10% of the total investment. This is a standard industry assumption reflecting the risks of investing in the volatile LNG industry.

Transportation to Asia is taken from Cheniere's financial reports and estimates for West Coast projects. The West Coast is closer to Asia and has a significant transportation advantage.

The final line, in bold, sums the costs and arrives at the amount that the projects require as a fee for natural gas suppliers to take their feed gas to Asia.

The next chart (Figure 3) shows the price of Canadian natural gas in Alberta, the cheapest possible feedstock for the project plus the Jordan Cove tolling fee, as compared to the JKM price marker. The convergence of these two series seen in recent years suggests that the economics of this project are questionable at best.

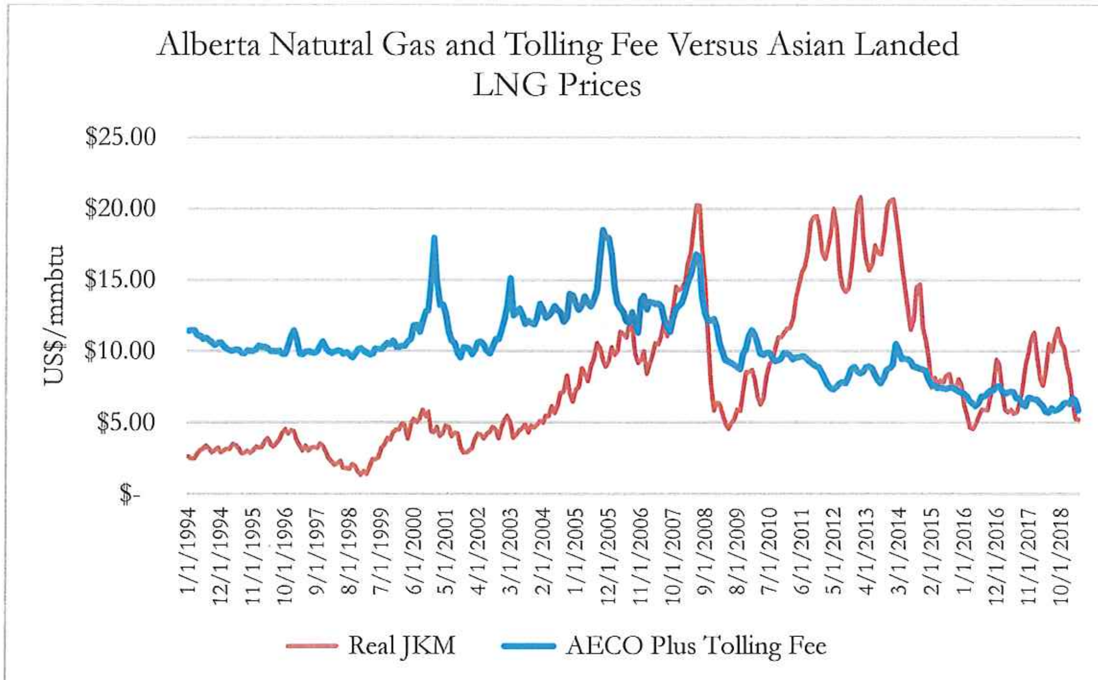


*Figure 3: Delivered Cost and Asian Prices*

In addition to our retrospective analysis, McCullough Research has developed a Monte Carlo model designed to predict the probability of success for West Coast LNG export terminals.

The Monte Carlo method was invented by Stanislaw Ulam during the Second World War at Los Alamos National Laboratory where models were used to help design the first thermonuclear weapons. One of the challenges Dr. Ulam and his colleagues faced in developing atomic fission was the sheer complexity of the possible reactions. Calculating over all possible interactions was impossible given the limited computers of his era (who generally were staff doing computations on mechanical calculators). The Monte Carlo method relies on large volumes of random samples. Each pick of variables is called a "game" and the results, when averaged, closely approximate what a very extensive analysis might develop. Today, Monte Carlo models are frequently used in economics, finance, engineering, and science.

Our model compares all the possible combinations of feed gas and Asian landed gas prices observed over the past decade, to generate a total of 92,416 games. Even with the unusually high post-earthquake prices of 2011-16 included in the study period, this analysis indicates that the probability of Jordan Cove successfully reaching FID is no more than 34%, as shown in Figure 4 below.

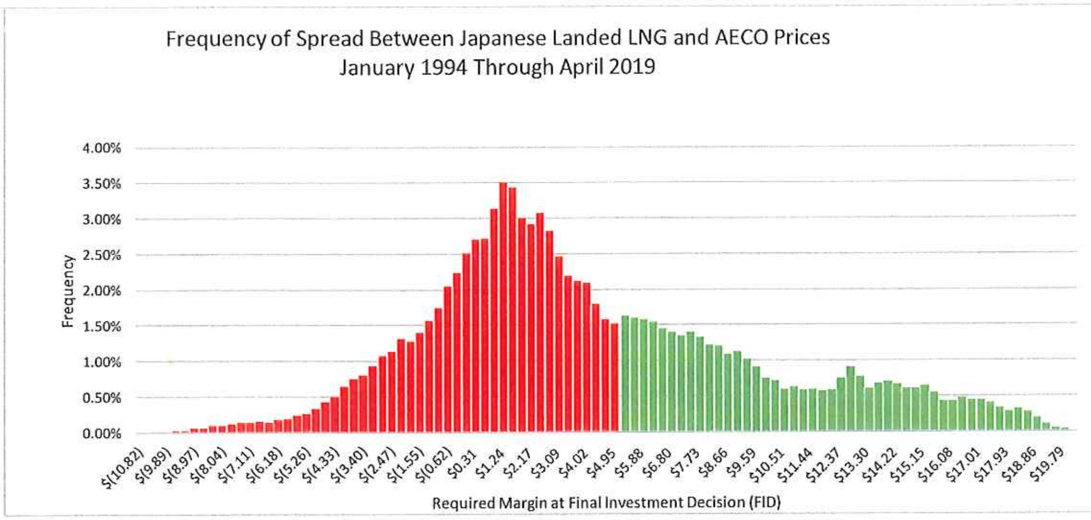


*Figure 4: Monte Carlo Results*

The modeling suggests strongly that more often than not, the spread between these prices is substantially less than what would be required to cover the costs of Jordan Cove, let alone earn any profits.

A critical issue in the future of Jordan Cove is the supply of natural gas and, very importantly, its price. The West Coast's major market for natural gas is in California. Pipelines extend into California from the north (Alberta and Colorado) and the east (the Gulf States).

Not surprisingly, prices are lower at the wells and increase with distance. Since California enjoys competition between different sources, the price for natural gas tends to increase or decrease with the major trading hub at Henry Hub, Louisiana. When prices fall at Henry Hub, competitors elsewhere in the U.S. and Canada must lower their prices to compete.

The locations where multiple suppliers and customers meet to negotiate transactions are known as a "hub". The term is meant to remind us of a wheel where spokes (pipelines) fan out from a central location.

On the West Coast there are ten major hubs as shown in the map in Figure 5:

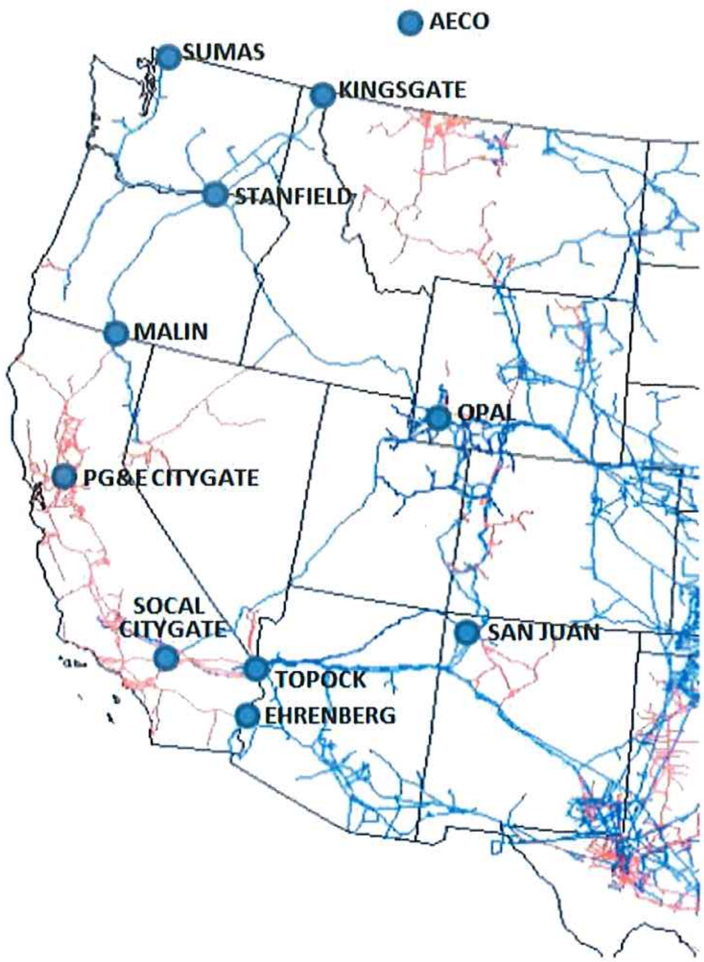


*Figure 5: West Coast Natural Gas Hubs and Pipelines*[9]

The trader's term for the difference in prices between hubs is *basis differential*. This value represents the expected difference between lower priced areas like Alberta and high-priced areas like Southern California. Traders watch these differentials and seize upon moments when they can profit by moving natural gas between hubs.

