170 FERC ¶ 61,202
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Richard Glick and Bernard L. McNamee.

Jordan Cove Energy Project L.P. — Docket Nos. CP17-495-000
Pacific Connector Gas Pipeline, LP — CP17-494-000

ORDER GRANTING AUTHORIZATIONS UNDER SECTIONS 3 AND 7 OF THE NATURAL GAS ACT

(Issued March 19, 2020)

1. On September 21, 2017, in Docket No. CP17-495-000, Jordan Cove Energy Project L.P. (Jordan Cove) filed an application for authorization under section 3 of the Natural Gas Act (NGA)[1] and Part 153 of the Commission's regulations[2] to site, construct, and operate a new liquefied natural gas (LNG) export terminal and associated facilities (Jordan Cove LNG Terminal) in unincorporated Coos County, Oregon.

2. On the same day, in Docket No. CP17-494-000, Pacific Connector Gas Pipeline, LP (Pacific Connector) filed an application under NGA section 7(c)[3] and Parts 157 and 284 of the Commission's regulations[4] for a certificate of public convenience and necessity to construct and operate a new interstate natural gas pipeline system (Pacific Connector Pipeline) in Klamath, Jackson, Douglas, and Coos Counties, Oregon. The Pacific Connector Pipeline comprises a new, 229-mile-long pipeline, three new meter stations, and one new compressor station to transport natural gas to the Jordan Cove LNG Terminal for liquefaction and export. Pacific Connector also requests blanket certificates under Part 284, Subpart G of the Commission's regulations to provide open-access transportation services, and under Part 157, Subpart F of the Commission's regulations to perform certain routine construction activities and operations.

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[1] 15 U.S.C. § 717b (2018).

[2] 18 C.F.R. pt. 153 (2019).

[3] 15 U.S.C. § 717f.

[4] 18 C.F.R. pts. 157 and 284 (2019).

3. For the reasons discussed below, we will authorize Jordan Cove's proposal under section 3 to site, construct, and operate the Jordan Cove LNG Terminal. We will also authorize Pacific Connector's proposal under section 7(c) to construct and operate the Pacific Connector Pipeline and grant the requested blanket certificate authorizations. These authorizations are subject to the conditions discussed herein.

I. Background

4. Jordan Cove and Pacific Connector are both Delaware limited partnerships, each with its principal place of business in Houston, Texas. Both companies are wholly-owned subsidiaries of Jordan Cove LNG L.P., which is an indirect, wholly-owned subsidiary of Pembina Pipeline Corporation (Pembina), a Canadian corporation.[5] Upon the commencement of operations proposed in its application, Pacific Connector will become a natural gas company within the meaning of section 2(6) of the NGA[6] and will be subject to the Commission's jurisdiction. As its operations will not be in interstate commerce, Jordan Cove will not be a "natural gas company" as defined in the NGA, although it will be subject to the Commission's jurisdiction under NGA section 3.

5. Because a number of the comments and protests filed in these proceedings discuss a set of previous proposals filed by Jordan Cove and Pacific Connector, we will provide a brief summary of those previous proposals. In March 2013, Jordan Cove filed an application, in Docket No. CP13-483-000, for authorization under section 3 of the NGA to site, construct, and operate an LNG export terminal in Coos County, Oregon. In June 2013, Pacific Connector filed an application, in Docket No. CP13-492-000, for a certificate of public convenience and necessity to construct and operate an interstate pipeline, which would deliver gas from interconnections near Malin, Oregon to Jordan Cove's proposed export terminal. Pacific Connector did not conduct an open season for its proposed pipeline and did not submit any precedent agreements or contracts with its application.[7] Between May of 2014 and October of 2015, Commission staff sent Pacific Connector four data requests asking for precedent agreements or some other evidence of

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[5] At the time the applications were filed, Jordan Cove LNG L.P. was an indirect, wholly-owned subsidiary of Veresen, Inc. (Veresen), also a Canadian corporation. On May 1, 2017, Veresen announced that it would be acquired by Pembina. On October 2, 2017, Pembina acquired 100 percent of the outstanding shares of Veresen. *See* Jordan Cove and Pacific Connector's October 4, 2017 filings.

[6] 15 U.S.C. § 717a(6).

[7] *Jordan Cove Energy Project, L.P.*, 154 FERC ¶ 61,190, at P 14 (2016). (*Jordan Cove*).

the public benefits of its proposal.[8] Pacific Connector failed to make such a showing, and, on March 11, 2016, the Commission denied the applications.[9]

6. Specifically, the denial of Pacific Connector's proposal was based on the Commission's finding that Pacific Connector failed to demonstrate sufficient need for its proposal (through failing to provide precedent agreements for the project or presenting sufficient other evidence of need) to justify the adverse impacts associated with the proposal, including the use of eminent domain.[10] And the denial of Jordan Cove's proposal was based on the Commission's finding that, without a source of gas (i.e., Pacific Connector's pipeline), the terminal could provide no benefit to counterbalance any impacts associated with construction, making the terminal inconsistent with the public interest.[11] The Commission noted that the denials were without prejudice to the applicants submitting new applications "should the companies show a market need for these services in the future."[12]

II. Proposals

A. Jordan Cove LNG Terminal (CP17-495-000)

7. Jordan Cove seeks authorization to site, construct, and operate the Jordan Cove LNG Terminal on the bay side of the North Spit of Coos Bay in unincorporated Coos County, Oregon. The project will produce up to 7.8 million metric tonnes per annum (MTPA) of LNG for export. The Jordan Cove LNG Terminal will consist of the following major components: gas inlet and gas conditioning facilities, liquefaction facilities, LNG storage facilities, LNG loading and marine facilities, and support systems.

8. Natural gas delivered to the Jordan Cove LNG Terminal will be treated at a gas conditioning train before entering the liquefaction facilities. The gas conditioning train will include systems for mercury removal, acid gas removal, and dehydration. Treated gas will be liquefied in one of five liquefaction trains, each with a maximum capacity

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[8] *Id.* PP 15-18 and 39-41.

[9] *Id.*, *reh'g denied*, 157 FERC ¶ 61,194 (2016).

[10] *Jordan Cove*, 154 FERC ¶ 61,190 at PP 34-42. The Commission noted that Pacific Connector had obtained easements for only 5 percent and 3 percent, respectively, of its necessary permanent and construction right-of-way. *Id.* P 18, *reh'g denied*, 157 FERC ¶ 61,194 at P 27.

[11] *Jordan Cove*, 154 FERC ¶ 61,190 at PP 43-46.

[12] *Id.* P 48.

of 1.56 MTPA, for a total maximum capacity of 7.8 MTPA. In each liquefaction train, the dry treated gas will flow into a refrigerant exchanger, where it will be cooled and turned into liquid.[13] LNG produced by the five trains will be stored in two full-containment storage tanks, which will each be designed to store up 160,000 cubic meters (m^3) of LNG.

9. The Jordan Cove LNG Terminal will include a marine slip. Jordan Cove proposes to construct a new access channel to connect the marine slip with the Coos Bay Federal Navigation Channel.[14] Within the marine slip, Jordan Cove proposes to construct one LNG carrier loading berth and one emergency lay berth. The LNG carrier loading berth will be capable of accommodating LNG carriers with a cargo capacity of 89,000 m^3 to 217,000 m^3. LNG will be transferred from the storage tanks to the LNG carriers via four marine loading arms, consisting of two liquid loading arms, one hybrid arm, and one ship vapor return arm. The transfer equipment will be designed to load the carrier at a rate of 12,000 m^3 per hour. Jordan Cove expects the terminal will load between 110 and 120 carriers per year. The marine slip will also include a berth for docking tugboats and security vessels.

10. Jordan Cove proposes to construct a material off-loading facility in an area just outside of the marine slip. The material off-loading facility will receive equipment and materials during project construction and will remain a permanent feature of the terminal following construction, as it will support maintenance and replacement of large equipment components.

11. Jordan Cove also proposes to construct support systems and buildings, including an operations building, an administration and office space, a warehouse, a chemical and material storage building, guard houses and security, and associated infrastructure necessary to support operations.[15]

12. Construction of the Jordan Cove LNG Terminal will affect about 577 acres of land, and mitigation associated with the project is anticipated to impact about

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[13] The liquefaction facilities also include waste heat recovery systems and heavy hydrocarbon removal units.

[14] In its application, Jordan Cove states it plans to dredge four areas abutting the current boundary of the Coos Bay Federal Navigation Channel to allow for more efficient transit of LNG carriers. Jordan Cove's Application at 9. The proposed modifications to the channel are under the jurisdiction of the U.S. Army Corps of Engineers.

[15] Jordan Cove plans to construct a non-jurisdictional Southwest Oregon Regional Safety Center, which will be used for incident management and response by Jordan Cove and multiple state agencies to manage safety and security in the event of emergencies. Jordan Cove's Application at 4.

778 additional acres of land. Once construction is complete, operation of the Jordan Cove LNG Terminal will require the use of approximately 200 acres, across two parcels, Ingram Yard and the South Dunes Site, which are connected by a one-mile-long Access Utility Corridor. The main LNG production facilities will be located on the Ingram Yard parcel, while the interconnection with the Pacific Connector Pipeline will be located on the South Dunes Site parcel. Fort Chicago LNG II U.S. L.P., an affiliate of Jordan Cove, currently owns 295 acres of land at the terminal site. Jordan Cove will acquire the use of the remaining lands through easements or leases.

13. In December 2011, Jordan Cove received authorization from the Department of Energy, Office of Fossil Energy (DOE/FE) to export annually up to 438 billion cubic feet (Bcf) equivalent of natural gas in the form of LNG to countries with which the United States has a Free Trade Agreement (FTA);[16] and, in March 2014, Jordan Cove received conditional authorization to export annually up to 292 Bcf equivalent to non-FTA countries.[17] The 2011 FTA authorization stated that the 30-year term of the authorization would commence on the earlier of the date of the first export or December 7, 2021; and, the 2014 non-FTA, 20-year authorization required Jordan Cove to commence operations within seven years of the date of the authorization (i.e., by March 24, 2021).[18]

14. On February 6, 2018, Jordan Cove applied to amend its FTA and non-FTA authorizations to modify the quantity of LNG Jordan Cove is authorized to export (reflecting changes Jordan Cove made to its proposed facilities and additional engineering analysis) and to "re-set the dates by which [Jordan Cove] must commence exports."[19] Specifically, Jordan Cove requested to reduce the approved export volume to FTA countries from 438 Bcf equivalent to 395 Bcf equivalent, and to increase the approved export volume to non-FTA countries from 292 Bcf equivalent to 395 Bcf equivalent. In July 2018, DOE/FE amended Jordan Cove's FTA authorization in

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[16] *Jordan Cove Energy Project, L.P.*, FE Docket No. 11-127-LNG, Order No. 3041 (December 7, 2011).

[17] *Jordan Cove Energy Project, L.P.*, FE Docket No. 12-32-LNG, Order No. 3413 (March 24, 2014).

[18] These authorizations were associated with Jordan Cove's previously proposed export terminal, in Docket No. CP13-483-000. As explained above, the Commission denied that proposal, along with Pacific Connector's previously proposed pipeline project (Docket No. CP13-492-000), on March 11, 2016. *Jordan Cove*, 154 FERC ¶ 61,190, *reh'g denied*, 157 FERC ¶ 61,194.

[19] Jordan Cove's February 6, 2018 Amendment Application filed in FE Docket Nos. 11-127-LNG and 12-32-LNG at 3-5.

accordance with Jordan Cove's request.[20] Jordan Cove's requested amendment of its non-FTA authorization remains pending before the DOE/FE.[21]

B. Pacific Connector Pipeline (CP17-494-000)

1. Facilities and Service

15. In conjunction with the Jordan Cove LNG Terminal, Pacific Connector proposes to construct and operate a new interstate natural gas transmission system designed to provide up to 1,200,000 dekatherms per day (Dth/d) of firm natural gas transportation service. Natural gas transported on the Pacific Connector Pipeline will be received from interconnects with existing natural gas pipeline systems near Malin, Oregon, to the Jordan Cove LNG Terminal for liquefaction and export. The Pacific Connector Pipeline will consist of the following facilities:

- approximately 229 miles of 36-inch-diameter pipeline, extending from the proposed interconnects with Ruby Pipeline and Gas Transmission Northwest in Klamath County, and traversing Coos, Douglas, Jackson, and Klamath Counties, Oregon, to the Jordan Cove LNG Terminal in Coos County;

- a new 62,200-horsepower (hp) compressor station, consisting of two 31,100-hp natural gas-fired, turbine-driven centrifugal compressor units,[22] located at milepost (MP) 228.8 in Klamath County (Klamath Compressor Station);

- three new meter stations: one new delivery meter station in Coos County and two receipt meter stations in Klamath County;[23] and

[20] *Jordan Cove Energy Project, L.P.*, FE Docket No. 11-127-LNG, Order No. 3041-A (July 20, 2018). According to the amended authorization, Jordan Cove is authorized to export up to 395 Bcf equivalent to FTA countries for a 30-year term beginning on the earlier date of the first export or July 20, 2028. All other obligations, rights, and responsibilities established in the December 2011 authorization remain in effect.

[21] The application is pending before the DOE/FE in FE Docket No. 12-32-LNG.

[22] The compressor station will also include a third 31,000-hp natural gas-fired unit, which will be a spare unit used for reliability purposes.

[23] The two receipt meter stations will be co-located within the fenced boundaries of the Klamath Compressor Station at MP 228.8.

- related appurtenant facilities including five pig launcher/receivers, 17 mainline block valves, and communication towers.

16. Pacific Connector estimates the total cost for the Pacific Connector Pipeline to be approximately $3.184 billion.[24]

17. Prior to holding an open season, Pacific Connector executed two precedent agreements with Jordan Cove for 95.8 percent of the firm capacity available on the pipeline; one precedent agreement relates to service during commissioning of the Jordan Cove LNG Terminal and the other is a long-term precedent agreement relating to service once the terminal has achieved commercial operation.[25] Pacific Connector subsequently held an open season from July 18 to August 17, 2017, during which it offered firm transportation service on the Pacific Connector Pipeline to other potential shippers. Pacific Connector states that it received no qualifying bids during the open season.[26] Consequently, Jordan Cove was awarded a full allocation of 1,150,000 Dth/d of capacity. Pacific Connector proposes to provide service to Jordan Cove at negotiated rates.

18. Pacific Connector requests approval of its *pro forma* tariff. Pacific Connector proposes to offer firm transportation service and interruptible transportation service under Rate Schedules FT and IT, respectively. Pacific Connector also requests approval of certain non-conforming provisions of its service agreements with Jordan Cove.

2. Blanket Certificates

19. Pacific Connector requests a blanket certificate of public convenience and necessity pursuant to Part 284, Subpart G of the Commission's regulations, authorizing Pacific Connector to provide transportation service to customers requesting and qualifying for transportation service under its proposed FERC Gas Tariff, with pre-granted abandonment authority.[27]

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[24] Pacific Connector's Application at Exhibit K.

[25] Pacific Connector's Application at 16-17.

[26] Pacific Connector received two bids from an entity that did not meet Pacific Connector's creditworthiness requirements. These bids, and the related protest filed by Energy Fundamentals Group Inc., are discussed further below. *Infra* PP 66-80.

[27] 18 C.F.R. § 284.221 (2019).

20. Pacific Connector also requests a blanket certificate of public convenience and necessity pursuant to Part 157, Subpart F of the Commission's regulations, authorizing certain future facility construction, operation, and abandonment.[28]

III. Procedural Matters

A. Notice, Interventions, Comments, and Protests

21. Notice of Jordan Cove's and Pacific Connector's applications was issued on October 5, 2017, and published in the *Federal Register* on October 12, 2017.[29] The notice established October 26, 2017, as the deadline for filing interventions, comments, and protests. Timely, unopposed motions to intervene and notices of intervention are granted by operation of Rule 214 of the Commission's Rules of Practice and Procedure.[30] On January 29 and September 13, 2018, and January 8 and April 23, 2019, the Commission issued notices granting numerous late motions to intervene. We grant the remaining unopposed, late motions to intervene.[31]

22. Numerous individuals and entities filed protests and adverse comments concerning the following issues: (1) the need for the projects; (2) the use of eminent domain for the Pacific Connector Pipeline; (3) the public benefits derived from the projects; and (4) the potential impact of the projects on domestic natural gas prices. These concerns are addressed below.

23. In addition, many comments express concern about the environmental impacts of the projects, including land use, safety and security, geological hazards, threatened and endangered species, water quality, cultural resources, air emissions, and environmental justice. These comments are addressed in the final Environmental Impact Statement (EIS) and, as appropriate, below.

24. We also received numerous comments in support of the applications, asserting the projects would bring jobs and tax benefits to the local area, facilitate economic growth in the region, and provide access to new gas markets.

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[28] 18 C.F.R. § 157.204 (2019).

[29] 82 Fed. Reg. 47,502.

[30] 18 C.F.R. § 385.214 (2019). Motions to intervene filed during the draft Environmental Impact Statement (EIS) comment period are deemed timely, *see id.* §§ 157.10(a)(2) and 380.10(a), and are granted by operation of Rule 214 of the Commission's Rules of Practice and Procedure.

[31] 18 C.F.R. § 385.214(d).

25. On November 13, 2017, and June 18, 2018, Jordan Cove and Pacific Connector filed joint motions for leave to answer and answers to the protests and comments filed in the proceedings. Although the Commission's Rules of Practice and Procedure generally do not permit answers to protests,[32] we will accept the applicants' answers because the answers provide information that has assisted in our decision-making.

B. Request for Formal Hearing

26. In its motion to intervene, filed on October 25, 2017, Rogue Climate requests a formal (i.e., trial-type) hearing. The Commission has broad discretion to structure its proceedings so as to resolve a controversy in the best way it sees fit.[33] A trial-type hearing is necessary only where there are material issues of fact in dispute that cannot be resolved on the basis of the written record.[34] Otherwise, we provide a hearing in which we reach a decision based on the written record. Rogue Climate raises no material issue of fact that the Commission cannot resolve on the basis of the written record. Accordingly, the Commission denies the request for a formal hearing.

C. Request for Additional Procedures

27. On October 19, 2018, intervenor Stacey McLaughlin filed a motion requesting additional procedures. Specifically, Ms. McLaughlin requests that the Commission issue a preliminary determination of need for the projects based on non-environmental factors. In order to make the preliminary determination, Ms. McLaughlin requests the Commission require Pacific Connector to fully demonstrate the number or percentage of landowners that have signed pipeline easements,[35] and require Jordan Cove and Pacific Connector to produce signed sales agreements for the gas.

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[32] 18 C.F.R. § 385.213(a)(2).

[33] *See Columbia Gas Transmission, LLC*, 161 FERC ¶ 61,200, at P 15 (2017) (*Columbia I*) (citing *Stowers Oil and Gas Co*., 27 FERC ¶ 61,001 (1984); *PJM Transmission Owners*, 120 FERC ¶ 61,013 (2007)).

[34] *See, e.g.*, *Columbia I*, 161 FERC ¶ 61,200 at P 15 (citing *Dominion Transmission, Inc.*, 141 FERC ¶ 61,183, at P 15 (2012); *Southern Union Gas Co. v. FERC*, 840 F.2d 964, 970 (D.C. Cir. 1988)).

[35] As part of Commission staff's review of Pacific Connector's proposal, staff issued a data request on December 12, 2018, asking for an update on easement negotiations, including the current percentage of mileage of easements entered. Pacific Connector provided this information on December 21, 2018, and provided an updated filing on July 29, 2019. *See infra* P 89.

28. During one period of time in the past, when reviewing applications for certificates of public convenience and necessity, the Commission sometimes issued a preliminary determination on non-environmental issues, including need, and then, in a subsequent order, reviewed the environmental impacts of the proposal.[36] After determining that issuing multiple orders regarding one project was not an efficient use of our resources, for some time now, however, the Commission has reviewed the non-environmental aspects of a proposal and the proposal's environmental impacts in a single order. We find that implementing additional procedures in these proceedings is not needed or appropriate: this order reviews both the non-environmental and environmental issues associated with the proposals. As noted above, the Commission has broad discretion to structure its proceedings to resolve a controversy in the best way it sees fit.[37]

IV. Discussion

A. Jordan Cove LNG Terminal (CP17-495-000)

29. Because the proposed LNG terminal facilities will be used to export natural gas to foreign countries, the siting, construction, and operation of the facilities require Commission approval under section 3 of the NGA.[38] Section 3 provides that an application for the exportation or importation of natural gas shall be approved unless the proposal "will not be consistent with the public interest," and also provides that an application may be approved "in whole or in part, with such modification and upon such

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[36] This procedure was not required by the NGA or the Commission's regulations.

[37] *See, e.g.*, *Columbia I*, 161 FERC ¶ 61,200 at P 15.

[38] The regulatory functions of NGA section 3 were transferred to the Secretary of Energy in 1977 pursuant to section 301(b) of the Department of Energy Organization Act, Pub. L. No. 95-91, 42 U.S.C. § 7101 *et seq*. The Secretary of Energy subsequently delegated to the Commission the authority to approve or disapprove the construction and operation of natural gas import and export facilities and the site at which such facilities shall be located. The most recent delegation is in DOE Delegation Order No. 00-004.00A, effective May 16, 2006. The Commission does not authorize importation or exportation of the commodity itself. Rather, applications for authorization to import or export natural gas must be submitted to the DOE. *See EarthReports, Inc. v. FERC*, 828 F.3d 949, 952-53 (D.C. Cir. 2016) (detailing how regulatory oversight for the export of LNG and supporting facilities is divided between the Commission and DOE).

terms and conditions as the Commission may find necessary or appropriate."[39] NGA section 3(a) further provides that, for good cause shown, the Commission may make such supplemental orders as it may find "necessary or appropriate."[40]

30. A number of the comments and protests filed in these proceedings raise issues regarding economic harm associated with the proposed exportation of LNG. For example, numerous individuals and entities allege that: (1) Jordan Cove's proposal will increase domestic natural gas prices;[41] (2) exporting LNG will harm the U.S. balance of trade;[42] (3) exporting LNG will harm U.S. manufacturing jobs;[43] (4) exporting LNG is not in the national interest in terms of energy security;[44] (5) additional exports will compete with already-approved LNG terminals in the Gulf Coast;[45] and (6) authorized exports should be limited to domestically sourced gas so as not to harm U.S. gas producers.[46]

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[39] 15 U.S.C. §§ 717b(a), (e)(3). For a discussion of the Commission's authority to condition its approvals of LNG facilities under section 3 of the NGA, see *Distrigas Corp. v. FPC*, 495 F.2d 1057, 1063-64 (D.C. Cir. 1974), and *Dynegy LNG Prod. Terminal, L.P.*, 97 FERC ¶ 61,231 (2001).

[40] 15 U.S.C. § 717b(a).

[41] *See, e.g.*, Allison K Vasquez's October 17, 2017 Motion to Intervene; Patricia J Weber's October 23, 2017 Motion to Intervene at 1.

[42] *See, e.g.*, Citizens Against LNG Inc. and Jody McCaffree's (jointly filed) October 26, 2017 Comments at 9 (CALNG October 26, 2017 Comments).

[43] *See, e.g.*, Western Environmental Law Center's October 6, 2017 Motion to Intervene at 1; Rogue Riverkeeper's October 10, 2017 Motion to Intervene at 1; CALNG October 26, 2017 Comments at 8-9.

[44] *See, e.g.*, Cascadia Wildlands's October 25, 2017 Motion to Intervene at 3; Oregon Wild's September 28, 2017 Motion to Intervene at 1.

[45] *See, e.g.*, Thane Tienson's (writing on behalf of affected landowners Robert Barker, Oregon Women's Land Trust, Evans Schaaf Family LLC, Ronald Schaaf, Deborah Evans, Stacey and Craig McLaughlin, Bill Gow, Landowners United, Clarence Adams, Pamela Brown Ordway, and Barbara Brown) October 3, 2017 Comments at 2-3 (Tienson's October 3 Landowner Comments).

[46] *See, e.g.*, *id.* As discussed further below, Jordan Cove plans to receive natural gas for liquefaction from supply basins in both the U.S. Rocky Mountains and western Canada. *See* Jordan Cove's Application at 2-3.

31. Section 3 of the NGA states, in part, that "no person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the Commission authorizing it to do so."[47] As noted above, in 1977, the Department of Energy Organization Act transferred the regulatory functions of section 3 of the NGA to the Secretary of Energy.[48] Subsequently, the Secretary of Energy delegated to the Commission authority to "[a]pprove or disapprove the construction and operation of particular facilities, the site at which such facilities shall be located, and with respect to natural gas that involves the construction of new domestic facilities, the place of entry for imports or exit for exports…."[49]

32. However, the Secretary has not delegated to the Commission any authority to approve or disapprove the import or export of the commodity itself.[50] Nor is there any indication that the Secretary's delegation authorized the Commission to consider the types of economic issues raised in these proceedings as part of the Commission's public interest determination, thus duplicating and possibly contradicting the Secretary's own decisions. Therefore, we decline to address commenters' economic claims (e.g., that exports will increase domestic natural gas prices), which are relevant only to the

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[47] 15 U.S.C. § 717b(a).

[48] Section 301(b) of the DOE Organization Act transferred regulatory functions under section 3 of the NGA from the Commission's predecessor, the Federal Power Commission (FPC), to the Secretary of Energy. Section 402 of the DOE Organization Act transferred regulatory functions under other sections of the NGA, including sections 1, 4, 5, and 7, from the FPC to the Federal Energy Regulatory Commission. Section 402(f) states:

> (f) Limitation
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> No function described in this section which regulates the exports or imports of natural gas ... shall be within the jurisdiction of the Commission unless the Secretary assigns such a function to the Commission.

[49] DOE Delegation Order No. 00-004.00A (effective May 16, 2006).

[50] *See supra* note 38; *see also Freeport LNG Development, L.P.*, 148 FERC ¶ 61,076, *reh'g denied,* 149 FERC ¶ 61,119 (2014), *aff'd sub nom. Sierra Club v. FERC*, 827 F.3d 36 (D.C. Cir. 2016) (*Freeport*) (finding that because the Department of Energy, not the Commission, has sole authority to license the export of any natural gas through LNG facilities, the Commission is not required to address the indirect effects of the anticipated export of natural gas in its NEPA analysis); *Sabine Pass Liquefaction, LLC*, 146 FERC ¶ 61,117, *reh'g denied*, 148 FERC ¶ 61,200 (2014), *aff'd sub nom. Sierra Club v. FERC*, 827 F.3d 59 (D.C. Cir. 2016).

exportation of the commodity of natural gas, which is within DOE's exclusive jurisdiction, and are not implicated by our limited action of reviewing proposal terminal sites.

33. Commenters also express concern regarding global market support for the project, application of the Commission's *Hackberry* policy, and whether the proposal is in the public interest: we address these concerns in turn. First, commenters and protestors argue that global market conditions do not support the proposals. For example, commenters contend that the global market is already "awash" in gas,[51] that supply will exceed demand for "years to come,"[52] and that markets will not support exports beyond the capacity provided by facilities already approved by the Commission.[53] Further, numerous commenters allege that, because Jordan Cove has not finalized tolling agreements with future customers, Jordan Cove has not sufficiently demonstrated market support for the Jordan Cove LNG Terminal and, consequently, the proposal is not in the public interest.[54] The commenters argue that, given the absence of customer agreements, the Commission must deny the proposal, as it did Jordan Cove's previous proposal.[55]

34. We find that these issues regarding global market support (i.e., whether exports from Jordan Cove LNG Terminal are supported by global market conditions) are beyond the Commission's purview, as they relate to exportation of the commodity and not to construction and operation of the terminal. In addition, finalized tolling agreements are required to be filed with DOE,[56] but not with the Commission. As explained above, the Commission's authority under NGA section 3 applies "only to the siting and operation of

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[51] Oregon Wild's September 28, 2017 Motion to Intervene at 1.

[52] Charles A Reid's October 16, 2017 Motion to Intervene at 1.

[53] *See, e.g.*, Sierra Club, Cascadia Wildlands, Center for Sustainable Economy, Citizens Against LNG, Citizens for Renewables, Hair on Fire Oregon, Oregon Shores Conservation Coalition, Oregon Wild, Oregon Women's Land Trust, Pipeline Awareness Southern Oregon, Rogue Climate, Rogue Riverkeeper, and Western Environmental Law Center's (jointly filed) October 26, 2017 Comments and Protests at 13-14 (Sierra Club's October 26, 2017 Protest).

[54] *See, e.g.*, *id.* at 9-13.

[55] *Id.*; CALNG October 26, 2017 Comments at 1 and 4-10.

[56] *See Jordan Cove Energy Project, L.P.*, FE Docket No. 11-127-LNG, Order No. 3041 at 15 (December 7, 2011).

the facilities necessary to accomplish an export[,]"[57] while "export decisions [are] squarely and exclusively within the [DOE]'s wheelhouse . . . ."[58]

35. We also clarify that the Commission did not deny Jordan Cove's previous proposal because Jordan Cove failed to provide finalized tolling agreements. Rather, the Commission denied Pacific Connector's proposal because Pacific Connector, by failing to provide precedent agreements or sufficient other evidence of need, failed to demonstrate market support for its proposal. As explained further below, under the Commission's Certificate Policy Statement, the Commission applies a balancing test when reviewing NGA section 7 applications. If the Commission issues a certificate of public convenience and necessity, the NGA gives the certificate holder eminent domain authority (conversely, NGA section 3 authorizations do not carry with them eminent domain authority); thus, before issuing such a certificate, the Commission ensures that the public benefits of the proposal outweigh any adverse effects, including economic effects. With regard to Pacific Connector's previous proposal, the Commission found that Pacific Connector's "generalized allegations of need," without the support of any precedent agreements, "[did] not outweigh the risk of eminent domain on landowners and communities;"[59] therefore, the Commission denied Pacific Connector's NGA section 7 application. The Commission went on to deny Jordan Cove's NGA section 3 application because, without a source of gas (i.e., the Pacific Connector Pipeline), the terminal would not be able to function. As discussed below, we are approving Pacific Connector's present proposal, which will provide a source of gas to the proposed Jordan Cove LNG Terminal.

36. Several intervenors request that the Commission decline to apply its *Hackberry* Policy to the Jordan Cove LNG Terminal.[60] Under the *Hackberry* Policy,[61] the

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[57] *Trunkline Gas Co., LLC*, 155 FERC ¶ 61,328, at P 18 (2016).

[58] *Sierra Club v. FERC*, 827 F.3d at 46.

[59] *Jordan Cove Energy Project, L.P.*, 157 FERC ¶ 61,194, at P 29 (2016).

[60] Thane Tienson's (writing on behalf of affected landowners Evans Schaaf Family LLC, Ronald Schaaf, Deborah Evans, Stacey and Craig McLaughlin, Oregon Women's Land Trust, Landowners United, Clarence Adams, Robert Barker, John Clarke, Bill Gow, and Pamela Brown Ordway) June 1, 2018 Comments at 2 (Tienson's June 1 Landowner Comments).

[61] In *Hackberry LNG Terminal, L.L.C.*, the Commission found that its traditional open access regulatory approach and its requirement that providers use NGA section 3 service to maintain tariffs and rate schedules may deter new investment; as a result, the Commission announced it would adopt a less intrusive regulatory regime under NGA

Commission applies a "less intrusive" regulatory regime for LNG terminal service compared to NGA section 7 service; specifically, LNG terminal applicants are not required to offer open-access service under a tariff with cost-based rates. The Energy Policy Act of 2005[62] codified this policy by amending NGA section 3 to provide that, before January 1, 2015, the Commission could not deny an application for authorization of an LNG terminal solely on the basis that the applicant proposed to use the LNG terminal exclusively or partially for gas that the applicant or an affiliate would supply to the facility, or condition an order on the applicant's offering open-access service or any regulation of the rates, charges, terms, or conditions of service.[63] The intervenors argue that, because the January 1, 2015 date has passed, the Commission should use its discretion to deny Jordan Cove's application because Jordan Cove has subscribed for the majority of the capacity on the Pacific Connector Pipeline.

37. The intervenors miscomprehend both the Commission's *Hackberry* Policy and NGA section 3(e)(3)(B)(i). The reference in section 3(e)(3)(B)(i) to "gas that the applicant or an affiliate *will supply to the facility*" speaks to ownership, not transportation, of the gas. Neither the *Hackberry* Policy nor the prohibition in section 3(e)(3)(B)(i) seeks to place limits on a terminal operator's acquisition of capacity on a connecting pipeline. Rather, they address a terminal operator's holding of capacity in its own terminal facility. The intervenors provide no justification for why the Commission should require Jordan Cove to operate its terminal on an open-access basis or impose other economic regulation on its services. We note that the record contains no evidence that any entity other than Jordan Cove is interested in service from the terminal. Other LNG export terminals operate in this manner, transporting their own sources of gas on affiliated upstream pipelines.[64]

38. Intervenors and commenters argue that the environmental impacts of the construction and operation of the Jordan Cove LNG Terminal are not consistent with the

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section 3. 101 FERC ¶ 61,294, at PP 22-24 (2002), *order on reh'g*, *Cameron LNG, LLC*, 104 FERC ¶ 61,269 (2003).

[62] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).

[63] 15 U.S.C. §§ 717b(e)(3)(B), 717b(e)(4).

[64] *See, e.g.*, *Corpus Christi Liquefaction, LLC*, 149 FERC ¶ 61,283, at PP 4 & 11, and nn. 7 & 8 (2014) (*Corpus Christi*) (Corpus Christi Liquefaction subscribing to 100 percent of the capacity on affiliated Cheniere Pipeline Project). This continues to be how recently authorized, but not yet constructed, LNG export terminals propose to source their gas. *See, e.g.*, *Driftwood LNG LLC*, 167 FERC ¶ 61,054, at P 4 (2019) (Driftwood LNG subscribing to 100 percent of the capacity on affiliated Driftwood Pipeline Project).

public interest, and that the application should accordingly be denied.[65] In addition, intervenors and commenters allege that there are no public benefits associated with the proposal, in part because "most of the corporate profits would be Canadian . . . ."[66]

39. As the U.S. Court of Appeals for the D.C. Circuit has explained, the NGA section 3 standard that a proposal "shall" be authorized unless it "will not be consistent with the public interest[,]"[67] "sets out a general presumption favoring such authorizations."[68] To overcome this favorable presumption and support denial of an NGA section 3 application, there must be an "affirmative showing of inconsistency with the public interest."[69]

40. We have reviewed Jordan Cove's application to determine if the siting, construction, and operation of its LNG facilities would be inconsistent with the public interest.[70] The proposed site for the Jordan Cove LNG Terminal comprises primarily

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[65] *See, e.g.*, Cascadia Wildlands's October 25, 2017 Motion to Intervene at 2-3; Waterkeeper Alliance's October 25, 2017 Motion to Intervene at 2. Some of the environmental harms alleged are associated with exportation of the commodity (i.e., "exporting natural gas is not in the public interest because it will increase the harmful and controversial practice of fracking . . . ." Oregon Wild's September 28, 2017 Motion to Intervene at 1), and thus are beyond the Commission's purview. *Supra* PP 31-32.

[66] Oregon Wild's September 28, 2017 Motion to Intervene at 1. We note that many of the arguments about public benefits are tied to allegations of economic harm associated with the proposed exportation of LNG (e.g., alleging no public good will result from exporting gas to potential future adversaries, James Meunier's October 27, 2017 Comments), which, as noted above, is a matter beyond the Commission's jurisdiction. *See supra* PP 30-32.

[67] 15 U.S.C. § 717b(a).

[68] *EarthReports v. FERC*, 828 F.3d at 953 (citing *W. Va. Pub. Servs. Comm'n v. U.S. Dep't of Energy*, 681 F.2d 847, 856 (D.C. Cir. 1982)); *see also Sierra Club v. U.S. Dep't of Energy*, 867 F.3d 189, 203 (D.C. Cir. 2017).

[69] *Sierra Club v. U.S. Dep't of Energy*, 867 F.3d at 203 (quoting *Panhandle Producers & Royalty Owners Ass'n v. Econ. Regulatory Admin.*, 822 F.2d 1105, 1111 (D.C. Cir. 1987)).

[70] *See Nat'l Steel Corp.*, 45 FERC ¶ 61,100, at 61,332-33 (1998) (observing that DOE, "pursuant to its exclusive jurisdiction, has approved the importation with respect to every aspect of it except the point of importation," and that the "Commission's authority in this matter is limited to consideration of the place of importation, which necessarily includes the technical and environmental aspects of any related facilities.").

privately controlled land consisting of a combination of brownfield decommissioned industrial facilities, an existing landfill requiring closure, and open land.[71] In addition, portions of the proposed site were previously used for disposal of dredged material.[72] Further, as discussed below, the final EIS prepared for the proposed projects finds that, although the project would result in temporary, long-term, and permanent impacts on the environment, some of which would be significant (e.g., constructing the Jordan Cove LNG Terminal would temporarily but significantly impact housing in Coos Bay, and constructing and operating the terminal would permanently and significantly impact the visual character of Coos Bay), most impacts would be reduced to less-than-significant levels if the projects are constructed and operated in accordance with applicable laws and regulations and the environmental mitigation measures recommended in the final EIS and adopted by this order.[73] In addition, we note that the proposal would have economic and public benefits, including benefits to the local and regional economy and the provision of new market access for natural gas producers.[74] We find that the various arguments raised regarding the Jordan Cove LNG Terminal do not amount to the affirmative showing of inconsistency with the public interest that is necessary to overcome the presumption in section 3 of the NGA.

41. In accordance with the Memorandum of Understanding signed on August 31, 2018, by the Commission and the Pipeline and Hazardous Materials Safety Administration (PHMSA) within the U.S. Department of Transportation (DOT),[75] PHMSA undertook a review of the proposed facility's ability to comply with the federal safety standards contained in Part 193, Subpart B, of Title 49 of the Code of Federal

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[71] Final EIS at 5-6.

[72] *Id.* at 4-424.

[73] *Id.* at ES-6 to ES-7 and 5-1.

[74] In addition, pursuant to NGA section 3(c), the exportation of gas to FTA nations "shall be deemed to be consistent with the public interest." 15 U.S.C. § 717b(c). As noted above, Jordan Cove has received authorization to export to FTA nations. *See supra* PP 13-14.

[75] *Memorandum of Understanding Between the Department of Transportation and the Federal Energy Regulatory Commission Regarding Liquefied Natural Gas Transportation Facilities* (Aug. 31, 2018), https://www.ferc.gov/legal/mou/2018/FERC-PHMSA-MOU.pdf.

Regulations.[76] On September 11, 2019,[77] PHMSA issued a Letter of Determination indicating Jordan Cove has demonstrated that the siting of its proposed LNG facilities complies with those federal safety standards. If the proposed project is subsequently modified so that it differs from the details provided in the documentation submitted to PHMSA, further review would be conducted by PHMSA.

42. Jordan Cove is proposing to operate its LNG terminal under the terms and conditions mutually agreed to by its prospective customers and will solely bear the responsibility for the recovery of any costs associated with construction and operation of the terminal. Accordingly, Jordan Cove's proposal does not trigger NGA section 3(e)(4).[78]

43. Accordingly, we find that, subject to the conditions imposed in this order, Jordan Cove's proposal is not inconsistent with the public interest. Therefore, we will grant Jordan Cove's application for authorization under NGA section 3 to site, construct, and operate its proposed LNG terminal facilities.

B. Pacific Connector Pipeline (CP17-494-000)

1. Section 7 of the NGA

44. Several commenters contend that the Pacific Connector Pipeline cannot be authorized under section 7 of the NGA; these commenters assert that the pipeline may only be authorized under section 3 of the NGA.[79] The commenters state that, because the pipeline will serve only the export terminal and because the pipeline is located wholly within the state of Oregon, the facilities will not be used to transport gas in interstate commerce and, accordingly, cannot be authorized under section 7.[80] As support for this

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[76] 49 C.F.R. pt. 193, Subpart B (2019).

[77] *See* Commission staff's September 24, 2019 Memo filed in Docket No. CP17-495-000 (containing PHMSA's Letter of Determination).

[78] 15 U.S.C. § 717b(e)(4) (governing orders for LNG terminal offering open access service).

[79] *See* Niskanen Center and Affected Landowners' (jointly filed) July 5, 2019 Comments at 48-53 (Niskanen Center's July 5, 2019 Comments); Snattlerake Hills, LLC's July 5, 2019 Comments at 14 (Snattlerake's July 5, 2019 Comments).