Financial markets like the Chicago Mercantile Exchange (which now includes the New York Mercantile Exchange – NYMEX) and the Intercontinental Exchange (ICE) document prices at the various hubs and facilitate long term commodity contracts.

[9] Bonneville Power Administration. Power Market Price Study and Documentation, BP-18-E-BPA-04. Page 40. https://www.bpa.gov/secure/Ratecase/Documents.aspx

An LNG export project like Jordan Cove requires a firm supply of feed gas delivered to its location, which is the purpose of the Pacific Connector pipeline connecting the proposed export terminal to the natural gas trading hub at Malin, Oregon near the California border.

The commercial success of the project thus very much depends on future movements in the price of gas at Malin. Commodities futures contracts, used to hedge against the risk of adverse price movements, are typically executed with respect to a basis differential, which specifies a discount or premium above or below an index price. Gas futures are priced with respect to the spot price at the Henry Hub in Louisiana, which is the delivery location specified by NYMEX for natural gas futures contracts and thus serves as the index price of US natural gas.[10]

As shown in Table 2 below, most Pacific Northwest gas hubs trade at a discount to Henry Hub, while California markets trade at a premium. The basis differential from Henry Hub at Malin is an estimate of the cost of long-term gas supply to the Jordan Cove project, while the competing LNG Canada project will be able to source its feed gas at a much lower price, due to the much wider basis discount seen at the AECO hub in Alberta.[11]

[10] "Henry Hub refers to the central delivery location (or, hub) located near the Louisiana's Gulf Coast, connecting several intrastate and interstate pipelines. Henry Hub has been used as a pricing reference for the futures since April 1990." https://www.cmegroup.com/trading/why-futures/welcome-to-nymex-henry-hub-natural-gas-futures.html

[11] "The AECO-C price is derived from the U.S. Henry Hub market price, taking into account transportation differentials, regional demand, and the U.S./Canadian dollar exchange rate. Similarly, the Alberta Reference Price (ARP) is derived from the AECO-C price, taking into account Alberta pipeline transportation costs." https://www.aer.ca/providing-information/data-and-reports/statistical-reports/commodity-prices-methodology

BPA Rate Cases: Power Risk and Market Price Studies

| FY | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|---|
| Henry Hub | $4.08 | $4.35 | $3.86 | $4.05 | 3.24 | 3.25 |
| AECO | -0.37 | -0.39 | -0.4 | -0.42 | -0.61 | -0.64 |
| Kingsgate | -0.19 | -0.19 | -0.16 | -0.16 | -0.2 | -0.21 |
| Malin | -0.09 | -0.08 | -0.03 | -0.04 | -0.07 | -0.07 |
| Opal | -0.12 | -0.13 | -0.13 | -0.15 | -0.13 | -0.13 |
| PG&E | 0.25 | 0.27 | 0.31 | 0.32 | 0.34 | 0.36 |
| SoCal City | 0.05 | 0.05 | 0.24 | 0.26 | 0.22 | 0.22 |
| Ehrenberg | 0.05 | 0.05 | 0.12 | 0.13 | 0.04 | 0.04 |
| Topock | 0.05 | 0.05 | 0.12 | 0.13 | 0.04 | 0.04 |
| San Juan | -0.12 | -0.1 | -0.16 | -0.17 | -0.13 | -0.13 |
| Stanfield | -0.15 | -0.14 | -0.1 | -0.11 | -0.14 | -0.14 |
| Sumas | -0.03 | -0.06 | -0.09 | -0.1 | | |

*Table 2: BPA Rate Case Basis Differentials*

Table 2 shows estimates for basis differentials developed by the Bonneville Power Administration.[12] Their estimate for 2019 is that Alberta's natural gas prices are $.64/MMBTU less than the hub at Henry Hub, Louisiana. By the time natural gas has travelled to the Oregon/California border, the price advantage has fallen to $.07/MMBTU. One of the reasons why LNG Canada has received its Final Investment Decision is that its natural gas supply is directly from the oil and natural gas fields priced at the AECO hub.

In conclusion, Jordan Cove faces a number of insurmountable challenges:

1. Jordan Cove's costs are higher – roughly $1 / MMBTU more – than its competitors.
2. With the rapid decline in Asian landed LNG prices, it is unlikely that it will reach a Final Investment Decision.
3. Its technology is likely to be less reliable and more costly than the electric compression methods used elsewhere.

As with a number of other LNG export projects proposed for the Pacific Northwest, the chances of its successful completion seem quite low.

[12] Bonneville Power Administration. Power Market Price Study and Documentation for BPA Rate Case in 2014, 2016, 2018, 2020. (e.g. BP-20-E-BPA-04) https://www.bpa.gov/secure/Ratecase/Documents.aspx

# Pembina Pipeline Corporation Reports First Quarter Results

Thu, 02 May 2019

***Pembina reports first quarter results and announces a five percent dividend increase***

All financial figures are in Canadian dollars unless noted otherwise.

CALGARY, May 2, 2019 /CNW/ - Pembina Pipeline Corporation ("Pembina" or the "Company") (TSX: PPL; NYSE: PBA) announced today its financial and operating results for the first quarter of 2019.

## Financial and Operational Overview

| | 3 Months Ended March 31 | |
|---|---|---|
| *($ millions, except where noted) (unaudited)* | **2019** | 2018 |
| Revenue | **1,968** | 1,837 |
| Net revenue[(1)] | **774** | 719 |
| Gross profit | **588** | 568 |
| Earnings | **313** | 330 |

| | | |
|---|---|---|
| Earnings per common share – basic and diluted *(dollars)* | **0.55** | 0.59 |
| Cash flow from operating activities | **608** | 498 |
| Cash flow from operating activities per common share – basic *(dollars)*(1) | **1.20** | 0.99 |
| Adjusted cash flow from operating activities(1) | **578** | 530 |
| Adjusted cash flow from operating activities per common share – basic *(dollars)*(1) | **1.14** | 1.05 |
| Common share dividends declared | **290** | 272 |
| Dividends per common share *(dollars)* | **0.57** | 0.54 |
| Capital expenditures | **361** | 324 |
| Total volume *(mboe/d)*(2) | **3,403** | 3,266 |
| Adjusted EBITDA(1) | **773** | 688 |

(1) Refer to "Non-GAAP Measures".

(2) Total revenue volumes. Revenue volumes are physical volumes plus volumes recognized from take-or-pay commitments. Volumes are stated in thousand barrels of oil equivalent per day ("mboe/d"), with natural gas volumes converted to mboe/d from millions of cubic feet per day ("MMcf/d") at a 6:1 ratio.

## Financial and Operational Overview by Division

| | **3 Months Ended March 31** | | | | | |
|---|---|---|---|---|---|---|
| | **2019** | | | 2018 | | |
| *($ millions, unless otherwise noted) (unaudited)* | **Volumes(1)** | **Gross Profit** | **Adjusted EBITDA(2)** | Volumes(1) | Gross Profit | Adjusted EBITDA(2) |
| Pipelines Division | **2,507** | **340** | **457** | 2,424 | 294 | 402 |
| Facilities Division | **896** | **158** | **232** | 842 | 143 | 218 |
| Marketing & New Ventures Division(3) | **—** | **93** | **121** | — | 133 | 104 |
| Corporate | **—** | **(3)** | **(37)** | — | (2) | (36) |
| Total | **3,403** | **588** | **773** | 3,266 | 568 | 688 |

(1) Pipelines and Facilities Divisions are revenue volumes which are physical volumes plus volumes recognized from take-or-pay commitments. Volumes are stated in mboe/d, with natural gas volumes converted to mboe/d from MMcf/d at a 6:1 ratio.

(2) Refer to "Non-GAAP Measures".

(3) Marketed NGL volumes are excluded from Volumes to avoid double counting. Refer to "Marketing & New Ventures Division" in the MD&A for further information.