[80] *See* Snattlerake's July 5, 2019 Comments at 14.

argument, the commenters cite to *Border Pipe Line v. FPC*[81] and *Big Bend Conservation Alliance v. FERC*.[82]

45. *Border* involved a pipeline "located wholly within the state of Texas," delivering gas from a production field in Texas and selling "to an industrial consumer which transports the gas into Mexico and uses it there."[83] In *Border*, the court rejected the Commission's determination that the otherwise intrastate pipeline was an interstate pipeline subject to regulation under section 7, solely because the pipeline sold gas to a customer who then exported the gas to Mexico.[84] On appeal, the court declined to interpret "interstate commerce" to include foreign commerce, and vacated the Commission's order subjecting the pipeline to its section 7 authority as an interstate pipeline.[85]

46. Similarly, *Big Bend* involved a pipeline (the Trans-Pecos Pipeline) that delivered gas produced in Texas to the Texas-Mexico border. The Commission authorized the border-crossing facilities (a 1,093-foot pipeline running from a metering station to the international border) under section 3 of the NGA, and determined that the Trans-Pecos Pipeline, which would deliver gas to those facilities, was an intrastate pipeline and not

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[81] 171 F.2d 149 (D.C. Cir. 1948) (*Border*).

[82] 896 F.3d 418 (D.C. Cir. 2018) (*Big Bend*).

[83] 171 F.2d at 150; *see also id.* at 151 (noting that the "operation before us is wholly local, and it is only because of petitioner's sales for foreign commerce that the Commission seeks to control all its activities").

[84] *Id.* at 151. NGA section 2(7) defines interstate commerce as "commerce between any point in a State and any point outside thereof . . . but only insofar as such commerce takes place within the United States." 15 U.S.C. § 717a(2). In an underlying order, the Commission concluded, erroneously, that the "statutory definition of 'interstate commerce' is to be interpreted as embracing 'foreign commerce,' for 'any point outside' of a State includes a point in a foreign country." *Reynosa Pipe Line Co.*, 5 FPC 130, 136 (1946). The court expressly rejected the Commission's interpretation of section 2(7) to assert section 7 jurisdiction over the pipeline. *Border*, 171 F.2d at 151-52.

[85] *Border*, 151 F.2d at 151-52 (clarifying that the latter phrase of section 2(7) requires gas be transported between two states to be in interstate commerce, explaining that "the exportation of natural gas from the United States to a foreign country, or the importation of natural gas from a foreign country is not 'interstate commerce' as that term is contemplated by the [NGA].").

subject to section 7 of the NGA.[86] On appeal, the court affirmed the Commission, noting that "substantial evidence supports FERC's conclusion that the [Trans-Pecos Pipeline] 'initially will only transport natural gas produced in Texas and received from other Texas intrastate pipelines or Texas processing plants[,]'" and that "there is 'abundant Texas-sourced natural gas to supply the Trans-Pecos Pipeline without relying on interstate volumes.'"[87]

47. Unlike the pipelines in *Border* and *Big Bend*, the Pacific Connector Pipeline will not be delivering gas solely produced in Oregon. Rather, the Pacific Connector Pipeline will deliver gas received from interconnects with existing interstate natural gas pipeline systems, specifically Ruby Pipeline and Gas Transmission Northwest.[88] Ruby Pipeline is a 675-mile-long pipeline, extending from Wyoming to Oregon, delivering gas from the Rocky Mountain production area to west coast markets.[89] Gas Transmission Northwest's interstate pipeline system extends for approximately 1,351 miles between the United States-Canada border at Kingsgate, British Columbia, and the Oregon-California border, providing open-access service in Idaho, Washington, and Oregon.[90]

48. The Commission and the courts have consistently held that "[g]as crossing a state line at any stage of its movement to the ultimate consumer is in interstate commerce during the entire journey."[91] Accordingly, the transportation service provided by the Pacific Connector Pipeline will be in interstate commerce.

49. The Commission has interpreted section 3 of the NGA to mean that, "when companies construct a pipeline to transport import or export volumes, only a small segment of the pipeline close to the border is deemed to be the import or export facility for which section 3 authorization is necessary."[92] Whether the rest of the pipeline is

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[86] *Big Bend*, 896 F.3d at 420.

[87] *Id.* at 422 (quoting *Trans-Pecos Pipeline, LLC*, 157 FERC ¶ 61,081, at PP 9, 11 (2016)).

[88] *See supra* P 15.

[89] *See Ruby Pipeline, L.L.C.*, 136 FERC ¶ 61,054, at P 1 (2010).

[90] *See Gas Transmission Northwest, LLC*, 142 FERC ¶ 61,186, at P 2 (2013).

[91] *Maryland v. Louisiana*, 451 U.S. 725, 755 (1981). *See also California v. Lo-Vaca Gathering Co.*, 379 U.S. 366, 369 (1965); *Western Gas Interstate Co.*, 59 FERC ¶ 61,022, at 61,049 (1992) (*Western*).

[92] *Trans-Pecos Pipeline, LLC*, 155 FERC ¶ 61,140, at P 31 n.33 (2016) (citing *Southern LNG, Inc.*, 131 FERC ¶ 61,155, at P 15 n.17 (2010)). *See also Western*,

subject to section 7 depends on whether it will be transporting gas in intrastate commerce, and thus be NGA exempt, or interstate commerce, and thereby be subject to the Commission's jurisdiction.

50. Here, we do not find it reasonable or appropriate to consider the entire 229-mile-long Pacific Connector Pipeline part of the section 3 export facility as commenters contend. The limited section 3 authority DOE has delegated to the Commission covers only "the construction and operation of particular facilities, the site at which such facilities shall be located, and with respect to natural gas that involves the construction of new domestic facilities, the place of entry for imports or exit for exports."[93] The Commission's determination that its section 3 authority is restricted to "particular facilities" at "the place of entry for imports and exit for exports" is consistent with DOE's delegation.[94]

51. Because Pacific Connector's proposed pipeline facilities will be used to transport natural gas in interstate commerce subject to the jurisdiction of the Commission, the construction and operation of the facilities are subject to the requirements of subsections (c) and (e) of section 7 of the NGA.[95]

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59 FERC at 61,048 (the Commission's "regulatory responsibility under section 3 of the NGA over import/export facilities includes only the siting, construction, and operations of the facilities at the site of exportation. We have continually held that [the] Commission's section 3 jurisdiction is limited to the point of import/exportation.") (citations removed); *Yukon Pacific Corp.*, 39 FERC ¶ 61,216, at 61,758 (1987) (determining that the Commission would have jurisdiction under section 3 to approve or disapprove the "place of export," and that "[s]uch jurisdiction [would be] independent of any additional jurisdiction the Commission may have . . . to approve or disapprove the siting, construction and operation of new gas pipeline facilities necessary to implement the export.").

[93] DOE Delegation Order No. 00-004.00A, section 1.21(A) (effective May 16, 2006).

[94] For border-crossing facilities, the Commission, under section 3, typically authorizes several hundred feet of pipe, extending from the border to a meter (or other physically identifiable point).

[95] 15 U.S.C. §§ 717f(c), (e).

2. Certificate Policy Statement

52. The Certificate Policy Statement provides guidance for evaluating proposals to certificate new construction.[96] The Certificate Policy Statement establishes criteria for determining whether there is a need for a proposed project and whether the proposed project will serve the public interest. The Certificate Policy Statement explains that in deciding whether to authorize the construction of major new natural gas facilities, the Commission balances the public benefits against the potential adverse consequences. The Commission's goal is to give appropriate consideration to the enhancement of competitive transportation alternatives, the possibility of overbuilding, subsidization by existing customers, the applicant's responsibility for unsubscribed capacity, the avoidance of unnecessary disruptions of the environment, and the unneeded exercise of eminent domain in evaluating new pipeline construction.

53. Under this policy, the threshold requirement for applicants proposing new projects is that the applicant must be prepared to financially support the project without relying on subsidization from its existing customers. The next step is to determine whether the applicant has made efforts to eliminate or minimize any adverse effects the project might have on the applicant's existing customers, existing pipelines in the market and their captive customers, and landowners and communities affected by the construction of the new natural gas facilities. If residual adverse effects on these interest groups are identified after efforts have been made to minimize them, the Commission will evaluate the project by balancing the evidence of public benefits to be achieved against the residual adverse effects. This is essentially an economic test. Only when the benefits outweigh the adverse effects on economic interests will the Commission proceed to consider the environmental analysis where other interests are addressed.

a. Subsidization and Impact on Existing Customers

54. As stated above, the threshold requirement for pipelines proposing new projects is that the pipeline must be prepared to financially support the project without relying on subsidization from existing customers. As Pacific Connector is a new company, it has no existing customers. As such, there is no potential for subsidization on Pacific Connector's system or degradation of service to existing customers.

b. Need for the Project

55. Intervenors and commenters challenge the need for the Pacific Connector Pipeline on several grounds including: (1) the use of precedent agreements with an affiliate to

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[96] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227, *corrected*, 89 FERC ¶ 61,040 (1999), *clarified*, 90 FERC ¶ 61,128, *further clarified*, 92 FERC ¶ 61,094 (2000) (Certificate Policy Statement).

demonstrate need; (2) Pacific Connector's open season was not conducted in a transparent and non-discriminatory manner; and (3) public benefits of the proposal are nonexistent or overstated.

i. <u>Precedent Agreements with Affiliate Shipper</u>

56. Several intervenors and commenters allege that Pacific Connector has failed to demonstrate market support for its proposal. In particular, Sierra Club claims that Pacific Connector's precedent agreements with Jordan Cove are "weak evidence of market demand."[97] Sierra Club contends that we should treat Jordan Cove as an "overnight" affiliate shipper because the agreements were entered into "as an apparent hasty last resort,"[98] and, consequently and pursuant to the Commission's finding in *Independence Pipeline Co.*,[99] we should be skeptical of the agreements as evidence of market support.

57. Sierra Club further argues that other circumstances of these proceedings undermine the value of any support offered by the precedent agreements. First, Sierra Club asserts that, in the past, when the Commission has found market support for a pipeline on the basis of a precedent agreement with an affiliated LNG export project, the pipeline required little, if any, new rights-of-way and was not opposed by local landowners, unlike the Pacific Connector Pipeline.[100] Second, Sierra Club states that in those instances when market support for a pipeline was demonstrated on the basis of a precedent agreement with an affiliated LNG export project, the affiliate exporter had "generally already finalized liquefaction tolling agreements,"[101] which made clear that it would be able to provide support for the pipeline. For these reasons, Sierra Club argues

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[97] Sierra Club's October 26, 2017 Protest at 16. ("Nonetheless, while FERC may accept such agreements [with affiliates] as evidence, FERC has clearly indicated they are *weak* evidence. The certificate policy statement explains that 'a precedent agreement with an affiliate' provides a weaker demonstration of need than a project with multiple precedent agreements with unaffiliated customers.") (emphasis in original) (citing Certificate Policy Statement, 88 FERC at 61,748-49).

[98] Sierra Club's October 26, 2017 Protest at 18.

[99] 89 FERC ¶ 61,283 (1999) (*Independence*).

[100] Sierra Club's October 26, 2017 Protest at 17 (citing *Golden Pass Products LLC*, 157 FERC ¶ 61,222 (2016) (*Golden Pass*); *Magnolia LNG, LLC*, 155 FERC ¶ 61,033 (2016) (*Magnolia*); *Sabine Pass Liquefaction Expansion, LLC*, 151 FERC ¶ 61,012 (2015) (*Sabine Pass*); *Corpus Christi*, 149 FERC ¶ 61,283 (2014) (*Corpus Christi*)).

[101] Sierra Club's October 26, 2017 Protest at 17.

that a "stronger" showing of market support is required here.[102] Sierra Club concludes that "[m]arket support is essential to the demonstration of public benefits" and the applicants' "failure to show market support here is therefore fatal to their assertion of public benefits."[103]

58. In their November 13, 2017 answer, the applicants assert that the Commission has determined that precedent agreements are sufficient to demonstrate project need. Moreover, the applicants state that the Commission has established that it does not distinguish between agreements with affiliates and non-affiliates for such purposes, so long as they are binding agreements.[104] The applicants explain that, unlike the facts in *Independence*, Jordan Cove "was created for the purpose of developing the LNG Terminal, is not a new company, and was not created 'to falsely evidence market need for the project.'"[105] In addition, they note that the Commission has previously accepted agreements between a terminal sponsor and a pipeline as evidence of market need.[106] Lastly, the applicants argue that Sierra Club provides no precedent for why the

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[102] *Id.* at 15-19.

[103] *Id.* at 8.

[104] Several landowners contend that Pacific Connector's precedent agreements with Jordan Cove are likely not binding. *See, e.g.*, Tienson's October 3 Landowner Comments at 2. In their November 13, 2017 answer, the applicants clarify that the precedent agreements are in fact binding. See Pacific Connector and Jordan Cove's November 13, 2017 Answer at 6.

[105] Pacific Connector and Jordan Cove's November 13, 2017 Answer at 8 (quoting *Mountain Valley Pipeline, LLC*, 161 FERC ¶ 61,043, at P 48 (2017) (*Mountain Valley*)).

[106] In its application, Pacific Connector notes that in *Golden Pass*, 157 FERC ¶ 61,222; *Magnolia*, 155 FERC ¶ 61,033; *Sabine Pass*, 151 FERC ¶ 61,012; and *Corpus Christi*, 149 FERC ¶ 61,283, the Commission accepted agreements between the terminal sponsor and pipeline as evidence of market support for the pipeline. Several landowners assert that in each of those proceedings, the Commission approved the proposals "only with the stipulation that they be confined to U.S. domestically-sourced natural gas." *See* Tienson's October 3 Landowner Comments at 2. Although the orders approving each of these proposals note that the pipelines would transport "domestic" natural gas, the Commission was merely summarizing the applicants' proposals and not examining the issue of whether the pipelines should be "confined" to transporting only domestically sourced gas. *See Golden Pass*, 157 FERC ¶ 61,222 at P 12; *Magnolia*, 155 FERC ¶ 61,033 at P 9; *Sabine Pass*, 151 FERC ¶ 61,012 at P 37; and *Corpus Christi*, 149 FERC ¶ 61,283 at P 9.

Commission should veer from its current policy of "not look[ing] behind precedent or service agreements to make judgments about the needs of individual shippers."[107]

Commission Determination

59. The Certificate Policy Statement established a new policy under which the Commission would allow an applicant to rely on a variety of relevant factors to demonstrate need, rather than continuing to require that a particular percentage of the proposed capacity be subscribed under long-term precedent or service agreements.[108] These factors might include, but are not limited to, precedent agreements, demand projections, potential cost savings to consumers, or a comparison of projected demand with the amount of capacity currently serving the market.[109] The Commission stated that it would consider all such evidence submitted by the applicant regarding project need. The policy statement made clear that, although precedent agreements are no longer required to be submitted, they are still significant evidence of project need or demand.[110]

60. Sierra Club is incorrect in its assertion that the Certificate Policy Statement deems precedent agreements with affiliates to be "weak evidence" of market support. Rather, the Certificate Policy Statement states:

> A project that has precedent agreements with multiple new customers may present a greater indication of need than a project with only a precedent agreement with an affiliate. The new focus, however, will be on the impact of the project on the relevant interests balanced against the benefits to be gained from the project. As long as the project is built without subsidies from the existing ratepayers, the fact that it would be used by affiliated shippers is unlikely to create a rate impact on existing ratepayers.[111]

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[107] Pacific Connector and Jordan Cove's November 13, 2017 Answer at 7 (quoting *Atlantic Coast Pipeline, LLC*, 161 FERC ¶ 61,042, at P 54 (2017)).

[108] Certificate Policy Statement, 88 FERC at 61,747. Prior to the Certificate Policy Statement, the Commission required a new pipeline project to have contractual commitments for at least 25 percent of the proposed project's capacity. *See id.* at 61,743.

[109] *Id.* at 61,747.

[110] *Id*. The policy statement specifically recognized that such agreements "always will be important evidence of demand for a project[.]" *Id.* at 61,748.

[111] Certificate Policy Statement, 88 FERC at 61,748-49.

Thus, the Commission is less focused on whether the contracts are with affiliated or unaffiliated shippers and more focused on whether existing ratepayers would subsidize the project.[112]

61. The fact that the project shipper is an affiliate of Pacific Connector does not require the Commission to look behind the precedent agreements to evaluate project need or view that contract differently from one with a non-affiliate. As the court affirmed in *Minisink Residents for Environmental Preservation & Safety v. FERC*, the Commission may reasonably accept the market need reflected by the applicant's existing contracts with shippers and not look behind those contracts to establish need.[113] And in *Appalachian Voices v. FERC*, the court affirmed the Commission's determination that "[a]n affiliated shipper's need for new capacity and its obligation to pay for such service under a binding contract are not lessened just because it is affiliated with the project sponsor."[114]

62. When considering applications for new certificates, the Commission's primary concern regarding affiliates of the pipeline as shippers is whether there may have been undue discrimination against a non-affiliate shipper.[115] Although one such allegation was made, as discussed further below,[116] we have determined that Pacific Connector did not engage in anticompetitive behavior or undue discrimination.

63. In addition, we find that *Independence* is distinguishable from the facts here. *Independence* was a pre-Certificate Policy Statement proceeding. Thus, as discussed above,[117] under the then-applicable policy the pipeline was required to demonstrate contractual commitments for at least 25 percent of the proposed project's capacity. However, Independence had provided no contractual evidence of market support when it

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[112] *See, e.g.*, *Mountain Valley*, 161 FERC ¶ 61,043, at P 43 n.51.

[113] 762 F.3d 97, 110 n.10 (D.C. Cir. 2014) (*Minisink*) ; *see also Sierra Club v. FERC*, 867 F.3d 1357, 1379 (D.C. Cir. 2017) (*Sabal Trail*) (finding that the pipeline project proponent satisfied the Commission's "market need" where 93 percent of the pipeline project's capacity has already been contracted for).

[114] No. 17-1271, 2019 WL 847199, at *1 (D.C. Cir. Feb. 19, 2019) (unpublished) (quoting *Mountain Valley Pipeline, LLC*, 161 FERC ¶ 61,043 at P 45).

[115] *See* 18 C.F.R. § 284.7(b) (2019) (requiring transportation service to be provided on a non-discriminatory basis).

[116] *See infra* PP 66-80.

[117] *See supra* note 108.

filed its application. After repeated statements by Independence that eleven shippers had expressed interest in the project, followed by its failure to provide precedent agreements to support those statements, Commission staff informed Independence that it would dismiss Independence's application by a specified deadline, if the precedent agreements were not submitted.[118] On the eve of the deadline, Independence created an affiliate marketer with whom it signed a precedent agreement.[119] The Commission rejected the precedent agreement as evidence of market support for the project finding Independence had created an affiliate "virtually overnight" to falsely evidence market need for the project.[120] Here, Pacific Connector signed binding precedent agreements with Jordan Cove before filing its application with the Commission in September 2017. Moreover, Jordan Cove is a limited partnership that was created in 2005,[121] years prior to the filing date of Pacific Connector's application, and was established for the purpose of developing the Jordan Cove LNG Terminal; without more this is insufficient to establish that Jordan Cove was created to falsely evidence market need for the Pacific Connector Pipeline.

64. The other reasons proffered by Sierra Club as to why Pacific Connector's precedent agreements with Jordan Cove are insufficient evidence of market support are unconvincing.[122] Sierra Club contends that the Commission has not previously authorized a pipeline for which market support was demonstrated on the basis of a precedent agreement with an affiliate LNG export terminal, if: (1) the pipeline would require new rights-of-way or had opposition from landowners; or (2) the affiliate LNG export terminal had not yet finalized its tolling agreements. The Commission does not require finalized tolling agreements in order to make a finding that an LNG export terminal's precedent agreement with a supplying pipeline provides sufficient market support; we recognize that these tolling agreements are often finalized after the

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[118] *See Independence*, 89 FERC ¶ 61,283, at 61,820.

[119] *See id.* at 61,840.

[120] *See id.*

[121] *See* Jordan Cove's Application at Exhibit A (State of Delaware Certificate of Limited Partnership).

[122] Sierra Club and others also assert that our determination regarding project need for Pacific Connector's previous proposal (CP13-492-000) supports our making a similar determination in the instant proceeding. *See* Sierra Club's October 26, 2017 Protest at 1-2. We disagree. The current proposal is distinguishable from the previous proposal in that Pacific Connector has provided precedent agreements for nearly 96 percent of the firm capacity available on the pipeline. This necessarily changes our evaluation of project need and market support.

Commission issues an authorization. We do not believe that the mere fact that an LNG terminal and the supplying pipeline may be affiliated warrants a change in our approach. In addition, although the Commission evaluates applications for new pipeline construction under its Certificate Policy Statement, which includes consideration of whether a pipeline has made efforts to minimize adverse impacts on landowners and surrounding communities, the Certificate Policy Statement itself recognizes that pipelines are not always able to resolve all opposition from landowners.[123] Thus, here, we balance the landowner opposition against the fact that nearly 96 percent of the pipeline's service capability has been subscribed under long-term precedent agreements.

65. In conclusion, we find that the precedent agreements entered into between Pacific Connector and Jordan Cove for approximately 96 percent of the pipeline's capacity adequately demonstrate that the project is needed. Ordering Paragraph (G) of this order requires that Pacific Connector file a written statement affirming that it has executed contracts for service at the levels provided for in the precedent agreements prior to commencing construction.

ii. Pacific Connector's Open Season

66. Energy Fundamentals Group Inc. (EFG) protested the proceedings, arguing that Pacific Connector did not conduct its open season in a transparent and non-discriminatory manner. While generally supportive of Jordan Cove and Pacific Connector's proposals, EFG alleges that it was precluded from securing capacity on the Pacific Connector Pipeline because Pacific Connector did not want market bids from entities other than its affiliate, Jordan Cove.[124]

67. EFG[125] states that it submitted two bids[126] for capacity during Pacific Connector's open season but that its bids were deemed "unacceptable [because EFG] did not meet the creditworthiness requirement in the Open Season Notice."[127] EFG alleges that the open season did not describe in specificity the creditworthiness requirement a bidder would

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[123] Certificate Policy Statement, 88 FERC at 61,749.

[124] EFG's October 26, 2017 Protest at 3 and 7.

[125] In its protest, EFG notes that, through an agreement with Pembina, it holds an option to acquire up to a 20 percent equity interest in Jordan Cove. EFG states it has not yet exercised this right. *Id.* at 3.

[126] EFG states that its bids were submitted through Energy Fundamentals Group LLC. *Id.* at 4.

[127] *Id.* at 4.

need to provide in conjunction with its bid. EFG also argues it was not provided Pacific Connector's tariff but that it "appear[ed] . . . such information was made available to Jordan Cove[.]"[128] And, EFG notes that Pacific Connector and Jordan Cove negotiated a number of non-conforming provisions.

68. EFG contends that it was "similarly situated" to Jordan Cove but that its bids were rejected while Jordan Cove's bids were accepted.[129] EFG asserts that Pacific Connector "could not have negotiated in an arms-length fashion with its affiliate," and that Pacific Connector "was seeking a single shipper result from the Open Season on the most favorable terms with its affiliate."[130] EFG alleges that Jordan Cove may be acting as a placeholder for prospective terminal users or other pipeline shippers, or that Jordan Cove may intend to assign its position to another entity a later date; EFG contends that these other entities may not meet Pacific Connector's creditworthiness requirement.[131] For these reasons, EFG claims that "undue discrimination seems obvious and apparent."[132]

69. In its November 13, 2017 answer, Pacific Connector explains that it conducted its open season in an open and non-discriminatory manner in accordance with Commission policy. Pacific Connector states that each of EFG's open season bids were for the full capacity of the pipeline and that, because the combined bids of EFG and Jordan Cove were greater than the capacity of the pipeline,[133] Pacific Connector needed "to ensure all bids were valid to allocate the available capacity correctly."[134] Pacific Connector asserts that its open season notice stated that "[Pacific Connector] reserves the right to reject [open season bids] in the event that requesting parties are unable to meet applicable creditworthiness requirements,"[135] and that confirming creditworthiness of its customers following the open season was critical to its ability to move forward with the project. Pacific Connector contends that it would invest "substantial funds in developing the

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[128] *Id.* at 5-6.

[129] *Id.* at 7.

[130] *Id.* at 6.

[131] *Id.* at 5.

[132] *Id.* at 7.

[133] As noted above, the precedent agreements executed with Jordan Cove were for 95.8 percent of the firm capacity of the pipeline.

[134] Pacific Connector and Jordan Cove's November 13, 2017 Answer at 30.

[135] *Id.*; *see also* Pacific Connector's Application at Exhibit Z-2.

[p]ipeline,"[136] and that it would not be prudent to incur those costs without adequate assurances of creditworthiness from its customers. In addition, Pacific Connector notes that it would raise funds for its pipeline through a mix of debt and equity, and its "ability to repay the borrowed funds and provide equity investors a return on capital is directly related to its receipt of full and timely payment from its customers."[137]

70. Pacific Connector states that, at the close of its open season, it "requested that all bidders[138] submit adequate assurances that, at the proper time, each bidder would be able to deliver the credit support required under the precedent agreements."[139] According to Pacific Connector, a bidder could either prove it qualifies as creditworthy,[140] or provide adequate assurances that it could post the required credit support at the appropriate time under the precedent agreement.[141]

71. Pacific Connector explains that it asked both EFG and Jordan Cove to meet the applicable creditworthiness requirements but that only Jordan Cove sufficiently satisfied this request. Pacific Connector states that it provided EFG multiple opportunities to provide adequate assurances of its creditworthiness but that EFG failed to do so; EFG and its affiliates do not have a credit rating, and EFG did not show it could post the required support.[142] Jordan Cove did provide adequate assurances that it could meet its future obligations. Jordan Cove submitted a letter from its parent company at the time,

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[136] Pacific Connector and Jordan Cove's November 13,2 017 Answer at 30.

[137] *Id.* at 31.

[138] Jordan Cove and EFG were the only bidders.

[139] Pacific Connector and Jordan Cove's November 13, 2017 Answer at 29.

[140] Pacific Connector explains that creditworthiness can be established by having a qualifying credit rating ("BBB" or better from Standard & Poor's, "Baa2" or better from Moody's Investor Services, or an equivalent rating from another ratings agency) or following an analysis of audited financial statements. *Id.*

[141] Pacific Connector states that non-creditworthy bidders could post credit support for three years' of reservation charges in the form of a guarantee from a creditworthy entity, a letter of credit, or another form of credit support acceptable to Pacific Connector. *Id.* at 29-30.

[142] *Id.* at 31-33.

Veresen,[143] demonstrating that Veresen was creditworthy and willing to provide a guarantee of Jordan Cove's obligations.[144]

72. Pacific Connector avers that it could not take the risk that EFG would default on its obligation and that relying on such an agreement could impede Pacific Connector's own ability to obtain financing. Accordingly, Pacific Connector alleges that Jordan Cove and EFG were not similarly situated and that EFG's bids were properly rejected while Jordan Cove's bids were accepted.

73. Pacific Connector asserts that inclusion of additional credit support obligations for shippers in the open season notice and precedent agreements is permitted under Commission policy, and that a pipeline's ability "to assess the legitimacy of the bidders in the open season . . . protects the Commission's open season process from the possibility of abuse."[145]

74. Lastly, Pacific Connector explains that entities bidding on new pipelines regularly submit bids without a copy of the tariff because the open season takes place before the certificate application and the *pro forma* tariff are filed with the Commission. In addition, Pacific Connector notes that its tariff would be subject to review and approval by the Commission, and entities would be free to file comments on and request changes to the tariff once it was submitted to the Commission. Further, Pacific Connector states that it was impossible for EFG and Pacific Connector to have any discussions regarding non-conforming provisions because EFG submitted its bids "[s]econds before the end of the open season[.]"[146] Moreover, Pacific Connector contends that shippers similarly situated to its anchor shipper, Jordan Cove, would have been offered non-conforming provisions, but it was under no obligation to offer such contractual rights to EFG because EFG's bids were rejected.

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[143] *See supra* note 5.

[144] In its November 13, 2017 Answer, Pacific Connector notes that Jordan Cove's current parent company, Pembina, also qualifies as "a creditworthy entity permitted to provide a guarantee under Jordan Cove's precedent agreements." Pacific Connector and Jordan Cove's November 13, 2017 Answer at 34 n.119.

[145] *Id.* at 32.

[146] *Id.* at 29 and 35.

Commission Determination

75. For pipeline capacity that has been constructed and placed in service, the Commission's general policy has been to permit pipelines to require shippers that fail to meet a pipeline's creditworthiness requirements for service put up collateral equal to three months' worth of reservation charges.[147] When undertaking the construction of new pipeline infrastructure, however, the Commission recognizes that "pipelines need sufficient collateral from non-creditworthy shippers to ensure, prior to the investment of significant resources into the project, that it can protect its financial commitment to the project."[148] Therefore, the Commission's creditworthiness policy permits larger collateral requirements for pipeline construction projects to be executed between the pipeline and the initial shippers. The Commission has explained that:

> For mainline projects, the pipeline's collateral requirement must reasonably reflect the risk of the project, particularly the risk to the pipeline of remarketing the capacity should the initial shipper default. Because these risks may vary depending on the specific project, no predetermined collateral amount would be appropriate for all projects.[149]

76. The precedent agreements EFG signed in order to place its bids specified Pacific Connector's creditworthiness requirements.[150] Following the close of its open season, and consistent with the signed precedent agreements and open season notice, Pacific Connector requested that all bidders provide adequate assurances that, at the proper time, each bidder would be able to deliver the credit support required under the precedent agreements.[151] The precedent agreements for Jordan Cove and EFG included "identical credit support obligations to apply at the same time."[152] According to Pacific Connector, EFG, unlike Jordan Cove, was unable to provide the necessary credit support. EFG does not provide any evidence that it did, in fact, meet Pacific Connector's creditworthiness

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[147] *See Policy Statement on Creditworthiness for Interstate Natural Gas Pipelines and Order Withdrawing Rulemaking Proceeding*, 111 FERC ¶ 61,412, at P 11 (2005).

[148] *Id.* P 17.

[149] *Id.* (citing *Calpine Energy Servs., L.P. v. Southern Natural Gas Co.*, 103 FERC ¶ 61,273, at P 31 (2003) (approving 30 month collateral requirement based on the risks faced by the pipeline)).

[150] *See* Pacific Connector and Jordan Cove's November 13, 2017 Answer at 33-34.

[151] *See id.* at Attachment 1.

[152] *Id.* at 34.

requirement and, thus, that its bid was improperly rejected,[153] nor does it claim that Pacific Connector's creditworthiness requirements were unreasonable.

77. Consequently, we find that Pacific Connector's request for bidders to demonstrate creditworthiness and Pacific Connector's subsequent rejection of EFG's bids, following EFG's failure to provide adequate assurances of creditworthiness, were reasonable and consistent with Commission policy. EFG's apparent inability to meet Pacific Connector's creditworthiness requirement does not constitute undue discrimination.

78. Although EFG expresses concern that Jordan Cove is potentially acting as a placeholder for prospective terminal users or other pipeline shippers, this does not mean Pacific Connector's rejection of EFG's bid was the result of undue discrimination. As explained above, the Commission's policy is not to look behind precedent agreements to evaluate shippers' business decisions to acquire capacity.[154] Jordan Cove has signed binding precedent agreements with Pacific Connector for nearly 96 percent of the pipeline's capacity and Jordan Cove has established the required credit support for the full capacity of its precedent agreements. As explained in Pacific Connector's November 13 answer, Pacific Connector required this demonstration of credit support in order to continue moving forward with development of its pipeline.[155]

79. In addition, we agree with Pacific Connector that EFG's late involvement in the open season process greatly limited Pacific Connector's ability to have any substantive discussions with EFG regarding non-conforming provisions and other matters prior to EFG submitting its bids. Further, we have no reason to doubt that, as Pacific Connector asserts, shippers similarly situated to its anchor shipper, Jordan Cove, would have been offered non-conforming provisions, but EFG's bids were rejected. We also find that EFG's inability to review Pacific Connector's tariff before submitting its bids does not render Pacific Connector's open season process discriminatory. EFG does not explain how this impacted its bids or formed a basis for Pacific Connector's denial. The record reflects that EFG's bids were rejected simply because EFG failed to adequately demonstrate creditworthiness, and, as noted by Pacific Connector, had EFG's bids been

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[153] EFG simply states "[i]t is EFG's position, that its bid in fact represented a similarly situated 'anchor shipper' bid that conformed to the requirements of the Open Season process including adequate and acceptable assurance that credit support would be furnished at the commencement of the Credit Period as required by the terms of the [Transportation Services Precedent Agreement]." EFG's October 26, 2017 Protest at 6.

[154] *See, e.g.*, *PennEast Pipeline Co., LLC*, 164 FERC ¶ 61,098, at P 16 (2018); *Spire STL Pipeline LLC*, 164 FERC ¶ 61,085, at P 83 (2018).

[155] Pacific Connector and Jordan Cove's November 13, 2017 Answer at 30-31.

accepted, EFG would have had ample time to review and contest provisions in the *pro forma* tariff once the tariff was filed with the Commission.

80. Based on the record before us, we do not find that Pacific Connector conducted its open season in an unduly discriminatory or non-transparent manner.

iii. <u>Public Benefits of the Proposal</u>

81. Sierra Club contends that even if Pacific Connector has demonstrated market support for its proposal, Pacific Connector "ha[s] not shown that the [] pipeline will provide any of the benefits contemplated by the Certificate Policy Statement."[156] Sierra Club and other intervenors allege that there are no, or few, public benefits associated with the proposal because the pipeline will be used to transport Canadian gas to the liquefaction facility, and from there the LNG will go to other foreign markets.[157] Sierra Club states that the pipeline will not reduce consumer costs or deliver any gas to communities along the pipeline route.[158] Sierra Club argues that "if the projects end up solely serving to allow a Canadian company to sell Canadian natural gas to buyers in Asian countries, the project will not provide any U.S. Community with any public benefits of the type described in the Certificate Policy Statement."[159] Sierra Club and others note that an affiliate of Jordan Cove previously received approval from DOE to import gas from Canada (for purposes of delivering that gas to Jordan Cove's previously proposed export terminal) sufficient to meet the entire supply needs of the pipeline.[160] Moreover, Sierra Club and other intervenors contend that any other purported benefits from the pipeline, such as increased tax revenue and job creation, standing alone cannot provide a basis for a grant of eminent domain authority.[161]

[156] Sierra Club's October 26, 2017 Protest at 19.

[157] *Id.* at 21; *see also, e.g.*, Dania Colegrove's October 26, 2017 Motion to Intervene; Oregon Women's Land Trust's October 13, 2017 Motion to Intervene.

[158] Sierra Club's October 26, 2017 Protest at 19-20.

[159] *Id.* at 21.

[160] *Id.* at 20-21 (citing *Jordan Cove LNG L.P.*, FE Docket No. 13-141-LNG, Order No. 3412 (March 18, 2014)); Tienson's October 3 Landowner Comments at 2.

[161] Sierra Club's October 26, 2017 Protest at 21; *see also, e.g.*, League of Women Voters Klamath County's October 23, 2017 Motion to Intervene at 2.

82. In its November 13, 2017 answer, Pacific Connector asserts that:

> [a] broad range of public benefits may be offered as proof that a project is required by the public convenience and necessity. As the Commission has explained, '[t]he types of public benefits that might be shown are quite diverse but could include meeting unserved demand, eliminating bottlenecks, access to new supplies, lower costs to consumers, providing new interconnects that improve the interstate grid, providing competitive alternatives, increasing electric reliability, or advancing clean air objectives.[162]

Pacific Connector also notes that, although not currently proposed, the pipeline will "allow potential future deliveries to communities along the [p]ipeline that have previously not had access to clean-burning natural gas."[163]

Commission Determination

83. It is well established that precedent agreements are significant evidence of demand for a project.[164] As the court stated in *Minisink* and again in *Myersville Citizens for a Rural Community, Inc., v. FERC*, nothing in the Certificate Policy Statement or in any precedent construing it suggest that the policy statement requires, rather than permits, the Commission to assess a project's benefits by looking beyond the market need reflected by the applicant's precedent agreements with shippers.[165] Yet Sierra Club and others

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[162] Pacific Connector and Jordan Cove's November 13, 2017 Answer at 12.

[163] *Id.* at 8-9 (citing Pacific Connector's Application at 4).

[164] Certificate Policy Statement, 88 FERC at 61,748 (precedent agreements, though no longer required, "constitute significant evidence of demand for the project"); *Sabal Trail*, 867 F.3d at 1379 (affirming Commission reliance on preconstruction contracts for 93 percent of project capacity to demonstrate market need); *Twp. of Bordentown v. FERC*, 903 F.3d 234, 263 (3d Cir. 2018) ("As numerous courts have reiterated, FERC need not 'look[] beyond the market need reflected by the applicant's existing contracts with shippers.'") (quoting *Myersville Citizens for a Rural Cmty., Inc., v. FERC*, 783 F.3d 1301, 1311 (D.C. Cir. 2015)); *Appalachian Voices v. FERC*, No. 17-1271, 2019 WL 847199 at *1 (unpublished) (precedent agreements are substantial evidence of market need).

[165] *Minisink*, 762 F.3d 97, 110 n.10; *see also Myersville Citizens for a Rural Cmty., Inc., v. FERC*, 783 F.3d at 1311. Further, Ordering Paragraph (E) of this order requires that Pacific Connector file a written statement affirming that it has executed

argue the Commission must do just that: look beyond or behind the need for transportation of natural gas in interstate commerce evidenced by the precedent agreements in this proceeding (as noted above, the Jordan Cove LNG Terminal cannot function without the transportation service to be provided by the Pacific Connector Pipeline) and make a judgement based on benefits associated with where the gas might come from and/or how it will be used after it is delivered at the end of the pipeline and interstate transportation is completed. However, it is current Commission policy not to look beyond precedent or service agreements to make judgements about the origins or ultimate end use of the commodity or the needs of individual shippers,[166] and we see no justification to make an exception to that policy here. Just as the precedent agreements provide evidence of market demand, they are also evidence of the public benefits of the project.[167]

84. The principle purpose of Congress in enacting the NGA was to encourage the orderly development of reasonably priced gas supplies.[168] Thus, the Commission takes a broad look in assessing actions that may accomplish that goal. Gas imports and exports benefit domestic markets; thus, contracts for the transportation of gas that will be imported or exported are appropriately viewed as indicative of a domestic public benefit. The North American gas market has numerous points of export and import, with volumes changing constantly in response to changes in supply and demand, both on a local scale, as local distribution companies' and other users' demand changes, and on a regional or national scale, as the market shifts in response to weather and economic patterns.[169] Any

contracts for service at the levels provided for in their precedent agreements prior to commencing construction.

[166] Certificate Policy Statement, 88 FERC at 61,744 (citing *Transcontinental Gas Pipe Line Corp.*, 82 FERC ¶ 61,084, at 61,316 (1998)).

[167] *See, e.g.*, *PennEast Pipeline Co., LLC*, 162 FERC ¶ 61,053, at P 42 (2018); *Columbia Gas Transmission, LLC*, 161 FERC ¶ 61,314, at P 44 (2017).

[168] *NAACP v. FPC*, 425 U.S. 662, 669-70 (1976). *See generally Adelphia Gateway, LLC*, 169 FERC ¶ 61,220 (2020) (McNamee, Comm'r, concurrence) (elaborating on the purpose of the NGA).

[169] *See, e.g.*, U.S. Energy Information Administration (EIA), *Increases in natural gas production from Appalachia affect natural gas flows* (March 12, 2019), https://www.eia.gov/todayinenergy/detail.php?id=38652 (explaining how the increase in shale gas production in the Mid-Atlantic has altered inflows and outflows of gas to the Eastern Midwest and South Central Regions, and to Canada); EIA, *Natural Gas Weekly Update* (October 24, 2018), https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2018/10_25/ (pipeline explosion in Canada leads to lower U.S. gas

constraint on the transportation of gas to or from points of export or import risks negating the efficiency and economy the international trade in gas provides to domestic consumers.

85. While Sierra Club is correct that an affiliate of Jordan Cove previously received authorization from DOE to import gas from Canada (for purposes of delivering that gas to Jordan Cove's previously proposed export terminal) sufficient to meet the entire supply needs of the pipeline,[170] that does not mean that the Pacific Connector Pipeline will transport only Canadian gas. As Pacific Connector explains in its application, "natural gas producers in the Rocky Mountains and Western Canada . . . . have seen their access to markets in the eastern and central regions of the United States and Canada erode with the development and ramp-up of natural gas production from the Marcellus and Utica shales."[171] Thus, domestic upstream natural gas producers will benefit from the project by being able to access additional markets for their product. The applicants have stated that they "cannot meet the gas supply needs of the [Jordan Cove LNG] Terminal and the purpose of the overall [proposed projects] without accessing U.S. Rocky Mountain supplies, which are available from the Ruby pipeline."[172] In addition, we received a number of comments regarding the benefits that the Pacific Connector Pipeline will provide to natural gas producers in the Rockies, specifically producers in the Uintah/Piceance and Green River Basins. For example, Caerus Piceance LLC, a natural gas producer in the Piceance Basin of western Colorado, states:

> The abundance of natural gas reserves in western Colorado and the existing midstream infrastructure make it possible for the Piceance Basin to be a major supplier for LNG exports worldwide via the west coast. The Piceance Basin in western Colorado has significant proven reserves—estimated at tens of thousands of future Williams Fork locations—along

imports and higher regional prices).