## Financial & Operational Highlights

- Record first quarter adjusted EBITDA of $773 million, representing a 12 percent increase over the same period in 2018 was driven primarily by increased gross profit from both the Pipeline and Facilities divisions from new assets that were placed into service in late 2018 and additional commitments on existing assets; the adoption of IFRS 16; a realized gain compared to a realized loss on commodity related derivatives in the Marketing & New Ventures Division; and was partially offset by higher general and administrative costs;

- First quarter earnings of $313 million, a five percent decrease over the same period of the prior year, was primarily due to, with the exception of the adoption of IFRS 16, the factors affecting adjusted EBITDA as well as an unrealized loss on commodity related derivatives compared to an unrealized gain in the previous period and higher net finance costs, as net finance costs in the prior period included a gain related to the Company's convertible debentures. First quarter earnings was also positively impacted by a $33 million settlement from an ongoing contract dispute that was resolved during the quarter.

- Cash flow from operating activities of $608 million for the first quarter, a 22 percent increase over the same period in 2018, was primarily due to increased operating results, increased distributions from equity accounted investees, and changes in non-cash working capital, offset by higher taxes paid. On a per share (basic) basis, cash flow from operating activities for the first quarter increased by 21 percent, compared to the same period in the prior year;

- Adjusted cash flow from operating activities increased by nine percent to $578 million in the first quarter of 2019, compared to the same period in 2018, mainly attributable to an increase in operating results, higher distributions from equity accounted investees, partially offset by an increase in current tax expense and interest paid. On a per share (basic) basis, adjusted cash flow from operating activities for the first quarter increased nine percent compared to the same period of the prior year; and

- Total volumes of 3,403 mboe/d for the first quarter of 2019, a four percent increase over the prior year.

**Divisional Highlights**

- Pipelines Division reported first quarter adjusted EBITDA of $457 million, representing a 14 percent increase, and volumes of 2,507 mboe/d, representing a three percent increase, compared to the same period of 2018. Higher volumes were predominately the result of the Phase IV and Phase V Peace Pipeline expansions, which were placed into service in December 2018, marginally offset by a force majeure impacting the Vantage system;

- Facilities Division reported first quarter adjusted EBITDA of $232 million, representing a six percent increase, and volumes of 896 mboe/d, representing an increase of six percent, compared to the same period of 2018. These increases were caused primarily by higher volumes at Veresen Midstream, due in part to the North Central Liquids Hub being placed into service in June 2018, combined with higher volumes at the Redwater complex; and

- Marketing & New Ventures Division reported first quarter adjusted EBITDA of $121 million, representing a 16% increase, and NGL sales volumes of 216 mboe/d, representing a 14 percent increase, compared to the same period in 2018. Higher NGL sales volumes was driven by higher volumes at the Redwater complex. The increase in adjusted EBITDA was primarily due to the higher NGL sales volumes, increased contribution from Aux Sable as a result of lower operating expenses, the adoption of IFRS 16 and a realized gain on commodity-related derivatives in the first quarter compared to a realized loss in the same period in 2018.

**Executive Overview**

In the first quarter of 2019, Pembina has once again delivered strong financial and operational results, including record quarterly results for adjusted EBITDA and adjusted cash flow from operating activities, while continuing to announce new major projects supporting ongoing growth of our business.

Quarterly results were driven by strong year-over-year increases in operating results in the Pipelines and Facilities divisions as a result of new assets placed into service and higher utilization of existing assets, as well as higher NGL sales volumes and a realized gain on commodity related derivatives in the marketing business.

The most notable achievement during the quarter was our announcement that Pembina along with Petrochemical Industries Company K.S.C. of Kuwait ("PIC"), reached a positive final investment decision to construct a 550,000 tonne per annum integrated propane dehydrogenation ("PDH") plant and polypropylene ("PP") upgrading facility ("PDH/PP Facility") through their equally-owned joint venture entity, Canada Kuwait Petrochemical Corporation. The announcement was the culmination of many years of hard work with PIC to develop a project that is well positioned to capitalize on Alberta's abundant supply of propane and undertake value-added processing that benefits all of Pembina's stakeholders, the Province of Alberta and indeed all of Canada. Sanctioning of the PDH/PP Facility is the largest step taken to date by Pembina in executing its strategy to secure global market prices for customers' hydrocarbons produced in western Canada and provides another exciting platform for future growth.

We also were pleased to announce another expansion of the Peace Pipeline system, Phase VIII, which will accommodate incremental customer demand in the Montney area by debottlenecking constraints, accessing downstream capacity and further enhancing product segregation on the system. Phase VIII is yet another example of the advantages that our strategic footprint provides, namely the opportunity to complete staged expansions that deliver timely and reliable transportation service solutions for our customers.

With the approval of our PDH/PP Facility and Phase VIII we currently have $5.5 billion of secured projects that will diversify and strengthen our business, extend our value chain and ultimately enhance our service offering.

With the continued strength in the business, we are pleased once again to announce today a five percent dividend increase. This is the eighth consecutive year of increasing the dividend and we are extremely proud of the value we have been able to return to shareholders, reinforcing our commitment to provide our investors with sustainable cash flow and dividend per share growth.

**Projects and New Developments**

**Pipelines Division**

- Pembina continues to progress its Phase VI Peace Pipeline expansion, which includes upgrades at Gordondale, Alberta; a new 16-inch pipeline from La Glace to Wapiti, Alberta and associated pump station and terminal upgrades; and a 20-inch pipeline from Kakwa to Lator, Alberta. Detailed engineering is nearing completion and construction has begun in some areas. The estimated $280 million project is trending over budget and on schedule, with an anticipated in-service date in the second half of 2019, subject to environmental and regulatory approvals;

- Aligning with the Phase VI expansion, the Company is progressing the Wapiti Condensate Lateral, a 12-inch lateral, which will connect growing condensate volumes from a third-party owned facility in the Pipestone Montney region into Pembina's Peace Pipeline. Early works construction is underway for this lateral. Subject to regulatory and environmental approvals, this lateral is expected to be in service in the second half of 2019;

- Pembina continues to progress the Phase VII Peace Pipeline expansion, which includes a new 20-inch, approximately 220-kilometer pipeline in the La Glace-Valleyview-Fox Creek corridor, as well as six new pump stations or terminal upgrades, between La Glace and Edmonton, Alberta. The expansion is currently in Front End Engineering Design ("FEED") with the engineering schedule issued and on track. This project has an estimated capital cost of $950 million and is anticipated to be in service in the first half of 2021, subject to environmental and regulatory approvals;

- As previously announced during the quarter Pembina is proceeding with the Phase VIII Peace Pipeline expansion, which includes new 10 and 16-inch pipelines in the Gordondale to La Glace corridor as well as six new pump stations or terminal upgrades located between Gordondale and Fox Creek, Alberta. Pre-FEED work is underway for this expansion. This project has an estimated capital cost of $500 million and is anticipated to be placed into service in stages starting in 2020 through the first half of 2022, subject to regulatory and environmental approvals; and

- Development continues on the previously announced NEBC Montney Infrastructure in proximity to the Company's Birch Terminal. Construction is underway for this project. This new infrastructure is anticipated to be in service in third quarter of 2019.

**Facilities Division**

- The Company's one million-barrel Burstall Ethane Storage facility located near Burstall, Saskatchewan was placed into service in January 2019;

- The Company's 45 MW co-generation facility at the Redwater complex was placed into service at the end of March;

- Subsequent to the quarter, Pembina executed further agreements with Chevron Canada to construct sour gas treating facilities at the Duvernay complex (the "Duvernay Sour Treatment Facilities"). These facilities will include a 150 mmcf/d sour gas sweetening system with the potential for 300 mmcf/d of amine regeneration capability and one tonne of sulphur per day of acid gas incineration. These facilities have an expected capital cost of approximately $65 million and an anticipated in-service date in the first quarter of 2020, subject to environmental and regulatory approvals. Engineering for the project is progressing and long lead equipment has been ordered. The Duvernay Sour Treating Facilities will have a 20-year contractual life and be back-stopped by fixed-return arrangements. Further, with the addition of sour treating infrastructure, Pembina is positioned to handle future third-party sour gas volumes at the Duvernay complex;

- Pembina continues to progress construction of Duvernay II, which includes 300 mmcf/d of raw gas separation and water removal infrastructure; a 100 MMcf/d sweet gas, shallow cut processing facility; 30,000 bpd of condensate stabilization; and other associated infrastructure. In conjunction with the Duvernay Sour Treating Facilities, the capital cost of Duvernay II has been revised to $320 million reflecting the modifications required to meet sour specifications. Engineering is substantially complete and long lead equipment has begun to arrive onsite. The project continues to track on budget and schedule with an expected in-service date in the fourth quarter of 2019, subject to regulatory and environmental approvals;

- Pembina is progressing the previously announced Duvernay III, which includes a 100 MMcf/d sweet gas, shallow cut processing facility; 20,000 bpd of condensate stabilization; and other associated infrastructure. In conjunction with the Duvernay Sour Treating Facilities, the capital cost of Duvernay III has been revised to $175 million reflecting the modifications required to meet sour specifications. Detailed design is progressing and long lead equipment is currently in the process of being ordered. The project continues to track on budget and schedule with an expected in-service date in mid-to-late 2020, subject to regulatory and environmental approvals;

- Pembina continues with the construction of new fractionation and terminalling facilities at the Company's Empress, Alberta extraction plant for a total expected capital cost of approximately $120 million. Engineering for the project is nearing completion with early works construction underway. These facilities are expected to add approximately 30,000 bpd of propane-plus capacity to Pembina's Empress NGL Extraction Facility and have an anticipated in-service date of late 2020;

- Construction continues at Pembina's Prince Rupert LPG export terminal located on Watson Island, British Columbia. Grading and drainage of the main facilities area has been completed and material deliveries have started. The 25,000 bpd project will source LPG from the Company's Redwater complex is anticipated to have a total capital cost of $250 million with an anticipated in-service date in mid-2020, subject to regulatory and environmental approvals;

- Pembina continues to progress the Hythe Developments project whereby Pembina and its 45 percent owned joint venture, Veresen Midstream will construct natural gas gathering and processing infrastructure in the Pipestone Montney region. Long lead equipment for both the facility and the pipeline has been ordered. Collectively, the Hythe Developments have an estimated total capital cost of approximately $380 million ($185 million net to Pembina) and an anticipated in-service date of late 2020, subject to regulatory and environmental approvals; and

- On April 4, 2019, Pembina elected to cause all of the Veresen Midstream Class B Units held by its joint venture partner to be converted to Class A Units. This election will eliminate further dilution of Pembina's ownership in Veresen Midstream. Pembina's interest in Veresen Midstream for the three months ended March 31, 2019, and subsequent to the conversion of Class B Units is approximately 45 percent.

### Marketing & New Ventures Division

- During the quarter, Pembina along with PIC, announced a positive final investment decision to construct a 550,000 tonne per annum integrated PDH/PP Facility through their equally-owned joint venture entity, Canada Kuwait Petrochemical Corporation. The PDH/PP Facility will be located adjacent to Pembina's Redwater fractionation complex and will convert approximately 23,000 bpd of locally supplied propane into polypropylene, a high value recyclable polymer used in a wide range of finished products including automobiles, medical devices, food packaging and home electronic appliances, among others. The project is now transitioning into the execution phase including obtaining engineering, procurement and construction bids, site clearing activities and the placement of long-lead equipment orders. Pembina's net investment in this project is expected to be $2.5 billion with an expected in-service date in mid-2023, subject to environmental and regulatory approvals; and

- A key component of Pembina's strategy involves securing access to global markets for hydrocarbon resources in the basins where Pembina operates. The Company is committed to the Jordan Cove LNG project as a means of delivering long-lived, highly economic North American natural gas resources to global demand markets.

  Regulatory processes for Jordan Cove are progressing. On March 29, 2019 the FERC issued a Draft Environmental Impact Statement, which provides a constructive framework for the approval of Jordan Cove essentially as proposed, with reasonable conditions that work with the project development process and with only minor suggested changes. A final FERC decision is expected by January 2020.

  Oregon State permit approvals including those under the Coastal Zone Management Act and the Oregon Department of Environmental Quality 401 are also progressing with decisions on both approvals expected by the end of 2019. Each of the permits are a critical component of the regulatory process and enable the commercial viability and critical investment in Oregon to move forward.

  Pembina continues to see Jordan Cove as a viable project, however the Company has decided to limit pre-FID capital investment on non-permitting related activities. Pembina has approved incremental funding of approximately $50 million for 2019 in support of the remaining critical regulatory and permitting work streams.

The Company will conclude Federal and Oregon regulatory processes allowing it to catch up with certain other project work streams. Given the anticipated regulatory timeline, we expect these activities to resume in early 2020, subject to receipt of the requisite FERC and State of Oregon approvals.

Suspending non-permitting related activities will affect the construction schedule of the project and first gas is expected to be delayed up to one year from the previously anticipated date in 2024.

Commercialization efforts have continued and as previously disclosed the Company has executed non-binding off-take agreements with customers in excess of the planned design capacity of 7.5 Mtpa. Commercial discussions with prospective customers are continuing as regulatory permitting is progressed and under the new timeline the Company will work to conclude binding off-take agreements by early 2020.

Pembina previously disclosed that given the size of this project, the Company intends to seek partners for both the pipeline and liquification facility thereby reducing its 100 percent ownership interest to a net ownership interest of between 40 and 60 percent with the intention to reduce the capital, operating and other project risks. This process to find partners is expected to commence upon securing binding off-take agreements, and under the new timeline is expected to occur in early 2020.

**Financial Impact of Adoption of IFRS 16**

- The nature of expenses related to identified lessee arrangements changed as IFRS 16 replaced straight-line operating lease expense with depreciation of right of use assets and interest expense relating to lease liabilities. The change resulted in a $1 million increase to earnings and a $15 million increase to adjusted EBITDA for the three months ended March 31, 2019. In addition, cash flow from operating activities and adjusted cash flow from operating activities increased $15 million and cash flow from financing activities decreased by the same amount, as lease obligation repayments are now reported as financing activities on the Condensed Consolidated Interim Statement of Cash Flows. There was no net impact on cash flows.

### Guidance

- Based on the expected full year impact of IFRS 16, Pembina is revising both the low and the high end of its 2019 Adjusted EBITDA guidance range by $50 million, to $2.85 to $3.05 billion.

### Financing

- Subsequent to quarter end, Pembina closed an $800 million issuance of senior unsecured medium-term notes (the "Offering") on April 3, 2019. The Offering was conducted in two tranches consisting of $400 million in senior unsecured medium-term notes, series 12, having a fixed coupon of 3.62 percent per annum, paid semi-annually, and maturing on April 3, 2029 and $400 million in senior unsecured medium-term notes, series 13, having a fixed coupon of 4.54 percent per annum, paid semi-annually, and maturing on April 3, 2049. The net proceeds will be used to repay short-term indebtedness of the Company under its credit facilities, as well as to fund Pembina's capital program and for general corporate purposes.

### Dividends

- Declared and paid dividends of $0.19 per qualifying common share for the applicable record dates in January, February and March 2019;

- On May 2, 2019, Pembina's Board of Directors approved a five percent increase in its monthly common share dividend rate (from $0.19 per common share to $0.20 per common share), commencing with the dividend to be paid on June 14, 2019;

- Declared and paid quarterly dividends per qualifying preferred shares of: Series 1: $0.306625; Series 3: $0.29375; Series 5: $0.3125; Series 7: $0.28125; Series 9: $0.296875; Series 11: $0.359375; Series 13: $0.359375; and Series 21: $0.30625 to shareholders of record as of February 1, 2019. Declared and paid quarterly dividends per qualifying preferred shares of: Series 15: $0.279; Series 17: $0.3125; and Series 19: $0.3125 to shareholders of record on March 15, 2019;

- On January 30, 2019, Pembina announced that it did not intend to exercise its right to redeem the currently outstanding 6,000,000 Cumulative Redeemable Rate Reset Class A Preferred Shares, Series 3 ("Series 3 Shares") on March 1, 2019. The annual dividend rate for the Series 3 Shares for the five-year period from and including March 1, 2019 to, but excluding, March 1, 2024 will be 4.478%. For more information on the terms of, and risks associated with an investment in, the Series 3 Shares please see the prospectus supplement dated September 25, 2013 filed on SEDAR at www.sedar.com (http://www.sedar.com) and available at www.pembina.com (http://www.pembina.com) and the news release dated January 30, 2019;

- On March 1, 2019, Pembina announced that it did not intend to exercise its right to redeem the currently outstanding 6,000,000 Cumulative Redeemable Rate Reset Class A Preferred Shares, Series 17 ("Series 17 Shares") on March 31, 2019. The annual dividend rate for the Series 17 Shares for the five-year period from and including March 31, 2019 to, but excluding, March 31, 2024 will be 4.821%. For more information on the terms of, and risks associated with an investment in, the Series 17 Shares please see the prospectus supplement dated October 11, 2013 filed on SEDAR at www.sedar.com (http://www.sedar.com) and available at www.pembina.com (http://www.pembina.com) and the news release dated March 1, 2019; and

- Subsequent to quarter end, on May 2, 2019, Pembina announced that it did not intend to exercise its right to redeem the currently outstanding 10,000,000 Cumulative Redeemable Rate Reset Class A Preferred Shares, Series 5 ("Series 5 Shares") on June 3, 2019 (the "Conversion Date"). As a result, and subject to certain terms of the Series 5 Shares, the holders of the Series 5 Shares will have the right to elect to convert all or any of their Series 5 Shares into Cumulative Redeemable Floating Rate Class A Preferred Shares, Series 6 of Pembina ("Series 6 Shares") on the basis of one Series 6 Share for each Series 5 Share on the Conversion Date. The deadline to provide notice of exercise of the right to convert Series 5 Shares into Series 6 Shares is 3:00 p.m. (MST) / 5:00 p.m. (EST) on May 17, 2019. For more information on the terms of, and risks associated with an investment in, the Series 5 Shares and the Series 6 Shares, please see Pembina's prospectus supplement dated January 9, 2014 which can be found on SEDAR at www.sedar.com (http://www.sedar.com) and available at www.pembina.com (http://www.pembina.com) and the news release dated May 2, 2019.