[170] *See Jordan Cove LNG L.P.*, FE Docket No. 13-141-LNG, Order No. 3412 (March 18, 2014) (authorizing Jordan Cove LNG L.P. to import natural gas from Canada in a total volume of 565 Bcf per year, or 1.55 Bcf per day, for a 25-year term). The 25-year term commences on the earlier of the date of first export from Canada or the date of 10 years from the date of authorization (i.e., March 18, 2024).

[171] Pacific Connector's Application, Resource Report 1 at 3; *see also, e.g.*, State of Wyoming and Wyoming Pipeline Authority's (jointly filed) October 23, 2017 Motion to Intervene at 4-5 (noting that the Pacific Connector Pipeline will provide "much needed markets for natural gas produced in [Wyoming]").

[172] Jordan Cove and Pacific Connector's July 22, 2019 Response to Comments on draft EIS at 18.

> with tremendous potential reserves in the deeper Mancos and Niobrara formations. The existing midstream pipelines in western Colorado are currently underutilized. The [proposal] would connect the existing Ruby Pipeline to the proposed 230-mile Pacific Connector pipeline to transport affordable, clean-burning natural gas from western Colorado to the Jordan Cove LNG terminal, allowing western Colorado natural gas to flow to the Pacific without requiring additional pipeline construction.[173]

We also note that the referenced DOE import authorization acknowledges that Jordan Cove will also access gas supplies in the U.S. Rockies and that the proposed imports are "designed to create flexibility in the Project's sourcing of natural gas."[174]

86. Moreover, Congress directed, in NGA section 3(c), that the importation or exportation of natural gas from or to "a nation with which there is in effect a free trade agreement requiring national treatment for trade in natural gas, shall be deemed to be consistent with the public interest, and applications for such importation or exportation shall be granted without modification or delay."[175] While this provision of the NGA is not directly implicated by Pacific Connector's application under NGA section 7(c), it is indicative of the importance that Congress has placed on establishing reciprocal gas trade between the United States and those countries with which it has entered free trade agreements. We further note that DOE has determined that both the import of natural gas from Canada by Jordan Cove's affiliate and the export of LNG from the Jordan Cove LNG Terminal to FTA nations by Jordan Cove are in the public interest.[176] The Pacific Connector Pipeline will provide the interstate transportation service necessary for Jordan Cove and its affiliate to perform those functions.

87. As explained further below, once the Commission makes a determination that proposed interstate pipeline facilities are in the public convenience and necessity, section 7(h) of the NGA authorizes a certificate holder to acquire the necessary land or property to construct the approved facilities by exercising the right of eminent domain if

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[173] Caerus Piceance LLC's July 8, 2019 Comments at 2.

[174] *See Jordan Cove LNG L.P.*, FE Docket No. 13-141-LNG, Order No. 3412 at 5-6 (March 18, 2014).

[175] 15 U.S.C. § 717b(a).

[176] *See Jordan Cove LNG L.P.*, FE Docket No. 13-141-LNG, Order No. 3412 at 8 (March 18, 2014); *Jordan Cove Energy Project, L.P.*, FE Docket No. 11-127-LNG, Order No. 3041-A at 4 (July 20, 2018).

it cannot acquire the easement by an agreement with the landowner.[177] Congress did not suggest that there was a further test, beyond the Commission's determination under NGA section 7(c)(e),[178] that a proposed pipeline was required by the public convenience and thus entitled to use eminent domain.

c. Existing Pipelines and their Customers

88. The Pacific Connector Pipeline is designed to transport gas from supply basins in the U.S. Rocky Mountains and western Canada to the proposed Jordan Cove LNG Terminal. The project is not intended to replace service on other pipelines, and no pipelines or their customers have filed adverse comments regarding Pacific Connector's proposal. Several landowners assert that, because the Certificate Policy Statement requires the Commission to consider whether a new pipeline will have adverse impacts on existing pipelines, the Commission should also consider whether the Jordan Cove LNG Terminal will have adverse impacts on existing terminals on the Gulf Coast.[179] As noted above, we find that this issue of whether exports from Jordan Cove will compete with exports from LNG terminals on the Gulf Coast is beyond the Commission's purview as it relates to exportation of the commodity of natural gas.[180] Based on the foregoing, we find that the Pacific Connector Pipeline will not adversely affect other pipelines or their captive customers.

d. Landowners and Communities

89. Regarding impacts on landowners and communities along the pipeline route, Pacific Connector proposes to locate its pipeline within or parallel to existing rights-of-way, where feasible. Approximately 43.7 percent of Pacific Connector's pipeline rights-of-way will be collocated or adjacent to existing powerline, road, and pipeline corridors.[181] Approximately 82 miles of the total pipeline right-of-way are on public land (federal or state-owned land), and the remaining 147 miles are on privately owned

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[177] 15 U.S.C. § 717f(h).

[178] 15 U.S.C. § 717f(e).

[179] Tienson's October 3 Landowner Comments at 2 and 4.

[180] *Supra* PP 30-32.

[181] Pacific Connector's September 18, 2019 Revised Plan of Development at 8.

land.[182] Of those 147 miles, 60 miles are held by timber companies.[183] On July 29, 2019, Pacific Connector stated that it had obtained easements from 72 percent of private, non-timber landowners (representing 75 percent of the mileage from such landowners) and 93 percent of timber company landowners (representing 92 percent of the mileage from timber companies).[184] Pacific Connector engaged in public outreach during the Commission's pre-filing process, working with interested stakeholders, soliciting input on route concerns, and engaging in reroutes where practicable to minimize impacts on landowners and communities.

90. Accordingly, while we recognize that Pacific Connector has been unable to reach easement agreements with some landowners, we find that Pacific Connector has taken sufficient steps to minimize adverse impacts on landowners and surrounding communities for purposes of our consideration under the Certificate Policy Statement.

e. <u>Balancing of Adverse Impacts and Public Benefits</u>

91. Some intervenors assert that the adverse impacts associated with the proposal outweigh any public benefits, compelling denial of the application.[185] Sierra Club also contends that, while Commission practice is to generally consider all non-environmental

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[182] *See* final EIS at Table 4.7.2.1-1.

[183] Pacific Connector's July 29, 2019 Land Statistics Update.

[184] *Id.* Pacific Connector provided a prior update on December 21, 2018 as part of its response to Commission Staff's December 12, 2018 Data Request. On January 2, 2019, landowner-intervenors Stacey McLaughlin, Deb Evans, and Ron Schaaf filed comments alleging that Pacific Connector had misrepresented the number of landowners with whom it had entered into easement agreements. The landowners asserted that the data provided by Pacific Connector did not match a public record search for easements recorded in the four impacted counties. On January 4, 2019, Pacific Connector filed a response, explaining it had not yet recorded all the easements it obtained and that there was no legal requirement for it to record such easements within a specific timeframe. Further, Pacific Connector stated that it was honoring multiple landowner requests to delay recording of an easement until a later date out of concerns regarding harassment by potential project opponents.

[185] *See, e.g.*, Sierra Club's October 26, 2017 Protest at 21; Tienson's June 1, 2018 Comments at 1.

issues first, environmental impacts "must be incorporated into the balancing or sliding scale assessment of the public interest."[186]

92. The Certificate Policy Statement's balancing of adverse impacts and public benefits is not an environmental analysis process, but rather an economic test that we undertake before our environmental analysis.[187]

93. The Certificate Policy Statement states that

> elimination of all adverse effects will not be possible in every instance. When it is not possible, the Commission's policy objective is to encourage the applicant to minimize the adverse impact on each of the relevant interests. After the applicant makes efforts to minimize the adverse effects, construction projects that would have residual adverse effects would be approved only where the public benefits to be achieved from the project can be found to outweigh the adverse effects.[188]

94. Pacific Connector's proposed project will enable it to transport natural gas to the Jordan Cove LNG Terminal, where the gas will be liquefied for export. Pacific Connector executed a precedent agreement with Jordan Cove for nearly 96 percent of the pipeline's capacity. The Pacific Connector Pipeline will not have any adverse impacts on existing customers, or other pipelines and their captive customers. In addition, Pacific Connector has taken steps to minimize adverse impacts on landowners and communities. For these reasons, we find that the benefits the Pacific Connector Pipeline will provide outweigh the adverse effects on economic interests.

3. Eminent Domain Authority

95. A number of commenters assert that is inappropriate for Pacific Connector to obtain property for the project through eminent domain because Pacific Connector is a for-profit, "Canadian company."[189] Some landowners also assert that the Commission's

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[186] Sierra Club's October 26, 2017 Protest at 6

[187] *See, e.g.*, *Algonquin Gas Transmission, LLC*, 154 FERC ¶ 61,048, at P 245 (2016).

[188] Certificate Policy Statement, 88 FERC at 61,747.

[189] *See, e.g.*, Frank Adams's October 12, 2017 Motion to Intervene (noting he is "deeply disappointed that the United States government would allow a Canadian company to use the eminent domain to take private property . . . ."); *see also* Keri Wu's October 17, 2017 Motion to Intervene at 2 ("I object to the use of eminent domain by a foreign corporation to rob Americans of their property.").

process violates the Due Process Clause because landowners were not provided a sufficient draft EIS or an adequate opportunity to be heard prior to the taking of their property.[190]

96. First, we note that Pacific Connector is not a Canadian company; as noted above, Pacific Connector is a Delaware limited partnership, with its principal place of business in Houston, Texas, that is authorized to do business in the state of Oregon.[191] And, second, we clarify that any eminent domain power conferred on Pacific Connector under the NGA "requires the company to go through the usual condemnation process, which calls for an order of condemnation and a trial determining just compensation prior to the taking of private property."[192] Further, "if and when the company acquires a right of way through any [landowner's] land, the landowner will be entitled to just compensation, as established in a hearing that itself affords due process."[193]

97. The Commission itself does not confer eminent domain powers. Under NGA section 7, the Commission has jurisdiction to determine if the construction and operation of proposed interstate pipeline facilities are in the public convenience and necessity. Once the Commission makes that determination and issues a natural gas company a certificate of public convenience and necessity, it is NGA section 7(h) that authorizes that certificate holder to acquire the necessary land or property to construct the approved facilities by exercising the right of eminent domain if it cannot acquire the easement by an agreement with the landowner.[194] In crafting this provision, Congress made no distinction between for-profit and non-profit companies.

98. Some landowners along the pipeline route allege that the use of eminent domain to construct the pipeline would violate the Takings Clause of the Fifth Amendment of the

[190] Tonia Moro's (writing on behalf of affected landowners Ron Schaaf, Deb Evans, Craig and Stacey McLaughlin, and Greater Good Oregon) April 19, 2019 Complaint and Motion Seeking Order at 8-11 (April 19, 2019 Landowner Motion).

[191] *Supra* P 4; Pacific Connector's Application at Exhibits A and B.

[192] *Appalachian Voices v. FERC*, No. 17-1271, 2019 WL 847199, at *2 (unpublished) (quoting *Transwestern Pipeline Co., LLC v. 17.19 Acres of Prop. Located in Maricopa Cnty.*, 550 F.3d 770, 774 (9th Cir. 2008)).

[193] *Id.* (quoting *Delaware Riverkeeper Network v. FERC*, 895 F.3d 102, 110 (D.C. Cir. 2018)).

[194] 15 U.S.C. § 717f(h).

U.S. Constitution because the project provides no public benefit.[195] These landowners further allege that the Commission's practice of issuing conditional certificates, pursuant to which projects cannot be built until additional federal and state authorizations are obtained, violates the Takings Clause as, here, it would enable Pacific Connector to obtain land via eminent domain before there is legal certainty its project can actually be built.[196]

99. The Commission has explained that, while a taking must serve a public use to satisfy the Takings Clause, the Supreme Court has defined this concept broadly.[197] Here, Congress articulated in the NGA its position that " . . . Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the public interest."[198] Congress did not suggest that, beyond the Commission's determination under NGA section 7(c)(e),[199] there was a further test that a proposed pipeline was required by the public convenience and necessity, such that certain certificated pipelines furthered a public use, and thus were entitled to use eminent domain, although others did not. The power of eminent domain conferred by NGA section 7(h) is a Congressionally mandated part of the statutory scheme to regulate the transportation and sale of natural gas in interstate commerce.

100. Where the Commission determines that a proposed pipeline project is in the public convenience and necessity, it is not required to make a separate finding that the project serves a "public use" to allow the certificate holder to exercise eminent domain. In short, the Commission's public convenience and necessity finding is equivalent to a "public use" determination.

101. We also reject commenters' argument that the Commission's decision to issue a conditional certificate violates the Takings Clause of the Fifth Amendment. Pacific Connector, as a certificate holder under section 7(h) of the NGA, can commence eminent domain proceedings in a court action if it cannot acquire the property rights by negotiation. Pacific Connector will not be allowed to construct any facilities on such property unless and until a court authorizes acquisition of the property through eminent domain and there is a favorable outcome on all outstanding requests for necessary approvals. Because Pacific Connector may go so far as to survey and designate the

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[195] Niskanen Center's July 5, 2019 Comments at 60-62.

[196] *Id.* at 64-68.

[197] *Hawaii Housing Auth. v. Midkiff*, 467 U.S. 229 (1984).

[198] 15 U.S.C. § 717(a).

[199] *Id.* § 717f(e).

bounds of an easement but no further, e.g., it cannot cut vegetation or disturb ground pending receipt of any necessary approvals, any impacts on landowners will be minimized. Further, Pacific Connector will be required to compensate landowners for any property rights it acquires.

4. <u>Blanket Certificates</u>

102. Pacific Connector requests a Part 284, Subpart G blanket certificate in order to provide open-access transportation services. Under a Part 284 blanket certificate, Pacific Connector will not need individual authorizations to provide transportation services to particular customers. Pacific Connector filed a *pro forma* Part 284 tariff to provide open-access transportation services. Because a Part 284 blanket certificate is required for Pacific Connector to participate in the Commission's open-access regulatory regime, we will grant Pacific Connector a Part 284 blanket certificate, subject to the conditions imposed herein.

103. Pacific Connector also requests a Part 157, Subpart F blanket certificate. The Part 157 blanket certificate gives an interstate pipeline NGA section 7 authority to automatically, or after prior notice, perform a restricted number of routine activities related to the construction, acquisition, abandonment, replacement, and operation of existing pipeline facilities provided the activities comply with constraints on costs and environmental impacts.[200] Because the Commission has previously determined through a rulemaking that these blanket-certificate eligible activities are in the public convenience and necessity,[201] it is the Commission's practice to grant new natural gas companies a Part 157 blanket certificate if requested.[202] Accordingly, we will grant Pacific Connector a Part 157 blanket certificate, subject to the conditions imposed herein.[203]

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[200] 18 C.F.R. § 157.203 (2019).

[201] *Revisions to the Blanket Certificate Regulations and Clarification Regarding Rates*, Order No. 686, 117 FERC ¶ 61,074, at P 9 (2006), *order on reh'g*, Order No. 686-A, 119 FERC ¶ 61,303, *order on reh'g,* Order No. 686-B, 120 FERC ¶ 61,249 (2007).

[202] *C.f. Rover Pipeline LLC*, 161 FERC ¶ 61,244, at P 13 (2017) (denying a request for a blanket certificate where the company's actions had eroded the Commission's confidence it would comply with all the requirements of the blanket certificate program, including the environmental requirements).

[203] A commenter's request for the Commission to review environmental impacts associated with blanket certificates is discussed further below. *Infra* PP 189-190.

5. <u>Rates</u>

a. <u>Initial Recourse Rates</u>

104. Pacific Connector proposes to offer firm transportation service under Rate Schedule FT-1 and interruptible transportation service under Rate Schedule IT-1. In its application, Pacific Connector designed its rates based on a first-year cost of service of $592,859,938, utilizing a capital structure of 50 percent debt and 50 percent equity, an overall rate of return of 10.00 percent based on a 6.00 percent cost of debt and 14.00 percent return on equity, and a depreciation rate of 2.75 percent based on a 40-year depreciation life and a negative salvage rate of 0.25 percent.[204]

105. On February 16, 2018, in response to a staff data request, Pacific Connector revised its proposed cost of service and initial recourse rates to reflect changes in the federal tax code pursuant to the Tax Cuts and Jobs Act of 2017,[205] which became effective January 1, 2018.[206] Pacific Connector's work papers show that the effect of the tax code change is a reduction in its estimated first-year cost of service to $525,904,728, resulting in lower initial charges for firm and interruptible services. As the calculations in Pacific Connector's data response reflect the federal tax code that will be in effect when the project goes into service, the Commission will use the revised cost of service for the purpose of establishing the initial recourse rates.

106. Using the revised cost of service, Pacific Connector proposes an initial maximum monthly recourse reservation charge for firm transportation (FT-1) service of $36.5212 per Dth, and a usage charge for its FT-1 service of $0.0000 per Dth.[207] Pacific Connector asserts that the proposed rates reflect a straight fixed-variable (SFV) rate design, but also states that it expects to incur only a small amount of variable costs associated with

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[204] Pacific Connector's Application at Exhibits O and P.

[205] Pub. L. No. 115-97, 131 Stat. 2054 (Dec. 22, 2017).

[206] On December 13, 2018, in response to a staff data request, Pacific Connector stated it is not a Master Limited Partnership and that it does not incur income taxes in its own name. Pacific Connector states its actual income tax liability ultimately will be reflected on the consolidated income tax returns of its corporate parent companies.

[207] Pacific Connector's February 16, 2018 Data Response (updated "Exhibit P, Explanatory Statement of Rate Methodology").

operating a single compressor station on its system.[208] Therefore, Pacific Connector explains that its cost of service is classified entirely as reservation charge-related.

107. Pacific Connector proposes rates for interruptible transportation (IT-1) service and authorized overrun service of $1.2007 per Dth, which is the 100 percent load factor daily equivalent of the maximum FT-1 reservation charge.

108. The Commission has reviewed Pacific Connector's proposed cost of service and initial rates and finds they generally reflect current Commission policy, with the exception of variable costs. Pacific Connector asserts that its rates reflect an SFV rate design. However, Pacific Connector does not classify any variable costs to a usage charge even though it will have two compressor units on its system.[209] Section 284.7(e) of the Commission's regulations[210] does not allow the recovery of variable costs in the reservation charge, and there is no "de minimis" cost exception to the rule. Section 284.10(c)(2) of the Commission's regulations[211] states that variable costs should be used to determine the volumetric charge. In its December 13, 2018 response to a staff data request, Pacific Connector identified a total of $1,120,000 in non-labor Operating and Maintenance expenses for FERC Account Nos. 853 (Compressor Station Labor & Expenses), 857 (Measuring and Regulating Station Expenses), 864 (Maintenance of Compressor Station Expenses) and 865 (Maintenance of Measuring and Regulating Station Equipment). These costs are properly classified as variable costs and, consistent with the Commission's regulations requiring the use of an SFV rate design methodology,[212] should be recovered through a usage charge, not through the reservation charge.[213] Therefore, the Commission approves the proposed rates, subject to modification in accordance with this discussion.

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[208] Pacific Connector's Application at Exhibit P.

[209] Pacific Connector's Application at 7-8 (both compressor units, along with a redundant spare backup unit, will be housed in a single compressor station, the Klamath Compressor Station).

[210] 18 C.F.R. § 284.7(e).

[211] 18 C.F.R. § 284.10(c)(2) (2019).

[212] 18 C.F.R. § 284.7(e).

[213] *Columbia Gulf Transmission, LLC*, 152 FERC ¶ 61,214 (2015); *Dominion Transmission, Inc.*, 153 FERC ¶ 61,382 (2015).

b. **Fuel Rate**

109. Pacific Connector proposes an in-kind system fuel retainage percentage with a tracking mechanism to recover fuel use and lost-and-unaccounted-for gas (L&U). Pacific Connector states that it will make a semi-annual fuel tracker filing pursuant to section 4 of the Natural Gas Act to adjust its fuel reimbursement percentage, and will annually true-up any differences between the fuel retained from shippers and the actual fuel consumed and L&U. Pacific Connector proposes an initial fuel retainage percentage of 0.8 percent, which consists of 0.719 percent for fuel use and 0.081 percent for L&U.[214] The Commission accepts Pacific Connector's proposed initial fuel retainage percentage. The proposed tracker mechanism is addressed further below.

c. **Three-Year Filing Requirement**

110. Consistent with Commission precedent, Pacific Connector is required to file a cost and revenue study no later than three months after its first three years of actual operation to justify its existing cost-based firm and interruptible recourse rates.[215] In that filing, the projected units of service should be no lower than those upon which Pacific Connector's approved initial rates are based. The filing must include a cost and revenue study in the form specified in section 154.313 of the Commission's regulations to update cost of service data.[216] Pacific Connector's cost and revenue study should be filed through the eTariff portal using a Type of Filing Code 580. In addition, Pacific Connector is advised to include as part of the eFiling description a reference to Docket No. CP17-494-000 and the cost and revenue study.[217] After reviewing the data, the Commission will determine whether to exercise its authority under NGA section 5 to investigate whether the rates remain just and reasonable. In the alternative, in lieu of that filing, Pacific Connector may make an NGA general section 4 rate filing to propose alternative rates to be effective no later than three years after the in-service date for its proposed facilities.

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[214] Pacific Connector's Application at 26-27.

[215] *Florida Southeast Connection, LLC*, 154 FERC ¶ 61,080, at P 139 (2016); *Bison Pipeline LLC,* 131 FERC ¶ 61,013, at P 29 (2010); *Ruby Pipeline, L.L.C.*, 128 FERC ¶ 61,224, at P 57 (2009); *MarkWest Pioneer, L.L.C.*, 125 FERC ¶ 61,165, at P 34 (2008).

[216] 18 C.F.R. § 154.313 (2019).

[217] *Electronic Tariff Filings*, 130 FERC ¶ 61,047, at P 17 (2010).

d. Negotiated Rates

111. Pacific Connector proposes to provide service to Jordan Cove at negotiated rates. Pacific Connector must file either its negotiated rate agreement(s) or a tariff record setting forth the essential terms of the agreement(s) in accordance with the Commission's Alternative Rate Policy Statement[218] and negotiated rate policies.[219] Pacific Connector must file the negotiated rate agreement(s) or tariff record at least 30 days, but not more than 60 days, before the proposed effective date for such rates.[220]

6. Tariff

112. As part of its application, Pacific Connector filed a *pro forma* open-access tariff applicable to services provided on its proposed pipeline. We approve the *pro forma* tariff as generally consistent with Commission policies, with the following exceptions. Pacific Connector is directed to include the proposed revisions in its compliance filing.

a. Parking and Lending Service

113. The Commission's regulations provide that a pipeline with imbalance penalty provisions in its tariff must provide, to the extent operationally practicable, parking and lending or other services that facilitate the ability of shippers to manage their transportation imbalances, as well as the opportunity to obtain similar imbalance management services from other providers without undue discrimination or preference.[221] Pacific Connector's proposed General Terms and Conditions (GT&C) section 22.5

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[218] *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines; Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 FERC ¶ 61,076, *order granting clarification*, 74 FERC ¶ 61,194, *order on reh'g and clarification denied*, 75 FERC ¶ 61,024, *reh'g denied*, 75 FERC ¶ 61,066, *reh'g dismissed*, 75 FERC ¶ 61,291 (1996), *petition for review denied sub nom. Burlington Resources Oil & Gas Co. v. FERC,* 172 F.3d 918 (D.C. Cir. 1998).

[219] *Natural Gas Pipelines Negotiated Rate Policies and Practices; Modification of Negotiated Rate Policy,* 104 FERC ¶ 61,134 (2003), *order on reh'g and clarification,* 114 FERC ¶ 61,042, *reh'g dismissed and clarification denied,* 114 FERC ¶ 61,304 (2006).

[220] Pipelines are required to file any service agreement containing non-conforming provisions and to disclose and identify any transportation term or agreement in a precedent agreement that survives the execution of the service agreement. 18 C.F.R. § 154.112(b) (2019).

[221] 18 C.F.R. § 284.12(b)(2)(iii) (2019).

contains imbalance penalty provisions. Although GT&C section 22.7 states that Pacific Connector will waive imbalance penalties incurred for certain reasons described therein or "for other good cause, including Transporter's reasonable judgment that Shipper's or Receiving Party's imbalances did not jeopardize system integrity," the possibility that Pacific Connector would waive a penalty does not satisfy the regulation's requirement to offer an operationally feasible service that would enable a shipper to avoid the penalty to begin with.[222] Therefore, Pacific Connector must either propose a parking and lending service or similar service, or fully explain and document why it is operationally infeasible to do so. In addition, Pacific Connector must state whether and how its shippers would have the opportunity to obtain such services from other providers.

b. <u>Index Price Point</u>

114. Various sections of Pacific Connector's *pro forma* tariff refer to an index price point described as "Malin," published in "Platts Gas Daily." The Commission approves this point as an index price point subject to Pacific Connector revising every tariff reference to such point as it is identified in *Platts Gas Daily*: "PG&E, Malin."

115. In the Commission's *Price Index Order*,[223] the Commission stated that it will presume that a proposed index location will result in just and reasonable charges if the proposed index location meets two qualifications: (1) the index location is published by a price index developer identified in the *Price Index Order*; and (2) the index location meets one or more of the applicable criteria for liquidity (i.e., the index must be developed on a sufficient number of reported transactions involving sufficient volumes of natural gas for the appropriate review period).[224] While the Commission requires a pipeline to demonstrate the liquidity of an index location, the Commission recognizes that liquidity may fluctuate for various price indices due to constant changes in market conditions. As such, the Commission directs Pacific Connector to include in its compliance filing, a showing that its index price point meets the Commission's liquidity requirements.

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[222] *Atlantic Coast Pipeline, LLC*, 161 FERC ¶ 61,042, at PP 185-186 (citing Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services, Order No. 637, FERC Stats. & Regs. ¶ 31,091, at 31,309 (2000) (cross-referenced at 90 FERC ¶ 61,109)).

[223] *Price Discovery in Natural Gas and Electric Markets; Policy Statement on Natural Gas and Electric Price Indices*, 104 FERC ¶ 61,121 (2003), *clarified*, 109 FERC ¶ 61,184 (2004) (*Price Index Order*).

[224] *Price Index Order*, 109 FERC ¶ 61,184 at P 66 and Ordering Paragraph (D).

c. Available Capacity (GT&C Section 9) and Right of First Refusal (GT&C Section 10)

116. GT&C section 9 describes how Pacific Connector will allocate system capacity, conduct open season bidding for capacity, implement prearranged transactions, and reserve existing capacity for future expansions. GT&C section 10 includes additional open season procedures if capacity posted for bidding under GT&C section 9 is subject to a right of first refusal (ROFR) under section 284.221(d)(2)(ii) of the Commission's regulations (hereinafter, ROFR capacity).[225] As detailed below, portions of GT&C sections 9 and 10 are inconsistent with Commission policy and precedent.

i. Prearranged Transactions (GT&C Section 9.5)

117. GT&C section 9.5 provides that Pacific Connector "may enter into a prearranged transaction with any creditworthy party for any Available Capacity or potentially Available Capacity" as defined in GT&C section 9.1.2. GT&C section 9.1.2 defines potentially available capacity to include "capacity that may be made available at a future date" if Pacific Connector exercises its option to provide a termination notice under a firm service agreement with an evergreen provision, or terminate a shipper's service agreement pursuant to GT&C section 8.2 for failure to maintain credit or pursuant to GT&C section 24.3.3 for failure to pay bills.

118. Section 9.2.1 requires Pacific Connector to post information about all Available Capacity within 10 business day of becoming aware of such availability. Section 9.2.2 requires Pacific Connector to post information about potentially Available Capacity, including capacity that may become available as a result of the pipeline's option to terminate under an evergreen provision or for failure to maintain credit or pay bills.

119. According to GT&C section 9.5, a prospective prearranged shipper may propose to enter into a transaction with Pacific Connector by submitting a binding "prearranged offer request" for any Available Capacity or potentially Available Capacity that the pipeline has posted pursuant to section 9.2. GT&C section 9.5 states that Pacific Connector will reject any prearranged offer request for Available Capacity or "potentially Available Capacity currently held by a Shipper with a Right of First Refusal" when such offer request is submitted more than eighteen months before the termination date or "potential termination date" of the existing shipper's service agreement. The pipeline may also reject any prearranged offer request for potentially Available Capacity requested with conditions or at less than the maximum rate. If the offer request is deemed acceptable, Pacific Connector will provide a termination notice to any existing shipper whose capacity is included in the prearranged offer request and thereafter post the

[225] 18 C.F.R. § 284.221(d)(2)(ii) (2019). A shipper holding ROFR capacity is referred to herein as a ROFR shipper.

prearranged transaction for open season bidding.

120. After the open season, the prearranged shipper will be awarded the capacity if the agreed-to prearranged transaction rate exceeds or matches the economic value of the best third-party bid. However, if the prearranged transaction includes ROFR capacity, the ROFR shipper will have the ultimate right to match either the best third-party bid or the prearranged transaction rate in order to retain its capacity.

121. The Commission rejects Pacific Connector's proposal to permit prearranged transactions to include ROFR capacity. In *PG&E Gas Transmission*, the Commission held that a pipeline "cannot enter into any prearranged deals before capacity is posted as available."[226] Because section 284.221(d)(2) of the Commission's regulations[227] gives eligible shippers a regulatory right to request an open season to potentially avoid pregranted abandonment of their ROFR capacity, ROFR capacity cannot be considered available. For this reason, such capacity cannot be included in a prearranged transaction until the ROFR shipper either relinquishes its right to compete in an open season for the capacity, or otherwise fails or chooses not to retain such capacity at the conclusion of an open season.[228]

122. Therefore, the Commission directs Pacific Connector to remove any language from its proposed tariff indicating that ROFR capacity can be included in a prearranged transaction.[229]

ii. <u>Posting Prearranged Transactions (GT&C Section 9.5)</u>

123. GT&C section 9.5 states, in part, that "the first prearranged offer request that is acceptable to Transporter will be posted as a prearranged transaction pursuant to Section 9.6 and will be subject to competitive bid." However, GT&C Section 9.5 does not provide a deadline by which Pacific Connector must post the prearranged transaction. Commission policy requires a pipeline to post the prearranged deal as soon as it is entered into to permit other parties an opportunity to bid for the capacity on a long-term

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[226] *PG&E Gas Transmission, Northwest Corp.*, 103 FERC ¶ 61,061, at P 12 (2003) (*PG&E*).

[227] 18 C.F.R. § 284.221(d)(2) (2019).

[228] *See Natural Gas Pipeline Co. of Am.*, 82 FERC ¶ 61,036, at 61,142 (1998).

[229] For example, GT&C section 12.2(b), addressing negotiated rates, notes that prearranged transactions may include potentially available capacity.

basis.[230] Pacific Connector is directed to revise GT&C Section 9.5 to be consistent with this policy.

iii. <u>Bids for Capacity for Service with a Future Start Date (GT&C Section 9.9.1)</u>

124. GT&C section 9.8.1 states in part:

> [F]or a prearranged transaction for service commencing at a future date at any rate, competing bids will be allowed for service to start either on such future date or on any date between the earliest time the capacity is available and such future date.

125. In addition, GT&C section 9.9.1 provides:

> [F]or prearranged transactions starting a year or more after the underlying capacity becomes available, Transporter will evaluate bids based on net present value of the reservation charge bid for new [Contract Demand] and/or term extension bid for existing Service Agreements.
> . . . .
> When the net present value methodology is utilized, the net present value will be computed *from the Monthly reservation revenues per Dekatherm to be received over the term of the Service Agreement.* (Emphasis added).

126. Commission policy requires that bids for prearranged transactions reserving capacity for future service must be evaluated on a net present value (NPV) basis,[231] and that "[i]n calculating net present value, the current value of the future bid would be reduced by the time value of the delay in the pipeline receiving that revenue."[232] The Commission therefore directs Pacific Connector to revise the italicized language quoted above from GT&C section 9.9.1 to be consistent with such policy.

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[230] *Gas Transmission Northwest Corp.*, 109 FERC ¶ 61,141, at P 17 (2004) (*GTN*); *Northern Natural Gas Co.*, 109 FERC ¶ 61,388, at P 27 (2004) (*Northern*).

[231] *Northern*, 109 FERC ¶ 61,388 at P 27.

[232] *GTN*, 109 FERC ¶ 61,141 at P 17; *see also Northern*, 109 FERC ¶ 61,388 at P 27.

iv. Open Season for ROFR Capacity (GT&C Section 10.4)

127. GT&C section 10.4 (Solicitation of Bids) states:

> Pursuant to Section 9, Transporter may enter into prearranged deals which will be subject to competitive bid, or hold an open season for capacity that is subject to a ROFR, no earlier than eighteen (18) Months prior to the termination or expiration date or potential termination date for the eligible Service Agreement. An open season for capacity that is subject to a ROFR shall commence no later than one hundred and eighty (180) days prior to the expiration of the current Service Agreement and last at least twenty (20) days.

128. In *Transcontinental Gas Pipe Line Corp.*, the Commission stated that "[u]nder the ROFR [process], a reasonable period before a contract ends, normally six months to a year, a shipper would provide notice to the pipeline stating whether or not it was interested in renewing its contract."[233] Pacific Connector is directed to revise its open season process for ROFR capacity to be consistent with the timeframe found reasonable by the Commission in *Transco I*.

v. Match Process for ROFR Shippers (GT&C Section 10.7)

129. GT&C section 10.7 states, in part:

> (a) if the best bid is a Recourse Rate bid, Shipper must match both the rate and term of the bid for all or a volumetric portion of the bid;
>
> (b) if the best bid is a discounted Recourse Rate bid, Shipper must offer a rate and term (*not to exceed the term for such bid*) equivalent to all or a volumetric portion of the bid on a net present value basis; or
>
> (c) if the best bid is a Negotiated Rate bid, Shipper can either match the Negotiated Rate and term or agree to pay the Recourse Rate for the bid term for all or a volumetric portion of the bid. (Emphasis added).

130. In *Transcontinental Gas Pipe Line Corp.*, the Commission determined that "[u]nder an NPV bid evaluation method, shippers may bid whichever combination of rate

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[233] *Transcontinental Gas Pipe Line Corp.*, 103 FERC ¶ 61,295, at P 20 (2003) (*Transco I*).

and term best represents the value they place on the capacity."[234] The Commission directs Pacific Connector to revise the above-quoted italicized language from GT&C section 10.7(b) to be consistent with the Commission's determination in *Transco II.*

vi. Open Season Procedural Timeframes (GT&C Sections 9 and 10)

131. GT&C sections 9 and 10 do not specify time limits within which Pacific Connector must evaluate and determine the best bids, or within which it must notify either the prearranged shipper or ROFR shipper of its determination. Similarly, although the ROFR shipper must execute a service agreement within five days after receiving notification that it has been awarded capacity, there is no deadline by which Pacific Connector must proffer the agreement for execution. Pacific Connector is directed to state deadlines for such actions that are within the range of deadlines previously approved by the Commission.

vii. Reserved Capacity (GT&C Section 9.10)

132. GT&C section 9.10 provides that Pacific Connector may reserve capacity for expansion projects. This proposal is generally consistent with Commission policy. However, pipelines considering an expansion project involving reserved capacity must offer existing shippers the opportunity for a non-binding solicitation of turned-back capacity, so that any turned back capacity may substitute for the expansion capacity, thereby minimizing the size of the expansion.[235] The solicitation of turned-back capacity should occur either as part of, or close in time to, the open season for the expansion project, since that is when the size of the project is being assessed. Therefore, Pacific Connector is directed to incorporate a turnback solicitation process into its capacity reservation proposal consistent with Commission policy.

d. Fuel Reimbursement Tracking Mechanism (GT&C Section 17)

133. Pacific Connector proposes in-kind recovery of gas used for fuel in providing transportation service and L&U gas, by retaining a percentage of receipts. Pacific Connector states that it will make semi-annual fuel tracker filings pursuant to section 4 of the NGA to adjust its fuel reimbursement percentage, and will annually true-up any

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[234] *Transcontinental Gas Pipe Line Corp.*, 105 FERC ¶ 61,365, at P 20 (2003) (*Transco II*).

[235] *Florida Gas Transmission Co., LLC*, 136 FERC ¶ 61,008, at P 26 (2011); *Iroquois Gas Transmission Sys.*, 100 FERC ¶ 61,279, at P 8 (2002).

differences between the fuel retained from shippers and the actual fuel consumed and L&U.[236]

134. GT&C section 17 sets forth Pacific Connector's fuel tracking mechanism, which also includes a surcharge for tracking and reconciling the difference between actual and retained fuel use and L&U gas. GT&C section 17.3(b) states that at least thirty days prior to the effective date of each fuel adjustment filing, "Transporter shall file with the Commission and post, as defined by 18 CFR § 159.2(d) (sic), a schedule of the effective Fuel Reimbursement Percentage. With respect to the adjustment described herein, *such filing shall be in lieu of any other rate change filing required by the Commission's regulations under the Natural Gas Act.*" (Emphasis added).

135. GT&C section 17 is generally consistent with Commission precedent, except for GT&C section 17.3(b). The emphasized language quoted above could be interpreted as permitting Pacific Connector to adjust its fuel reimbursement percentage only by posting and filing with the Commission a schedule of such changes, rather than, as represented in its application, making a limited NGA section 4 rate filing that proposes and supports such changes, thereby giving shippers an opportunity to review and challenge the basis for the changes. Fuel retention charges are rates under the NGA. Posting and filing changed rates cannot be in lieu of any other rate change filing proposal required by NGA section 4. Pacific Connector is directed to revise GT&C section 17.3(b) to be consistent with Commission precedent.[237]

e. <u>Imbalances (GT& C Section 22)</u>

136. GT&C section 22.4 defines a shipper imbalance as the difference between the "aggregate Scheduled Quantity for receipt, net of the associated Fuel Reimbursement, under a Shipper's Service Agreement on any Gas Day and the aggregate Scheduled Quantity for delivery under such Service Agreement on such Gas Day." The Commission has held that imbalance calculations should be based on the difference between actual rather than scheduled volumes.[238] Pacific Connector is directed to revise GT&C section 22.4 accordingly.

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[236] Pacific Connector's Application at 27.

[237] *See Rover Pipeline LLC*, 158 FERC ¶ 61,109, at P 140 (2017).

[238] *Algonquin Gas Transmission Co.*, 62 FERC ¶ 61,132, at 61,892 (1993); *Texas Eastern Transmission Corp.*, 62 FERC ¶ 61,015, at 61,117 (1993).

f. Imbalances and Penalties (GT&C Section 22)

137. GT&C section 22.1 provides in part that "Transporter *may in its discretion* enter into [Operational Balancing Agreements (OBAs)] with upstream and downstream interconnecting parties (hereinafter referred to as an 'OBA Party')." (Emphasis added). Further, GT&C section 22.1 lists five conditions under which Pacific Connector would have no obligation to negotiate and execute OBAs with any OBA Party. However, North American Energy Standards Board (NAESB) Wholesale Gas Quadrant (WGQ) Flowing Gas Related Standard 2.3.29 provides that "[a]t a minimum, [pipeline] should enter into [OBAs] at all pipeline-to-pipeline (interstate and intrastate) interconnects." In addition, section 284.12(b)(2)(i) of the Commission's regulations provides that "[a] pipeline *must* enter into [OBAs] at all points of interconnection between its system and the system of another interstate or intrastate pipeline." (Emphasis added). Accordingly, Pacific Connector is directed to revise its tariff to comply with NAESB WGQ Flowing Gas Related Standard 2.3.29 and section 284.12(b)(2)(i) of the Commission's regulations.[239]

g. Interruptible Revenue Credits (GT&C Section 26)

138. The Commission's policy regarding new interruptible services requires either a 100 percent crediting of the interruptible revenues, net of variable costs, to maximum rate firm and interruptible customers or an allocation of costs and volumes to these services.[240] Moreover, the Commission has clarified that a pipeline and its negotiated rate customers may agree in their contracts to allow for crediting and sharing of a proportionate amount of interruptible revenues collected by the pipeline, subject to eligible recourse rate shippers receiving a proportionate share of 100 percent of the interruptible revenues collected.[241]

139. Pacific Connector does not propose to allocate any costs to interruptible service. Instead, GT&C section 26 provides for an interruptible revenue crediting mechanism, and states in part:

> 26.1 Applicability
>
> Transporter will credit to eligible Shippers all revenue it receives under Rate Schedule IT-1 during a calendar year, <u>net of any incremental cost-of-</u>

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[239] 18 C.F.R. § 284.12(b)(2)(i) (2019). With these changes, the five conditions under which Pacific Connector would have no obligation to negotiate and execute OBAs will not be applicable to an interconnection with another interstate or intrastate pipeline.