## First Quarter 2019 Conference Call & Webcast

Pembina will host a conference call on Friday, May 3, 2019 at 8:00 a.m. MT (10:00 a.m. ET) for interested investors, analysts, brokers and media representatives to discuss details related to the first quarter 2019 results. The conference call dial-in numbers for Canada and the U.S. are 647-427-7450 or 888-231-8191. A recording of the conference call will be available for replay until May 10, 2019 at 11:59 p.m. ET. To access the replay, please dial either 416-849-0833 or 855-859-2056 and enter the password 4976398.

A live webcast of the conference call can be accessed on Pembina's website at pembina.com under Investor Centre, Presentation & Events, or by entering: https://event.on24.com/wcc/r/1880618/81FD9B5DBEEB0D2BF7D38CA19EDC43B7 (https://c212.net/c/link/?t=0&l=en&o=2454630-1&h=598800519&u=https%3A%2F%2Fevent.on24.com%2Fwcc%2Fr%2F1880618%2F81FD9B5DBEEB0D2BF7D38CA19EDC43B7&a=https%3A%2F%2Fevent.on24.com%2Fwcc%2Fr%2F1880618%2F81FD9B5DBEEB0D2BF7D38CA19EDC43B7) in your browser. Shortly after the call, an audio archive will be posted on the website for a minimum of 90 days.

## Annual and Special Meeting of Common Shareholders and Special Meeting of Preferred Shareholders

The Company will hold its Annual and Special Meeting of common shareholders ("AGM") on Friday, May 3, 2019 at 2:00 p.m. MT (4:00 p.m. ET) in the Ballroom at the Metropolitan Conference Centre, 333 - 4th Avenue S.W., Calgary, Alberta, Canada.

The Company will hold its Special Meeting of Class A preferred shareholders on Friday, May 3, 2019 at 1:00 p.m. MT (3:00 p.m. ET) in the Grand Lecture Theatre at the Metropolitan Conference Centre, 333 - 4th Avenue S.W., Calgary, Alberta, Canada.

A live webcast of Pembina's AGM presentation can be accessed on Pembina's website at www.pembina.com (http://www.pembina.com) under Investor Centre, Presentation & Events, or by entering: https://event.on24.com/wcc/r/1937359/0069DA07C36B92C7D7AC740E7FE09605 (https://c212.net/c/link/?t=0&l=en&o=2454630-1&h=12008810&u=https%3A%2F%2Fevent.on24.com%2Fwcc%2Fr%2F1937359%2F0069DA07C36B92C7D7AC740E7FE09605&a=https%3A%2F

%2Fevent.on24.com%2Fwcc%2Fr%2F1937359%2F0069DA07C36B92C7D7AC740E7FE09605) in your web browser. Participants are recommended to register for the webcast at least 10 minutes before the presentation start time.

**2019 Investor Day**

Pembina will hold an Investor Day on Tuesday, May 14, 2019 at The Omni King Edward Hotel in Toronto, Ontario. For parties interested in attending the event, please email investor-relations@pembina.com (mailto:investor-relations@pembina.com) to request an invitation.

**About Pembina**

*Calgary-based Pembina Pipeline Corporation is a leading transportation and midstream service provider that has been serving North America's energy industry for over 60 years. Pembina owns an integrated system of pipelines that transport various hydrocarbon liquids and natural gas products produced primarily in western Canada. The Company also owns gas gathering and processing facilities and an oil and natural gas liquids infrastructure and logistics business. Pembina's integrated assets and commercial operations along the majority of the hydrocarbon value chain allow it to offer a full spectrum of midstream and marketing services to the energy sector. Pembina is committed to identifying additional opportunities to connect hydrocarbon production to new demand locations through the development of infrastructure that would extend Pembina's service offering even further along the hydrocarbon value chain. These new developments will contribute to ensuring that hydrocarbons produced in the Western Canadian Sedimentary Basin and the other basins where Pembina operates can reach the highest value markets throughout the world.*

*Purpose of Pembina:*

*To be the leader in delivering integrated infrastructure solutions connecting global markets;*

- ***Customers** choose us first for reliable and value-added services;*
- ***Investors** receive sustainable industry-leading total returns;*
- ***Employees** say we are the 'employer of choice' and value our safe, respectful, collaborative and fair work culture; and*
- ***Communities** welcome us and recognize the net positive impact of our social and*

*environmental commitment.*

**Forward-Looking Statements and Information**

*This document contains certain forward-looking statements and information (collectively, "forward-looking statements"), including forward-looking statements within the meaning of the "safe harbor" provisions of applicable securities legislation, that are based on Pembina's current expectations, estimates, projections and assumptions in light of its experience and its perception of historical trends. In some cases, forward-looking statements can be identified by terminology such as "continue", "anticipate", "schedule", "will", "expects", "estimate", "potential", "planned", "future" and similar expressions suggesting future events or future performance.*

*In particular, this document contains forward-looking statements, including certain financial outlook, pertaining to, without limitation, the following: Pembina's corporate strategy; expectations about industry activities and development opportunities; expectations about future growth opportunities and demand for our service; expectations regarding new corporate developments and impact on access to markets; anticipated adjusted EBITDA projections for* 2019 *and financial performance expectations resulting from Pembina's capital expenditures; planning, construction, capital expenditure estimates, schedules, locations, regulatory and environmental applications and approvals, expected capacity, incremental volumes, in-service dates, rights, activities and operations with respect to planned new construction of, or expansions on existing pipelines, gas services facilities, fractionation facilities, terminalling, storage and hub facilities, facility and system operations and throughput levels; expectations regarding the involvement of partners on the Jordan Cove project; dilution of Pembina's ownership in certain joint ventures; anticipated synergies between assets under development, assets being acquired and existing assets of the Company; the future level and sustainability of cash dividends that Pembina intends to pay its shareholders, including the expected future cash flows and the sufficiency thereof.*

*The forward-looking statements are based on certain assumptions that Pembina has made in respect thereof as at the date of this news release regarding, among other things: oil and gas industry exploration and development activity levels and the geographic region of such activity; the success of Pembina's operations and growth projects; prevailing commodity prices and exchange rates and the ability of Pembina to maintain current credit ratings; the availability of capital to fund future capital requirements relating to existing assets and projects; future operating costs; geotechnical and integrity costs; that any third-party projects relating to*

*Pembina's growth projects will be sanctioned and completed as expected; that any required commercial agreements can be reached; that all required regulatory and environmental approvals can be obtained on the necessary terms in a timely manner; that counterparties will comply with contracts in a timely manner; that there are no unforeseen events preventing the performance of contracts or the completion of the relevant facilities; that there are no unforeseen material costs relating to the facilities which are not recoverable from customers; prevailing interest and tax rates; prevailing regulatory, tax and environmental laws and regulations; maintenance of operating margins; the amount of future liabilities relating to lawsuits and environmental incidents; and the availability of coverage under Pembina's insurance policies (including in respect of Pembina's business interruption insurance policy).*

*Although Pembina believes the expectations and material factors and assumptions reflected in these forward-looking statements are reasonable as of the date hereof, there can be no assurance that these expectations, factors and assumptions will prove to be correct. These forward-looking statements are not guarantees of future performance and are subject to a number of known and unknown risks and uncertainties including, but not limited to: the regulatory environment and decisions; the impact of competitive entities and pricing; labour and material shortages; reliance on key relationships and agreements; the strength and operations of the oil and natural gas production industry and related commodity prices; non-performance or default by counterparties to agreements which Pembina or one or more of its affiliates has entered into in respect of its business; actions by governmental or regulatory authorities including changes in tax laws and treatment, changes in royalty rates, climate change initiatives or policies or increased environmental regulation; the failure to realize the anticipated benefits or synergies of acquisitions due to the factors set out herein, integration issues or otherwise; fluctuations in operating results; adverse general economic and market conditions in Canada, North America and worldwide, including changes, or prolonged weaknesses, as applicable, in interest rates, foreign currency exchange rates, commodity prices, supply/demand trends and overall industry activity levels; ability to access various sources of debt and equity capital; changes in credit ratings; counterparty credit risk; technology and cyber security risks; and certain other risks detailed from time to time in Pembina's public disclosure documents available at www.sedar.com (https://c212.net/c/link/?t=0&l=en&o=2454630-1&h=3783694410&u=http%3A%2F%2Fwww.sedar.com%2F&a=www.sedar.com), www.sec.gov (https://c212.net/c/link/?t=0&l=en&o=2454630-1&h=1276717020&u=http%3A%2F%2Fwww.sec.gov%2F&a=www.sec.gov) and through Pembina's website at www.pembina.com (https://c212.net/c/link*

*/?t=0&l=en&o=2454630-1&h=3532173053&u=http%3A%2F%2Fwww.pembina.com%2F&a=www.pembina.com).*

*This list of risk factors should not be construed as exhaustive. Readers are cautioned that events or circumstances could cause results to differ materially from those predicted, forecasted or projected. The forward-looking statements contained in this document speak only as of the date of this document. Pembina does not undertake any obligation to publicly update or revise any forward-looking statements or information contained herein, except as required by applicable laws. Readers are cautioned that management of Pembina approved the financial outlook contained herein as of the date of this press release. The purpose of the* 2019 *Adjusted EBITDA projection is to provide investors with an indication of the value to Pembina of capital projects that have been and will be brought into service in* 2019. *Readers should be aware that the information contained in the financial outlook contained herein may not be appropriate for other purposes. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.*

**Non-GAAP Measures**

*In this news release, Pembina has used the terms net revenue, adjusted earnings before interest, taxes, depreciation and amortization (Adjusted EBITDA), Adjusted EBITDA per common share, cash flow from operating activities per common share, adjusted cash flow from operating activities per common share, which do not have any standardized meaning under IFRS ("Non-GAAP Measures"). Since Non-GAAP financial measures do not have a standardized meaning prescribed by GAAP and are therefore unlikely to be comparable to similar measures presented by other companies, securities regulations require that Non-GAAP financial measures are clearly defined, qualified and reconciled to their nearest GAAP measure. These Non-GAAP measures are calculated and disclosed on a consistent basis from period to period. Specific adjusting items may only be relevant in certain periods. The intent of Non-GAAP measures is to provide additional useful information respecting Pembina's financial and operational performance to investors and analysts and the measures do not have any standardized meaning under IFRS. The measures should not, therefore, be considered in isolation or used in substitute for measures of performance prepared in accordance with IFRS.*

*Non-GAAP Proportionate Consolidation of Investments in Equity Accounted Investees Results*

*In accordance with IFRS, Pembina's jointly controlled investments are accounted for using equity* *accounting. Under equity accounting, the assets and liabilities of the investment are net into a single line item in the Consolidated Statement of Financial Position, Investments in Equity Accounted Investees. Net earnings from Investments in Equity Accounted Investees are recognized in a single line item in the Consolidated Statement of Earnings and Comprehensive Earnings, share of profit from equity accounted investees. Cash contributions and distributions from Investments in Equity Accounted Investees represent Pembina's proportionate share paid and received in the period to and from the equity accounted investment.*

*To assist the readers' understanding and evaluation of the performance of these investments, Pembina is supplementing the IFRS disclosure with Non-GAAP disclosure of Pembina's proportionately consolidated interest in the Investments in Equity Accounted Investees. Pembina's proportionate interest in Investments in Equity Accounted Investees has been included in Adjusted EBITDA.*

*Other issuers may calculate these Non-GAAP measures differently. Investors should be cautioned that these measures should not be construed as alternatives to revenue, earnings, cash flow from operating activities, gross profit or other measures of financial results determined in accordance with GAAP as an indicator of Pembina's performance. For additional information regarding Non-GAAP measures, including reconciliations to measures recognized by GAAP, please refer to Pembina's management's discussion and analysis for the period ended March 31, 2019, which is available online at www.sedar.com (http://www.sedar.com), www.sec.gov (http://www.sec.gov) and through Pembina's website at www.pembina.com (https://c212.net/c/link/?t=0&l=en&o=2454630-1&h=3532173053&u=http%3A%2F%2Fwww.pembina.com%2F&a=www.pembina.com).*

SOURCE Pembina Pipeline Corporation

(/our-responsibility/) (/media-centre/)

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**State Land Board**

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April 10, 2019

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

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

Dear Mr. Vowels:

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

## Overview of Decision Process and Need for Additional Information

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

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

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

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

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

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

December 6, 2018. OAR 141 Division 85 contains the standards and criteria that will be considered throughout the review of this application.

- Section (3) of the OAR provides that "The Department will issue a permit if it determines the project described in the application:
  - (a) Has independent utility;
  - (b) Is consistent with the protection, conservation and best use of the water resources of this state as specified in ORS 196.600 to 196.990, and
  - (c) Would not unreasonably interfere with the paramount policy of this state to preserve the use of its waters for navigation, fishing and public recreation."

- Section (4) of the OAR provides that "In determining whether to issue a permit, the Department will consider all of the following:
  - (a) The public need for the proposed fill or removal and the social, economic or other public benefits likely to result from the proposed fill or removal. When the applicant for a permit is a public body, the Department may accept and rely upon the public body's findings as to local public need and local public benefit;
  - (b) The economic cost to the public if the proposed fill or removal is not accomplished;
  - (c) The availability of alternatives to the project for which the fill or removal is proposed;
  - (d) The availability of alternative sites for the proposed fill or removal;
  - (e) Whether the proposed fill or removal conforms to sound policies of conservation and would not interfere with public health and safety;
  - (f) Whether the proposed fill or removal is in conformance with existing public uses of the waters and with uses designated for adjacent land in an acknowledged comprehensive plan and land use regulations;
  - (g) Whether the proposed fill or removal is compatible with the acknowledged comprehensive plan and land use regulations for the area where the proposed fill or removal is to take place or can be conditioned on a future local approval to meet this criterion;
  - (h) Whether the proposed fill or removal is for stream bank protection; and
  - (i) Whether the applicant has provided all practicable mitigation to reduce the adverse effects of the proposed fill or removal in the manner set forth in ORS 196.600."

- Section (5) of the OAR provides that "The Department will issue a permit only upon the Department's determination that a fill or removal project is consistent with the protection, conservation and best use of the water resources of this state and would not unreasonably interfere with the preservation of the use of the waters of this state for navigation, fishing and public recreation. The Department will analyze a proposed project using the criteria set forth in the determinations and considerations in sections (3) and (4) above (OAR 141-085-0565). The applicant bears the burden of providing the Department with all information necessary to make this determination."

## Summary of Substantive Public Comments

DSL has reviewed all the comments received concerning Jordan Cove application for a removal-fill permit. The Department's summary of the substantive comments (below) is not exhaustive. Jordan Cove should review and address the substantive comments that relate directly to the proposed removal and fill or that relate to the potential impacts of the proposed removal and fill. All substantive comments received are provided here.

**Jordan Cove failed to demonstrate the project is in the public interest, Jordan Cove failed to demonstrate a public need. (ORS 196.825(3)(a)):** Comments received on this topic stressed that the Department must affirmatively determine that the project would address a public need consistent with *Citizens for Resp. Devel. In the Dalles v. Walmart* 295 Or App 310 (2018). With a privately-sponsored project of this scale and complexity, the Department must consider public need in a transparent and comprehensive analysis that weighs all the relevant impacts and alleged benefits of the project.

**Jordan Cove failed to demonstrate the project is consistent with the protection, conservation, and best use of Oregon's waters. (ORS 196.825(1)(a)):** Commenters are concerned that the project would likely do unnecessary harm and damage to water quality in Oregon and suggest the applicants have failed to demonstrate that the project is consistent with the protection, conservation and best use of the water resources of this state. The proposed project will likely impair designated beneficial uses, threatening drinking water supplies and fish habitat. It will also likely further degrade stream segments in which water quality is already impaired for temperature, dissolved oxygen, pH, turbidity, mercury, and sedimentation.

**The project does not conform to sound policies of conservation and will likely interfere with public health and safety (ORS 196.825(3)(e)):** The Department received comments with concerns that the applicant has failed to demonstrate that the project will not interfere with public health and safety. Potential risks to public health and safety include natural hazards, such as floods, tsunamis, wildfires, landslides, and earthquakes, identified under Statewide Planning Goal 7. The potential for high-flow events that expose the pipeline or inadvertent drilling fluid releases (frac-outs) during construction at proposed stream crossings may result in increased risks to public health and safety. Failure at any of the major waterbody crossings claiming avoidance by using either Hydraulic Directional Drill (HDD) method, conventional bore or direct pipe method would have detrimental impacts to waters of the state and potentially contaminate state waters. Several risks to public health and safety were raised during public review that need to be addressed by the applicant, such as the list provided below. Please address these adverse impacts of this project:

- An accidental explosion of a fully loaded Liquefied Natural Gas (LNG) ship or at the terminal, including the worst-case scenario for the immediate area;
- How are the Federal Aviation Administration (FAA) presumed hazard determinations being addressed by Jordan Cove;
- Tsunami risks increasing from the project dredging activities;
- Improper facility siting, Society for International Gas Tanker and Terminal Operators (SIGTTO) standards not followed (i.e., on the outside bend of the navigation channel, near other terminal users, near population centers);
- Impacts on municipal drinking water sources, private wells, irrigation sources and agricultural uses;
- Increased wildfire risks as construction season coincides with the in-water work period which also coincides with fire season; and
- Impacts of massive scale clearing and grubbing with pipeline installation on water quality, land stability, erosion and turbidity of doing these activities during the rainy winter seasons, all water flows downhill.