[240] *Corpus Christi,* 149 FERC ¶ 61,283, at P 38.

[241] *Wyoming Interstate Co., Ltd.*, 121 FERC ¶ 61,135, at P 11 (2007) (*Wyoming*).

> service incurred to generate such revenues, *that is in excess of any shortfall during such calendar year in Transporter's recovery of the Commission-approved cost-of-service level for Rate Schedule FT-1 design capacity underlying its currently effective Recourse Rates* which is not contractually committed under Negotiated Rates. The Shippers eligible to be credited a share of any such excess interruptible revenue are all Shippers with Service Agreements under Rate Schedule FT-1 and Rate Schedule IT-1 for service at the maximum Recourse Rate ("Eligible Recourse Rate Shippers") and Shippers with Service Agreements under Rate Schedule FT-1 for service at a Negotiated Rate ("Eligible Negotiated Rate Shippers").
>
> 26.2 Allocation and Distribution of Credits
>
> Eligible Recourse Rate Shippers will be allocated pro rata shares based on amounts paid to Transporter of Transporter's excess interruptible revenue based on revenues received by Transporter during the calendar year under each Eligible Recourse Rate Shipper's Service Agreement, *net of credits from Capacity Releases. Unless otherwise provided in an Eligible Negotiated Rate Shipper's Service Agreement, Eligible Negotiated Rate Shippers will be allocated fifty percent (50%) of their pro rata shares of Transporter's excess interruptible revenue based on revenues received by Transporter during the calendar year under each Eligible Negotiated Rate Shipper's Service Agreement, and Transporter shall retain the remaining fifty percent (50%).* (Emphasis added).

140. In GT&C section 26.1 quoted above, the underlined phrase is unclear and could be interpreted as reducing creditable revenues by more than the reduction for variable costs allowed under the above-stated Commission policy. Moreover, the italicized language in GT&C section 26.1 implies that Pacific Connector could delay crediting interruptible revenues until it meets the revenue requirements associated with recourse rate service. The Commission has prohibited pipelines from making the crediting of interruptible revenues contingent on recovering the revenue requirements underlying their firm service rates.[242] Therefore, Pacific Connector should revise GT&C section 26.1 by deleting the underlined and italicized language above. Also, if Pacific Connector believes that it will not be able to meet its revenue requirements, it has the option to file an NGA section 4 rate case to address that issue.

141. In addition, the Commission has held that a pipeline may agree to provide shippers paying negotiated rates with interruptible revenue credits after eligible recourse rate shippers have been credited with 100 percent of interruptible revenues net of variable

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[242] *Sonora Pipeline, LLC*, 120 FERC ¶ 61,032, at P 28 (2007).

costs.[243] However, negotiated rate shippers may receive such credits as a component of an individually negotiated rate rather than by virtue of the Commission's policy on interruptible revenue crediting. Accordingly, as provisions of a negotiated rate, such credits are required to be reported in a negotiated rate tariff filing. Therefore, we direct Pacific Connector to remove from GT&C section 26.1 all references to the eligibility of negotiated rate shippers to receive interruptible revenue credits, and also the italicized language above from GT&C section 26.2.

h. NAESB WGQ Standards (GT&C Section 27)

142. GT&C section 27.1 implements the NAESB WGQ Version 3.0 business practice standards that the Commission incorporated by reference in its regulations. In the time since Pacific Connector filed its proposed tariff in this proceeding, the Commission amended its regulations to incorporate by reference, with certain enumerated exceptions, the NAESB WGQ Version 3.1 business practice standards.[244] Thus, we direct Pacific Connector to filed revised tariff records, no less than 30 days prior to its in-service date, implementing the NAESB WGQ Version 3.1 business practice standards or, if applicable, the latest future version of the NAESB WGQ standards adopted by the Commission. Further, Pacific Connector is directed to revise its tariff to:

> (1) Revise GT&C section 15.2(b), Nomination, Confirmation and Scheduling Timelines – Evening Nomination Cycle (time on Day prior to flow Day), to provide that "Scheduled Quantities available to Shippers and point operators, including bumped parties (notice to bumped parties): 9:00 P.M.;"
>
> (2) Include a new section GT&C 15.2(d), Nomination, Confirmation and Scheduling Timelines, to provide that for purposes of GT&C sections 15.2(b) and (c), the word "provides" shall mean, for transmittals pursuant to NAESB WGQ Standards 1.4.x, receipt at the designated site, and for purposes of other forms of transmittal, it shall mean send or post;
>
> (3) Change the reference from standard "1.3.2(i-v)" to "1.3.2(i-vi)" in the section titled "Standards not Incorporated by Reference and their Location

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[243] *Wyoming*, 121 FERC ¶ 61,135 at P 11.

[244] *Standards for Business Practices of Interstate Natural Gas Pipelines,* Order No. 587-Y, 165 FERC ¶ 61,109 (2018). Under Order No. 587-Y, interstate natural gas pipelines are required to file compliance filings with the Commission by April 1, 2019, and are required to comply with the Version 3.1 standards incorporated by reference in this rule on and after August 1, 2019.

in the Tariff:" in GT&C section 27.1, NAESB WGQ Business Practice Standards;

(4) Change the reference from "Tariff Provision 15.3" to "Tariff Provision 15.2" in the section titled "Standards not Incorporated by Reference and their Location in the Tariff:" in GT&C section 27.1, NAESB WGQ Business Practice Standards;

(5) Change the reference from "GT&C Section 14, Capacity" to "GT&C Section 14, Capacity Release" in the section titled "Standards not Incorporated by Reference and their Location in the Tariff:" in GT&C section 27.1, NAESB WGQ Business Practice Standards;

(6) Add standard "2.3.29" to the section titled "Standards not Incorporated by Reference and their Location in the Tariff:," and identify the tariff record in which the standard is located, in GT&C section 27.1, NAESB WGQ Business Practice Standards;

(7) Change the reference from standard "0.4.1*" to "0.4.4" in the section titled "Location Data Download: - Data Set:" in GT&C section 27.1, NAESB WGQ Business Practice Standards; and

(8) Remove standard "2.3.29" from the section titled "Flowing Gas Related Standards" in GT&C section 27.1, NAESB WGQ Business Practice Standards.

7. Request for Waiver of Segmentation

143. Pacific Connector requests waiver of section 284.7(d) of the Commission's regulations,[245] which requires pipelines to offer shippers the ability to segment their capacity to the extent operationally feasible. Pacific Connector asserts that it is not proposing to offer segmentation rights on its system because segmentation is not operationally feasible, noting that it will receive gas from adjacent, receipt-only interconnections with upstream pipelines and transport the gas to a single delivery point at the Jordan Cove LNG Terminal.[246] Further, Pacific Connector explains that there are no intermediate points on its system between its two receipt points near Malin and its sole delivery point. Pacific Connector contends that the Commission has granted waiver of segmentation for similarly structured pipelines. In addition, Pacific Connector states that, to the extent it becomes capable of providing segmentation in the future and a party

[245] 18 C.F.R. § 284.7(d).

[246] Pacific Connector's Application at 28.

requests segmentation, it will consider such request.[247] Finally, Pacific Connector notes that Jordan Cove, as the sole anchor shipper, has not requested segmentation.

144. Based on Pacific Connector's proposed configuration, we will grant Pacific Connector a limited waiver from implementing segmentation on its system. The Commission has held that segmentation of the type contemplated by the regulations is not feasible on a pipeline that has only one delivery point, because there is no way for two transactions to simultaneously occur using different receipt and delivery points, as required for segmentation.[248] If additional points are added to its system that would make segmentation feasible, Pacific Connector must file new or revised tariff records in accordance with the Commission's regulations to provide for segmentation and flexible point rights.

8. Non-conforming Provisions

145. As noted above, Pacific Connector executed two precedent agreements with Jordan Cove, as the Pacific Connector's anchor shipper, for 95.8 percent of the pipeline's capacity. According to Pacific Connector, the precedent agreements require Jordan Cove to execute corresponding Firm Transportation Agreements and Negotiated Rate Agreements. Pacific Connector states that those agreements differ in certain aspects from the *pro forma* Rate Schedule FT-1 transportation service agreement in its tariff. Pacific Connector requests that the Commission approve these non-conforming provisions.

146. Specifically, Pacific Connector requests approval of the following non-conforming provisions:

- in both agreements, creditworthiness provisions that differ from the tariff;
- in one of the agreements, a provision allowing Jordan Cove to extend the term of the agreement for two additional ten-year periods;
- in one of the agreements, an evergreen provision with a one-month rollover period; and

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[247] *Id.* at 28 n.37.

[248] *Venice Gathering Sys., L.L.C.*, 98 FERC ¶ 61,234 (2002); *Gulf States Transmission Corp.*, 96 FERC ¶ 61,159, at 61,693 (2001).

- in both agreements, a provision that Jordan Cove's aggregate firm daily quantity at primary receipt points may exceed Jordan Cove's contract demand.[249]

147. Pacific Connector asserts that none of these provisions are unduly discriminatory, and that, under the Commission's existing policy, project sponsors are permitted to provide rate incentives to anchor shippers on a number of grounds. Pacific Connector states that the Commission regularly approves separate credit provisions applicable to anchor shippers because of the financial commitment involved in construction of new facilities. In addition, Pacific Connector notes that the Commission has approved non-conforming provisions giving extension and rollover rights to anchor customers, again in recognition of their early commitment that enables new projects to move forward. Pacific Connector argues that the Commission should approve the provision related to aggregate primary receipt point rights because pipelines regularly allow such excess receipt point rights. Finally, Pacific Connector maintains that because no shipper is similarly situated to Jordan Cove, there is no risk of undue discrimination.[250]

148. If a pipeline and a shipper enter into a contract that materially deviates from the pipeline's form of service agreement, the Commission's regulations require the pipeline to file the contract containing the material deviations with the Commission.[251] In *Columbia Gas Transmission Corp.* (*Columbia II*), the Commission clarified that a material deviation is any provision in a service agreement that: (1) goes beyond filling in the blank spaces with the appropriate information allowed by the tariff; and (2) affects the substantive rights of the parties.[252] The Commission prohibits negotiated terms and conditions of service that result in a shipper receiving a different quality of service than that offered other shippers under the pipeline's generally applicable tariff or that affect the quality of service received by others.[253] However, not all material deviations are impermissible. As the Commission explained in *Columbia II*, provisions that materially deviate from the corresponding *pro forma* agreement fall into two general categories: (1) provisions the Commission must prohibit because they present a significant potential

[249] Pacific Connector's Application at 29.

[250] *Id.* at 30.

[251] 18 C.F.R. §§ 154.1(d), 154.112(b).

[252] *Columbia Gas Transmission Corp.,* 97 FERC ¶ 61,221, at 62,002 (2001) (*Columbia II*).

[253] *Monroe Gas Storage Co., LLC*, 130 FERC ¶ 61,113, at P 28 (2010).

for undue discrimination among shippers; and (2) provisions the Commission can permit without a substantial risk of undue discrimination.[254]

149. The Commission finds that the identified non-conforming provisions in Jordan Cove's precedent agreements do constitute material deviations from Pacific Connector's *pro forma* form of FT-1 service agreement. However, in other proceedings, the Commission has found that non-conforming provisions may be necessary to reflect the unique circumstances involved with the construction of new infrastructure and to provide the needed security to ensure the viability of a project.[255] We find the non-conforming provisions identified by Pacific Connector are permissible because they do not present a risk of undue discrimination, do not adversely affect the operational conditions of providing service, and do not result in any customer receiving a different quality of service.[256] As discussed further below, when Pacific Connector files its non-conforming service agreements, we require Pacific Connector to identify and disclose all non-conforming provisions or agreements affecting the substantive rights of the parties under the tariff or service agreement. This required disclosure includes any such transportation provision or agreement detailed in a precedent agreement that survives the execution of the service agreement.

150. At least 30 days, but not more than 60 days, before providing service to any project shipper under a non-conforming agreement, Pacific Connector must file an executed copy of the non-conforming agreement and identify and disclose all non-conforming provisions or agreements affecting the substantive rights of the parties under the tariff or service agreement. Consistent with section 154.112 of the Commission's regulations, Pacific Connector must also file a tariff record identifying the agreements as non-conforming agreements.[257] In addition, the Commission emphasizes that the above determination relates only to those items publicly included by Pacific Connector in its application and not to the entirety of the corresponding precedent agreement or transportation service agreement.[258]

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[254] *Columbia II*, 97 FERC at 62,003-04; *see also Equitrans, L.P.*, 130 FERC ¶ 61,024, at P 5 (2010).

[255] *See, e.g.*, *Tennessee Gas Pipeline Co., L.L.C*, 144 FERC ¶ 61,219 (2013); *Midcontinent Express Pipeline LLC*, 124 FERC ¶ 61,089 (2008).

[256] *See, e.g.*, *Columbia Gulf Transmission, LLC*, 152 FERC ¶ 61,214; *Transcontinental Gas Pipe Line Co., LLC*, 145 FERC ¶ 61,152, at P 34 (2013).

[257] 18 C.F.R. § 154.112.

[258] A Commission ruling on non-conforming provisions in a certificate proceeding does not waive any future review of such provisions when the executed copy of the non-

9. Accounting

151. Allowance for Funds Used During Construction (AFUDC) is a component of the overall construction cost for Pacific Connector's facilities. Gas Plant Instruction No. 3(17) of the Commission's accounting regulations prescribes a formula for determining the maximum amount of AFUDC that may be capitalized.[259] That formula, however, is not applicable here as it uses prior year book balances and cost rates of borrowed and other capital that either do not exist or could produce inappropriate results for initial construction projects of newly created entities such as Pacific Connector. Accordingly, to ensure that AFUDC is properly capitalized for this project, we will require Pacific Connector to capitalize the actual costs of borrowed and other funds for construction purposes, not to exceed the amount of AFUDC that would have been capitalized using the approved overall rate of return.[260]

V. Environmental Analysis

152. To satisfy the requirements of the National Environmental Policy Act of 1969 (NEPA),[261] Commission staff evaluated the potential environmental impacts of the proposed projects in an EIS. Several entities participated as cooperating agencies in the preparation of the EIS: the U.S. Department of the Interior, Bureau of Land Management (BLM), Bureau of Reclamation (Reclamation), and Fish and Wildlife Service (FWS); U.S. Department of Agriculture, Forest Service (Forest Service); DOE; U.S. Army Corps of Engineers (Corps); U.S. Environmental Protection Agency (EPA); U.S. Department of Commerce, National Oceanic and Atmospheric Administration, National Marine Fisheries Services (NMFS); U.S. Department of Homeland Security, Coast Guard (Coast Guard); PHMSA; and the Coquille Indian Tribe. Cooperating agencies have jurisdiction by law or special expertise with respect to resources potentially affected by the proposals and participate in the NEPA analysis.

153. On March 29, 2019, Commission staff issued a draft EIS addressing issues raised up to the point of publication. Notice of the draft EIS was published in the Federal

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conforming agreement(s) and a tariff record identifying the agreement(s) as non-conforming are filed with the Commission, consistent with section 154.112 of the Commission's regulations. *See, e.g.*, *Tennessee Gas Pipeline Co., L.L.C.*, 150 FERC ¶ 61,160, at P 44 n.33 (2015).

[259] 18 C.F.R. pt. 201 (2019).

[260] *See Weaver's Cove Energy, LLC.*, 112 FERC ¶ 61,070 (2005).

[261] 42 U.S.C. §§ 4321 *et seq.* (2018). *See also* the Commission's NEPA-implementing regulations at Title 18 of the Code of Federal Regulations, Part 380.

Register on April 5, 2019, establishing a 90-day comment period ending on July 5, 2019.[262] Commission staff held four public comment sessions[263] between June 24 and June 27, 2019, to receive comments on the draft EIS.[264] Between issuance of the draft EIS and the end of the comment period on July 5, 2019, the Commission received 1,449 individual comment letters[265] from federal, state, and local agencies; Native American tribes; elected officials; companies/organizations; and individuals in response to the draft EIS.[266]

154. On November 15, 2019, Commission staff issued the final EIS for the projects, which addresses all substantive environmental comments received on the draft EIS.[267] The final EIS addresses geology; soils; water resources; wetlands; vegetation; wildlife and aquatic resources; threatened, endangered, and other special status species; land use; recreation and visual resources; socioeconomics; transportation; cultural resources; air quality and noise; reliability and safety; cumulative impacts; and alternatives.

155. The final EIS concludes that construction and operation of the projects would result in temporary, long-term, and permanent environmental impacts. Many of these impacts would not be significant or would be reduced to less-than-significant levels with the implementation of the applicants' proposed and Commission staff's recommended avoidance, minimization, and mitigation measures, which are included as conditions in the appendix to this order. However, some of the environmental impacts would be significant. Specifically, simultaneous construction of the Jordan Cove LNG Terminal and the Pacific Connector Pipeline would result in temporary but significant impacts on the short-term housing market in Coos County; construction of the Jordan Cove LNG Terminal would result in temporary but significant noise impacts in the Coos Bay area; and construction and operation of the Jordan Cove LNG Terminal would result in

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[262] 84 Fed. Reg. 13,648.

[263] Commission staff held the public comment sessions in Coos Bay, Myrtle Creek, Medford, and Klamath Falls, Oregon.

[264] Transcripts for the public comment sessions were placed in the public record for the proceedings.

[265] Some of the filings combined letters from multiple agencies or individuals and are considered one single comment letter for purposes of this total.

[266] The Commission received additional comments on the draft EIS after the close of the comment period, which were addressed in the final EIS to the extent practicable.

[267] Final EIS at Appendix R.

permanent and significant impacts on the visual character of Coos Bay.[268] Additionally, Commission staff determined that construction and operation of the Jordan Cove LNG Terminal and the Pacific Connector Pipeline would adversely affect federally listed threatened and endangered species, including the marbled murrelet, northern spotted owl, and coho salmon, and would likely adversely affect critical habitat designated for some species. Additionally, construction of the projects would adversely affect historic properties.

156. Between issuance of the final EIS and December 31, 2019, the Commission received comments on the final EIS from the applicants, two individuals, the Pacific Fishery Management Council, EPA, Oregon Department of Justice (on behalf of certain Oregon state agencies), and the Cow Creek Band of Umpqua Tribe of Indians.[269] In addition, on February 20, 2020, the Oregon Department of Land Conservation and Development (Oregon DLCD) filed its federal consistency determination pursuant to the Coastal Zone Management Act (CZMA), which discussed its findings regarding the direct, indirect, and cumulative effects of the projects on the coastal zone. The comments on the final EIS and Oregon DLCD's comments, the major environmental issues addressed in the final EIS, and a variety of issues relating to the NEPA process, scope of the EIS, and conditional certificates are all discussed below.

A. Issues Relating to the NEPA Process, Scope of the EIS, and Conditional Certificates

1. Arguments Regarding the NEPA Process

157. We received several comments, including a motion filed by affected landowners, concerning the NEPA process. First, a number of entities requested an extension of the draft EIS comment period.[270] The Commission's standard draft EIS comment period is 45 days, which is consistent with the Council for Environmental Quality's (CEQ) regulations implementing NEPA.[271] However, to accommodate the needs of BLM and

[268] The final EIS also determined that operation of the Jordan Cove LNG Terminal could significantly impact the Southwest Oregon Regional Airport. Based on determinations made by the FAA after issuance of the final EIS, we no longer conclude the project could significantly impact the airport. *See infra* PP 244- 247.

[269] During this time, the Commission also received courtesy copies of comments filed to other federal and state agencies with permitting authority over the proposals. Those comments are not addressed below.

[270] *See, e.g.*, April 19, 2019 Landowner Motion at 3.

[271] 40 C.F.R. § 1506.10(c) (2019).

the Forest Service, Commission staff issued the draft EIS for the Jordan Cove LNG Terminal and Pacific Connector Pipeline with a 90-day comment period. We feel that 90 days was sufficient time to review and comment on the draft EIS. Moreover, as noted above, in preparing the final EIS, Commission staff considered late-filed comments on the draft EIS to the extent practicable.[272]

158. Second, commenters also took issue with the Commission not providing paper copies of the draft EIS to landowners and other entities interested in reviewing the document.[273] The Commission mailed a copy of the Notice of Availability of the draft EIS to federal, state, and local government representatives and agencies; elected officials; environmental and public interest groups; Indian Tribes; potentially affected landowners and other interested individuals and groups; and newspapers and libraries in the area of the projects. This notice explained that the draft EIS was available in electronic format on the Commission's website. In addition, paper copies of the draft EIS were made available for inspection in public libraries in Coos, Douglas, Jackson, and Klamath Counties. The Commission is not required, pursuant to NEPA or the Commission's regulations, to provide paper copies of the draft EIS.

159. Lastly, some commenters allege that the draft EIS was deficient because it contained errors[274] or because it had "substantial information gaps"[275] that precluded meaningful public participation in the NEPA process. Commenters contend that examples of missing or incomplete information in the draft EIS include Commission staff's Biological Assessment (prepared to initiate formal consultation with FWS and NMFS under the Endangered Species Act),[276] incomplete or draft plans regarding

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[272] *See supra* note 266.

[273] *See, e.g.*, April 19, 2019 Landowner Motion at 10.

[274] *See id.* at 4-7.

[275] *See, e.g.*, Snattlerake's July 5, 2019 Comments at 17.

[276] *See, e.g.*, Western Environmental Law Center, et al.'s (jointly filed) July 3, 2019 Comments at 289-90 (WELC's July 3, 2019 Comments). While we acknowledge that Commission staff's Biological Assessment was not available for review during the draft EIS comment period, it was placed in the public record (and submitted to FWS and NMFS) shortly after the close of the comment period. Parties were free to comment on the document once it became available in the record. As noted above, in the final EIS Commission staff considered late-filed comments on the draft EIS, to the extent practicable, and we are considering comments filed on the final EIS in this order to the extent practicable. While WELC points out what it alleges is a procedural error, it does

mitigation,[277] and forthcoming authorizations from other agencies.[278] Some commenters argue that a corrected or supplemental draft EIS should have been issued for comment.[279]

160. The draft EIS is a draft of the agency's proposed final EIS and, as such, its purpose is to elicit suggestions for change. A draft is adequate when it allows for "meaningful analysis" and "make[s] every effort to disclose and discuss" major points of view on the environmental impacts.[280] NEPA does not require a complete mitigation plan be actually formulated at the onset, but only that the proper procedures be followed for ensuring that the environmental consequences have been fairly evaluated.[281] In addition, NEPA does not require every study or aspect of an analysis to be completed before an agency can issue a final EIS, and the courts have held that agencies do not need perfect information before it takes any action.[282]

161. The final EIS identified baseline conditions for all relevant resources. Final mitigation plans will not present new environmentally significant information nor pose

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not demonstrate how the complained of action in any way precluded it from commenting in full on the issues in this proceeding.

[277] *See, e.g.*, WELC's July 3, 2019 Comments at 14-15; Snattlerake's July 5, 2019 Comments at 18-19.

[278] *See, e.g.*, Natural Resources Defense Council's July 5, 2019 Motion to Intervene and Comments at 45 (NRDC's July 5, 2019 Comments).

[279] *See, e.g.*, April 19, 2019 Landowner Motion at 15-16; WELC July 3, 2019 Comments at 299.

[280] 40 C.F.R. § 1502.9(a) (2019); *see also Nat'l Comm. for the New River, Inc. v. FERC*, 373 F.3d 1323, 1328 (D.C. Cir. 2004) (*Nat'l Comm. for the New River*) (holding that FERC's draft EIS was adequate even though it did not have a site-specific crossing plan for a major waterway where the proposed crossing method was identified and thus provided "a springboard for public comment") (quoting *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 349 (1989) (*Methow Valley Citizens Council*)).

[281] *See Methow Valley Citizens Council*, 490 U.S. at 352-53.

[282] *U.S. Dep't of the Interior v. FERC*, 952 F.2d 538, 546 (D.C. Cir. 1992); *State of Alaska v. Andrus*, 580 F.2d 465, 473 (D.C. Cir. 1978), *vacated in part sub nom. W. Oil & Gas Ass'n v. Alaska*, 439 U.S. 922 (1978) ("NEPA cannot be 'read as a requirement that [c]omplete information concerning the environmental impact of a project must be obtained before action may be taken.'") (quoting *Jicarilla Apache Tribe of Indians v. Morton*, 471 F.2d 1275, 1280 (9th Cir. 1973)).

substantial changes to the proposed action that would otherwise require a supplemental EIS. As we have explained in other cases, practicalities require the issuance of orders before completion of certain reports and studies because large projects, such as this, take considerable time and effort to develop.[283] Perhaps more important, their development is subject to many variables whose outcomes cannot be predetermined. Accordingly, post-certification studies may properly be used to develop site-specific mitigation measures.[284]

162. As discussed further below, the final EIS recommends, and we require in this order, that the applicants not commence construction of the projects until they provide certain outstanding information[285] and confirm they have received all applicable authorizations required under federal law.[286]

163. We also disagree that there was a need to issue a revised draft EIS. CEQ regulations require agencies to prepare supplements to either draft or final EISs if: (i) the agency makes substantial changes to the proposed action that are relevant to environmental concerns; or (ii) there are significant new circumstances or information relevant to environmental concerns and bearing on the proposed action or its impact.[287] Here, the final EIS, which incorporates comments filed on the draft EIS, contains ample information for the Commission to fully consider and address the environmental impacts associated with the Jordan Cove LNG Terminal and Pacific Connector Pipeline. The additional material in the final EIS relates to issues discussed in

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[283] *See, e.g.*, *Algonquin Gas Transmission, LLC*, 154 FERC ¶ 61,048, at P 94 (2016)*; East Tennessee Natural Gas Co.*, 102 FERC ¶ 61,225, at P 23 (2003), *aff'd sub nom. Nat'l Comm. for the New River*, 373 F.3d 1323.

[284] In some instances, the certificate holder may need to access property in order to obtain the necessary information. *Midwestern Gas Transmission Co.*, 116 FERC ¶ 61,182, at P 92 (2006).

[285] For example, Environmental Condition 17 requires Pacific Connector to file an updated landslide identification study prior to beginning construction of the Pacific Connector Pipeline. The study must identify specific mitigation that will be implemented for any previously unidentified moderate or high-risk landslide areas of concern, as well as the final monitoring protocols and/or mitigation measures for all landslide areas that were not accessible during previous studies.

[286] *See* Environmental Condition 11.

[287] 40 C.F.R. § 1502.9(c) (2019).

the draft EIS and does not result in any significant modification of the projects that would require additional public notice or issuance of a revised draft EIS for further comment.

164. Based on the above, we find that the Commission has provided the public a meaningful opportunity to participate in the NEPA process (as well as our larger application review process) and doing so has resulted in an informed Commission decision. Accordingly, we deny the motion seeking an order requiring correction of the draft EIS, the dissemination of paper copies, and an extension of comment period filed jointly by several landowner-intervenors on April 19, 2019.[288]

2. Arguments Regarding the Scope of Analysis in the EIS

a. Programmatic EIS

165. Several commenters argue that the Commission must prepare a programmatic EIS for all LNG export proposals "already approved, in line for approval or in the planning stages to be approved."[289] CEQ's regulations implementing NEPA do not require broad or "programmatic" NEPA reviews. In guidance, CEQ has stated that such a review may be appropriate where an agency is: (1) adopting official policy; (2) adopting a formal plan; (3) adopting an agency program; or (4) proceeding with multiple projects that are temporally or spatially connected.[290]

166. As the Commission has previously explained, there is no Commission program, plan, or policy with respect to export of natural gas (a matter within DOE's ambit) or the development of LNG terminals.[291] The mere fact that there are a number of approved, proposed, or planned LNG export projects does not evidence the existence of a regional plan or policy of the Commission. Instead, this information confirms that such development is initiated solely by a number of different companies in private industry.

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[288] *See supra* note 190.

[289] *See, e.g.*, Ronald Crete's July 1, 2019 Comments at 3; *see also* Citizens Against LNG Inc. and Jody McCaffree's (jointly filed) November 13, 2017 Comments at 1.

[290] Memorandum from CEQ to Heads of Federal Departments and Agencies, *Effective Use of Programmatic NEPA Reviews* 13-15 (Dec. 24, 2014), https://ceq.doe.gov/docs/ceq-regulations-and-guidance/Effective_Use_of_Programmatic_NEPA_Reviews_Final_Dec2014_searchable.pdf.

[291] *See Magnolia LNG, LLC*, 157 FERC ¶ 61,149, at P 17 (2016) (citing *Corpus Christi Liquefaction, LLC*, 151 FERC ¶ 61,098, at PP 24-31 (2015); *Cameron LNG, LLC*, 147 FERC ¶ 61,230, at PP 70-72 (2014)).

As the Supreme Court held in in *Kleppe v. Sierra Club*,[292] a programmatic EIS is not required to evaluate the regional development of a resource by private industry if the development is not part of, or responsive to, a federal plan or program in that region.[293]

167. While the Commission's practice is to consider each LNG export project application on its own merits, we may, however, choose to prepare a multi-project environmental document regarding projects that are closely related in time or geography, where that is the most efficient way to review project proposals,[294] and the Commission's NEPA documents do consider the cumulative impacts of other projects in the same geographic and temporal scope as the proposal under consideration. Here are no proposed LNG export terminal proposals in the same geographic area and temporal scope as the Jordan Cove LNG Terminal, so that preparing a programmatic EIS would not assist in our decision making. Thus, we find a programmatic EIS is neither required nor useful under the circumstances here.

b. <u>Lifecyle Evaluation of Impacts</u>

168. A number of commenters assert that the Commission must provide a lifecycle evaluation of environmental impacts, namely emissions, associated with the projects.[295] Although the Commission did provide direct emissions estimates associated with construction and operation of the Jordan Cove LNG Terminal and Pacific Connector Pipeline,[296] commenters ague the Commission must also analyze indirect impacts associated with upstream production and downstream end use.[297]

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[292] 427 U.S. 390 (1976).

[293] *Id.* at 401-02.

[294] *See* 40 C.F.R. § 1508.25 (2019); *see also, e.g.*, EA for the Monroe to Cornwell Project and the Utica Access Project, Docket Nos. CP15-7-000 & CP15-87-000 (filed Aug. 19, 2015); Final Multi-Project Environmental Impact Statement for Hydropower Licenses: Susquehanna River Hydroelectric Projects, Project Nos. 1888-030, 2355-018, and 405-106 (filed Mar. 11, 2015).

[295] *See, e.g.*, NRDC's July 5, 2019 Comments at 61-70.

[296] *See infra* P 259.

[297] *See, e.g.*, NRDC's July 5, 2019 Comments at 61-70.

169. Indirect effects are defined as those "which are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable."[298] Accordingly, to determine whether an impact should be studied as an indirect impact, the Commission must determine whether it is: (1) caused by the proposed action; and (2) reasonably foreseeable.[299]

170. Courts have found that an impact is reasonably foreseeable if it is "sufficiently likely to occur that a person of ordinary prudence would take it into account in reaching a decision."[300] Although NEPA requires "reasonable forecasting,"[301] an agency "is not required to engage in speculative analysis"[302] or "to do the impractical, if not enough information is available to permit meaningful consideration."[303]

171. In *Freeport*,[304] the D.C. Circuit examined the Commission's responsibility to study indirect effects relating to the export of natural gas when exercising its NGA section 3 responsibilities. The court explained that NEPA requires a reasonably close causal relationship between a project and its potential effects and thus the Commission need not "examine everything for which the Projects could conceivably be a but-for cause."[305] The court further found that the "Commission's NEPA analysis did not have to address the indirect effects of the anticipated export of natural gas" "because the Department of Energy, not the Commission has sole authority to license the export of any natural gas going through the Freeport facilities."[306] The court explained that "[i]n the

[298] 40 C.F.R. § 1508.8(b) (2019).

[299] *See id.*; *see also id.* § 1508.25(c).

[300] *EarthReports, Inc. v. FERC*, 828 F.3d at 955 (citations omitted); *see also Sierra Club v. Marsh*, 976 F.2d 763, 767 (1st Cir. 1992).

[301] *N. Plains Res. Council, Inc. v. Surface Transp. Bd.*, 668 F.3d 1067, 1079 (9th Cir. 2011) (quoting *Selkirk Conservation Alliance v. Forsgren*, 336 F.3d 944, 962 (9th Cir. 2003)).

[302] *Id.* at 1078.

[303] *Id.* (quoting *Envtl. Prot. Info. Ctr. v. U.S. Forest Serv.*, 451 F.3d 1005, 1014 (9th Cir. 2006) (internal quotation marks and citation omitted)).

[304] *Freeport*, 827 F.3d 36.

[305] *Id.* at 46.

[306] *Id.* at 47.

specific circumstances where, as here, an agency 'has no ability to prevent a certain effect due to' that agency's 'limited statutory authority over the relevant action[],' then that action 'cannot be considered a legally relevant cause of the effect' for NEPA purposes."[307]

172. Commenters assert, however, that the *Freeport* decision was specific to the Commission's authority under section 3 of the NGA and that the Commission's NGA section 7 authority over pipelines is broader.[308] Specifically, the Western Environmental Law Center (WELC) notes that the D.C. Circuit in *Sabal Trail*[309] differentiated the Commission's authority to consider indirect effects when evaluating NGA section 3 applications and NGA Section 7 applications.[310] Accordingly, commenters assert that *Freeport* does not limit the scope of the Commission's review of the Pacific Connector Pipeline.[311]

173. In particular, commenters argue that the Commission can reasonably foresee the amount and location of additional gas production that the Pacific Connector Pipeline Project may cause.[312] Natural Resources Defense Council (NRDC) argues that the Commission could estimate the number of wells and production methods used based on average production rates and methods, which can be obtained from state databases.[313] Similarly, WELC contends that there are readily available data and tools to estimate the

[307] *Id.* (quoting *Dep't of Transp. v. Public Citizen*, 541 U.S. 752, 770 (2004)). *See also Sabine Pass Liquefaction, LLC*, 146 FERC ¶ 61,117, *reh'g denied*, 148 FERC ¶ 61,200 (2014), *aff'd sub nom. Sierra Club v. FERC*, 827 F.3d 59 (D.C. Cir. 2016); *Dominion Cove Point LNG, LP*, 148 FERC ¶ 61,244 (2014), *reh'g denied*, 151 FERC ¶ 61,095 (2015), *aff'd sub nom. EarthReports, Inc. v. FERC*, 828 F.3d 949 (D.C. Cir. 2016). *See generally Adelphia Gateway, LLC*, 169 FERC ¶ 61,220 (2020) (McNamee, Comm'r, concurrence) (elaborating on the purpose of the NGA).

[308] *See, e.g.*, WELC's July 3, 2019 Comments at 274 (citing *Sabal Trail*, 867 F.3d at 1372-73).

[309] 867 F.3d 1357.

[310] WELC's July 3, 2019 Comments at 274.

[311] *Id.*

[312] *See, e.g.*, WELC's July 3, 2019 Comments at 277.

[313] NRDC's July 5, 2019 Comments at 63.

amount and regions of additional gas production.[314] NRDC and WELC also state that, to the extent information about upstream production is unknown, the Commission should further develop the record.

174. Here, the specific source of natural gas to be transported via the Pacific Connector Pipeline has not been identified with any precision and will likely change throughout the project's operation, as the pipeline will receive gas from other interstate pipelines. As we have previously concluded in other natural gas infrastructure proceedings and affirm with respect to Pacific Connector Pipeline, the environmental effects resulting from natural gas production are generally neither caused by a proposed pipeline project nor are they reasonably foreseeable consequences of our approval of an infrastructure project, as contemplated by CEQ's regulations, where the supply source is unknown.[315] NRDC and WELC provide only general information and ask the Commission to extrapolate the data to determine specific project effects. However, there is no evidence that the information cited would help predict the number and location of any additional wells that would be drilled as a result of any increased production demand associated with the project.[316] Moreover, there is no evidence demonstrating that, absent approval of the project, this gas would not be brought to market by other means. Therefore, we conclude that the environmental impacts of upstream natural gas production are not an indirect effect of the project.[317]

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[314] WELC's July 3, 2019 Comments at 277-78 (citing ICF International, *U.S. LNG Exports: Impacts on Energy Markets and the Economy* (Mar. 2013, Nov. 2013, Sept. 2017); Deloitte MarketPoint, *Analysis of the Economic Impact of LNG Exports from the United States* (Oct. 2012); EIA, *Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets* (Oct. 2014); EIA, *Annual Energy Outlook* (2018, 2019); EIA, *Oil and Gas Supply Module of the National Energy Modeling System* (2018)).

[315] *See, e.g.*, *Cent. N.Y. Oil & Gas Co., LLC*, 137 FERC ¶ 61,121, at PP 81-101 (2011), *order on reh'g*, 138 FERC ¶ 61,104, at PP 33-49 (2012), *petition for review dismissed sub nom. Coal. for Responsible Growth and Res. Conservation v. FERC*, 485 F.App'x. 472, 474-75 (2d Cir. 2012) (unpublished opinion).

[316] *See Sierra Club v. U.S. Dep't of Energy*, 867 F.3d at 200 (accepting DOE's "reasoned explanation" as to why the indirect effects pertaining to induced natural gas production were not reasonably foreseeable where DOE noted the difficulty of predicting both the incremental quantity of natural gas that might be produced and where at the local level such production might occur, and that an economic model estimating localized impacts would be far too speculative to be useful).

[317] *Birckhead v. FERC*, 925 F.3d 510, 517-18 (D.C. Cir. 2019) (holding the Commission did not violate NEPA in not considering upstream impacts where there was

175. With respect to indirect impacts associated with downstream end use, in *Sabal Trail*, the D.C. Circuit held that where it is known that the natural gas transported by a project will be used for a specific end-use combustion, the Commission should "estimate[] the amount of power-plant carbon emissions that the pipelines will make possible."[318] However, outside the context of known specific end use, the D.C. Circuit affirmed in *Birckhead v. FERC*, the fact that "emissions from downstream gas combustion are [not], as a categorical matter, always a reasonably foreseeable indirect effect of a pipeline project."[319]

176. In this case, Pacific Connector has executed two precedent agreements with Jordan Cove for 95.8 percent of the firm capacity available on the pipeline. Jordan Cove will use some of the natural gas at the terminal site to power steam turbine generators: emissions associated with that use are included in the emissions estimate Commission staff provided regarding operation of the Jordan Cove LNG Terminal.[320] However, the majority of the gas delivered to the Jordan Cove LNG Terminal will be liquefied for export. The end-use of the liquefied gas is unknown, and the Commission does not have authority over, and need not address the effects of, the anticipated export of the gas.[321]

c. <u>DOE's Authorization as a "Connected Action"</u>

177. Some commenters allege that even if the Commission's authorizations are not the legally relevant cause of upstream and downstream impacts, these impacts still must be evaluated as part of DOE's approval, which they claim is a "connected action." Arguing that the issue was left unanswered by the court in *Freeport*, WELC contends that the Commission's approval of the siting, construction, and operation of the Jordan Cove LNG Terminal and DOE's authorization of LNG exports from the project are "connected

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no evidence to predict the number and location of additional wells that would be drilled as a result of a project).

[318] *Sabal Trail*, 867 F.3d at 1371.

[319] *Birckhead v. FERC*, 925 F.3d at 519 (citing *Calvert Cliffs' Coordinating Comm., Inc. v. U.S. Atomic Energy Comm'n*, 449 F.2d 1109, 1122 (D.C. Cir. 1971)). The court in *Birckhead* also noted that "NEPA . . . requires the Commission to at least attempt to obtain the information necessary to fulfill its statutory responsibilities," but citing to *Delaware Riverkeeper Network*, the court acknowledged that NEPA does not "demand forecasting that is not meaningfully possible." *Birckhead v. FERC*, 925 at 520 (quoting *Delaware Riverkeeper Network v. FERC*, 753 F.3d 1304, 1310 (D.C. Cir. 2014)).

[320] *See infra* P 259.