**The project would interfere with navigation, fishing, and public recreation:** Comments received on this topic addressed that the Department must conduct a weighing of the public benefits of the project against interference with factors including navigation, fishing, and public recreation (See *Citizens for Resp. Devel. In the Dalles v. Walmart,* 295 Or App 310 (2018)). As part of this weighing of public benefits, the Oregon Legislature has clearly demonstrated that it is the State's "paramount policy" to preserve Oregon waters for navigation, fishing, and public recreation. ORS 196.825(1).

The comments indicate that the applicant has failed to demonstrate that the project will not unreasonably interfere with navigation, fishing, and public recreation in this application. Potential conflicts include but are not limited to:

- Crabbing, fishing and all types of recreational uses in and around Coos Bay;
- Safe bar passage issues/LNG tanker bar crossings only at high tides conflict with recreational fishers and the commercial fleets that also cross the bar at high slack tides for safety reasons should be evaluated;
- Exclusion zones required around LNG tankers while the LNG tanker is in transit will impact the recreating public crabbing via the ring method. This is reportedly the most common recreational crabbing method in Coos Bay. High slack tides are optimum for crabbing and if an LNG tanker must transit only at high tides, given the security and exclusion zones, there is interference with existing recreational uses within Coos Bay; and
- Impacts on the commercial fisheries uses of Coos Bay and adjacent ocean resources.

**Jordan Cove failed to demonstrate independent utility (OAR 141-085-0565(3)(a)):** Commenters assert that the project is connected to the Coos Bay Channel Modification (CBCM) Project. The applicant would be the primary benefactor from the proposed widening and deepening of the federal navigation channel as part of the CBCM project or similar efforts to expand the navigation channel. Further, there are serious questions about the feasibility of LNG vessels transiting the federal navigation channel under the dredging currently proposed as part of this application. Oregon Department of Fish and Wildlife (ODFW) contends that the Jordan Cove Energy Project and Port of Coos Bay Channel Modification project are connected actions and should be evaluated that way. The applicant has failed to demonstrate that the project has independent utility as required under OAR 141-085-0565(3)(a).

**Jordan Cove failed to demonstrate a comprehensive analysis of alternatives to the project (OAR 141-085-0550(5), ORS 196.825(3)(c) and (d)):** Commenters outline that the applicant has failed to demonstrate a comprehensive analysis of alternatives to the project, and therefore, the Department does not have the information to consider the availability of alternatives both for the project and for proposed fill and removal sites. Also, the Department was not able to determine that the project is the practicable alternative with the least adverse impacts on state water resources. Comments detail that through a flawed, overly-narrow purpose and need statement, the resulting biased alternative analysis prevents the Department from considering a reasonable range of alternatives to the project.

**Navigation Reliability Improvements (NRI) Dredging:** Comments indicate that there is no documented need for the 590,000 cubic yards to dredge the four corners outside the existing Federal Navigation Channel (FNC). Comments also state that Jordan Cove can export 99.5% of the anticipated annual output of the LNG facility (7.8 million tons) without the NRI dredging, which leaves the question, is there a 'need' to excavate 590,000 cubic yards of material for a nominal gain in transport capacity to allow Jordan Cove to travel at higher wind speeds than the current channel configuration could safely allow. Comments further suggest this minor economic benefit to only Jordan Cove does not equate to a 'need' to impact trust resources of the State of Oregon. The adverse impacts are understated or not explained in terms of the salinity impacts and hydrologic changes that will result from widening the existing navigational channel. The potential tsunami run-up impacts are not well explained either, nor are any hydrodynamic changes that would likely result or any analysis on potential increases to bank erosion adjacent to the proposed NRI channel improvements. The need should be substantiated, and a robust alternatives analysis prepared to address these issues and justify the dimensions and depths needed with supporting documentation in the form of simulation modelling showing that the current channel is insufficient for Jordan Cove.

**Pile Dike-Rock Apron:** Comments raised concerns that no alternatives were presented regarding the proposed 6,500 cubic yards (cy) of rock riprap proposed to protect the existing pile dike against erosion from the slip and access channel location, depth and dimensions. With no alternatives presented on the dimensions or design alignment of the slip and access channel, no reasonable range of alternatives can be considered. There is no discussion on impact avoidance, minimization, and/or mitigation to offset any adverse impacts to waters of the state. Please address:
- Why 6,500 cy?
- Why not more?
- Why not less?
- Why any at all?

**Dredged Material Disposal (DMD) transfer of materials to APCO 1 & 2 from the NRI dredging:** Comments received raised the following questions, please answer:
- How will the rock be excavated and transferred to the DMD site? Vague alternatives analysis presented, leaves more questions than answers.
- What types of equipment will be used to excavate the NRI's?
- Which works best in what type of materials (bedrock, rock, sand or silts), which has least environmental impacts depending on the material encountered?
- How will the rock be dredged? Different equipment?
- Can rock be transferred to a DMD site via slurry line as the application states? Inadequate discussion on alternatives, leaving the details to the contractor is insufficient.

**Slip and Access Channel:** Comments raised the concern of a lack of discernable alternative analysis for the precise dimensions and location of the slip and access channel. The slip and access channel are designed for a ship class of 217,000 cubic meters, yet the Coast Guard Waterway Suitability Analysis recommends allowing ships no larger than 148,000 cubic meters. Please answer the following questions and concerns:
- Why design a slip to accommodate a ship class that is not currently allowed nor physically capable of navigating into Coos Bay given the constraints of the Coos Bay bar and currently authorized limitations of the federal navigation channel?
- The application claims the stated depth needed for the slip and access channel is to maintain 'underkeel clearance' while an LNG ship is at dock. This is misleading as an LNG ship can only safely navigate the current channel at a high tide advantage, above 6ft tides to get through the channel to the slip before the tide recedes which would strand the vessel if it is not safely docked in the slip. Any LNG ship, 148,000 cubic meter class ship, would not be able to transit Coos Bay except periods of high tide, there would be no way for a ship to exit the slip at any lower tidal elevation as the ships draft would exceed navigational depth of the channel which could pose huge safety concern in the event of a tsunami.
- Water quality concerns from the 'sump effect' of having the proposed 45ft Mean Low Low Water (MLLW) deep slip and access adjacent to and on the outside bend of the 37ft MLLW navigation channel need to be addressed.
- What are the sedimentation impacts, salinity impacts, temperature and dissolved oxygen impacts that would likely result from a deep-water pocket created for the slip?

Questions were raised over whether the access channel dimensions can change, as no alternatives discussion exists, it is just one option, take it or leave it. Any reduction in the size of the slip or access channel would reduce water impacts and reduce the required mitigation. Any reduction in size or depth would also reduce adverse impacts associated with this project. The need should be substantiated, and a robust alternatives analysis prepared to address these issues.

**DMD Alternatives:** Commenters would also like to know why Jordan Cove will move 300,000 cubic yards of sand to the Kentuck site when other alternatives exist that would have less impact than transferring a line all the way across Coos Bay to Kentuck slough. The log spiral bay could accommodate more than 300,000 cubic yards, it is much closer to the dredge sites and would have significantly less impacts than the Kentuck proposal, yet it is dismissed. Please explain more thoroughly the alternatives that were considered and why those alternatives were dismissed within the greater DMD plan.

**APCO DMD Site:** Commenters have concerns over the capacity of the APCO site. Does this site have the capacity for the initial dredging and maintenance dredging over the lifespan of this project? Commenters also have site stabilization and liquefaction concerns over a mountain of sand piled up adjacent to Coos Bay in an earthquake and tsunami zone. There is safety, engineering, project feasibility, and water resources concerns that must all be addressed.

**The project does not conform with existing land use laws (ORS 196.825(3)(g)):** Commenters indicate that the applicant has failed to demonstrate that the project conforms with existing land uses designated in the applicable comprehensive plan and land use regulations. They also mentioned that the applicant has failed to provide the Department with the information necessary to make the determinations required by ORS 196.825(3)(g) that the applicant's proposed fill or removal is compatible with the requirements of the comprehensive plan and land use regulations for the area in which it will take place. Current, up-to-date Land Use Consistency Statements are required for all parts of this project in all jurisdictions with an explanation of the current status, pending or resolved local issues, processes, or appeals status.

Further, commenters are concerned the applicant has failed to obtain land use permits for the project in Coos Bay. Because of the reasons adopted by the Land Use Board of Appeals (LUBA) in remanding the prior land use application are directly related to the inconsistency of the proposed dredge and fill in wetlands and in the Coos Bay Estuary with the Coos Bay Estuary Management Plan, the project cannot be conditioned on a future land use approval to meet this criterion.

In January 2019, the Douglas County Circuit Court Judge reversed the Douglas County extensions from December 2016 and 2017 that approved the Pacific Connector Gas Pipeline as a conditional use. Because the pipeline will require a new application for conditional use permit and utility facility necessary for public service, the applicant has not met its burden to demonstrate to the Department that the project conforms to Douglas County's acknowledged comprehensive plan and land use regulations.

The comments received indicate that the applicant has not met their burden to demonstrate to the Department that the project conforms to Jackson County's acknowledged comprehensive plan and land use regulations.

**Insufficient Mitigation-Kentuck Compensatory Wetland Mitigation (CWM) Site:** Concerns were raised about the lack of a discernable alternative analysis on many components of the Kentuck mitigation proposal to see what alternatives were considered and on what basis were rejected. The mitigation proposal itself is the largest wetland impact in this project proposal. Please answer the following questions:

- Why import 300,000 cubic yards of sand?
- Why not more or less materials?
- Why not use more suitable materials native to the area?
- Why sand vs. native cohesive clay soils for use as fill?
- What are the alternatives to move the sand to the site?
- Why were upland routes dismissed without reasonable justification?
    - Trucking the materials is a viable option with no impact to waters of the state.
- What other mitigation sites or options have you looked at addressing the following concern?
- The Kentuck site is already a freshwater wetland and has increased its functions in the past 10 years to the point that the current mitigation strategy might be inappropriate to offset functional losses. Please answer these questions as well:
    - Why is the dike so big, long, and wide?
    - Why is there no justification given to support dimensions of the proposed dike?
    - Why are there no alternatives are presented to evaluate the adverse effects of the dike and mitigation strategy?
    - Address the landowner concerns regarding the Kentuck Mitigation proposal and the Saltwater Intrusion impacts on adjacent lands.
    - Further address the concerns of flooding and impacting agricultural activities and existing farm uses.
    - Why is the pipeline proposed under a proposed mitigation site?
    - Where is the avoidance and/or impact minimization, especially given that each impact reduces the overall size of the mitigation project, therefore diminishing its potential function and values? Concerns were raised about the suitability of having a pipeline under the mitigation site that is supposed to be protected in perpetuity.

**Insufficient Mitigation-Eelgrass CWM Site:** Comments raised concerns about the lack of a discernable alternative analysis on many components of the eelgrass mitigation proposal. The CWM citing was found not to be in-kind or in proximity mitigation which would replace similar lost functions and values of the impact site. Disturbing existing mudflats and adjacent eelgrass beds is likely to have additional adverse impacts from construction. The proposal is inconsistent with ODFW Habitat Mitigation Policy. Alternatives should be considered, in consultation with ODFW, that favor impact avoidance to adjacent high value habitats (mudflats and adjacent eelgrass beds) and seek out appropriate in-kind, in proximity mitigation. The project impacts are to eelgrass beds adjacent to deep water habitats, while the proposed mitigation is near the airport runway and in shallow water habitats a considerable distance from deep water habitats. There are likely unforeseen FAA issues with the proximity of the mitigation site to the airport runway, this should be explored in detail with the FAA. The location of the eelgrass CWM site is situated in a portion of the Coos Bay Estuary classified as "52-Natural Aquatic" in the Coos Bay Estuary Management Plan where dredging is not allowed. This issue needs to be clarified by Coos County with respect to land use consistency.

**Insufficient Mitigation-Stream Impacts:** Comments assert that the project will impact many waterways' beneficial uses, water quantity and quality will be further impaired from construction of this project. Potential impacts include but are not limited to increased water temperatures, dissolved water oxygen, turbidity, etc. from riparian shade removal in 303(d) listed waterways and other waters. Disruption of fluvial processes, increased erosion and downstream sedimentation and turbidity from construction activities, impacts on spawning and rearing habitats, impacts on fish migration and passage.

Many people have raised concerns that Federal Energy Regulatory Commission (FERC) procedures are vague and will not provide assurances that water quality/quantity standards will be protected. Stream risk analysis, alternative ways to avoid and minimize impacts for each water crossing are not possible on properties with denied access. How are any reasonable alternatives considered if access is denied and unattainable without a FERC Order granting condemnation authority? Alternatives are not fully explored or explained to avoid and minimize impacts at every opportunity.

**ODFW Habitat Mitigation Policy Inconsistencies:** Commenters expressed that the applicants should work with ODFW to appropriately categorize each wetland and waterway impact from start to end along the proposed pipeline route. Once the appropriate habitat category has been assigned in agreement with ODFW, appropriate mitigation can be discussed based on resources impacted. Currently, temporary impacts mitigation is insufficient and inconsistent with the ODFW Habitat Mitigation Policy for streams and wetlands crossed by the pipeline.

**Fish Passage-Coastal Zone Management Act (CZMA) and Non-CZMA Streams:** Comments expressed concern that fish passage has not been addressed by the applicant. According to ODFW, applications for fish passage have not been submitted and this is critical to the Department for impact analysis determinations yet to be made. Fish passage applications may need to include a contingency method for crossing each waterway. For instance, if any of the HDD's fail, what is next, certainly not open trench, wet cut methods that are not currently being evaluated as alternative crossing methods under consideration.

**Wetland Delineations/Concurrence:** Public comments point out that some of the wetland delineation reports have either expired or are about to expire, see C4, C5, C9 and C10 of the application.

## Additional Information Requested by the Department

**Delineation-status for JCEP/PCGP:** To allow adequate review time of the wetland delineation report in order to meet the decision deadline, please submit the following data requests by the dates requested.

1) By April 17, 2019: GIS shape files of the new routes and re-routes so DSL can finish the initial review and provide any additional review comments in time to address this summer (involving additional field work, if needed);
2) End of April 2019: Responses to the initial delineation review questions and delineation maps (prototype subset of each map series for completeness review);
3) June 7, 2019: Responses to GIS review questions;
4) Last week of June 2019: Site visits (possible); and
5) August 9, 2019: Everything due: responses to all remaining requests for information based on site visits, GIS review responses and follow-up review requests, all final delineation maps, and all supporting materials for the concurrence.

**Bonding Requirements:** Prior to any permit issuance, a performance bond should be negotiated and put in place for the Eelgrass and Kentuck CWM projects. Bonds are required for non-public agencies that have permanent impacts greater than 0.2 acre. Proposed financial instruments need to demonstrate consistency with OAR 141-085-0700.

**Administrative Protections Required for Eelgrass and Kentuck CWM projects**: Administrative protection instruments need to demonstrate consistency with OAR 141-085-0695.

**Oregon Department of State Lands, Land Management Issues:** Any proposed uses or activities on, over, or under state owned lands requires Department proprietary authorizations.

**Extensive Comments-Detailed response requested.** The Department requests that the applicant respond to all substantive comments. Certain commenters provided extensive, detailed comments. The Department would like to call these comments to the applicant's attention to ensure that the applicant has time to sufficiently address them.

- Mike Graybill;
- Jan Hodder;
- Rich Nawa, KS Wild;
- Stacey Detwiler, Rogue Riverkeepers;
- Jared Margolis, Center for Biological Diversity;
- Jodi McCaffree, Citizens Against LNG;
- Walsh and Weathers, League of Womens Voters;
- Wim De Vriend;
- The Klamath Tribes, Dawn Winalski;
- Tonia Moro, Atty for McLaughlin, Deb Evans and Ron Schaaf;
- Regna Merritt, Oregon Physicians for Societal Responsibility;
- Oregon Women's Land Trust;
- Sarah Reif, ODFW;
- Margaret Corvi, CTLUSI;
- Deb Evans and Ron Schaaf;
- Maya Watts; and
- Steve Miller.

All comments received during the public review of this application were previously provided to Jordan Cove by the Department via Dropbox and should be responded to as well. Please submit any responses to the Department and copy the commenting party if contact information was provided.

The Department asks that any responses be submitted in writing within 25 days of the date of this letter to allow adequate time for review prior to making a permit decision. If Jordan Cove wishes to provide a response that will take more than 25 days to prepare, please inform me as soon as possible of the anticipated submittal date.

The Department will make a permit decision on your application by September 20, 2019, unless Jordan Cove requests to extend that deadline. Please call me at (503) 986-5282 if you have any questions.

Sincerely,

Robert Lobdell

Robert Lobdell
Aquatic Resource Coordinator
Aquatic Resource Management

RL:jar:amf