[321] *Freeport*, 827 F.3d at 47.

actions," the impacts of which must be fully analyzed in the Commission's EIS.[322] Specifically, WELC asserts that the Commission, as the lead agency responsible for reviewing the environmental effects of the applicants' proposals under NEPA, must ensure that the review consists of impacts of all related approvals, including the indirect effects of both the construction and operation of the Jordan Cove LNG Terminal facilities as well as the export of LNG from those facilities.[323] WELC claims that the projects will increase gas production, increase domestic use of coal, and increase use of natural gas overseas, all of which are foreseeable effects of the Commission's and DOE's authorizations and should be analyzed in the EIS.[324]

178. WELC distorts the concept of "connected actions." The requirement that an agency consider connected actions in a single environmental document is to "prevent agencies from dividing one project into multiple individual actions" with less significant environmental effects[325] and "to prevent the government from 'segmenting' its *own* 'federal actions into separate projects and thereby failing to address the true scope and impact of the activities that should be under consideration.'"[326]

179. Here, the proposals before the Commission are requests to site, construct, and operate the Jordan Cove LNG Terminal and the Pacific Connector Pipeline. These projects were considered together in a single environmental analysis. The export of natural gas from the Jordan Cove LNG Terminal, by contrast, was not a proposal before the Commission because, as the *Freeport* court noted, "[DOE], not the Commission, has

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[322] WELC's July 3, 2019 Comments at 275-76.

[323] *Id.* at 276.

[324] *Id.* at 276-81.

[325] *Myersville Citizens for a Rural Cmty., Inc. v. FERC*, 783 F.3d at 1326 (approving the Commission's determination that, although a Dominion-owned pipeline project's excess capacity may be used to move gas to the Cove Point terminal for export, the projects are "unrelated" for NEPA purposes); *see also City of W. Chicago, Ill. v. U.S. Nuclear Regulatory Comm'n*, 701 F.2d 632, 650 (7th Cir. 1983) (citing *City of Rochester v. U.S. Postal Serv.*, 541 F.2d 967, 972 (2d Cir. 1976)).

[326] *Sierra Club v. U.S. Army Corps of Eng'rs*, 803 F.3d 31, 49-50 (D.C. Cir. 2015) (emphasis added) (quoting *Delaware Riverkeeper Network v. FERC*, 753 F.3d at 1313).

sole authority to license the export of any natural gas going through the [Jordan Cove LNG] facilities."[327]

180. Further, in arguing that DOE's export authorizations are connected actions because the Energy Policy Act of 2005 calls for the Commission to serve as "lead agency" for a coordinated NEPA review, WELC erroneously conflates the CEQ regulations on "connected actions"[328] and "lead agencies."[329] In the Energy Policy Act of 2005, Congress designated the Commission as "the lead agency for the purposes of coordinating all applicable Federal authorizations and for the purposes of complying with the National Environmental Policy Act" for LNG-related authorizations required under section 3 of the NGA.[330] While the lead agency supervises the preparation of the environmental document where more than one federal agency is involved, the "lead agency" designation does not alter the scope of the project before the Commission either for approval or environmental review.[331] Nor does the lead agency role make the Commission responsible for ensuring a cooperating federal agency's compliance with its own NEPA responsibilities.[332] Thus, the Commission did not impermissibly segment its environmental review.

181. In any event, WELC's argument ignores the fact that DOE has authorized Jordan Cove to export up to 395 Bcf per year of natural gas to FTA countries.[333] This volume is equivalent to Jordan Cove LNG Terminal's nameplate capacity of 7.8 MTPA of LNG. Accordingly, the criteria for determining whether the Commission's proceeding is a connected action with the DOE's pending proceeding for additional export authorization

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[327] *See Freeport*, 827 F.3d at 47.

[328] 40 C.F.R. § 1508.25(a)(1).

[329] *Id*. § 1501.5.

[330] *See* 15 U.S.C. § 717n(b)(1); *see also Columbia Riverkeeper v. U.S. Coast Guard*, 761 F.3d 1084, 1087-88 (9th Cir. 2014) (discussing FERC's role as lead agency under the Energy Policy Act of 2005).

[331] *See* 40 C.F.R. § 1501.5(a) (detailing a lead agency's role).

[332] *See* 40 C.F.R. § 1503.3 (cooperating agency required to specify what additional information it needs to fulfill its own environmental review); *see also* 40 C.F.R. § 1506.3 (allowing a cooperating agency to adopt the lead agency's environmental document to fulfill its own NEPA responsibilities if independently satisfied that the environmental document adheres to the cooperating agency's comments and recommendations).

[333] *See supra* note 20.

to non-FTA countries cannot be met.[334] Specifically, the liquefaction project can proceed without obtaining from DOE export authorization to non-FTA countries and so does not depend on obtaining the authorization.[335]

d. Methodology for Assessing Climate Change

182. Some commenters assert that the Commission's NEPA analysis is flawed because the EIS does not use the Social Cost of Carbon, or a similar tool (e.g., the Social Cost of Methane or the Social Cost of Nitrous Oxide), to evaluate climate change impacts.[336] NRDC, WELC, and others assert that the Commission erroneously claims there is no reliable method for evaluating climate impacts.[337] They further argue that the Commission's failure to use the Social Cost of Carbon or a similar methodology renders NEPA's "hard look" requirement unmet.[338]

183. The Social Cost of Carbon has been described as an estimate of the monetized climate change damage associated with an incremental increase in CO_2 emissions in a given year.[339] The Commission has provided extensive discussion on why the Social Cost of Carbon is not appropriate in project-level NEPA review, and cannot meaningfully inform the Commission's decisions on natural gas infrastructure projects under the NGA.[340] We adopt that reasoning here. Moreover, the Commission has explained it does

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[334] *See* 40 C.F.R. § 1508.25(a)(1)(i)-(iii) (defining "connected actions").

[335] *Id.*

[336] *See, e.g.*, NRDC's July 5, 2019 Comments at 70-83; WELC's July 3, 2019 Comments at 267-272; Environmental Defense Fund, Institute for Policy Integrity at New York University School of Law, Montana Environmental Information Center, WELC, and Union of Concerned Scientists' (jointly filed) July 8, 2019 Comments.

[337] NRDC's July 5, 2019 Comments at 70-83; WELC's July 3, 2019 Comments at 268.

[338] *See, e.g.*, NRDC's July 5, 2019 Comments at 73-74.

[339] Interagency Working Group on the Social Cost of Greenhouse Gases, *Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866* at 3 (Aug. 2016), https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf

[340] *Mountain Valley*, 161 FERC ¶ 61,043, at P 296, *order on reh'g*, 163 FERC ¶ 61,197, at PP 275-297 (2018), *aff'd, Appalachian Voices v. FERC*, No. 17-1271, 2019 WL 847199, at *2 (unpublished) ("[The Commission] gave several reasons why it believed petitioners' preferred metric, the Social Cost of Carbon tool, is not an

not use monetized cost-benefit analyses as part of its NEPA review.[341] As discussed further below, there is no universally accepted methodology for evaluating the projects' impacts on climate change.[342]

e. Project Purpose and Need, and Range of Alternatives

184. Several commenters contend that the EIS defined the purpose and need of the projects too narrowly, which led to an insufficient analysis of the alternatives to the projects.[343] An agency's environmental document must include a brief statement of the purpose and need to which the proposed action is responding.[344] An agency uses the purpose and need statement to define the objectives of a proposed action and then to identify and consider legitimate alternatives.[345] CEQ has explained that "[r]easonable alternatives include those that are practical or feasible from the technical and economic standpoint and using common sense, rather than simply desirable from the standpoint of the applicant."[346]

185. Courts have upheld federal agencies' use of applicants' project purpose and need as the basis for evaluating alternatives.[347] When an agency is asked to consider a specific plan, the needs and goals of the parties involved in the application should be taken into

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appropriate measure of project-level climate change impacts and their significance under NEPA or the Natural Gas Act. That is all that is required for NEPA purposes.").

[341] *See Florida Southeast Connection, LLC*, 162 FERC ¶ 61,233, at PP 39-44 (2018).

[342] *See infra* P 261; *see also* final EIS at 4-850.

[343] *See, e.g.*, WELC's July 3, 2019 Comments at 282-83; the Confederated Tribes of Coos, Lower Umpqua, and Siuslaw Indians' July 8, 2019 Comments at 9-10; NRDC's July 5, 2019 Comments at 27.

[344] *See* 40 C.F.R. § 1508.9 (2019) (for an Environmental Assessment); 40 C.F.R. § 1502.13 (2019) (for an EIS).

[345] *See Colo. Envtl. Coal. v. Dombeck*, 185 F.3d 1162, 1175 (10th Cir. 1999).

[346] *Forty Most Asked Questions Concerning CEQ's National Environmental Policy Act Regulations*, 46 Fed. Reg. 18,026-27 (Mar. 23, 1981).

[347] *E.g., City of Grapevine v. U.S. Dep't of Transp.*, 17 F.3d 1502, 1506 (D.C. Cir. 1994).

account.[348] We recognize that a project's purpose and need should not be so narrowly defined as to preclude consideration of what may actually be reasonable alternatives.[349] Nonetheless, an agency need only consider alternatives that will bring about the ends of the proposed action, and the evaluation is "shaped by the application at issue and by the function that the agency plays in the decisional process."[350]

186. For the Jordan Cove LNG Terminal and Pacific Connector Pipeline, the EIS appropriately relied on the applicants' stated purpose and need. We find that doing so did not preordain that the projects as originally proposed were the only way to satisfy the specified purpose and need.[351] In fact, Commission staff identified numerous reasonable alternatives to the projects, which were evaluated in the EIS.[352] As discussed further below, staff found that, with the exception of one pipeline variation, the alternatives analyzed would either not meet the projects' purpose and need, would not be technically feasible, or would not offer a significant environmental advantage.[353]

187. We also reject NRDC's argument that the EIS "fail[ed] to include a true 'no-action' alternative."[354] NRDC claims that there is "no practical difference between the No Action Alternative and the Proposed Action" because the EIS notes that under the no-action alternative, other LNG export projects could be proposed to meet the demand the applicants intend to serve.[355] However, the EIS clearly states that under the no-action

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[348] *Citizens Against Burlington, Inc. v. Busey*, 938 F.2d 190, 196 (D.C. Cir. 1991).

[349] *Id.* at 196.

[350] *Id.* at 199; *see also Sierra Club v. U.S. Forest Serv.*, 897 F.3d 582 (4th Cir. 2018) (finding the statement of purpose and need for a Commission-jurisdictional natural gas pipeline project that explained where the gas must come from, where it will go, and how much the project would deliver, allowed for a sufficiently wide range of alternatives but was narrow enough that there were not an infinite number of alternatives).

[351] The Niskanen Center claims that "FERC has made the DEIS alternatives analysis artificially narrow in order to arrive at a preordained conclusion." Niskanen Center's July 5, 2019 Comments at 42.

[352] *See* final EIS at 3-1 to 3-52.

[353] *See infra* PP 269-272.

[354] NRDC's July 5, 2019 Comments at 32.

[355] *Id.* at 33.

alternative "the proposed action would not occur . . . and as a result, the environment would not be affected."[356] Moreover, the resource-by-resource discussion in section 4 of the final EIS first details the existing state of each resource and then describes the environmental impacts of the preferred alternative.[357] Section 5 of the final EIS summarizes staff's conclusions about those impacts.[358] By providing a description of the existing state of each resource and a description of the environmental impacts of the preferred alternative, the EIS provides the Commission with a meaningful comparison of the harm to be avoided under a no-action alternative.

188. Some commenters state that the EIS failed to evaluate the public benefit or market need for the projects. These commenters conflate the balancing of economic benefits (market need) and effects under the Certificate Policy Statement with the description of the purpose and need in the EIS.[359] The purpose and need statement in the final EIS complied with CEQ's regulations, which provide that this statement "shall briefly specify the underlying purpose and need to which the agency is responding in proposing the alternatives including the proposed actions" for purposes of its environmental analysis.[360] The public interest determinations for the projects and the determination of the need for the pipeline lie with the Commission. Neither NEPA nor the NGA requires the Commission to make its determination of whether a project is required by the public convenience and necessity before its final order. The final EIS appropriately stated that the determination of whether the Pacific Connector Pipeline satisfied a showing of market need according to the Certificate Policy Statement was beyond the scope of the environmental document.[361]

f. <u>Blanket Certificates</u>

189. One commenter suggests that the Commission violated NEPA by not evaluating the environmental impacts associated with Pacific Connector's requested blanket

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[356] Draft EIS at 3-4; final EIS at 3-4.

[357] Final EIS at 4-1 to 4-852.

[358] *Id.* at 5-1 to 5-12.

[359] *See, e.g.*, Niskanen Center's July 5, 2019 Comments at 37-41; Snattlerake's July 5, 2019 Comments at 21-24.

[360] 40 C.F.R. § 1502.13.

[361] *See* draft EIS at 1-18; final EIS at 1-7, 1-19, and R-331 (Appendix R).

certificates.[362] As explained above, a Part 157 blanket certificate gives an interstate pipeline NGA section 7 authority to automatically, or after prior notice, perform a restricted number of routine activities related to the construction, acquisition, abandonment, replacement, and operation of existing pipeline facilities provided the activities comply with constraints on costs and environmental impacts.[363] The blanket certificate authorization was created because the Commission found that a limited set of activities did not require case-specific scrutiny as they would not result in a significant impacts on rates, services, safety, security, competing natural gas companies or their customers, or on the environment.[364]

190. Given that Pacific Connector has not proposed to conduct any activity under a Part 157 blanket certificate, it would be premature for Commission staff to assess the environmental impacts of, or require mitigation for, such potential activities. Commission staff has no information regarding the location, scope, or timing of any potential activity on which to base its environmental review. In the event that Pacific Connector proposes to conduct an activity under its blanket certificate that causes ground disturbance or changes to operational air or noise emissions, Pacific Connector must notify landowners and adhere to the guidance set forth in section 380.15(a) and (b) of the Commission's regulations.[365] The blanket certificate regulations require prior notice in recognition that the projects requiring such notice may raise issues of concern for a pipeline company's existing shippers regarding possible effects on their services or may present valid environmental concerns to individual landowners, or others,

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[362] Francis Eatherington's July 5, 2019 Comments at 3.

[363] *Supra* P 103.

[364] *Revisions to the Blanket Certificate Regulations and Clarification Regarding Rates,* 117 FERC ¶ 61,074, at P 7 (explaining that "[t]he blanket certificate program was designed to provide an administratively efficient means to authorize a generic class of routine activities, without subjecting each minor project to a full, case-specific NGA section 7 certificate proceeding.").

[365] Section 380.15(a) of the Commission's regulations states that siting, construction, and maintenance of facilities shall be undertaken in a way that avoids or minimizes effects on scenic, historic, wildlife, and recreational values; and section 380.15(b) requires a pipeline to take into account the desires of landowners in the planning, location, clearing, and maintenance of rights-of-way and the construction of facilities on their property. 18 C.F.R. § 380.15(a)-(b) (2019).

notwithstanding that the pipeline companies will be able to satisfy all of the blanket certificate regulations' standard conditions.[366]

3. Commission's Practice of Issuing Conditional Certificates

191. Some commenters, including the Oregon Department of Energy and the Oregon DLCD, assert that the Commission should abandon its practice of issuing conditional certificates.[367] The Oregon state agencies claim that conditional orders violate various environmental laws, including the Clean Water Act, the Coastal Zone Management Act, the Clean Air Act, and the Endangered Species Act.[368] Further, the agencies contend that issuing conditional orders precludes the Commission from considering the full extent of the benefits and adverse impacts of a project before making a decision.[369] Other commenters allege that the practice violates NEPA.[370]

192. The Commission's practice of issuing conditional certificates has consistently been affirmed by courts as lawful.[371] The Commission's approach is a practical response

[366] *Equitrans LP*, 158 FERC ¶ 61,103, at P 11 (2017).

[367] As discussed above, *supra* PP 98-101, we find that the Commission's practice of using conditional certificates does not violate the Takings Clause of the Fifth Amendment of the U.S. Constitution.

[368] Oregon Department of Energy's October 26, 2017 Motion to Intervene at 3; Oregon DLCD's October 26, 2017 Motion to Intervene at 3.

[369] Oregon Department of Energy's October 26, 2017 Motion to Intervene at 3-4; Oregon DLCD's October 26, 2017 Motion to Intervene at 3; *see also* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 2.

[370] *See, e.g.*, Scott Jerger's October 19, 2017 Comments at 2.

[371] *See Del. Riverkeeper Network v. FERC*, 857 F.3d at 399 (upholding Commission's approval of a natural gas project conditioned on securing state certification under section 401 of the Clean Water Act); *see also Myersville Citizens for a Rural Cmty., Inc. v. FERC*, 783 F.3d at 1320-21 (upholding the Commission's conditional approval of a natural gas facility construction project where the Commission conditioned its approval on the applicant securing a required federal Clean Air Act air quality permit from the state); *Del. Dep't. of Nat. Res. & Envtl. Control v. FERC*, 558 F.3d 575, 578-79 (D.C. Cir. 2009) (holding Delaware suffered no concrete injury from the Commission's conditional approval of a natural gas terminal construction despite statutes requiring states' prior approval because the Commission conditioned its approval of construction on the states' prior approval); *Pub. Utils. Comm'n. of Cal. v. FERC*, 900 F.2d 269, 282

to the reality that it may be impossible for an applicant to obtain all approvals necessary to construct and operate a project in advance of the Commission's issuance of its certificate without unduly delaying a project.[372] Although Pacific Connector and Jordan Cove will be unable to exercise the authorizations to construct and operate the projects until they receive all necessary authorizations, the Commission takes this approach in order to make timely decisions on matters related to its NGA jurisdiction that will inform project sponsors, and other licensing agencies, as well as the public. We also find that there was a robust and well-developed record before us regarding the benefits and adverse impacts of the projects upon which to make our determinations.

B. Major Environmental Issues Addressed in the Final EIS

1. Geology

193. Construction of the Jordan Cove LNG Terminal will alter the topographic features at the site through clearing, grading, excavation, dredging, and fill placement.[373] No blasting is anticipated during construction of the Jordan Cove LNG Terminal, and construction and operation are not anticipated to have effects on identified mineral resources, active mines, or oil and gas production facilities.[374]

194. The Jordan Cove LNG Terminal will be located within the Cascadia subduction zone, which is a seismically active area.[375] Because the seismic risk to the site is considered high,[376] Jordan Cove will implement several measures. Jordan Cove will monitor ground motions at the facility with three sets of seismometers; if any of the seismometers exceed safe limits, an alarm would sound in the control room where operators could shut down the project.[377] In addition, the LNG storage tanks, systems to

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(D.C. Cir. 1990) (holding the Commission had not violated NEPA by issuing a certificate conditioned upon the completion of the environmental analysis).

[372] *See, e.g.*, *Broadwater Energy LLC*, 124 FERC ¶ 61,225, at P 59 (2008); *Crown Landing LLC*, 117 FERC ¶ 61,209, at P 26 (2006); *Millennium Pipeline Co., L.P.*, 100 FERC ¶ 61,277, at PP 225-231 (2002).

[373] Final EIS at 4-5.

[374] *Id.*

[375] *Id.* at 4-44.

[376] *See id.* at 4-776 to 4-777.

[377] *Id.* at 4-776.

isolate and maintain the LNG storage tanks in a safe shutdown condition, and systems that protect the integrity of the LNG storage tanks will be designed consistent with PHMSA regulations to withstand earthquake ground motions that have a 2 percent probability of being exceeded in 50 years.[378] Additionally, because the LNG Terminal project site has a moderate to high landslide susceptibility hazard, Jordan Cove will regrade the steep dunes to reduce the potential for a landslide to occur.[379] Furthermore, Environmental Condition 38 requires that Jordan Cove employ an inspector and provide inspection reports to be filed with the Commission, to ensure that the construction of the terminal conforms to the applicable design drawings and specifications developed for the facilities that are designed to meet these design requirements. [380]

195. Jordan Cove also conducted hydrodynamic and tsunami modeling studies and designed the LNG Terminal to be consistent with maximum tsunami run-up elevations.[381] The tsunami protection berms, safety critical elements of the facility, point of support elevations, invert levels, and underside of essential equipment would be at least one foot above the estimated maximum run-up elevation and most will be far above that elevation.[382] The final EIS concludes that the tsunami elevations used by Jordan Cove are suitable for the site,[383] and also that, consistent with international standards, the LNG Terminal would be able to withstand, without damage, tsunami inundation stemming from an event that has a 2 percent probability of being exceeded in 50 years.[384]

196. Much of the Pacific Connector Pipeline will be located in the Cascadia subduction zone. In addition, the pipeline route will cross steep slopes and mountain ranges which

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[378] *Id.* at 4-776 to 4-777.

[379] *Id.* at 4-784.

[380] *Id.* at 4-777 to 4-778 and 4-795. Environmental Condition 38 was changed slightly from the recommendation in the final EIS to clarify that the condition is specific to construction of the Jordan Cove LNG Terminal.

[381] *Id.* at 5-1 and 4-779.

[382] *Id.* at 4-779 to 4-780.

[383] *Id.* at 4-780.

[384] *Id.* at 4-775 to 4-780. Oregon DLCD raises concerns regarding potential impacts on the LNG terminal resulting from an earthquake or tsunami. *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 30.

increases the potential for erosion, landslides, and slope failures.[385] Pacific Connector designed the route, with input from stakeholders, to avoid areas with high geologic risk.[386] Pacific Connector will implement site-specific construction techniques and best management practices to address local geological hazards that could not be avoided.[387] The final EIS concludes, based on a review of potential impacts, historical data, seismic hazard mapping, peak horizontal ground acceleration values, pipeline tolerances, and Pacific Connector's proposed impact avoidance and minimization measures, that construction and operation of the pipeline would not be significantly affected by geological hazards.[388] However, to ensure the risk of landslides in five moderate risk areas is further reduced, the final EIS recommends, and we require in Environmental Condition 17, that, prior to construction, Pacific Connector file final monitoring protocols and mitigation measures and conduct an additional review of the most recent light detection and ranging data available from the Oregon Department of Geology and Mineral Industries.[389]

197. Untapped mineral resources are present along the pipeline route and the potential for future mining and mine claims is possible; however, the final EIS concludes that the Pacific Connector Pipeline would not significantly affect future mining development.[390]

198. Overall, based on Jordan Cove and Pacific Connector's proposed construction and operation procedures, methods, and plans to appropriately design for geological hazards, as well as the implementation of minimization and mitigation measures, the final EIS concludes that the projects would not significantly affect geology and would not be significantly affected by geological hazards.[391]

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[385] Final EIS at 5-1.

[386] *Id.* at 4-6.

[387] *Id.* at 4-6.

[388] *Id.* at 5-1.

[389] *Id.* at 4-25.

[390] *Id.* at 4-44.

[391] *Id.*

2. **Soils**

199. Construction and operation of the Jordan Cove LNG Terminal will permanently impact underlying soils,[392] although much of the project area has been previously modified by industrial activities and the placement of dredged materials.[393] To reduce impacts on soils, Jordan Cove will implement best management practices, as well as its project-specific *Erosion and Sediment Control Plan*, the applicants' *Upland Erosion Control, Revegetation, and Maintenance Plan* (Plan), and the applicants' *Wetland and Waterbody Construction and Mitigation Procedures* (Procedures).[394]

200. Low levels of soil, sediment, and groundwater contaminants have been identified at the terminal site.[395] The final EIS finds that implementation of erosion controls for runoff during construction and operation, as well as revegetation plans would prevent low-level contamination from entering surface waters.[396] Jordan Cove continues to work with the Oregon Department of Environmental Quality (Oregon DEQ) toward the determination of appropriate regulatory requirements for the handling of contaminated soil and sediment.[397] Once project design is finalized and prior to beginning construction, Jordan Cove will submit a disposal plan for contaminated soils to Oregon DEQ.[398] With implementation of Oregon DEQ's requirements and Jordan Cove's *Spill Prevention, Containment, and Countermeasures Plan*, the final EIS concludes that the

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[392] *Id.* at 5-2.

[393] *Id.* at 4-47.

[394] The applicants' Plan and Procedures are based on the 2013 FERC Plan and Procedures, which are a set of baseline construction and mitigation measures developed to minimize the potential environmental impacts of construction on upland areas, wetlands and waterbodies. *See* Federal Energy Regulatory Commission, *Environmental Guidelines* (May 2013), https://www.ferc.gov/industries/gas/enviro/guidelines.asp.

[395] Final EIS at 4-49 to 4-54.

[396] *Id.* at 4-51. The final EIS addresses this issue by citing Oregon DEQ's "No Further Action" determination, which states "[w]hile surface soils at the LNG terminal site meet human health and ecological screening criteria, they contain low levels of potentially bio-accumulating chemicals and must not be placed in waters of the state," and noting that Jordan Cove is working with Oregon DEQ on developing a disposal mitigation plan. *Id.*

[397] *Id.* at 4-52.

[398] *Id.*

project is not expected to spread existing contamination or cause additional contamination.[399]

201. The Pacific Connector Pipeline will cross approximately 68 miles of soils classified as prime farmland or farmland of statewide importance.[400] In areas where existing agricultural land uses would be affected, Pacific Connector will implement measures to reduce impacts on prime farmland and crop yields, such as topsoil salvaging, scarification, and subsequent testing to ensure potential compaction is remediated.[401] To reduce impacts on soils, Pacific Connector will implement its project-specific *Erosion Control and Revegetation Plan* and the applicants' Plan and Procedures.

202. The final EIS concludes that, based on Jordan Cove and Pacific Connector's proposed construction and operation procedures and methods and the avoidance, minimization, and mitigation measures that would be implemented, the projects would temporarily and permanently impact soils, but the impacts would not be significant.[402]

3. <u>Water Resources</u>

203. The Jordan Cove LNG Terminal project area is underlain by the unconfined Dune-Sand Aquifer.[403] Due to the proximity to the Pacific Ocean, saltwater intrudes into the aquifer and influences groundwater quality.[404] The Coos Bay-North Bend Water Board maintains 18 non-potable, groundwater withdrawal wells north of the terminal site, the closest of which is 3,500 feet north; the final EIS concludes that construction and operation of the Jordan Cove LNG Terminal would not impact these wells due to the distance from the project.[405]

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[399] *Id.* at 4-54.

[400] *Id.* at 4-57.

[401] *Id.*

[402] *Id.* at 5-2.

[403] *Id.* at 4-76.

[404] *Id.*

[405] *Id.* at 4-76 to 4-77. There are also four groundwater wells permitted for industrial use and fire protection within or near the disturbance area. *Id.* at 4-76. Three of the four wells will be buried to create a construction staging area and would be permanently abandoned; Jordan Cove has indicated that new wells will be drilled to replace the buried wells. *Id.* at 4-77. Additionally, some domestic supply wells could be impacted by the Kentuck Slough Wetland Mitigation Project, *see infra* P 209.

204. Jordan Cove will obtain water from the Coos Bay-North Bend Water Board to construct and operate the project.[406] Project construction could result in a small, temporary drawdown effect to the overlying lakes and wetlands, estimated to no more than 6 inches and typically less.[407] Excavation and grading at the site could cause local groundwater elevations to shift, but this change would be minor and localized.[408] To minimize potential impacts on groundwater from an inadvertent release of construction equipment-related fluids, Jordan Cove will implement its *Spill Prevention, Containment, and Countermeasures Plan* and the applicants' Plan and Procedures. The final EIS concludes that impacts on groundwater resources from the Jordan Cove LNG Terminal would not be significant.[409]

205. Approximately 26 miles of the Pacific Connector Pipeline route will cross areas where groundwater can be found at or near the surface.[410] The pipeline route will cross six wellhead protection areas, and groundwater-fed springs and seeps and private wells have been identified along the pipeline route.[411] For springs, seeps, and wells located within 200 feet of construction disturbance, Pacific Connector will implement its *Groundwater Supply Monitoring and Mitigation Plan*. The final EIS concludes that based on implementation of this plan, as well as implementation of best management practices and Pacific Connector's *Spill Prevention, Containment, and Countermeasures Plan* and *Contaminated Substances Discovery Plan*, construction and operation of the project would not significantly affect groundwater resources.[412]

Jordan Cove has initiated discussions with landowners regarding mitigation strategies to offset potential effects on these wells, including well replacement and other means of settlement. Final EIS at 4-79.

[406] Final EIS at 4-77.

[407] *Id.*

[408] *Id.* at 4-78.

[409] *Id.* at 5-2.

[410] *Id.* at 4-81.

[411] *Id.* at 4-80 to 4-81.

[412] *Id.* at 5-2.

206. Construction and operation of the Jordan Cove LNG Terminal and LNG carrier travel and water use during terminal operation will impact surface waters.[413] Based on Jordan Cove's proposed dredging and vessel operation methods and its mitigation and minimization measures, such as construction timing, treatment of decant waters prior to release, and implementation of its *Spill Prevention, Containment, and Countermeasures Plan*, the final EIS concludes the Jordan Cove LNG Terminal would not significantly affect surface waters.[414]

207. The Pacific Connector Pipeline will cross or be in close proximity to 337 waterbodies, including Coos Bay and the Coos, Umpqua, Rogue, and Klamath Rivers.[415] The pipeline will cross three rivers listed on the Nationwide Rivers Inventory, which is a listing maintained by the National Park Service of rivers with outstanding natural or cultural values judged to be at least regionally significant.[416] Pacific Connector proposes to install the pipeline across waterbodies using various crossing methods, including dry open cut, wet open cut, diverted open cut, direct pipe, bore and horizontal directional drilling (HDD).[417] Because Pacific Connector has not yet identified all drilling fluid additives that would be used with HDD crossings, the final EIS recommends, and we require in Environmental Condition 18, Pacific Connector file for Commission approval a list of the additives and other related information prior to construction. During construction, Pacific Connector will use a total of approximately 75,000 gallons of water per day for dust control, and between 31 and 65 million gallons of water for hydrostatic testing of the pipeline.[418] Water for dust control and hydrostatic

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[413] *Id.* at 4-84 and 5-3.

[414] *Id.* at 4-122 and 5-3 to 5-4. Oregon DLCD states that the project-related dredging could stir up contaminants and contaminate shellfish and salmon species. *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 12. The final EIS discusses potentially contaminated bay sediments that may be affected during construction of the access channel, along and adjacent to the Coos Bay Navigation Channel, and at the Kentuck Slough Wetland Mitigation Project. Final EIS at 4-54 to 4-55. We find that the final EIS's consideration of potentially contaminated bay sediments satisfy our NGA and NEPA statutory responsibilities.

[415] Final EIS at 4-95 and 5-3.

[416] *Id.* at 4-102.

[417] *Id.* at 4-96.

[418] *Id.* at 5-3.

testing will be primarily obtained from surface waters.[419] To minimize impacts associated with hydrostatic testing, Pacific Connector will implement its *Hydrostatic Test Plan*.[420]

208. With implementation of Pacific Connector's proposed waterbody crossing and restoration measures, including best management practices and measures in its *Contaminated Substances Discovery Plan* and *Drilling Fluid Contingency Plan for HDD Operations*, as well as required impact avoidance and minimization measures, including erosion controls and construction timing, the final EIS concludes the Pacific Connector Pipeline would not result in significant impacts on surface water resources.[421]

4. <u>Wetlands</u>

209. Construction and operation of the Jordan Cove LNG Terminal will affect approximately 86 acres of wetlands, of which 22 acres would be permanently lost.[422] Construction and operation of the Pacific Connector Pipeline will temporarily affect approximately 114 acres of wetlands and will permanently impact 5 acres.[423] To address the Corps' regulations and requirements to mitigate unavoidable impacts on wetlands, the applicants each developed a *Compensatory Wetland Mitigation Plan*. According to the plans, impacts on freshwater wetland resources will be mitigated via the Kentuck Slough Wetland Mitigation Project (Kentuck project),[424] and impacts on estuarine wetland

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[419] *Id.* at 4-113 to 4-116.

[420] Environmental Condition 22, discussed *infra* P 216, requires revisions to Pacific Connector's *Hydrostatic Test Plan*.

[421] *Id.* at 4-122 and 5-3 to 5-4. Oregon DLCD expresses concern regarding the upland impacts of constructing the Pacific Connector Pipeline on fish and wildlife habitat in streams. Oregon DLCD's February 20, 2020 Federal Consistency Determination at 16-17. As discussed above, the final EIS considers construction impacts to surface waters and mitigation measures to avoid and minimize surface water impacts.

[422] Final EIS at 5-4.

[423] *Id.*

[424] The Kentuck project consists of 140 acres on the eastern shore of Coos Bay at the mouth of Kentuck Slough. The property was formerly the Kentuck Golf Course but is currently owned by Jordan Cove. *Id.* at 2-18. Jordan Cove proposes to enhance and restore approximately 100 acres at the site.

resources will be mitigated via the Eelgrass Mitigation site[425] and the Kentuck project.[426] The Corps and other relevant agencies are still reviewing these plans.

210. With adherence to the applicants' project-specific Procedures and applicable permits, the final EIS concludes that the projects would not significantly affect wetlands.[427] Additionally, any permits issued by the Corps for the projects may require project-related adverse impacts on wetlands be offset by mitigation similar to that identified in the *Compensatory Wetland Mitigation Plan*.

5. **Vegetation**

211. Construction of the Jordan Cove LNG Terminal will result in the clearing of 499 acres of vegetation, of which approximately 168 acres will be permanently cleared.[428] Construction of the Pacific Connector Pipeline will result in the clearing of 4,176 acres of vegetation, of which 786 acres will be permanently affected due to maintenance of the pipeline right-of-way and aboveground facilities.[429] Except for 782 acres of late-successional and old-growth forest that will be cleared, most of the vegetation affected by the project is common and widespread in the project area.[430] The

[425] The Eelgrass Mitigation site is located near the Oregon Regional Airport in North Bend. Jordan Cove proposes to establish new eelgrass beds at the site. *Id.* Oregon DLCD expresses concern regarding impacts to eelgrass and recommends that the Commission consider alternative eelgrass mitigation sites. *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 21-22, 50. Because the Corps primarily regulates the eelgrass mitigation, we recommend that Oregon DLCD raise its concerns with the Corps.

[426] Final EIS at 5-4.

[427] *Id.* at 4-139 and 5-4. Oregon DLCD expresses concern that wetland mitigation projects are not successful. *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 12. Our reliance on wetland mitigation required by the Corps is reasonable. *See, e.g.*, *City of Oberlin v. FERC*, 937 F.3d 599, 610 (D.C. Cir. 2019).

[428] Final EIS at 4-156. Construction of the Kentuck project and Eelgrass Mitigation site would result in an additional 127 acres of vegetation clearing. Oregon DLCD expresses concern regarding the impact on upland vegetation and wildlife from constructing and operating the LNG terminal. As noted above, the final EIS considers these impacts.

[429] *Id.* at 4-165.

[430] *Id.* at 5-4.

loss of 782 acres of old-growth forest would represent a loss of 0.01 percent of old-growth forest in the four physiographic provinces crossed by the pipeline.[431] Forest fragmentation that will result from construction of the projects would result in new forest edges, which could lead to changes in species composition and increase the potential for the spread of exotic and invasive species.[432] Construction activities could increase the risk of wildfires, which would result in additional impacts on vegetative communities.[433] The applicants will implement numerous measures to reduce impacts on vegetation and ensure successful revegetation of disturbed areas, including measures in Pacific Connector's *Leave Tree Protection Plan*, *Integrated Pest Management Plan*, and *Fire Prevention and Suppression Plan*. The final EIS concludes that construction and operation of the projects would have permanent but not significant impacts on vegetation.[434]

6. Wildlife and Aquatic Resources

212. Construction of the Jordan Cove LNG Terminal will affect 577 acres of wildlife habitat, of which 186 acres will be permanently impacted.[435] Construction of the terminal will increase the rates of stress, injury, and mortality experienced by wildlife, and will result in wildlife avoidance and displacement, which could further increase rates of stress, injury, and mortality. Jordan Cove proposes to mitigate upland habitat impacts and loss at three mitigation sites: the Panhandle, Lagoon, and North Bank sites.[436] Additionally,

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[431] *Id.* at 4-171.

[432] *Id.* at 4-156 to 4-157 and 4-171.

[433] *Id.* at 4-177 to 4-178. We recognize that Oregon DLCD also raises concerns regarding wildfire risk. *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 31.

[434] Final EIS at 5-4.

[435] *Id.* at Table 4.5.1.1-2.

[436] *Id.* at 4-192. The Panhandle site is 133 acres and located north of the Trans-Pacific Parkway; Jordan Cove proposes to remove Scotch broom from portions of the parcel and to provide stewardship of the entire parcel for the life of the Jordan Cove LNG Terminal. At the 320-acre Lagoon site, Jordan Cove proposes to improve the ecology of 113 acres, including burying power lines and reseeding with native vegetation, and to provide stewardship of the entire parcel for the life of the Jordan Cove LNG Terminal. The North Bank site is 156 acres and located on the north bank of the Coquille River adjacent to the Bandon Marsh National Wildlife Refuge; Jordan Cove proposes to implement forestry activities that would provide diversity at the site and promote

Jordan Cove proposes a number of other measures to reduce and mitigate impacts on wildlife including conducting pre-construction surveys for the western pond turtle, northern red-legged frog, and clouded salamander, and, if located, capturing and transporting them to a suitable habitat.[437] Lastly, to further reduce impacts on wildlife, the final EIS recommends, and we require in Environmental Condition 20, Jordan Cove file its lighting plan, prior to beginning construction, which must include measures to minimize lighting impacts on fish and wildlife.

213. Construction of the Pacific Connector Pipeline will affect 4,936 acres of wildlife habitat, of which 850 acres will be permanently impacted.[438] Constructing and operating the pipeline facilities will affect wildlife and wildlife habitat. Impacts include habitat degradation, loss, modification, and fragmentation.[439] To minimize impacts on wildlife, Pacific Connector will implement a number of measures, including measures in its *Integrated Pest Management Plan*, *Erosion Control and Revegetation Plan,* and *Air, Noise and Fugitive Dust Control Plan*.[440]

214. The projects are located within the migratory bird Pacific Flyway, and construction and operation of the projects could impact migratory birds.[441] The applicants propose a number of measures, included in their draft *Migratory Bird Conservation Plan*, to reduce impacts on migratory birds.[442] The applicants continue to consult with FWS to finalize the plan.

215. Coos Bay contains a variety of anadromous, marine, and estuarine fish species, and a large diverse invertebrate population.[443] Individual fish, shellfish, and other aquatic species, as well as their food sources, will be directly lost due to construction of the

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progress towards a mature forest setting, and to provide stewardship of the parcel in perpetuity. *Id.* at 4-193.

[437] *See id.* at 4-190 to 4-199.

[438] *Id.* at Tables 4.5.1.2-5 and 4.5.1.2-6.

[439] *See id.* at 4-215.

[440] *See id.* at 4-215 to 4-231.

[441] *Id.* at 4-187, 4-196, and 4-224.

[442] *See id.* at 4-196 to 4-198 and 4-224 to 4-227.

[443] *Id.* at 4-245. Shellfish (predominantly clams, crabs, and shrimp) are of significant economic importance to the Coos Bay area. *Id.*

terminal, the initial and maintenance dredging, decreased water quality, and entrainment from vessel water intake.[444] Jordan Cove will implement numerous measures to mitigate, minimize, or avoid impacts on aquatic species, including in-water work construction windows, estuarine off-site mitigation,[445] and measures in its *Dredged Material Management Plan* and *Spill Prevention, Containment, and Countermeasures Plan*.[446]

216. The Pacific Connector Pipeline will cross under 2.3 miles of estuarine habitat in Coos Bay, which provide important habitat for migratory salmon, commercial and native oyster beds, and other aquatic species, and 69 other waterbodies known or presumed to be inhabited by fish.[447] To minimize impacts on aquatic species, Pacific Connector proposes a number of measures including use of best management practices, HDD crossings, in-water work construction windows, installation of large woody debris at certain crossings, and implementation of its *Erosion Control and Revegetation Plan*.[448] Because some tribes expressed concern with Pacific Connector's proposed fish salvage plan regarding lamprey,[449] which is an important tribal resource, the final EIS recommends, and we require in Environmental Condition 21, Pacific Connector file a

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[444] *Id.* at 4-316. Oregon DLCD expresses concern regarding the impacts dredging will have on habitat supporting benthic organisms. *See* Oregon DLCD's February 20, 2020 at 19-21. The final EIS considers dredging impacts on benthic organisms and finds that it is likely that rapid initial colonization of benthic organisms would occur within six months, that most typical benthos would recover within one year, and that some specific groups of benthic resources would never fully recover after initial dredging due to the 3- to 10-year maintenance dredging period. Final EIS at 4-249 to 4-255.

[445] *See supra* P 209.

[446] *See* Final EIS at 4-249 to 4-270. Oregon DLCD expresses concern regarding the introduction of non-indigenous species through ballast discharge. *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 23. The final EIS discusses the regulations that LNG vessels must comply with regarding ballast discharge and finds that ballast discharge will not substantially affect water quality in Coos Bay. Final EIS at 4-91 to 4-94.

[447] Final EIS at 4-271 and 4-274.

[448] *See id.* at 4-274 to 4-311.

[449] Adult Pacific lamprey are expected to be captured during salvage, but the proposed salvage methods may not be effective for salvaging lamprey ammocete larvae. *Id.* at 4-304. Oregon DLCD also expresses concern regarding the proposed fish salvage methods. *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 25.

final *Fish Salvage Plan*, prior to construction, developed in consultation with interested tribes, Oregon Department of Fish and Wildlife, FWS, and NMFS. In addition, to ensure fish and aquatic habitats are adequately protected during water withdrawals for hydrostatic testing, Environmental Condition 22 requires Pacific Connector file a revised *Hydrostatic Test Plan* that requires any water withdrawal from a flowing stream not exceed an instantaneous flow reduction of more than 10 percent of stream flow.

217. The Jordan Cove LNG Terminal and Pacific Connector Pipeline will impact designated Essential Fish Habitat (EFH).[450] Pursuant to the Magnuson-Stevens Fishery Conservation and Management Act (MSA), we consulted with NMFS regarding impacts on EFH. NMFS provided ten EFH conservation recommendations on January 10, 2020. In accordance with the MSA and its implementing regulations,[451] on February 3, 2020, Commission staff responded to NMFS, stating that staff recommends the Commission incorporate eight of the ten EFH conservation recommendations. Staff explained that the remaining two EFH conservation recommendations were not justified and could result in additional environmental impacts. We agree with staff's assessment.[452]

218. Based on implementation of the applicants' proposed minimization, mitigation, and avoidance measures and the characteristics of the wildlife and aquatic species in the project areas, the final EIS concludes that the projects would not significantly affect wildlife or aquatic resources.[453]

7. <u>Threatened, Endangered, and Other Special Status Species</u>

219. The final EIS identifies 36 species (or Distinct Population Segments (DPSs) or Evolutionarily Significant Units (ESUs) of species) that are federally listed as threatened or endangered (or are identified as proposed, candidates, or under review for federal listing) and may occur in or near the project areas. Critical habitat has been proposed or designated within or near the project areas for a number of these species.

220. Commission staff determined that the projects are *not likely to adversely affect* 17 listed species, and are *not likely to adversely affect* critical habitat designated for

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[450] *See* Final EIS at Appendix I.

[451] 16 U.S.C. § 1855(b)(4)(B) (2018); 50 C.F.R. § 600.920(k)(1) (2019).

[452] The eight recommendations recommended by staff are identical to terms and conditions included in NMFS's Incidental Take Statement. Compliance with the terms and conditions in the Incidental Take Statement is required by Environmental Condition 26.

[453] Final EIS at 5-5.

8 species.[454] Commission staff also determined that the projects are *not likely to jeopardize the continued existence* of 3 species proposed for listing and are *not likely to adversely modify* proposed critical habitat for 4 species.[455] Additionally, Commission staff determined that the projects are *likely to adversely affect* 16 listed species and are *likely to adversely affect* critical habitat designated for 5 species.[456]

221. As required by section 7 of the Endangered Species Act, Commission staff submitted a Biological Assessment to FWS and NMFS on July 29, 2019.[457] Commission staff requested concurrence with its *not likely to adversely affect* determinations and initiation of formal consultation regarding its *likely to adversely affect* determinations. On January 10 and January 31, 2020, NMFS and FWS, respectively, provided their Biological Opinions for the projects.[458]

222. In its Biological Opinion, NMFS determined that the projects are *likely to adversely affect* 9 listed species, including 5 whale species (blue whale, fin whale, humpback whale – Central American DPS, humpback whale – Mexican DPS, and sperm whale) and 4 fish species (Coho salmon – Southern Oregon/North California coast (ESU, Coho salmon – Oregon Coast ESU, Pacific eulachon – Southern DPS, and green sturgeon – Southern DPS). Further, NMFS determined that the projects are *likely to adversely affect* critical habitat for 3 listed species (Coho salmon – Southern Oregon/North California coast ESU, Coho salmon – Oregon Coast ESU, and green sturgeon – Southern DPS). For those 9 species and 3 critical habitat designations, NMFS determined that the

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[454] *Id.* at Table 4.6.1-1.

[455] *Id.* Oregon DLCD expresses concern regarding the impact of constructing and operating the LNG Terminal on the coastal marten, which the FWS proposed to list as a threatened species in October 2018. *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 14, 16. The final EIS discusses the LNG Terminal impacts on the coastal marten. Final EIS at 4-322 to 4-326. The final EIS states that surveys have not documented coastal martens at the LNG Terminal site. *Id.* at 4-323. Further, coastal marten species may benefit from proposed mitigation measures, including trash removal to reduce the potential for attracting predator species, *id.* at 4-324, and limiting the speed limit to 15 miles per hour for earthmoving equipment during construction, *id.*

[456] Final EIS at Table 4.6.1-1

[457] Information in the Biological Assessment was supplemented through responses to additional information requests.

[458] FWS originally submitted its Biological Opinion on January 17, 2020. On January 31, 2020, FWS submitted a revised Biological Opinion, which superseded its January 17 Biological Opinion.

projects would not likely jeopardize the continued existence of the species or result in the destruction or adverse modification of critical habitats, and, accordingly, NMFS provided an Incidental Take Statement. Environmental Condition 26 requires Jordan Cove and Pacific Connector to adhere to the Incidental Take Statement, including the reasonable and prudent measures and terms and conditions provided for listed species.[459]

223. In its Biological Opinion, FWS determined that the projects are *likely to adversely affect* 9 listed species, including 3 bird species (Western snowy plover, marbled murrelet, and northern spotted owl), 2 fish species (Lost River sucker and shortnose sucker), 1 invertebrate (vernal pool fairy shrimp), and 3 plant species (Applegate's milk-vetch, Gentner's fritillary, and Kincaid's lupine). Further, FWS determined that the projects are *likely to adversely affect* critical habitat for 5 listed species (Western snowy plover, marbled murrelet, northern spotted owl, Lost River sucker, and shortnose sucker).[460] For those 9 species and 5 critical habitat designations, FWS determined that the projects would not likely jeopardize the continued existence of the species or result in the destruction or adverse modification of critical habitats, and, accordingly, FWS provided Incidental Take Statements. Environmental Condition 26 requires Jordan Cove and Pacific Connector to adhere to the Incidental Take Statements, including the reasonable and prudent measures and terms and conditions provided for listed species.

224. With implementation of the measures in NMFS and FWS's Incidental Take Statements, we conclude our consultation with NMFS and FWS under section 7 of the Endangered Species Act is complete.

225. In addition, the final EIS recommends several measures to mitigate impacts on listed species. We adopt those recommendations as mandatory conditions in the appendix to this order. Environmental Condition 23 requires Jordan Cove to file a *Marine Mammal Monitoring Plan*, which will describe how the presence of whales will be determined during construction and will identify measures Jordan Cove will take to

[459] The final EIS's environmental recommendation 26, which stipulated that Jordan Cove and Pacific Connector not complete construction until Commission staff completes consultation under the Endangered Species Act, is no longer necessary and is removed.

[460] Oregon DLCD expresses concern regarding the LNG Terminal impacts on the Western snowy plover. *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 15. As stated above, FWS determined that the LNG Terminal would not likely jeopardize the continued existence of the Western snowy plover or result in the destruction or adverse modification of its designated critical habitat. Further, FWS issued an Incidental Take Statement for the Western snowy plover that requires Jordan Cove to comply with terms and conditions, including measures to address noise and predation. *See* FWS's January 31, 2020 Revised Biological Opinion at 204-207.

reduce potential noise effects on whales and other marine mammals.[461] Environmental Condition 24 requires Pacific Connector to file its commitment to adhere to FWS-recommended timing restrictions within threshold distances of marbled murrelet and northern spotted owl stands during construction, operation, and maintenance of pipeline facilities.[462] Additionally, Environmental Condition 25 requires Pacific Connector to conduct surveys for marbled murrelet and northern spotted owl habitat that may be affected by the Pacific Connector Pipeline.

226. The Jordan Cove LNG Terminal could impact marine mammals, which are protected under the Marine Mammal Protection Act (MMPA).[463] Jordan Cove proposes a number of measures to minimize impacts on marine mammals, and, as noted above, Environmental Condition 23 requires Jordan Cove to develop a *Marine Mammal Monitoring Plan*. Pursuant to the MMPA, consultation with NMFS regarding impacts on marine mammals is ongoing; NMFS may issue an incidental take authorization under the MMPA.

227. The final EIS identifies 13 state-listed threatened or endangered species with the potential to occur in the project area.[464] Based on the applicants' proposed mitigation,

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[461] Oregon DLCD states that it "advocated for expanding the scope of the recommended Marine Mammal Monitoring Plan to include consideration of the effects of noise on resident populations of adult and juvenile harbor seals . . . ." Oregon DLCD's February 20, 2020 Federal Consistency Determination at 13. Because Environmental Condition 23 applies to "other mammals" including Pacific harbor seals, we find that Oregon DLCD's concern is addressed.

[462] Oregon DLCD implies that the timing restriction for tree removal within the breeding season is the only mitigation measure to address impacts to the marbled murrelet and spotted owl. *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 18. Oregon DLCD is mistaken. Jordan Cove and Pacific Connector are required to comply with FWS's Incidental Take Statements that include additional terms and conditions, including requiring the applicants to avoid suitable and recruitment habitat, provide education and outreach materials, and make physical improvements to reduce corvid predation. *See* FWS's January 31, 2020 Revised Biological Opinion at 104-109; 168-169.

[463] *See* final EIS at 4-239, 4-257 to 4-261, and 4-329 to 4-334.

[464] *Id.* at 4-378.

minimization, and avoidance measures, the final EIS concludes that the projects would not significantly affect these species.[465]

8. Land Use

228. The Jordan Cove LNG Terminal site consists of a combination of brownfield decommissioned industrial facilities, an existing landfill requiring closure, open water, open land, and an area of forested dunes.[466] The nearest residence to the LNG terminal would be 1.1 miles away.[467] There are no planned residential or commercial developments within 0.25 mile of the project site.[468]

229. The Pacific Connector Pipeline will cross a variety of land uses including forest land, rangeland, agricultural lands, and developed lands.[469] Construction workspace will be located within 50 feet of seven residences, two of which are abandoned and would be removed by Pacific Connector.[470] Construction of the project will impact agricultural, commercial private forestlands, and residential lands, but Pacific Connector proposes numerous measures to minimize and mitigate impacts on these lands.[471]

230. The Jordan Cove LNG Terminal and a portion of the Pacific Connector Pipeline will be constructed within a designated coastal zone.[472] Accordingly, the projects are subject to a consistency review under the Coastal Zone Management Act. The Oregon DLCD is the designated state agency that implements the Oregon Coastal Management Program and undertakes the CZMA consistency review in Oregon.

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[465] *Id.* at 5-6; *see also id.* at 4-378 to 4-388.

[466] *Id.* at 4-424 to 4-425.

[467] *Id.* at 4-430. One residence would be located approximately 20 feet from the Kentuck project and another would be located approximately 30 feet from the North Bank site; neither residence is expected to be affected by project-related construction or operation.

[468] *Id.* at 4-434.

[469] *Id.* at 4-435.

[470] *Id.* at 4-441.

[471] *See id.* at 4-438 to 4-446.

[472] *Id.* at 4-430 and 4-441.

231. On April 11, 2019, the applicants submitted joint CZMA certifications to Oregon DLCD. On February 19, 2020, Oregon DLCD objected to the applicants' consistency certification on the basis that the applicants have not established consistency with specific enforceable policies of the Oregon Coastal Management Program and that it is not supported by adequate information. This decision can be appealed to the U.S. Secretary of Commerce. Oregon DLCD's objection also appears to be without prejudice. The final EIS recommends, and we require in Environmental Condition 27, the applicants file, prior to beginning construction, a determination of consistency with the Coastal Zone Management Plan issued by the State of Oregon.

232. The Pacific Connector Pipeline will cross approximately 31 miles of Forest Service lands within the Umpqua, Rogue River, and Winema National Forests, and 47 miles of lands managed by BLM within the Coos Bay, Roseburg, Medford, and Lakeview Districts.[473] Forest Service operates the lands under Land and Resource Management Plans (LRMPs)[474] and BLM operates the lands under Resource Management Plans (RMPs).[475] Forest Service and BLM analyzed amending their LRMPs and RMPs, respectively, to allow for the project to be sited within their lands, and solicited comments on the proposed amendments during the draft EIS comment period.[476] Forest Service and BLM will make final decisions on the respective authorizations before them, and Pacific Connector must obtain a right-of-way grant from BLM to cross federal lands, which may include compensatory mitigation requirements recommended by the Forest Service.[477]

233. Construction and operation of the projects will have both temporary and permanent effects on land uses.[478] Some permanently affected lands will be able to resume previous land uses, and other lands will be permanently converted to

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[473] *Id.* at 4-50 to 4-51.

[474] The lands affected by the Pacific Connector Pipeline are operated under the Umpqua National Forest LRMP, Rogue River National Forest LRMP, and the Winema National Forest LRMP.

[475] The lands affected by the Pacific Connector Pipeline are operated under the Southwestern Oregon RMP and the Northwestern and Coastal RMP.

[476] Final EIS at ES-3.

[477] *Id.* at 2-33 to 2-34 and 2-41.

[478] *Id.* at 4-552.

industrial/commercial use, precluding previous land uses.[479] The final EIS concludes that the projects would not significantly affect land use.[480]

9. Recreation and Visual Resources

234. In the vicinity of the Jordan Cove LNG Terminal, there are BLM-managed Recreation Management Areas, Forest Service-managed lands (including the Oregon Dunes National Recreation Area within the Siuslaw National Forest), and state and local forests and parks.[481] Pile-driving noise associated with construction, as well as other construction-related activities, could temporarily affect the quality of the recreation experience at these sites.[482] In addition, construction could temporarily increase traffic and travel time for individuals using the Trans-Pacific Parkway to access recreation sites.[483] Effects on recreational boaters could occur during construction of the slip, access channel, and modifications to the Coos Bay Federal Navigation Channel, but would be temporary and affect a limited area.[484] Project operation could cause short-term, occasional impacts on recreational boaters, as boaters will be required to avoid LNG carriers in transit within the waterway.[485]

235. The Pacific Connector Pipeline will be in the vicinity of some state and local recreation areas, and, as noted above, will cross through parts of three National Forests and four BLM districts.[486] In addition, the route will cross three federally designated scenic byways (the Pacific Coast, Rogue-Umpqua, and Volcanic Legacy Scenic Byways), a designated Wild and Scenic River (the Rogue River), the Pacific Crest

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[479] *Id.* at 5-6.

[480] *Id.*

[481] *Id.* at 4-553 to 4-558.

[482] *Id.* at 4-558.

[483] *Id.* at 4-559.

[484] *Id.* at 4-561 to 4-562.

[485] *Id.* at 4-562. Oregon DLCD expresses concern regarding the LNG Terminal's effect on recreation and tourism. *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 24, 27. As discussed above, the final EIS considers the project impacts on recreation and tourism and finds the impacts would be short-term and temporary.

[486] Final EIS at 4-563 to 4-566.

National Scenic Trail, and a water trail within the Coos Bay Estuary.[487] Pacific Connector proposes to cross two of the scenic byways, the Rogue River, and the Coos Bay Water Trail using HDD to avoid or minimize impacts at these areas.[488] To minimize impacts on the Pacific Crest National Scenic Trail and to control off-highway vehicle use on the pipeline right-of-way, Pacific Connector proposes to implement a number of measures included in its *Recreation Management Plan*.[489]

236. The final EIS concludes that the projects would result in impacts on recreation resources but, based on the applicants' proposed construction, mitigation, and operation procedures, the impacts would not be significant.[490]

237. Construction and operation of the Jordan Cove LNG Terminal will result in substantial short-term and long-term changes to the existing landscape within the view of the project.[491] The most visible components of the terminal will be the LNG storage tanks and nighttime lighting.[492] Adverse visual effects could be experienced by residents in the area and recreational users on Coos Bay. Although Jordan Cove attempted to mitigate for the visibility of project features (such as through use of landform contouring and stabilization, vegetative screening, architectural treatments, and hooded lighting), the final EIS concludes that, based on the size and location of the facilities, the Jordan Cove LNG Terminal would significantly affect visual resources for some views and viewing locations.[493]

238. Construction and operation of the Pacific Connector Pipeline will result in short-term and long-term visual effects, which will be greatest in areas where the new right-of-way would create new clearings through forestlands not characterized by large-scale

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[487] *Id.* at 4-563 and 4-566 to 4-571.

[488] *Id.* at 4-563 to 4-564 and 4-567 to 4-568.

[489] *Id.* at 4-570 to 4-571.

[490] *Id.* at 4-578.

[491] *Id.* at 4-608. Oregon DLCD raises concerns regarding the visual impacts of the LNG Terminal. *See* Oregon DLCD February 20, 2020 Federal Consistency Determination at 25-26. As discussed above, the final EIS and this order consider these impacts.

[492] Final EIS at 5-7.

[493] *Id.* at 4-608.

timber harvests.[494] Revegetation and restoration of the right-of-way, including replacement of slash, will be initiated following construction and will mitigate the visual contrast in color, line, and texture.[495] Pacific Connector will implement measures like structure co-location, painting, landscaping, and screening to limit the visual effects of aboveground facilities associated with the pipeline.[496] The final EIS concludes that, with implementation of Pacific Connector's *Aesthetics Management Plan*, construction and operation of the Pacific Connector Pipeline would not significantly affect visual resources.[497]

10. <u>Socioeconomics</u>

239. Construction and operation of the projects will result in impacts on socioeconomic resources.[498] Temporary impacts during construction will include increased demand for local services, including law enforcement, fire protection, and health care providers.[499] When considered together, construction of the Jordan Cove LNG Terminal and Pacific Connector Pipeline could cause significant effects (additional usage) to short-term housing in Coos County.[500] Therefore, the final EIS recommends, and we require in Environmental Condition 28, the applicants designate a Construction Housing Coordinator to serve as a liaison between the applicants, contractors, and communities affected by the projects.[501] The limited short-term housing availability that would occur as a result of construction of the projects could also affect tourism, as visitors would have

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[494] *Id.* at 4-608 and 4-599.

[495] *Id.* at 4-599.

[496] *Id.* at 4-608.

[497] *See id.* at 4-601 and 4-608.

[498] *Id.* at 4-652.

[499] *Id.* at 5-7.

[500] *Id.* at 4-652.

[501] As an effort to reduce impacts on housing, Jordan Cove proposes to construct a Workforce Housing Facility at the South Dunes Site. The final EIS notes that estimating whether this Workforce Housing Facility, as well as other potential informal worker camps along the pipeline route, could lead to an increase in crime would be speculative. *Id.* at 4-610 to 4-611 and 4-630 to 4-631.

to compete with construction workers for housing.[502] The projects could also affect supplemental subsistence activities, commercial fishing, and commercial oyster farms, but these impacts would not be significant.[503] The likelihood of the pipeline resulting in a long-term decline in property values is low.[504] The projects will provide direct employment opportunities for local workers, support other local and state services and industries, and generate local, state, and federal tax revenues.[505]

240. Executive Order 12898 requires that specified federal agencies make achieving environmental justice part of their missions by identifying and addressing, as appropriate, disproportionately high and adverse human or environmental health effects of their programs, policies, and activities on minorities and low income populations.[506] The Commission is not one of the specified agencies and the provisions of Executive Order 12898 are not binding on this Commission. Nonetheless, in accordance with our usual practice, the final EIS addresses this issue.[507]

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[502] *Id.* at 4-619, 4-644, and 4-652.

[503] *Id.* at 4-619 to 4-621, 4-644 to 4-645, and 5-8. Oregon DLCD expresses concern regarding impacts to ocean-based fisheries (including the Dungeness crab fishery), impacts to commercial oyster farms, and the effect of the Coast Guard's spatial restrictions on recreational and commercial fisheries. *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 23-24, 27-30. The final EIS finds that long-term impacts on the crabbing industry from sedimentation is not expected to result in long-term or population-wide effects on crabs. Final EIS at 4-621. The final EIS discusses the Pacific Connector Pipeline's effect on commercial oyster farms and the avoidance measures and contingency mitigation plans. Final EIS at 4-645. The final EIS finds that the spatial restrictions will not significantly affect recreational and commercial fisheries as the restrictions would be in place for approximately 20 to 30 minutes, similar to the timeframe for other deep-draft vessels using the channel. Final EIS at 4-620.

[504] *See* final EIS at 4-635. The final EIS acknowledges that it is not possible to ascertain from the limited information available whether property values near the Jordan Cove LNG Terminal would be affected. *Id.* at 4-614.

[505] *Id.* at 4-614 to 4-616 and 4-635 to 4-639.

[506] *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations*, Executive Order No. 12898 (Feb. 11, 1994), reprinted at 59 Fed. Reg. 7629.

[507] *See* final EIS at 4-622 to 4-629 and 4-646 to 4-650.

241. Low-income and/or minority populations are present within 3 miles of the Jordan Cove LNG Terminal and along portions of the Pacific Connector Pipeline route, including the census tract where the Klamath Compressor Station will be located.[508] Tribal populations are considered an environmental justice population with the potential to be disproportionately affected by construction and operation of the projects as a result of their unique relationship with the surrounding areas.[509]

242. The final EIS concludes that construction and operation of the projects is not expected to result in disproportionately high and adverse human health or environmental effects on nearby communities, except that the temporary increased demand for rental housing in Coos Bay would likely be more acutely felt by low-income households.[510] As noted above, Environmental Condition 28 requires designation of a Construction Housing Coordinator to address construction contractor housing needs and potential impacts in each county affected by the projects.

11. Transportation

243. The increase in marine traffic associated with construction and operation of the Jordan Cove LNG Terminal, when combined with current deep-draft vessel traffic, will be less than historic ship traffic through the channel.[511] Construction of the terminal could temporarily impact motor vehicle traffic in the area.[512] To mitigate impacts on vehicular traffic, Jordan Cove will implement measures identified in its *Traffic Impact Analysis*.[513] In addition, the final EIS recommends, and we require in Environmental Condition 29, Jordan Cove file documentation, prior to beginning construction, that it has entered into a cooperative improvement agreement with the Oregon Department of Transportation and traffic development agreements with Coos County and the City of North Bend.

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508 *Id.* at 4-626 to 4-627 and 4-647 to 4-648.

509 *Id.* at 4-629 and 4-649 to 4-650.

510 *Id.* at 4-628 to 4-629 and 4-649 to 4-650.

511 *Id.* at 5-8.

512 *Id.* at 4-654 to 4-656.

513 *See id.* at 4-655 to 4-656.

244. The Southwest Oregon Regional Airport is located less than one mile from the terminal site.[514] In addition, LNG carriers heading to and from the LNG terminal would pass by the airport to the west and would dock to the north less than one mile from the airport. Because the terminal and associated construction equipment and LNG carriers would be within proximity to the airport and would exceed heights that trigger notice to the Federal Aviation Administration (FAA),[515] Jordan Cove submitted a notice to the FAA regarding its proposed equipment and the LNG carrier transits.[516] On May 7, 2018, the FAA made initial findings that the LNG carriers (at multiple locations during transit), LNG storage tanks, and other facilities are obstructions and would be presumed hazards to navigation.[517] Therefore, the final EIS concludes that operating the LNG Terminal could significantly impact Southwest Oregon Regional Airport operations.[518]

245. However, the FAA bases final determination of whether a proposal would or would not be a hazard to air navigation on the findings of a completed aeronautical study. Following issuance of the final EIS, the FAA completed aeronautical studies for the LNG carrier transits, LNG storage tanks, and other onsite equipment and buildings. On December 23, 2019, the FAA issued a "Determination of No Hazard to Air Navigation" for onshore equipment and buildings, and a "Determination of No Hazard to Air Navigation for Temporary Structure" for docked and transiting LNG carriers.[519]

246. For the 33 permanent onshore structures reviewed by the FAA, only five were found to have a height which might affect air navigation: the two LNG storage tanks, the Oxidizer, the Amine Contactor, and the Amine Regenerator. For these five structures,

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[514] *Id.* at 4-656.

[515] 14 C.F.R. § 77.9 (2019).

[516] Final EIS at 4-790.

[517] *Id.* at 4-657; *see also* Jordan Cove's May 10, 2018 Response to Commission Staff's April 20, 2018 Data Request.

[518] Final EIS at 5-12.

[519] Separate FAA determinations can be found at http://oeaaa.faa.gov for Aeronautical Study Nos: 2017-ANM-5386-OE through 2017-ANM-5388-OE; 2017-ANM-5390-OE through 2017-ANM-5418; 2018-ANM-4-OE through 2018-ANM-8-OE; 2018-ANM-718-OE through 2018-ANM-720-OE; 2019-ANM-5196-OE; and 2019-ANM-5197-OE. Oregon DLCD's concerns regarding flight hazards does not appear to have taken into account FAA's December 23, 2019 Determination of No Hazard to Air Navigation. *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 31.

the FAA's aeronautical study determined that the structures would have no substantial adverse effects on the safe and efficient utilization of the navigable airspace by aircraft or on the operation of air navigation facilities. The FAA's conclusion was partly based on Jordan Cove adhering to the FAA requirements on marking/lighting the structures. The FAA also based its conclusions on Jordan Cove indicating, in a July 29, 2019 submittal to the FAA, that it would reduce the height of the proposed LNG storage tanks to 181 feet above grade level. Therefore, we have updated environmental recommendation 47 in the final EIS, included as Environmental Condition 48 in this order, to require that, prior to construction of final design, Jordan Cove file updated LNG storage tank drawings for review and approval that reflect the updated elevations referenced in the FAA's permanent structure aeronautical studies.

247. For the LNG carrier transit route, the FAA's aeronautical studies determined that the proposed LNG carrier transit locations would not have a substantial adverse effect on the safe and efficient utilization of the navigable airspace by aircraft or on any air navigation facility. The FAA based this determination on aircraft not conducting takeoff or landing operations until LNG carriers have cleared a specific area. An existing Southwest Oregon Regional Airport Letter of Agreement is currently used to coordinate aircraft operations when ships that exceed 142 feet in height are transiting by the airport. As a condition of the FAA determination, the FAA requires that Jordan Cove sign a Letter of Agreement with the airport before LNG carriers begin operations. The FAA determinations also note that a signed Letter of Agreement would relieve Jordan Cove from repeatedly filing future airspace studies for ongoing LNG carrier operations. Therefore, we require in Environmental Condition 39 that, prior to receiving LNG carriers, Jordan Cove file an affirmative statement indicating that it has signed and executed a Letter of Agreement with the Southwest Oregon Regional Airport as stipulated by the FAA's determination for temporary structures.

248. Construction of the Pacific Connector Pipeline could temporarily impact project-area roads and users but, with implementation of Pacific Connector's mitigation measures, these impacts would not be significant.[520]

12. Cultural Resources

249. Commission staff consulted with Indian tribes that may attach religious or cultural significance to sites in the region or may be interested in potential impacts from the projects on cultural resources. The Commission received comments from the Confederated Tribes of Coos, Lower Umpqua, and Siuslaw Indians, Coquille Indian Tribe, Cow Creek Band of Umpqua Indians, Confederated Tribes of the Grand Ronde

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[520] Final EIS at 4-657 to 4-660 and 5-8.

Community of Oregon, Karuk Tribe, Klamath Tribes, Tolowa Dee-Ni' Nation, and Yurok Tribe.[521]

250. A number of tribes, as well as Native American individuals, expressed concerns with the proposals through comments made at the public scoping sessions and comments filed in the project dockets.[522] Throughout the proceedings, Commission staff consulted with the tribes listed above and held numerous meetings, both in person and via teleconference.[523]

251. Cultural resource surveys are not yet complete for the Jordan Cove LNG Terminal or the Pacific Connector Pipeline.[524] Surveys that have been completed have identified sites that require monitoring during construction or other mitigation prior to construction.[525] In addition, further study and testing has been recommended for some sites if avoidance cannot be achieved.[526]

252. The Commission has not yet completed the process of complying with the National Historic Preservation Act.[527] Consultation with Indian tribes, the Oregon State Historic Preservation Officer (SHPO), and other applicable agencies is still ongoing.[528] The final EIS recommends, and we require in Environmental Condition 30, the applicants not begin construction of facilities or use of any staging, storage, temporary work areas, and new or to-be-improved access roads until: (1) the applicants file the remaining cultural resource surveys, site evaluations and monitoring reports (as necessary), a revised ethnographic study, final Historic Properties Management Plans for both projects, a final *Unanticipated Discovery Plan*, and comments from the SHPO, interested Indian tribes, and applicable federal land-managing agencies; (2) the Advisory Council on Historic Preservation is afforded an opportunity to comment on the undertaking; and

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[521] *See id.* at 4-667 to 4-675.

[522] *See id.* at 4-666 to 4-667. Some of these concerns are summarized in the final EIS at 4-667 to 4-675.

[523] *See id.* at 4-666; *see also id.* at Appendix L, Table L-5.

[524] *Id.* at 4-678 to 4-683 and 5-9.

[525] *Id.* at 5-9.

[526] *Id.*

[527] *Id.* and 4-684 to 4-686.

[528] *Id.* at 5-9.

(3) Commission staff reviews and approves all cultural resources reports, studies, and plans, and notifies the applicants in writing that treatment plans may be implemented and/or construction may proceed.

253. The final EIS concludes that construction and operation of the projects would have adverse effects on historic properties, but that an agreement document would be developed with the goal of resolving those impacts.[529] Commission staff distributed a draft agreement document to the Oregon SHPO, the Advisory Council on Historic Preservation, the applicants, federal land-managing agencies, and consulting Indian tribes on December 13, 2018.[530]

13. Air Quality and Noise

254. Construction of the Jordan Cove LNG Terminal may result in a temporary reduction in ambient air quality as a result of fugitive dust emissions and emissions from vehicles and marine vessels transporting workers, equipment, and construction materials.[531] Construction of the terminal will occur over a 5-year period, with concurrent emissions from commissioning and start-up occurring in year 5.[532] Construction of the Pacific Connector Pipeline will result in a temporary increase in emissions due to the combustion of fuel in vehicles and equipment, dust generated from soil disturbance, and general construction activities.[533] With implementation of the applicants' proposed best management practices, the final EIS concludes that construction of the projects would have a temporary, but not significant, impact on regional air quality and would not result in exceedance of the applicable National Ambient Air Quality Standards (NAAQS).[534]

255. Operational emissions from the Jordan Cove LNG Terminal and the Klamath Compressor Station will remain below thresholds requiring a Prevention of Significant Deterioration permit, but both projects would be considered Title V major sources for

[529] *Id.*

[530] The draft MOA was also filed in the project dockets.

[531] *Id.* at 4-699.

[532] *Id.*

[533] *Id.* at 4-703.

[534] *Id.* at 5-9.

certain criteria pollutants and each will require a Title V Operating Permit.[535] The final EIS concludes that operation of the projects would result in impacts on regional air quality, but the impacts would not be significant and emissions would not result in exceedance of the applicable NAAQS.[536]

256. Noise levels associated with construction of the Jordan Cove LNG Terminal will vary depending on the activity, with the highest levels of noise occurring during pile-driving work.[537] There are no Noise Sensitive Areas (NSAs) within one mile of the Jordan Cove LNG Terminal site.[538] The final EIS evaluates project-related noise at three representative NSAs near the site, as well as two other sites sensitive to sound level impacts (a recreation area and critical wildlife habitat for the western snowy plover).[539] The final EIS recommends, and we require in Environmental Condition 31, Jordan Cove limit pile-driving activities to between the hours of 7:00 a.m. and 10:00 p.m.[540] The final EIS concludes that noise impacts from pile-driving on the Coos Bay area would be significant, even with the inclusion of the time restriction required by Condition 31.[541] Operation of the Jordan Cove LNG Terminal is not expected to result in noise levels at

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[535] *Id.* at 4-702 and 4-706.

[536] *Id.* at 4-709 and 5-9 to 5-10. Oregon DLCD states that transportation, storage, and liquefaction of natural gas will expose workers and adjacent communities to numerous toxic air pollutants. *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 18. Because operational emissions from the Jordan Cove LNG Terminal and the Klamath Compressor Station will be subject to a Title V Operating Permit and will not exceed applicable NAAQS, which EPA established to protect human health, we are satisfied that the projects will not significantly affect air quality for workers or adjacent communities.

[537] Final EIS at 4-716 to 4-717. Oregon DLCD also raises concerns regarding construction noise impacts. *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 26.

[538] Final EIS at 4-713.

[539] *Id.*

[540] Jordan Cove notes that this limitation in hours could require pile-driving activities to occur over a four-year period, as opposed to a two-year period. *Id.* at 4-717. The final EIS concludes that, without this limitation, extremely high nighttime noise levels would result in a severe impact on thousands of residents, and, therefore, the limitation is necessary. *Id.* at 4-719.

[541] *See id.* at 4-717 to 4-721.

the nearest NSA exceeding the Commission's limit of a day-night average sound level (L_{dn}) 55 A-weighted decibels (dBA).[542] To ensure that noise impacts associated with operation are not significant, Environmental Condition 32 requires Jordan Cove file a full power load noise survey after placing the terminal into service.[543]

257. Noise impacts associated with construction of the Pacific Connector Pipeline are expected to last between 12 and 18 months;[544] due to the assembly-line nature of pipeline construction, activities in any area could occur intermittently over a period lasting from several weeks to a few months.[545] Construction noise will be audible to NSAs along the pipeline route, but construction will generally be limited to daytime hours (i.e., 7:00 a.m. to 7:00 p.m.).[546] HDD activities could occur at nighttime and could exceed the Commission's L_{dn} 55 dBA limit at nearby NSAs without mitigation.[547] To ensure mitigation measures implemented at the HDD locations reduce noise at the nearby NSAs, Environmental Condition 33 requires Pacific Connector file a site-specific noise mitigation plan prior to drilling activities at HDD sites, as well as bi-weekly reports during the drilling activities. Operation of the Klamath Compressor Station will result in noise impacts on nearby NSAs, but Pacific Connector will implement mitigation measures to reduce noise and meet the Commission's L_{dn} 55 dBA limit.[548] To ensure that noise impacts associated with operation are not significant, Environmental Condition 34 requires Pacific Connector file a noise survey after placing the Klamath Compressor Station into service.[549]

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[542] *Id.* at 5-10.

[543] Oregon DLCD expresses concern regarding operational noise impacts stating "[o]nce built the LNG Export Terminal would operate continuously, generating very high noise levels." *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 26. We address this concern above.

[544] Final EIS at 4-727.

[545] *Id.* at 5-10.

[546] *Id.* at 4-728.

[547] *Id.* at 4-729 to 4-730.

[548] *Id.* at 4-733 to 4-734.

[549] Environmental Condition 34 was changed slightly from the recommendation in the final EIS to clarify that, if a full noise survey cannot be completed with 60 days of placing the Klamath Compressor Station into service, the full noise survey shall be filed no later than 60 days after all liquefaction trains at the LNG Terminal are fully in service.

14. <u>Greenhouse Gas Emissions</u>

258. With respect to impacts from greenhouse gases (GHGs), the final EIS estimates the GHG emissions from construction and operation of the projects,[550] includes a qualitative discussion of the various potential climate change impacts in the region,[551] and discusses the regulatory structure for GHGs under the Clean Air Act.[552]

259. The final EIS estimates that operation of the projects, including the LNG Terminal and pipeline facilities, may result in GHG emissions of up to 2,145,387 metric tonnes per year of carbon dioxide equivalent (CO_2e).[553] To provide context to the direct and indirect[554] GHG estimate, according to the national net CO_2e emissions estimate in the EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (2019), 5.743 billion metric tonnes of CO_2e were emitted at the national level in 2017 (inclusive of CO_2e sources and sinks).[555] The operational emissions of these facilities could potentially increase annual CO_2e emissions based on the 2017 levels by approximately 0.0374 percent at the national level. Currently, there are no national targets to use as benchmarks for comparison.[556]

The Klamath Compressor Station will not be in full-load condition until the LNG Terminal is either commissioning or operating all five liquefaction trains simultaneously.

[550] Final EIS at Table 4.12.1.3-1 (LNG Terminal construction emissions), Table 4.12.1.3-2 (LNG Terminal operation emissions), Table 4.12.1.4-1 (pipeline facilities construction emissions), and Table 4.12.1.4-2 (pipeline facilities operation emissions).

[551] *Id.* at 4-848 to 4-851.

[552] *Id.* at 4-687 to 4-694.

[553] *Id.* at Tables 4.12.1.3-1, 4.12.1.3-2, 4.12.1.4-1, and 4.12.1.4-2. CO_2e emissions in the final EIS are expressed in short tons, which have been converted to metric tons in this order so the emissions may be viewed in context with the EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks*.

[554] Indirect GHG emissions are from vessel traffic associated with the project.

[555] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2017*, at ES-6 to ES-8 (2019), https://www.epa.gov/sites/production/files/2019-04/documents/us-ghg-inventory-2019-main-text.pdf.

[556] The national emissions reduction targets expressed in the EPA's Clean Power Plan were repealed, Greenhouse Gas Emissions From Existing Electric Utility Generating

260. In 2007, the State of Oregon enacted legislation establishing a state policy to meet the following three goals to reduce greenhouse gas emissions: (1) by 2010, arrest the growth of Oregon's greenhouse gas emissions and begin to reduce greenhouse gas emissions; (2) by 2020, achieve greenhouse gas levels that are 10 percent below 1990 levels (for a target total emissions of 51 million metric tonnes of CO_2e); and (3) by 2050, achieve greenhouse gas levels that are 75 percent below 1990 levels (for a target total emissions of 14 million metric tonnes of CO_2e).[557] The legislation, however, did not create any additional regulatory authority to meet its goals, and we are unaware of any measures Oregon has enacted to meet its goals that would apply to natural gas or LNG facilities.[558]

261. As noted above, the Jordan Cove LNG Terminal and the Pacific Connector Pipeline will result in annual CO_2e emissions of about 2.14 million metric tonnes of CO_2e. These annual emissions would impact the State's ability to meet its greenhouse gas reduction goals as the annual emissions would represent 4.2 percent and 15.3 percent of Oregon's 2020 and 2050 GHG goals, respectively.[559] Because we are unaware of any measures that Oregon has established to reduce GHGs directly emitted by natural gas or LNG facilities, we will not require the applicants to mitigate the impact on Oregon's ability to meet its GHG emission goals.

262. Furthermore, although an important consideration as part of our NEPA analysis, Oregon's emission goals are not the same as an objective determination that the GHG emissions from the projects will have a significant effect on climate change. The final EIS acknowledges that the quantified GHG emissions from the construction and operation of the projects will contribute incrementally to climate change.[560] However, as the Commission has previously concluded, we have neither the tools nor the expertise to determine whether project-related GHG emissions will have a significant impact on

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Units; Revisions to Emissions Guidelines Implementing Regulations, 84 Fed. Reg. 32,520, 32,522-32, 532 (July 8, 2019), and the targets in the Paris climate accord are pending withdrawal.

[557] The Oregon Global Warming Commission projects that Oregon will fall short of these goals without additional legislative action. Final EIS at 4-851.

[558] OR. REV. STAT. § 468A.205 (2007).

[559] Final EIS at 4-851; *see also* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 32-33.

[560] Final EIS at 4-850.

climate change and any potential resulting effects, such as global warming or sea rise.[561] The Commission has also previously concluded it could not determine whether a project's contribution to climate change would be significant.[562]

15. Reliability and Safety

263. As part of the NEPA review, Commission staff assessed potential impacts to the human environment in terms of safety and whether the proposed facilities would operate safely, reliably, and securely. Commission staff conducted a preliminary engineering and technical review of the Jordan Cove LNG Terminal, including potential external impacts based on the site location. Based on this review, the final EIS recommends mitigation measures for implementation prior to initial site preparation, prior to construction of final design, prior to commissioning, prior to introduction of hazardous fluids, prior to commencement of service, and throughout the life of the facility, to enhance the reliability and safety of the facility. With these measures, the final EIS concludes that acceptable layers of protection or safeguards would reduce the risk of a potentially hazardous scenario from developing that could impact the offsite public.[563] These recommendations have been adopted as mandatory conditions in the appendix to this order.

264. The applicants state that the proposed projects would be designed, constructed, operated, and maintained to meet or exceed Coast Guard Safety Standards,[564] the DOT Minimum Federal Safety Standards,[565] and other applicable federal and state regulations.[566] On May 10, 2018, the Coast Guard issued a Letter of Recommendation, indicating the Coos Bay Channel would be suitable for accommodating the type and frequency of LNG marine traffic associated with the Jordan Cove LNG Terminal.[567] If

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[561] *Rio Grande LNG, LLC*, 170 FERC ¶ 61,046, at P 108 (2020).

[562] *Id.*

[563] Final EIS at 5-11.

[564] 33 C.F.R. pts. 105 and 127 (2019).

[565] 49 C.F.R. pts. 192 and 193 (2019).

[566] *See* final EIS at 1-21 to 1-28 (Table 1.5.1-1) (summarizing the major federal, state, and local permits, approvals, and authorizations required for construction and operation of the projects).

[567] *See* Commission staff's June 1, 2018 Memo filed in Docket No. CP17-495-000 (containing the Coast Guard's May 10, 2018 Letter of Recommendation).

the Jordan Cove LNG Terminal is authorized and constructed, the facility would be subject to the Coast Guard's inspection and enforcement program to ensure compliance with the requirements of 33 C.F.R. Parts 105 and 127.[568]

265. Further, as described above,[569] PHMSA determined that the siting of the proposed Jordan Cove LNG Terminal complies with the applicable federal safety standards contained in Title 49 C.F.R. 193.[570] PHMSA's Letter of Determination summarizes its evaluation of the hazard modeling results and endpoints used to establish exclusion zones, as well as its review of Jordan Cove's evaluation of potential incidents and safety measures that could have a bearing on the safety of plant personnel and the surrounding public.[571]

266. The Pacific Connector Pipeline will be designed, constructed, operated, and maintained in accordance with the DOT Minimum Federal Safety Standards. These regulations, which are intended to protect the public and to prevent natural gas facility accidents and failures, include specifications for material selection and qualification, minimum design requirements, and protection of pipelines from corrosion. Accordingly, the final EIS concludes that Pacific Connector's compliance with the DOT's safety standards would ensure that construction and operation of the Pacific Connector Pipeline would not have a significant impact on public safety.[572]

16. <u>Cumulative Impacts</u>

267. The final EIS considers the cumulative impacts of the proposed Jordan Cove LNG Terminal and Pacific Connector Pipeline with other projects in the same geographic and temporal scope of the projects.[573] The types of other projects evaluated in the final EIS

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[568] 33 C.F.R. pts. 105 and 127.

[569] *See supra* P 41.

[570] *See* 49 C.F.R. pt. 193, Subpart B (2019).

[571] Oregon DLCD raises safety concerns related to the location of the LNG Terminal. *See* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 29-30. We find that the Coast Guard's Letter of Recommendation, PHMSA's Letter of Determination, and our engineering review on the use of various layers of protection or safeguards discussed in the final EIS address the issues raised by Oregon DLCD. *See* Final EIS at 4-738 to 4-808.

[572] Final EIS at 5-11.

[573] *Id.* at 4-822 to 4-852.

that could potentially contribute to cumulative impacts include Corps permits and mitigation projects, minor federal agency projects (including road/utility improvements, water flow control, weed treatments, and miscellaneous mitigation), residential and commercial development, timber harvest and forest management activities, livestock grazing, and solar panel fields.[574] As part of the cumulative impact analysis, Commission staff also considered non-jurisdictional utilities at the terminal site, the use of LNG carriers, ongoing maintenance dredging, modifications to the Coos Bay Federal Navigation Channel, project impact mitigation projects, and the potential removal of four dams on the Klamath River.[575]

268. The final EIS concludes that for the majority of resources where a level of impact could be ascertained, the projects' contribution to cumulative impacts on resources affected by the projects would not be significant, and that the potential cumulative impacts of the projects and other projects considered would not be significant.[576] However, the Jordan Cove LNG Terminal and Pacific Connector Pipeline would have significant cumulative impacts on housing availability in Coos Bay, the visual character of Coos Bay, and noise levels in Coos Bay.[577]

17. <u>Alternatives</u>

269. The final EIS evaluates numerous alternatives to the proposed projects, including the No-Action Alternative, system alternatives, LNG terminal site alternatives, and pipeline route alternatives and variations.[578] The final EIS concludes that, with the exception of one pipeline variation, the alternatives analyzed would either not meet the

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[574] *Id.* at 4-825.

[575] *Id.* at 4-828. The modifications to the Coos Bay Federal Navigation Channel include the Corps' Port of Coos Bay Channel Modification Project. *Id.* at 8-828, 8-836; *see also* Oregon DLCD's February 20, 2020 Federal Consistency Determination at 32.

[576] Final EIS at 4-852.

[577] *Id.* The final EIS also determined that the projects could have significant cumulative impacts on the Southwest Oregon Regional Airport. Based on determinations made by the FAA after issuance of the final EIS, we no longer conclude the projects could have significant cumulative impacts the airport. *See supra* PP 244- 247.

[578] *Id.* at 3-1 to 3-52.

projects' purpose and need, would not be technically feasible, or would not offer a significant environmental advantage.[579]

270. The final EIS does recommend one pipeline route variation: the Blue Ridge Variation. The 15.2-mile-long Blue Ridge Variation would deviate from the proposed route at MP 11 and would rejoin the proposed route near MP 25.[580] The Blue Ridge Variation is longer than the proposed route and crosses more than double the number of private parcels and miles of private lands.[581] In addition, the Blue Ridge Variation crosses more perennial waterbodies, known and assumed anadromous fish-bearing streams, and acres of wetlands.[582] However, the Blue Ridge Variation crosses less old-growth forest than the proposed route, and accordingly, substantially reduces the number of acres of occupied and presumed occupied marbled murrelet stands and acres of northern-spotted owl nesting, roosting, and foraging habitat that would be removed.[583]

271. The primary tradeoffs between the proposed route and the Blue Ridge Variation relate to terrestrial resources and aquatic resources and private lands.[584] Construction and operation of the proposed route would result in a permanent loss of old-growth forest and would adversely affect the marbled murrelet; there are minimal options for avoiding or reducing these impacts.[585] Conversely, impacts on aquatic resources under the Blue Ridge Variation would be temporary to short-term and could be minimized with implementation of the applicants' *Plan*, *Procedures*, and Pacific Connector's *Erosion Control and Revegetation Plan*.[586] Although the Blue Ridge Variation crosses more private lands, only one residence is within 50 feet of the construction right-of-way and, as discussed above, Pacific Connector will implement a number of measures to reduce impacts and facilitate restoration of the right-of-way.[587]

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[579] *Id.*

[580] *Id.* at 3-24.

[581] *Id.*

[582] *Id.*

[583] *Id.*

[584] *Id.*

[585] *Id.* at 3-25.

[586] *Id.*

[587] *Id.*

272. Based on the tradeoffs between the proposed route and the Blue Ridge Variation, the difference between the impacts in terms of temporal effects, as well as the scope of avoidance, minimization, and mitigation for these effects, and the magnitude of the effects, the final EIS concludes that the Blue Ridge Variation results in a significant environmental advantage compared to the proposed route.[588] We agree. Environmental Condition 16 requires Pacific Connector file alignment sheets incorporating the Blue Ridge Variation into its proposed route.

C. Comments Received After Issuance of the Final EIS

273. As noted above, between issuance of the final EIS and December 31, 2019, the Commission received comments on the final EIS from the applicants,[589] the Pacific Fishery Management Council, EPA, Oregon Department of Justice (on behalf of certain Oregon state agencies), two individuals, and the Cow Creek Band of Umpqua Tribe of Indians.[590]

1. Applicants' Comments

274. In their comments on the final EIS, the applicants request that the Commission not require the adoption of the Blue Ridge Variation into the pipeline route as recommended by staff. In support of their request, the applicants argue that the final EIS: (1) fails to account for the mitigation included in the applicants' proposed comprehensive mitigation plan; (2) fails to consider impacts in the context of BLM's 2016 Southwestern Oregon RMP; and (3) relies on improper habitat data and impact analysis that does not support

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[588] *Id.* at 3-26.

[589] In part, the applicants requested minor modifications to the wording of recommendations 34 and 38 in the final EIS. As discussed above, we have modified the wording of Environmental Conditions 34 and 38 accordingly. *See supra* notes 549 and 380. These modifications are not discussed further.

[590] During this time, the Commission also received courtesy copies of comments filed to other federal and state agencies with permitting authority over the proposals. Those comments are not addressed below. However, throughout the order we address comments raised in Oregon DLCD's February 20, 2020 Federal Consistency Determination. We find that we have adequately considered Oregon DLCD's comments in our final EIS and in this order, and that we have satisfied our obligations under NEPA and the NGA. Our authorizations do not impact any substantive determinations that need to be made by Oregon under federal statutes. Jordan Cove and Pacific Connector must receive the necessary state approvals under the federal statutes prior to construction.

the finding that the variation is preferable. Mr. Sheldon, a landowner on the Blue Ridge Variation, filed comments supporting the applicants' comments.

275. As explained above, Environmental Condition 16 requires Pacific Connector to incorporate the Blue Ridge Variation into its proposed route. The applicants' assertion that the analysis in the final EIS supporting Environmental Condition 16 did not consider the applicants' comprehensive mitigation plan is unsupported. Additionally, the applicants overstate the significance of the plan as it relates to impacts along Blue Ridge. The plan attempts to mitigate impacts for the projects; and, although general impacts may be mitigated by the plan, the plan does not reduce the amount or significance of impacts resulting along Blue Ridge. Furthermore, the mitigation measures in the plan have limited applicability to the habitat impacts specific to the proposed Blue Ridge route because the plan primarily mitigates for impacts on National Forest System lands, none of which are located along Blue Ridge. Measures in the plan that are specific to BLM lands pertain to watershed and aquatic habitat impacts and, therefore, are also not applicable to the analysis of forested habitat impacts on the Blue Ridge.

276. Information relevant to and regarding BLM RMPs was included in the final EIS to support BLM's consideration of the proposed amendments to its RMPs. As noted above, in order for the pipeline to be sited within BLM lands, BLM must amend its RMPs; additionally, Pacific Connector must obtain a right-of-way grant from BLM to cross federal lands. Concerns with proposed amendments to BLM RMPs should be directed to BLM. BLM was a cooperating agency for NEPA purposes and, accordingly, participated in the development of the draft and final EIS and associated analyses.

277. With regard to the applicants' comment that the final EIS analysis relies on improper habitat data and impact analysis that does not support the final EIS's conclusion, we acknowledge that inconsistent data exists for the amount and quality of old-growth forest affected by the proposed route and its significance as marbled murrelet and northern spotted owl habitat. Staff assessed available information, consulted with the cooperating agencies regarding data quality and sufficiency, and based its analysis on the best available information.[591] Using this information, staff concluded that, when comparing the duration of impacts, the Blue Ridge Variation would be environmentally preferable to the corresponding proposed route. As stated above, staff's conclusion was based primarily on the differences between temporary impacts on aquatic resources along the variation versus long-term or permanent impacts on forested habitat along the proposed route. As discussed in sections 4.3.2.2 and 4.5.2.3 of the final EIS, construction and operation of the projects would result in impacts on surface waterbodies and associated aquatic resources including turbidity and sedimentation, channel and streambank integrity and stability, in-stream flow, risk of hazardous material spills,

[591] We note that much of the data provided by the applicant for the Blue Ridge area was not collected according to FWS protocol.

potential regulatory status changes, and restrictions on fish passage. Generally, these impacts are temporary, occurring primarily during and immediately following active construction, and would be negligible once the waterbody banks and adjacent right-of-way are restored and successfully revegetated. As discussed in section 4.4.2.1 of the final EIS, impacts on forested habitat in general and old-growth specifically, would last for decades (80+ years) in temporary work areas, and would be a permanent impact within the maintained operational right-of-way. For these reasons, we find that staff's analysis appropriately considered available information, and, in Environmental Condition 16, we require that Pacific Connector incorporate the Blue Ridge Variation into its proposed route.

278. The applicants also request that the Commission remove the requirement to designate a Construction Housing Coordinator. The applicants argue that the recommendation is unwarranted because the projects would not have a significant impact on housing in the Coos Bay area. The applicants state that the analysis in the final EIS does not reflect the fact that "many local residents will be able to afford rental units associated with higher income brackets" because construction of the projects will create an economic stimulus and increase the incomes of many local residents.[592] They further argue that the final EIS did not take into consideration the less traditional housing options that may become available during construction.

279. The applicants' comments do not appear to account for the concurrent construction of the Jordan Cove LNG Terminal and Pacific Connector Pipeline in the Coos Bay area. We agree with the final EIS's determination that the combined and concurrent impact of these projects on demand for rental housing, although temporary, would be significant and would be likely more acutely felt by low-income households. Further, low-income households may not benefit from the potential economic stimulus associated with the projects. To address this impact, we require in Environmental Condition 28 that the applicants designate a Construction Housing Coordinator. Even with inclusion of this requirement, the final EIS concludes, and we agree, that impacts on short-term housing in Coos County would be significant.

280. In addition, the applicants state that the final EIS erroneously determined that the traditional cultural property proposed historic district known as "*Q'alya ta Kukwis schichdii me*" nominated by the Confederated Tribes of the Coos, Lower Umpqua, and Siuslaw Indians should be treated as eligible for listing in the National Register of Historic Places (National Register). The applicants claim that this determination was not supported in the administrative record.

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[592] Jordan Cove and Pacific Connector's December 6, 2019 Comments on the final EIS at 6.

281. As stated in the final EIS, the Oregon SHPO's finding that the traditional cultural property historic district is eligible for nomination to the National Register was conveyed to Commission staff in a letter dated July 19, 2019. That letter was filed in the Commission dockets for the proceedings, and thus the finding of eligibility is part of the administrative record.

282. The SHPO considered the arguments against the nomination of the traditional cultural property historic district raised by Jordan Cove, City of North Bend, Port of Coos Bay, and Confederated Tribes of Siletz Indians and dismissed them prior to making its finding of eligibility. Those arguments are not part of the administrative record that Commission staff considered when writing the final EIS because they were not filed in the proceedings until December 6, 2019. Nevertheless, staff acknowledged those objections to the nomination in its draft agreement document sent out for review by consulting parties on December 13, 2019. The National Park Service's rejection of the nomination for procedural and documentation deficiencies was noted in the final EIS.

283. Although the Commission determines if a property is eligible for listing, it does so in consultation with the SHPO. Generally, the Commission agrees with the opinions of the SHPO on findings of National Register eligibility and assessment of project effects. If a site is found to be eligible, it is considered to be a "historic property," in keeping with the definition in the regulations implementing Section 106 of the National Historic Preservation Act.[593]

284. Lastly, the applicants express concern with Commission staff's determination regarding the Franklin's bumble bee, which is a species newly proposed for listing under the Endangered Species Act.[594] Commission staff determined that construction and operation of the projects would not likely jeopardize the continued existence of the Franklin's bumble bee. Commission staff also made the provisional determination that, if the FWS lists the Franklin's bumble bee prior to completion of the projects, a *may affect, likely to adversely affect* determination would be warranted. The applicants claim that a "may affect" determination was not justified. We find that the applicants' comment is moot, as FWS subsequently made its own determination regarding the species based on Commission staff's determination as well as information provided by the applicant. In its Biological Opinion, FWS determined that the projects *may affect, but are not likely to adversely affect* the Franklin's bumble bee.

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[593] *See* 36 C.F.R. § 800.16(l) (2019).

[594] Staff's determination regarding the Franklin's bumblebee was made after issuance of the final EIS, in a December 2, 2019 Response to Data Gaps submittal to FWS.

2. Other Comments

285. In its comments on the final EIS, the Pacific Fishery Management Council (Council) reiterates its comments on the draft EIS and indicates that the projects will cause significant harm to EFH for several managed species (e.g., Chinook salmon, Coho salmon, rockfishes, English sole, lingcod and others) and that the projects' proposed wetland mitigation measures are not sufficient to offset the magnitude of loss or degradation to dozens of acres of estuarine habitat and many miles of riverine habitats. The Council also requests additional mitigation be required to avoid, minimize, and offset impacts on the environment. Lastly, the Council expresses concern that fishing vessel access to the Coos Bay Harbor will be constrained and requests additional information about how the LNG vessel safety zone will be implemented.

286. As noted above, the Commission consulted with NMFS regarding impacts on EFH. NMFS provided ten EFH conservation recommendation, eight of which are required by this order.[595] Further, as stated in the final EIS, the Commission defers to the Corps on wetland mitigation. The Corps and the Oregon Department of State Lands are currently working with the applicants on wetland mitigation requirements. Per the requirements of the Clean Water Act, the applicants must demonstrate that all impacts to wetlands are avoided or minimized to the extent practical as part of the Corps' 404 and 401 permitting processes. Additionally, the final EIS addresses impacts on commercial and recreational fishing vessels and concludes that impacts would occur but would not be significant. Regarding impacts to marine traffic, we defer to the Coast Guard, the entity responsible for regulating and managing safe vessel transit in Coos Bay.

287. In its comments, EPA Region 10 encourages the Commission to disclose all updated information concerning federal, state, and local permits to ensure the public and decision makers are fully informed about the potential impacts of the projects. All pertinent information received by the Commission regarding the projects has been included as appropriate in this order.

288. The Oregon Department of Justice, on behalf of certain Oregon state agencies, provided comments on the final EIS. These comments primarily reiterated comments made on the draft EIS concerning the projects' compliance with state requirements and guidance. As noted above, Pacific Connector and Jordan Cove would not be able to exercise the authorizations to construct and operate the projects until they receive all necessary federal and federally delegated state authorizations. We encourage our applicants to file for and receive the local and state permits, in good faith, as stewards of the community in which the facilities are located. However, this does not mean that state and local agencies, through application of state or local laws, may prohibit or

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[595] *See supra* P 217.

unreasonably delay the construction of facilities approved by the Commission.[596] With respect to needed federal authorizations, Environmental Condition 11 requires the applicants to receive all applicable authorizations required under federal law prior to construction. Additionally, Environmental Condition 27 requires that the applicants file, prior to beginning construction, a determination of consistency with the Coastal Zone Management Plan by the State of Oregon.[597]

289. Many of the Oregon SHPO's comments, which were included with the Oregon Department of Justice's filing, reiterate its comments on the draft EIS, which were addressed in Appendix R of the final EIS. We disagree that consultations with the SHPO on the definition of the area of potential effect have not occurred. The regulations implementing the National Historic Preservation Act, 36 C.F.R. § 800.2(a)(3) allow the agency "to use the services of applicants, consultants, or designees to prepare information, analyses, and recommendations." As is Commission practice, applicants or their consultants prepare cultural resources reports and submit them to the SHPO. The SHPO then typically comments on those reports, either in letters to the applicants/consultants or to Commission staff. Those reviews constitute part of the consultation process. In the case of the area of potential impact, the SHPO had the opportunity to comment in writing on cultural resources reports that spelled out the applicants/consultant definition, as well as comment on the draft and final EIS, which provided the Commission's definition of the area of potential impact.

290. In addition, our response to the Advisory Council on Historic Preservation's January 25, 2018 letter concerning the issue of monitoring pre-construction/project planning geotechnical testing at the LNG terminal was included in the draft and final EIS. Lastly, the SHPO has had the opportunity to comment on recommendations of NRHP eligibility and project effects in its review of reports submitted by the applicants and/or its consultants. Commission staff's determinations of eligibility and effect were provided in section 4.11.3 of the final EIS. In all cases, staff agrees with the SHPO's opinions. On December 13, 2019, Commission staff sent the SHPO a draft agreement document that defines the process that would be used to resolve adverse effects on historic properties that may be affected by the undertaking.

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[596] *See, e.g.*, *Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293 (1988); *Dominion Transmission, Inc. v. Summers*, 723 F.3d 238, at 243 (D.C. Cir. 2013) (holding state and local regulation is preempted by the NGA to the extent they conflict with federal regulation, or would delay the construction and operation of facilities approved by the Commission); *Iroquois Gas Transmission System, L.P.*, 52 FERC ¶ 61,091 (1990), *order on reh'g*, 59 FERC ¶ 61,094 (1992).

[597] *See supra* PP 230-231.

291. Two comment letters filed by the same individual, Ms. Jenny Jones, express concern with public safety, public need or benefit of the projects, noise impacts from pile-driving, and impacts on temporary housing. Public safety was addressed in section 4.13 of the final EIS, which, as noted above, concluded that acceptable layers of protection or safeguards would reduce the risk of a potentially hazardous scenario from developing that could impact the offsite public. The issue of the projects' public need or benefit is addressed elsewhere in this order.[598] Lastly, the final EIS and this order acknowledge the significant impacts that the projects would have on noise and housing availability in Coos Bay and require various measures to mitigate those impacts.[599]

292. The comments filed by the Cow Creek Band of Umpqua Tribe of Indians largely reiterate the tribe's comments on the draft EIS, which were addressed in Appendix R to the final EIS. The tribe expresses concern with the applicants' proposed mitigation for impacts to water resources and wetlands, and notes that some of the mitigation plans, as well as the Historic Properties Management Plan, are not yet final. As explained above, NEPA does not require a complete mitigation plan be actually formulated at the onset, but only that the proper procedures be followed for ensuring that the environmental consequences have been fairly evaluated.[600] Moreover, as explained above, Environmental Condition 30 requires that the applicants not begin construction of project facilities until, among other things, the applicants file the remaining cultural resource surveys, site evaluations and monitoring reports (as necessary), a revised ethnographic study, final Historic Properties Management Plans for both projects, a final *Unanticipated Discovery Plan*, and comments from the SHPO, interested Indian tribes, and applicable federal land-managing agencies. The draft agreement document, sent to the Cow Creek Band of Umpqua Tribe of Indians for review on December 13, 2019, also included stipulations that require the applicants to produce final versions of the Historic Properties Management Plans and *Unanticipated Discovery Plan* prior to construction.

D. Environmental Analysis Conclusion

293. We have reviewed the information and analysis contained in the final EIS regarding potential environmental effects of the projects, as well as other information in the record. We are adopting the environmental recommendations in the final EIS, as modified herein, and include them as conditions in the appendix to this order. Compliance with the environmental conditions appended to our orders is integral to ensuring that the environmental impacts of approved projects are consistent with those anticipated by our environmental analyses. Thus, Commission staff carefully reviews

[598] *See supra* PP 40-43 and 83-87.

[599] *See supra* PP 256-257 and 239.

[600] *See supra* P 160.

all information submitted. Commission staff will only issue a construction notice to proceed with an activity when satisfied that the applicant has complied with all applicable conditions. We also note that the Commission has the authority to take whatever steps are necessary to ensure the protection of environmental resources during construction and operation of the projects, including authority to impose any additional measures deemed necessary to ensure continued compliance with the intent of the conditions of the order, as well as the avoidance or mitigation of unforeseen adverse environmental impacts resulting from project construction and operation.[601]

294. We agree with the conclusions presented in the final EIS and find that if the projects are constructed and operated as described in the final EIS, the environmental impacts associated with the projects are acceptable considering the public benefits that will be provided by the projects. Accordingly, and for the reasons discussed throughout the order, we find that the Jordan Cove LNG Terminal is not inconsistent with the public interest and that the Pacific Connector Pipeline is required by the public convenience and necessity.

295. Any state or local permits issued with respect to the jurisdictional facilities authorized herein must be consistent with the conditions of this authorization and Certificate. The Commission encourages cooperation between applicants and local authorities.

VI. Conclusion

296. We find that the Jordan Cove LNG Terminal is not inconsistent with the public interest and that the Pacific Connector Pipeline is required by the public convenience and necessity.

297. The Commission on its own motion received and made part of the record in this proceeding all evidence, including the application, as supplemented, and exhibits thereto, and all comments, and upon consideration of the record,

The Commission orders:

(A) In Docket No. CP17-495-000, Jordan Cove is authorized under section 3 of the NGA to site, construct, and operate the proposed project in Coos County, Oregon, as described and conditioned herein, and as fully described in Jordan Cove's application and subsequent filings by the applicant, including any commitments made therein.

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[601] *See* Environmental Conditions 2 and 3.

(B) The authorization in Ordering Paragraph (A) above is conditioned on:

(1) Jordan Cove's facilities being fully constructed and made available for service within five years of the date of this order.

(2) Jordan Cove's compliance with the environmental conditions listed in the appendix to this order.

(C) In Docket No. CP17-494-000, a certificate of public convenience and necessity under section 7(c) of the NGA is issued to Pacific Connector authorizing it to construct and operate the proposed project, as described and conditioned herein, and as more fully described in Pacific Connector's application and subsequent filings by the applicant, including any commitments made therein.

(D) The certificate authorized in Ordering Paragraph (C) above is conditioned on:

(1) Pacific Connector's facilities being fully constructed and made available for service within five years of the date of this order pursuant to section 157.20(b) of the Commission's regulations;

(2) Pacific Connector's compliance with all applicable Commission regulations, particularly the general terms and conditions set forth in Parts 154, 157, and 284, and paragraphs (a), (c), (e), and (f) of section 157.20 of the Commission's regulations; and

(3) Pacific Connector's compliance with the environmental conditions listed in the appendix to this order.

(E) Pacific Connector's request for a blanket transportation certificate under Subpart G of Part 284 of the Commission's regulations is granted.

(F) Pacific Connector's request for a blanket construction certificate under Subpart F of Part 157 of the Commission's regulations is granted.

(G) Pacific Connector shall file a written statement affirming that it has executed firm contracts for the capacity levels and terms of service represented in its filed precedent agreement, prior to commencing construction.

(H) Pacific Connector's initial recourse rates, retainage percentages, and *pro forma* tariff are approved, as conditioned and modified above.

(I) Pacific Connector shall file actual tariff records that comply with the requirements contained in the body of this order at least 30 days prior to the commencement of interstate service consistent with Part 154 of the Commission's regulations.

(J) No later than three months after its first three years of actual operation of as discussed herein, Pacific Connector must make a filing to justify its existing cost-based firm and interruptible recourse rates. Pacific Connector's cost and revenue study should be filed through the eTariff portal using a Type of Filing Code 580. In addition, Pacific Connector is advised to include as part of the eFiling description, a reference to Docket No. CP17-494-000 and the cost and revenue study.

(K) Pacific Connector shall adhere to the accounting requirements discussed in the body of this order.

(L) Jordan Cove and Pacific Connector shall notify the Commission's environmental staff by telephone or e-mail of any environmental noncompliance identified by other federal, state, or local agencies on the same day that such agency notifies Jordan Cove or Pacific Connector. Jordan Cove and Pacific Connector shall file written confirmation of such notification with the Secretary of the Commission within 24 hours.

(M) The requests for a formal hearing and additional procedures are denied.

(N) The late, unopposed motions to intervene filed before issuance of this order in each respective docket are granted pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure.

(O) The motion filed by landowner-intervenors on April 19, 2019 is denied.

By the Commission. Commissioner Glick is dissenting with a separate statement attached.
Commissioner McNamee is concurring with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Appendix

Environmental Conditions

As recommended in the final environmental impact statement (EIS), this authorization includes the following conditions:

1. Jordan Cove Energy Project L.P. (Jordan Cove) and Pacific Connector Gas Pipeline, LP (Pacific Connector) shall follow the construction procedures and mitigation measures described in their respective applications and supplemental filings (including responses to staff data requests), and as identified in the Environmental Impact Statement (EIS), unless modified by the Order Granting Authorizations Under Sections 3 and 7 of the Natural Gas Act (Order). Jordan Cove and Pacific Connector must:
   a. request any modification to these procedures, measures, or conditions in a filing with the Secretary of the Commission (Secretary);
   b. justify each modification relative to site-specific conditions;
   c. explain how that modification provides an equal or greater level of environmental protection than the original measure; and
   d. receive approval in writing from the Director of the Office of Energy Projects (OEP) **before using that modification**.

2. For the liquefied natural gas (LNG) terminal, the Director of OEP, or the Director's designee, has delegated authority to address any requests for approvals or authorizations necessary to carry out the conditions of the Order, and take whatever steps are necessary to ensure the protection of life, health, property, and the environment during construction and operation of the Jordan Cove LNG Project. This authority shall include:
   a. the modification of conditions of the Order;
   b. stop-work authority and authority to cease operation; and
   c. the imposition of any additional measures deemed necessary to ensure continued compliance with the intent of the conditions of the Order as well as the avoidance or mitigation of unforeseen adverse environmental impact resulting from project construction and operation.

3. For the pipeline facilities, the Director of OEP, or the Director's designee, has delegated authority to address any requests for approvals or authorizations necessary to carry out the conditions of the Order, and take whatever steps are necessary to ensure the protection of environmental resources during construction and operation of the Pacific Connector Pipeline Project. This authority shall allow:

a. the modification of conditions of the Order;

b. stop-work authority; and

c. the imposition of any additional measures deemed necessary to ensure continued compliance with the intent of the conditions of the Order as well as the avoidance or mitigation of unforeseen adverse environmental impact resulting from project construction and operation activities.

4. **Prior to any construction,** Jordan Cove and Pacific Connector shall file an affirmative statement with the Secretary, certified by a senior company official, that all company personnel, Environmental Inspectors (EIs), and contractor personnel will be informed of the EI's authority and have been or will be trained on the implementation of the environmental mitigation measures appropriate to their jobs **before** becoming involved with construction and restoration activities.

5. The authorized facility locations shall be as shown in the EIS, as supplemented by filed site plans and alignment sheets, and shall include the route variations identified in condition 16 below. **As soon as they are available, and before the start of construction,** Jordan Cove and Pacific Connector shall file with the Secretary any revised detailed site plan drawings and survey alignment maps/sheets at a scale not smaller than 1:6,000 with station positions for all facilities approved by the Order. All requests for modifications of environmental conditions of the Order or site-specific clearances must be written and must reference locations designated on these site plan drawings.

   For the pipeline, Pacific Connector's exercise of eminent domain authority granted under Natural Gas Act (NGA) Section 7(h) in any condemnation proceedings related to the Order must be consistent with these authorized facilities and locations. Pacific Connector's right of eminent domain granted under NGA Section 7(h) does not authorize it to increase the size of its natural gas pipeline or facilities to accommodate future needs or to acquire a right-of-way for a pipeline to transport a commodity other than natural gas.

6. Jordan Cove and Pacific Connector shall file with the Secretary detailed site plan drawings, alignment maps/sheets, or aerial photographs at a scale not smaller than 1:6,000, identifying all route realignments, facility relocations, changes in site plan layout, staging areas, pipe storage yards, new access roads and other areas that would be used or disturbed and have not been previously identified in filings with the Secretary. Approval for each of these areas must be explicitly requested in writing. For each area, the request must include a description of the existing land use/cover type, documentation of landowner approval, whether any cultural resources or federally listed threatened or endangered species would be affected, and whether any other environmentally sensitive areas are within or abutting the area. All areas shall be clearly identified on the maps/sheets/aerial photographs.

Each area must be approved in writing by the Director of OEP **before construction in or near that area.**

This requirement does not apply to route variations required by the Order, extra workspace allowed by the Commission's *Upland Erosion Control, Revegetation, and Maintenance Plan* and/or minor field realignments per landowner needs and requirements which do not affect other landowners or sensitive environmental areas such as wetlands.

Examples of alterations requiring approval include all route realignments and facility location changes resulting from:

a. implementation of cultural resources mitigation measures;

b. implementation of endangered, threatened, or special concern species mitigation measures;

c. recommendations by state regulatory authorities; and

d. agreements with individual landowners that affect other landowners or could affect sensitive environmental areas.

7. **Within 60 days of the Order and before construction begins**, Jordan Cove and Pacific Connector shall each file an Implementation Plan with the Secretary for review and written approval by the Director of OEP. Jordan Cove and Pacific Connector must file revisions to the plan as schedules change. The plan shall identify:

a. how Jordan Cove and Pacific Connector will implement the construction procedures and mitigation measures described in its application and supplements (including responses to staff data requests), identified in the EIS, and required by the Order;

b. how Jordan Cove and Pacific Connector will incorporate these requirements into the contract bid documents, construction contracts (especially penalty clauses and specifications), and construction drawings so that the mitigation required at each site is clear to onsite construction and inspection personnel;

c. the number of EIs assigned, and how the company will ensure that sufficient personnel are available to implement the environmental mitigation;

d. company personnel, including EIs and contractors, who will receive copies of the appropriate material;

e. the location and dates of the environmental compliance training and instructions Jordan Cove and Pacific Connector will give to all personnel involved with construction and restoration (initial and refresher training as the Project progresses and personnel change), with the opportunity for OEP staff to participate in the training session(s);

f. the company personnel (if known) and specific portion of Jordan Cove's and Pacific Connector's organization having responsibility for compliance;

g. the procedures (including use of contract penalties) Jordan Cove and Pacific Connector will follow if noncompliance occurs; and

h. for each discrete facility, a Gantt or PERT chart (or similar Project scheduling diagram), and dates for:

1. the completion of all required surveys and reports;
2. the environmental compliance training of onsite personnel;
3. the start of construction; and
4. the start and completion of restoration.

8. Jordan Cove shall employ at least one EI for the LNG terminal and Pacific Connector shall employ a team of EIs for the pipeline facilities (i.e., at least one per construction spread or as may be established by the Director of OEP). The EIs shall be:

a. responsible for monitoring and ensuring compliance with all mitigation measures required by the Order and other grants, permits, certificates, or authorizing documents;

b. responsible for evaluating the construction contractor's implementation of the environmental mitigation measures required in the contract (see condition 7 above) and any other authorizing document;

c. empowered to order correction of acts that violate the environmental conditions of the Order, and any other authorizing document;

d. a full-time position separate from all other activity inspectors;

e. responsible for documenting compliance with the environmental conditions of the Order, as well as any environmental conditions/permit requirements imposed by other federal, state, or local agencies; and

f. responsible for maintaining status reports.

9. Beginning with the filing of its Implementation Plan, Jordan Cove shall file updated status reports with the Secretary on a **monthly** basis for the LNG terminal and Pacific Connector shall file updated status reports with the Secretary on a **biweekly** basis for the pipeline facilities until all construction and restoration activities are complete. Problems of a significant magnitude shall be reported to the Federal Energy Regulatory Commission (FERC or Commission) **within 24**

hours. On request, these status reports will also be provided to other federal and state agencies with permitting responsibilities. Status reports shall include:

a. an update on Jordan Cove's and Pacific Connector's efforts to obtain the necessary federal authorizations;

b. Project schedule, including current construction status of the LNG terminal/each pipeline spread, work planned for the following reporting period, and any schedule changes for stream crossings or work in other environmentally-sensitive areas;

c. a listing of all problems encountered, contractor nonconformance/deficiency logs, and each instance of noncompliance observed by the EI during the reporting period (both for the conditions imposed by the Commission and any environmental conditions/permit requirements imposed by other federal, state, or local agencies);

d. a description of the corrective and remedial actions implemented in response to all instances of noncompliance, nonconformance, or deficiency;

e. the effectiveness of all corrective and remedial actions implemented;

f. a description of any landowner/resident complaints which may relate to compliance with the requirements of the order, and the measures taken to satisfy their concerns; and

g. copies of any correspondence received by Jordan Cove and Pacific Connector from other federal, state, or local permitting agencies concerning instances of noncompliance, and Jordan Cove's and Pacific Connector's response.

10. Pacific Connector shall develop and implement an environmental complaint resolution procedure, and file such procedure with the Secretary, for review and approval by the Director of OEP. The procedure shall provide landowners with clear and simple directions for identifying and resolving their environmental mitigation problems/concerns during construction of the Project and restoration of the right-of-way. This procedure shall be in effect throughout the construction and restoration periods and two years thereafter. Prior to construction, Pacific Connector shall mail the complaint procedures to each landowner whose property will be crossed by the Project.

a. In its letter to affected landowners, Pacific Connector shall:

1. provide a local contact that the landowners should call first with their concerns; the letter should indicate how soon a landowner should expect a response;

2. instruct the landowners that if they are not satisfied with the response, they should call Pacific Connector's Hotline; the letter should indicate how soon to expect a response; and

3. instruct the landowners that if they are still not satisfied with the response from Pacific Connector's Hotline, they should contact the Commission's Landowner Helpline at 877-337-2237 or at LandownerHelp@ferc.gov.

b. In addition, Pacific Connector shall include in its bi-weekly status report a copy of a table that contains the following information for each problem/concern:

1. the identity of the caller and date of the call;

2. the location by milepost and identification number from the authorized alignment sheet(s) of the affected property;

3. a description of the problem/concern; and

4. an explanation of how and when the problem was resolved, will be resolved, or why it has not been resolved.

11. Jordan Cove and Pacific Connector must receive written authorization from the Director of OEP before commencing construction of any Project facilities, including any tree-felling or ground-disturbing activities. To obtain such authorization, Jordan Cove must file with the Secretary documentation that it has received all applicable authorizations required under federal law (or evidence of waiver thereof). Pacific Connector will not be granted authorization to commence construction of any of its Project facilities until 1) Jordan Cove has filed documentation that it has received all applicable authorizations required under federal law for construction of its terminal facilities (or evidence of waiver thereof) and 2) Pacific Connector has filed documentation that it has received all applicable authorizations required under federal law for construction of its pipeline facilities (or evidence of waiver thereof).

12. Jordan Cove must receive written authorization from the Director of OEP **prior to introducing hazardous fluids into the Project facilities**. Instrumentation and controls, hazard detection, hazard control, and security components/systems necessary for the safe introduction of such fluids shall be installed and functional.

13. Jordan Cove must receive written authorization from the Director of OEP **before placing into service** the LNG terminal and other components of the Jordan Cove LNG Project. Such authorization will only be granted following a determination that the facilities have been constructed in accordance with the FERC approval, can be expected to operate safely as designed, and the rehabilitation and restoration of the areas affected by the Project are proceeding satisfactorily.

14. Pacific Connector must receive written authorization from the Director of OEP **before placing the pipeline into service.** Such authorization will only be granted following a determination that rehabilitation and restoration of the right-of-way and other areas affected by the Pacific Connector Gas Pipeline Project are proceeding satisfactorily.

15. **Within 30 days of placing the authorized facilities in service**, Jordan Cove and Pacific Connector shall each file an affirmative statement with the Secretary, certified by a senior company official:

    a. that the facilities have been constructed in compliance with all applicable conditions, and that continuing activities will be consistent with all applicable conditions; or

    b. identifying which of the conditions of the Order Jordan Cove and Pacific Connector have complied with or will comply with. This statement shall also identify any areas affected by the Project where compliance measures were not properly implemented, if not previously identified in filed status reports, and the reason for noncompliance.

16. **Prior to construction,** Pacific Connector shall file with the Secretary, for review and written approval by the Director of OEP, revised alignment sheets that incorporate the Blue Ridge Variation into its proposed route between mileposts (MPs) 11 and 25. (*section 3.4.2.2*)

17. **Prior to construction,** Pacific Connector shall file an updated landslide identification study with the Secretary, for review and written approval by the Director of the OEP, that includes:

a. results of a review of any available Oregon Department of Geology and Mineral Industries (DOGAMI) landslide studies that were not previously used for landslide identification;

b. results of a review of the latest available DOGAMI Light Detection and Ranging (LiDAR) data for identification of landslides along the entire pipeline route;

    c. specific mitigation that will be implemented for any previously unidentified moderate or high-risk landslide areas of concern; and

    d. the final monitoring protocols and/or mitigation measures for all landslide areas that were not accessible during previous studies. (*section 4.1.2.4*)

18. **Prior to construction,** Pacific Connector shall file with the Secretary, for review and written approval by the Director of OEP, a listing of all drilling fluid additives, grout, and lost circulation material (LCM) that may be used during horizontal directional drill (HDD) activities, provide safety data sheets for these materials, and indicate the ecotoxicity of each additive mixed in the drilling fluid

to the identified toxicity for relevant biotic receptors. *(section 4.3.2.2)*

19. **Prior to construction,** Pacific Connector shall file with the Secretary a revised *Integrated Pest Management Plan*, for review and written approval by the Director of the OEP, that specifies that construction equipment will be cleaned after leaving areas of noxious weed infestations and pathogens and prior to entering United States Department of Interior Bureau of Land Management (BLM)-managed lands regardless of contiguous land owner. The revised plan shall also address BLM and United States Department of Agriculture Forest Service (Forest Service) requirements related to monitoring of invasive plant species and pathogens on federally managed lands, and documentation that the revised plan was found acceptable by the BLM and Forest Service. (*section 4.4.3.4*)

20. **Prior to construction,** Jordan Cove shall file with the Secretary, for review and written approval by the Director of OEP, its lighting plan. The plan shall include measures that will reduce lighting to the minimal levels necessary to ensure safe operation of the LNG facilities and any other measures that will be implemented to minimize lighting impacts on fish and wildlife. Along with its lighting plan, Jordan Cove shall file documentation that the plan was developed in consultation with the United States Fish and Wildlife Service (FWS), National Oceanic and Atmospheric Administration National Marine Fisheries Service (NMFS), and Oregon Department of Fish and Wildlife (ODFW). This lighting plan shall also be in compliance with condition 53. (*section 4.5.1.1)*

21. **Prior to construction,** Pacific Connector shall file with the Secretary documentation that the final *Fish Salvage Plan* was developed in consultation with interested tribes, ODFW, FWS, and NMFS. (*section 4.5.2.3*)

22. **Prior to construction**, Pacific Connector shall file with the Secretary, for review and written approval by the Director of OEP, a revised *Hydrostatic Test Plan* that requires that any water withdrawal from a flowing stream does not exceed an instantaneous flow reduction of more than 10 percent of stream flow. (*section 4.5.2.3*)

23. **Prior to construction**, Jordan Cove shall file with the Secretary, for review and written approval by the Director of OEP, a *Marine Mammal Monitoring Plan* that identifies how the presence of listed whales will be determined during construction, and measures Jordan Cove will take to reduce potential noise effects on whales and other marine mammals, and ensure compliance with NMFS underwater noise criteria for the protection of listed whales. *(section 4.6.1.1)*

24. **Prior to construction,** Pacific Connector shall file with the Secretary its commitment to adhere to FWS-recommended timing restrictions within threshold distances of marbled murrelet (MAMU) and northern spotted owl (NSO) stands

during construction, operations, and maintenance of the pipeline facilities. *(section 4.6.1.2)*

25. **Prior to construction,** Pacific Connector shall conduct standard protocol surveys of all suitable MAMU and NSO habitat that might be affected by the Project unless an alternate approach is approved by the FWS. Furthermore, Pacific Connector shall file with the Secretary the results of these surveys and documentation of its consultation with the FWS regarding the survey methods. *(section 4.6.1.2)*

26. Jordan Cove and Pacific Connector shall implement the reasonable and prudent measures and adopt the terms and conditions set forth for listed species in the Incidental Take Statements provided by NMFS and FWS on January 10 and January 31, 2020, respectively.

27. Jordan Cove and Pacific Connector **shall not begin construction** of the Project **until** they file with the Secretary a copy of the determination of consistency with the Coastal Zone Management Plan issued by the State of Oregon. (*section 4.7.1.2*)

28. **Prior to construction,** Jordan Cove and Pacific Connector shall file with the Secretary a statement affirming the designation of a Construction Housing Coordinator who will coordinate with contractors and the community to address housing concerns. Additionally, Jordan Cove and Pacific Connector shall describe the measures it will implement to inform affected communities about the Construction Housing Coordinator. *(section 4.9.2.2)*

29. **Prior to construction**, Jordan Cove shall file documentation that it has entered into a cooperative improvement agreement with the Oregon Department of Transportation (ODOT) and traffic development agreements with Coos County and the City of North Bend, as recommended in the *Traffic Impact Analysis report*. *(section 4.10.1.2)*

30. Jordan Cove and Pacific Connector shall **not begin construction of facilities and/or use** any staging, storage, or temporary work areas and new or to-be-improved access roads **until**:

    a. Jordan Cove and Pacific Connector each has filed with the Secretary:

        1. remaining cultural resources inventory reports for areas not previously surveyed;

        2. site evaluations and monitoring reports, as necessary;

        3. a revised Ethnographic Study Report that addresses the items outlined in staff's May 4 and October 23, 2018 environmental

information requests;

4. final Historic Properties Management Plans (HPMPs) for both Projects with avoidance plans;

5. final Unanticipated Discovery Plan (UDP); and

6. comments on the cultural resources reports, studies, and plans from the State Historic Preservation Officer (SHPO), applicable federal land managing agencies, and interested Indian tribes.

b. the Advisory Council on Historic Preservation (ACHP) is afforded an opportunity to comment on the undertaking; and

c. FERC staff reviews and the Director of OEP approves all cultural resources reports, studies, and plans, and notifies Jordan Cove and Pacific Connector in writing that treatment plans may be implemented and/or construction may proceed.

All materials filed with the Commission containing location, character, and ownership information about cultural resources must have the cover and any relevant pages therein clearly labeled in bold lettering: "Controlled Unclassified Information **(CUI)//Privileged (PRIV) - DO NOT RELEASE**." *(section 4.11.5*)

31. **During construction of the LNG terminal facilities and other activities requiring the use of vibratory and impact pile-driving**, Jordan Cove shall:

a. limit all active pile driving to between the hours of 7:00 a.m. and 10:00 p.m.; and

b. utilize wooden pile cushion/caps when conducting impact pile-driving work. (*section 4.12.2.3*)

32. Jordan Cove shall file a full power load noise survey with the Secretary **no later than 60 days after placing the entire LNG terminal into service**. If a full load noise survey is not possible, Jordan Cove shall file an interim survey at the maximum possible horsepower load **within 60 days** of placing the LNG terminal into service and file the full operational surveys **within 6 months**. If the noise attributable to the operation of all the equipment of the LNG terminal exceeds 55 decibels on the A-weighted scale, day-night equivalent (dBA L_{dn}) at any nearby noise sensitive areas (NSAs), under interim or full load conditions, Jordan Cove shall file a report on what changes are needed and install additional noise controls to meet the level **within 1 year** of the in-service date. Jordan Cove shall confirm compliance with this requirement by filing a second full power noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls. *(section 4.12.2.3)*

33. **Prior to drilling activities at HDD sites,** Pacific Connector shall file a site-

specific noise mitigation plan with the Secretary, for review and written approval by the Director of OEP. During any drilling operations, Pacific Connector shall implement the approved plan, monitor noise levels, and file in its biweekly reports documentation that the noise levels attributable to the drilling operations at NSAs does not exceed 55 L_{dn} dBA. (*section 4.12.2.4*)

34. Pacific Connector shall file a noise survey with the Secretary **no later than 60 days after placing the Klamath Compressor Station in service**. If a full load condition noise survey is not possible, Pacific Connector shall provide an interim survey at the maximum possible horsepower load and provide the full load survey **no later than 60 days after all liquefaction trains at the LNG Terminal are fully in service**. If the noise attributable to the operation of all of the equipment at the Klamath Compressor Station under interim or full horsepower load conditions exceeds an L_{dn} of 55 dBA at any nearby NSAs, Pacific Connector shall file a report on what changes are needed and shall install the additional noise controls to meet the level **within 1 year** of the in-service date. Pacific Connector shall confirm compliance with the above requirement by filing a second noise survey with the Secretary **no later than 60 days** after it installs the additional noise controls. *(section 4.12.2.4)*

35. **Prior to initial site preparation**, Jordan Cove shall file with the Secretary documentation of consultation with the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration (USDOT PHMSA) that the final design safety features demonstrates compliance with 49 Code of Federal Regulations (CFR) §193.2051 and National Fire Protection Association (NFPA) 59A 2.1.1(d). *(section 4.13.1.6)*

36. **Prior to construction of final design,** Jordan Cove shall file with the Secretary documentation of consultation with USDOT PHMSA staff as to whether the use of normally closed valves to remove stormwater from curbed areas will meet USDOT PHMSA requirements. *(section 4.13.1.6)*

37. **Prior to construction of final design**, Jordan Cove shall file with the Secretary the following information, stamped and sealed by the professional engineer-of-record, registered in Oregon:

    a. site preparation drawings and specifications;

    b. LNG terminal structures, LNG storage tank, and foundation design drawings and calculations (including prefabricated and field constructed structures);

    c. seismic specifications for procured Seismic Category I equipment prior to the issuing of request for quotations;

    d. quality control procedures to be used for civil/structural design and construction; and

e. a determination of whether soil improvement is necessary to counteract soil liquefaction.

In addition, Jordan Cove shall file, in its Implementation Plan, the schedule for producing this information. *(section 4.13.1.6)*

38. Jordan Cove shall employ a special inspector during construction of the LNG Terminal facilities and a copy of the inspection reports **shall be included in the monthly status reports** filed with the Secretary. The special inspector shall be responsible for:

a. observing the construction of the LNG terminal to be certain it conforms to the design drawings and specifications;

b. furnishing inspection reports to the engineer- or architect-of-record, and other designated persons. All discrepancies shall be brought to the immediate attention of the contractor for correction, then if uncorrected, to the engineer- or architect-of-record; and

c. submitting a final signed report stating whether the work requiring special inspection was, to the best of his/her knowledge, in conformance with approved plans and specifications and the applicable workmanship provisions. (section 4.13.1.6)

39. **Prior to receiving LNG carriers**, Jordan Cove shall file with the Secretary an affirmative statement indicating that a Letter of Agreement has been signed and executed with the Southwest Oregon Regional Airport as stipulated by the U.S. Department of Transportation Federal Aviation Administration's (FAA's) determination for temporary structures.

40. **Prior to commencement of service**, Jordan Cove shall file with the Secretary a monitoring and maintenance plan, stamped and sealed by the professional engineer-of-record registered in Oregon, which ensures the facilities are protected for the life of the LNG terminal considering settlement, subsidence, and sea level rise. *(section 4.13.1.6)*

Conditions 40 through 128 shall apply to the Jordan Cove LNG terminal. Information pertaining to these specific conditions shall be filed with the Secretary for review and written approval by the Director of OEP either: <u>prior to initial site preparation</u>; <u>prior to construction of final design</u>; <u>prior to commissioning</u>; <u>prior to introduction of hazardous fluids</u>; or <u>prior to commencement of service</u>, as indicated by each specific condition. Specific engineering, vulnerability, or detailed design information meeting the criteria specified in Order No. 683 (Docket No. RM06-24-000), including security information, shall be submitted as critical energy infrastructure information (CEII) pursuant to 18 CFR §388.112. See CEII, Order

No. 683, 71 Fed. Reg. 58,273 (October 3, 2006), FERC Stats. & Regs. ¶ 31,228 (2006). Information pertaining to items such as offsite emergency response; procedures for public notification and evacuation; and construction and operating reporting requirements will be subject to public disclosure. All information shall be filed <u>a minimum of 30 days</u> before approval to proceed is required.

41. **Prior to initial site preparation**, Jordan Cove shall file an overall Project schedule, which includes the proposed stages of the commissioning plan. *(section 4.13.1.6)*

42. **Prior to initial site preparation**, Jordan Cove shall file procedures for controlling access during construction. *(section 4.13.1.6)*

43. **Prior to initial site preparation**, Jordan Cove shall file quality assurance and quality control procedures for construction activities. *(section 4.13.1.6)*

44. **Prior to initial site preparation,** Jordan Cove shall file its design wind speed criteria for all other facilities not covered by USDOT PHMSA's Letter of Determination to be designed to withstand wind speeds commensurate with the risk and reliability associated with the facilities in accordance with ASCE 7-16 or equivalent. *(section 4.13.1.6)*

45. **Prior to initial site preparation**, Jordan Cove shall specify a spill containment system around the Warm Flare Knockout Drum. *(section 4.13.1.6)*

46. **Prior to initial site preparation**, Jordan Cove shall develop an Emergency Response Plan (ERP) (including evacuation) and coordinate procedures with the Coast Guard; state, county, and local emergency planning groups; fire departments; state and local law enforcement; and appropriate federal agencies. This plan shall include at a minimum:

    a. designated contacts with state and local emergency response agencies;

    b. scalable procedures for the prompt notification of appropriate local officials and emergency response agencies based on the level and severity of potential incidents;

    c. procedures for notifying residents and recreational users within areas of potential hazard;

    d. evacuation routes/methods for residents and public use areas that are within any transient hazard areas along the route of the LNG marine transit;

    e. locations of permanent sirens and other warning devices; and

    f. an "emergency coordinator" on each LNG marine vessel to activate sirens and other warning devices.

Jordan Cove shall notify the FERC staff of all planning meetings in advance and shall report progress on the development of its ERP **at 3-month intervals**. *(section 4.13.1.6)*

47. **Prior to initial site preparation**, Jordan Cove shall file a Cost-Sharing Plan identifying the mechanisms for funding all Project-specific security/emergency management costs that will be imposed on state and local agencies. This comprehensive plan shall include funding mechanisms for the capital costs associated with any necessary security/emergency management equipment and personnel base. Jordan Cove shall notify FERC staff of all planning meetings in advance and shall report progress on the development of its Cost Sharing Plan at **3-month intervals**. *(section 4.13.1.6)*

48. **Prior to construction of final design**, Jordan Cove shall file change logs that list and explain any changes made from the Front End Engineering Design (FEED) provided in Jordan Cove LNG Project's application and filings. A list of all changes with an explanation for the design alteration shall be provided and all changes shall be clearly indicated on all diagrams and drawings. The storage tank design shall reflect the updated elevations referenced in the FAA's permanent structure aeronautical studies. *(section 4.13.1.6)*

49. **Prior to construction of final design**, Jordan Cove shall file information/revisions pertaining to Jordan Cove's response numbers 8c, 13, 15, 21, 22, 23, 24, 26, 27, 28, and 31 of its December 20, 2018 filing and 6, 9, 10, 11, 17, 19, 32, 34, and 36 of its February 6, 2019 filing which indicated features to be included or considered in the final design. *(section 4.13.1.6)*

50. **Prior to construction of final design**, Jordan Cove shall file drawings and specifications for crash rated vehicle barriers at each facility entrance for access control. *(section 4.13.1.6)*

51. **Prior to construction of final design**, Jordan Cove shall file drawings of the security fence. The fencing drawings shall provide details of fencing that demonstrates it will restrict and deter access around the entire facility and has a setback from exterior features (e.g., power lines, trees, etc.) and from interior features (e.g., piping, equipment, buildings, etc.) that does not allow the fence to be overcome. *(section 4.13.1.6)*

52. **Prior to construction of final design**, Jordan Cove shall file drawings of internal road vehicle protections, such as guard rails, barriers, and bollards to protect transfer piping, pumps, compressors, hydrants, monitors, etc. to ensure that they are located away from roadway or protected from inadvertent damage from vehicles. *(section 4.13.1.6)*

53. **Prior to construction of final design**, Jordan Cove shall file security camera and intrusion detection drawings. The security camera drawings shall show the locations, areas covered, and features of each camera (e.g., fixed, tilt/pan/zoom, motion detection alerts, low light, mounting height, etc.) to verify camera coverage of the entire perimeter with redundancies for cameras interior to the facility to enable rapid monitoring of the facility, including a camera at the top of each LNG storage tank, and coverage within pretreatment areas, within liquefaction areas, within truck transfer areas, within marine transfer areas, and buildings. The drawings shall show or note the location of the intrusion detection to verify it covers the entire perimeter of the facility. *(section 4.13.1.6)*

54. **Prior to construction of final design**, Jordan Cove shall file lighting drawings. The lighting drawings shall show the location, elevation, type of light fixture, and lux levels of the lighting system and shall be in accordance with American Petroleum Institute (API) 540 and provide illumination along the perimeter of the facility, process equipment, mooring points, and along paths/roads of access and egress to facilitate security monitoring and emergency response operations. This lighting plan shall also be in compliance with condition 20. *(section 4.13.1.6)*

55. **Prior to construction of final design**, Jordan Cove shall file a plot plan of the final design showing all major equipment, structures, buildings, and impoundment systems. *(section 4.13.1.6)*

56. **Prior to construction of final design**, Jordan Cove shall file three-dimensional plant drawings to confirm plant layout for maintenance, access, egress, and congestion. *(section 4.13.1.6)*

57. **Prior to construction of final design**, Jordan Cove shall file up-to-date process flow diagrams (PFDs) and piping and instrument diagrams (P&IDs) including vendor P&IDs. The PFDs shall include heat and material balances. The P&IDs shall include the following information:

    a. equipment tag number, name, size, duty, capacity, and design conditions;

    b. equipment insulation type and thickness;

    c. storage tank pipe penetration size and nozzle schedule;

    d. valve high pressure side and internal and external vent locations;

    e. piping with line number, piping class specification, size, and insulation type and thickness;

    f. piping specification breaks and insulation limits;

    g. all control and manual valves numbered;

    h. relief valves with size and set points; and

i. drawing revision number and date. *(section 4.13.1.6)*

58. **Prior to construction of final design**, Jordan Cove shall file P&IDs, specifications, and procedures that clearly show and specify the tie-in details required to safely connect subsequently constructed facilities with the operational facilities. *(section 4.13.1.6)*

59. **Prior to construction of final design**, Jordan Cove shall file a car seal philosophy and a list of all car-sealed and locked valves consistent with the P&IDs. *(section 4.13.1.6)*

60. **Prior to construction of final design**, Jordan Cove shall file information to demonstrate the Engineering, Procurement, and Construction (EPC) contractor has verified that all FEED Hazard and Operability Study (HAZOP) and Layers of Protection Analysis (LOPA) recommendations have been addressed. *(section 4.13.1.6)*

61. **Prior to construction of final design**, Jordan Cove shall file a hazard and operability review, including a list of recommendations and actions taken on the recommendations, prior to issuing the P&IDs for construction. *(section 4.13.1.6)*

62. **Prior to construction of final design**, Jordan Cove shall provide a check valve upstream of the amine contractor column to prevent backflow or provide a dynamic simulation that shows that upon plant shutdown, the swan neck will be sufficient for this purpose. *(section 4.13.1.6)*

63. **Prior to construction of final design**, Jordan Cove shall specify how Mole Sieve Gas Dehydrator support and sieve material will be prevented from migrating to the piping system. *(section 4.13.1.6)*

64. **Prior to construction of final design**, Jordan Cove shall specify how the regeneration gas heater tube design temperature will be consistent with the higher shell side steam temperatures. *(section 4.13.1.6)*

65. **Prior to construction of final design**, Jordan Cove shall specify a cold gas bypass around the defrost gas heater to prevent defrost gas heater high temperature shutdown during low flow and startup conditions. *(section 4.13.1.6)*

66. **Prior to construction of final design**, Jordan Cove shall demonstrate that the differential pressure (dp) level transmitters on the LNG flash drum will not result in an excess number of false high-high-high level shutdowns. *(section 4.13.1.6)*

67. **Prior to construction of final design**, Jordan Cove shall specify a means to stop LNG flows to the boiloff gas (BOG) suction drum when the BOG compressor is shutdown to prevent filling the BOG suction drum with LNG. *(section 4.13.1.6)*

68. **Prior to construction of final design**, Jordan Cove shall specify a low instrument air pressure shutdown to prevent loss of control to air operated valves. *(section 4.13.1.6)*

69. **Prior to construction of final design**, Jordan Cove shall evaluate and, if applicable, address the potential for cryogenic feed gas back flow in the event relief valve 30-PSV-01002A/B is open. *(section 4.13.1.6)*

70. **Prior to construction of final design**, Jordan Cove shall include LNG tank fill flow measurement with high flow alarm. *(section 4.13.1.6)*

71. **Prior to construction of final design**, Jordan Cove shall specify a discretionary vent valve on each LNG storage tank that is operable through the Distributed Control System (DCS). In addition, a car sealed open manual block valve shall be provided upstream of the discretionary vent valve. *(section 4.13.1.6)*

72. **Prior to construction of final design**, Jordan Cove shall file the safe operating limits (upper and lower), alarm and shutdown set points for all instrumentation (e.g., temperature, pressures, flows, and compositions). *(section 4.13.1.6)*

73. **Prior to construction of final design**, Jordan Cove shall file cause-and-effect matrices for the process instrumentation, fire and gas detection system, and emergency shutdown system. The cause-and-effect matrices shall include alarms and shutdown functions, details of the voting and shutdown logic, and set points. *(section 4.13.1.6)*

74. **Prior to construction of final design**, Jordan Cove shall file an up-to-date equipment list, process and mechanical data sheets, and specifications. The specifications shall include:

   a. building specifications (e.g., control buildings, electrical buildings, compressor buildings, storage buildings, pressurized buildings, ventilated buildings, blast resistant buildings);

   b. mechanical specifications (e.g., piping, valve, insulation, rotating equipment, heat exchanger, storage tank and vessel, other specialized equipment);

   c. electrical and instrumentation specifications (e.g., power system, control system, safety instrument system [SIS], cable specifications, other electrical and instrumentation); and

   d. security and fire safety specifications (e.g., security, passive protection, hazard detection, hazard control, firewater). *(section 4.13.1.6)*

75. **Prior to construction of final design**, Jordan Cove shall file a list of all codes and standards and the final specification document number where they are referenced. *(section 4.13.1.6)*

76. **Prior to construction of final design**, Jordan Cove shall file complete specifications and drawings of the proposed LNG tank design and installation. *(section 4.13.1.6)*

77. **Prior to construction of final design**, Jordan Cove shall file an evaluation of emergency shutdown valve closure times. The evaluation shall account for the time to detect an upset or hazardous condition, notify plant personnel, and close the emergency shutdown valve(s). *(section 4.13.1.6)*

78. **Prior to construction of final design**, Jordan Cove shall file an evaluation of dynamic pressure surge effects from valve opening and closure times and pump operations that demonstrate that the surge effects do not exceed the design pressures. *(section 4.13.1.6)*

79. **Prior to construction of final design**, Jordan Cove shall demonstrate that, for hazardous fluids, piping and piping nipples 2 inches or less in diameter are designed to withstand external loads, including vibrational loads in the vicinity of rotating equipment and operator live loads in areas accessible by operators. *(section 4.13.1.6)*

80. **Prior to construction of final design**, Jordan Cove shall clearly specify the responsibilities of the LNG tank contractor and the EPC contractor for the piping associated with the LNG storage tank. *(section 4.13.1.6)*

81. **Prior to construction of final design**, Jordan Cove shall file the sizing basis and capacity for the final design of the flares and/or vent stacks as well as the pressure and vacuum relief valves for major process equipment, vessels, and storage tanks. *(section 4.13.1.6)*

82. **Prior to construction of final design**, Jordan Cove shall file an updated fire protection evaluation of the proposed facilities. A copy of the evaluation, a list of recommendations and supporting justifications, and actions taken on the recommendations shall be filed. The evaluation shall justify the type, quantity, and location of hazard detection and hazard control, passive fire protection, emergency shutdown and depressurizing systems, firewater, and emergency response equipment, training, and qualifications in accordance with NFPA 59A (2001). The justification for the flammable and combustible gas detection and flame and heat detection systems shall be in accordance with International Systems of America (ISA) 84.00.07 or equivalent methodologies and would need to demonstrate 90 percent or more of releases (unignited and ignited) that could

result in an off-site or cascading impact would be detected by two or more detectors and result in isolation and de inventory within 10 minutes. The analysis shall take into account the set points, voting logic, wind speeds, and wind directions. The justification for firewater shall provide calculations for all firewater demands based on design densities, surface area, and throw distance as well as specifications for the corresponding hydrant and monitors needed to reach and cool equipment. *(section 4.13.1.6)*

83. **Prior to construction of final design**, Jordan Cove shall file spill containment system drawings with dimensions and slopes of curbing, trenches, impoundments, and capacity calculations considering any foundations and equipment within impoundments, as well as the sizing and design of the down-comers. The spill containment drawings shall show containment for all hazardous fluids including all liquids handled above their flashpoint, from the largest flow from a single line for 10 minutes, including de-inventory, or the maximum liquid from the largest vessel (or total of impounded vessels) or otherwise demonstrate that providing spill containment would not significantly reduce the flammable vapor dispersion or radiant heat consequences of a spill. *(section 4.13.1.6)*

84. **Prior to construction of final design,** Jordan Cove shall file an analysis that demonstrates the flammable vapor dispersion from design spills will be prevented from dispersing underneath the elevated LNG storage tanks, or the LNG storage tanks will be able to withstand an overpressure due to ignition of the flammable vapor that disperses underneath the elevated LNG storage tanks.

85. **Prior to construction of final design**, Jordan Cove shall file electrical area classification drawings. *(section 4.13.1.6)*

86. **Prior to construction of final design**, Jordan Cove shall provide documentation demonstrating adequate ventilation, detection, and electrical area classification based on the final selection of the batteries, and associated hydrogen off-gassing rates. *(section 4.13.1.6)*

87. **Prior to construction of final design**, Jordan Cove shall file drawings and details of how process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system meet the requirements of NFPA 59A (2001). *(section 4.13.1.6)*

88. **Prior to construction of final design**, Jordan Cove shall file details of an air gap or vent installed downstream of process seals or isolations installed at the interface between a flammable fluid system and an electrical conduit or wiring system. Each air gap shall vent to a safe location and be equipped with a leak detection device that shall continuously monitor for the presence of a flammable fluid, alarm

the hazardous condition, and shut down the appropriate systems. *(section 4.13.1.6)*

89. **Prior to construction of final design**, Jordan Cove shall file complete drawings and a list of the hazard detection equipment. The drawings shall clearly show the location and elevation of all detection equipment. The list shall include the instrument tag number, type and location, alarm indication locations, and shutdown functions of the hazard detection equipment. *(section 4.13.1.6)*

90. **Prior to construction of final design**, Jordan Cove shall file a technical review of facility design that:

    a. identifies all combustion/ventilation air intake equipment and the distances to any possible flammable gas or toxic release; and

    b. demonstrates that these areas are adequately covered by hazard detection devices and indicates how these devices would isolate or shutdown any combustion or heating ventilation and air conditioning equipment whose continued operation could add to or sustain an emergency. *(section 4.13.1.6)*

91. **Prior to construction of final design**, Jordan Cove shall file a design that includes hazard detection suitable to detect high temperatures and smoldering combustion products in electrical buildings and control room buildings. *(section 4.13.1.6)*

92. **Prior to construction of final design**, Jordan Cove shall file an evaluation of the voting logic and voting degradation for hazard detectors. *(section 4.13.1.6)*

93. **Prior to construction of final design**, Jordan Cove shall file a list of alarm and shutdown set points for all hazard detectors that account for the calibration gas of the hazard detectors when determining the lower flammable limit set points for methane, ethylene, propane, isopentane, and condensate. *(section 4.13.1.6)*

94. **Prior to construction of final design**, Jordan Cove shall file a list of alarm and shutdown set points for all hazard detectors that account for the calibration gas of hazard detectors when determining the set points for toxic components such as condensate and hydrogen sulfide. *(section 4.13.1.6)*

95. **Prior to construction of final design**, Jordan Cove shall file a drawing showing the location of the emergency shutdown buttons. Emergency shutdown buttons shall be easily accessible, conspicuously labeled, and located in an area which will be accessible during an emergency. *(section 4.13.1.6)*

96. **Prior to construction of final design**, Jordan Cove shall file facility plan drawings and a list of the fixed and wheeled dry-chemical, hand-held fire

extinguishers, and other hazard control equipment. Plan drawings shall clearly show the location by tag number of all fixed, wheeled, and hand-held extinguishers and shall demonstrate the spacing of extinguishers meet prescribed NFPA 10 travel distances. The list shall include the equipment tag number, type, capacity, equipment covered, discharge rate, and automatic and manual remote signals initiating discharge of the units and shall demonstrate they meet NFPA 59A. *(section 4.13.1.6)*

97. **Prior to construction of final design**, Jordan Cove shall file drawings and specifications for the structural passive protection systems to protect equipment and supports from cryogenic releases. *(section 4.13.1.6)*

98. **Prior to construction of final design**, Jordan Cove shall file calculations or test results for the structural passive protection systems to protect equipment and supports from cryogenic releases. *(section 4.13.1.6)*

99. **Prior to construction of final design**, Jordan Cove shall file drawings and specifications for the structural passive protection systems to protect equipment and supports from pool and jet fires. *(section 4.13.1.6)*

100. **Prior to construction of final design**, Jordan Cove shall file a detailed quantitative analysis to demonstrate that adequate mitigation will be provided for each significant component within the 4,000 British thermal units per hour square foot (Btu/ft^2-hr) zone from pool and jet fires that could cause failure of the component. Trucks at the truck transfer station shall be included in the analysis. A combination of passive and active protection for pool fires and passive and/or active protection for jet fires shall be provided and demonstrate the effectiveness and reliability. Effectiveness of passive mitigation shall be supported by calculations or test results for the thickness limiting temperature rise and effectiveness of active mitigation shall be justified with calculations or test results demonstrating flow rates and durations of any cooling water would mitigate the heat absorbed by the vessel. *(section 4.13.1.6)*

101. **Prior to construction of final design**, Jordan Cove shall file an evaluation and associated specifications and drawings of how it would prevent cascading damage of transformers (e.g., fire walls or spacing) in accordance with NFPA 850 or equivalent. *(section 4.13.1.6)*

102. **Prior to construction of final design**, Jordan Cove shall file facility plan drawings showing the proposed location of the firewater and any foam systems. Plan drawings shall clearly show the location of firewater and foam piping, post indicator valves, and the location and area covered by, each monitor, hydrant, hose, water curtain, deluge system, foam system, water-mist system, and sprinkler. All areas of the pretreatment area shall have adequate coverage. The drawings

shall also include piping and instrumentation diagrams of the firewater and foam systems. *(section 4.13.1.6)*

103. **Prior to construction of final design**, Jordan Cove shall specify that the firewater pump shelter is designed to allow removal of the largest firewater pump or other component for maintenance with an overhead or external crane. *(section 4.13.1.6)*

104. **Prior to construction of final design**, Jordan Cove shall demonstrate that the firewater storage tanks are in compliance with NFPA 22 or demonstrate how API Standard 650 provides an equivalent or better level of safety. *(section 4.13.1.6)*

105. **Prior to construction of final design**, Jordan Cove shall specify that the firewater flow test meter is equipped with a transmitter and that a pressure transmitter is installed upstream of the flow transmitter. The flow transmitter and pressure transmitter shall be connected to the distributed control system (DCS) and recorded. *(section 4.13.1.6)*

106. **Prior to construction of final design**, Jordan Cove shall file drawings of the storage tank piping support structure and support of horizontal piping at grade including pump columns, relief valves, pipe penetrations, instrumentation, and appurtenances. *(section 4.13.1.6)*

107. **Prior to construction of final design**, Jordan Cove shall file the structural analysis of the LNG storage tank and outer containment demonstrating they are designed to withstand all loads and combinations. *(section 4.13.1.6)*

108. **Prior to construction of final design**, Jordan Cove shall file an analysis of the structural integrity of the outer containment of the full containment LNG storage tank demonstrating it can withstand the radiant heat from a roof tank top fire or adjacent tank roof fire. *(section 4.13.1.6)*

109. **Prior to construction of final design**, Jordan Cove shall file a projectile analysis to demonstrate that the outer concrete impoundment wall of a full-containment LNG storage tank could withstand projectiles from explosions and high winds. The analysis shall detail the projectile speeds and characteristics and method used to determine penetration or perforation depths. *(section 4.13.1.6)*

110. **Prior to commissioning**, Jordan Cove shall file a detailed schedule for commissioning through equipment startup. The schedule shall include milestones for all procedures and tests to be completed: prior to introduction of hazardous fluids and during commissioning and startup. Jordan Cove shall file documentation certifying that each of these milestones has been completed before authorization to commence the next phase of commissioning and startup will be issued. *(section 4.13.1.6)*

111. **Prior to commissioning**, Jordan Cove shall file detailed plans and procedures for: testing the integrity of onsite mechanical installation; functional tests; introduction of hazardous fluids; operational tests; and placing the equipment into service. *(section 4.13.1.6)*

112. **Prior to commissioning**, Jordan Cove shall file settlement results from the hydrostatic tests of the LNG storage containers and shall file a plan to periodically verify settlement is as expected and does not exceed the applicable criteria set forth in API 620, API 625, API 653, and ACI 376. The plan shall also specify what actions will be taken after various levels of seismic events. *(section 4.13.1.6)*

113. **Prior to commissioning**, Jordan Cove shall file the operation and maintenance procedures and manuals, as well as safety procedures, hot work procedures and permits, abnormal operating conditions reporting procedures, simultaneous operations procedures, and management of change procedures and forms. *(section 4.13.1.6)*

114. **Prior to commissioning**, Jordan Cove shall file a plan for clean-out, dry-out, purging, and tightness testing. This plan shall address the requirements of the American Gas Association's Purging Principles and Practice, and shall provide justification if not using an inert or non-flammable gas for clean-out, dry-out, purging, and tightness testing. *(section 4.13.1.6)*

115. **Prior to commissioning**, Jordan Cove shall tag all equipment, instrumentation, and valves in the field, including drain valves, vent valves, main valves, and car-sealed or locked valves. *(section 4.13.1.6)*

116. **Prior to commissioning**, Jordan Cove shall file a plan describing how it will maintain a detailed training log to demonstrate that operating, maintenance, and emergency response staff have completed the required training. *(section 4.13.1.6)*

117. **Prior to commissioning**, Jordan Cove shall file the procedures for pressure/leak tests which address the requirements of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC) Section VIII and ASME B31.3. In addition, Jordan Cove shall file a line list of pneumatic and hydrostatic test pressures. *(section 4.13.1.6)*

118. **Prior to introduction of hazardous fluids**, Jordan Cove shall complete and document a pre-startup safety review to ensure that installed equipment meets the design and operating intent of the facility. The pre-startup safety review shall include any changes since the last hazard review, operating procedures, and operator training. A copy of the review with a list of recommendations, and actions taken on each recommendation, shall be filed. *(section 4.13.1.6)*

119. **Prior to introduction of hazardous fluids**, Jordan Cove shall complete and document all pertinent tests (Factory Acceptance Tests, Site Acceptance Tests, Site Integration Tests) associated with the DCS and SIS that demonstrates full functionality and operability of the system. *(section 4.13.1.6)*

120. **Prior to introduction of hazardous fluids**, Jordan Cove shall develop and implement an alarm management program to reduce alarm complacency and maximize the effectiveness of operator response to alarms. *(section 4.13.1.6)*

121. **Prior to introduction of hazardous fluids**, Jordan Cove shall complete and document clean agent acceptance tests. *(section 4.13.1.6)*

122. **Prior to introduction of hazardous fluids**, Jordan Cove shall complete and document a firewater pump acceptance test and firewater monitor and hydrant coverage test. The actual coverage area from each monitor and hydrant shall be shown on facility plot plan(s). *(section 4.13.1.6)*

123. **Prior to introduction of hazardous fluids**, Jordan Cove shall complete and document foam system and sprinkler system acceptance tests. *(section 4.13.1.6)*

124. Jordan Cove shall file a request for written authorization from the Director of OEP **prior to unloading or loading the first LNG commissioning cargo**. After production of first LNG, Jordan Cove shall file weekly reports on the commissioning of the proposed systems that detail the progress toward demonstrating the facilities can safely and reliably operate at or near the design production rate. The reports shall include a summary of activities, problems encountered, and remedial actions taken. The weekly reports shall also include the latest commissioning schedule, including projected and actual LNG production by each liquefaction train, LNG storage inventories in each storage tank, and the number of anticipated and actual LNG commissioning cargoes, along with the associated volumes loaded or unloaded. Further, the weekly reports shall include a status and list of all planned and completed safety and reliability tests, work authorizations, and punch list items. Problems of significant magnitude shall be reported to the FERC within 24 hours. *(section 4.13.1.6)*

125. **Prior to commencement of service**, Jordan Cove shall file a request for written authorization from the Director of OEP. Such authorization will only be granted following a determination by the Coast Guard, under its authorities under the Ports and Waterways Safety Act, the Magnuson Act, the Maritime Transportation Security Act of 2002, and the Security and Accountability For Every Port Act, that appropriate measures to ensure the safety and security of the facility and the waterway have been put into place by Jordan Cove or other appropriate parties. *(section 4.13.1.6)*

126. **Prior to commencement of service**, Jordan Cove shall notify the FERC staff of any proposed revisions to the security plan and physical security of the plant. *(section 4.13.1.6)*

127. **Prior to commencement of service**, Jordan Cove shall label piping with fluid service and direction of flow in the field, in addition to the pipe labeling requirements of NFPA 59A (2001). *(section 4.13.1.6)*

128. **Prior to commencement of service**, Jordan Cove shall provide plans for any preventative and predictive maintenance program that performs periodic or continuous equipment condition monitoring. *(section 4.13.1.6)*

129. **Prior to commencement of service**, Jordan Cove shall develop procedures for offsite contractors' responsibilities, restrictions, and limitations and for supervision of these contractors by Jordan Cove staff. *(section 4.13.1.6)*

In addition, conditions 129 through 132 shall apply throughout the life of the Jordan Cove LNG Project.

130. The facility shall be subject to regular FERC staff technical reviews and site inspections on at least an **annual** basis or more frequently as circumstances indicate. Prior to each FERC staff technical review and site inspection, Jordan Cove shall respond to a specific data request including information relating to possible design and operating conditions that may have been imposed by other agencies or organizations. Up-to-date detailed P&IDs reflecting facility modifications and provision of other pertinent information not included in the semi-annual reports described below, including facility events that have taken place since the previously submitted semi-annual report, shall be submitted. *(section 4.13.1.6)*

131. **Semi-annual** operational reports shall be filed with the Secretary to identify changes in facility design and operating conditions; abnormal operating experiences; activities (e.g., ship arrivals, quantity and composition of imported and exported LNG, liquefied and vaporized quantities, boil off/flash gas); and plant modifications, including future plans and progress thereof. Abnormalities shall include, but not be limited to, unloading/loading/shipping problems, potential hazardous conditions from offsite vessels, storage tank stratification or rollover, geysering, storage tank pressure excursions, cold spots on the storage tank, storage tank vibrations and/or vibrations in associated cryogenic piping, storage tank settlement, significant equipment or instrumentation malfunctions or failures, non-scheduled maintenance or repair (and reasons therefore), relative movement of storage tank inner vessels, hazardous fluids releases, fires involving hazardous fluids and/or from other sources, negative pressure (vacuum) within a storage tank, and higher than predicted boil off rates. Adverse weather conditions and the

effect on the facility also shall be reported. Reports shall be submitted **within 45 days after each period ending June 30 and December 31**. In addition to the above items, a section entitled "Significant Plant Modifications Proposed for the Next 12 Months (dates)" shall be included in the semi-annual operational reports. Such information would provide the FERC staff with early notice of anticipated future construction/maintenance at the LNG facilities. *(section 4.13.1.6)*

132. In the event the temperature of any region of the LNG storage container, including any secondary containment and imbedded pipe supports, becomes less than the minimum specified operating temperature for the material, the Commission shall be notified **within 24 hours** and procedures for corrective action shall be specified. *(section 4.13.1.6)*

133. Significant non-scheduled events, including safety-related incidents (e.g., LNG, condensate, refrigerant, or natural gas releases; fires; explosions; mechanical failures; unusual over pressurization; and major injuries) and security-related incidents (e.g., attempts to enter site, suspicious activities) shall be reported to the FERC staff. In the event that an abnormality is of significant magnitude to threaten public or employee safety, cause significant property damage, or interrupt service, notification shall be made **immediately**, without unduly interfering with any necessary or appropriate emergency repair, alarm, or other emergency procedure. In all instances, notification shall be made to the FERC staff **within 24 hours**. This notification practice shall be incorporated into the liquefaction facility's emergency plan. Examples of reportable hazardous fluids-related incidents include:

a. fire;

b. explosion;

c. estimated property damage of $50,000 or more;

d. death or personal injury necessitating in-patient hospitalization;

e. release of hazardous fluids for 5 minutes or more;

f. unintended movement or abnormal loading by environmental causes, such as an earthquake, landslide, or flood, that impairs the serviceability, structural integrity, or reliability of an LNG facility that contains, controls, or processes hazardous fluids;

g. any crack or other material defect that impairs the structural integrity or reliability of an LNG facility that contains, controls, or processes hazardous fluids;

h. any malfunction or operating error that causes the pressure of a pipeline or LNG facility that contains or processes hazardous fluids to rise above its maximum allowable operating pressure (or working pressure for LNG facilities) plus the build-up allowed for operation of pressure-limiting or control devices;

i. a leak in an LNG facility that contains or processes hazardous fluids that constitutes an emergency;

j. inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of an LNG storage tank;

k. any safety-related condition that could lead to an imminent hazard and cause (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent reduction in operating pressure or shutdown of operation of a pipeline or an LNG facility that contains or processes hazardous fluids;

l. safety-related incidents from hazardous fluids transportation occurring at or en route to and from the LNG facility; or

m. an event that is significant in the judgment of the operator and/or management even though it did not meet the above criteria or the guidelines set forth in an LNG facility's incident management plan.

In the event of an incident, the Director of OEP has delegated authority to take whatever steps are necessary to ensure operational reliability and to protect human life, health, property, or the environment, including authority to direct the LNG facility to cease operations. Following the initial company notification, the FERC staff would determine the need for a separate follow-up report or follow up in the upcoming semi-annual operational report. All company follow-up reports shall include investigation results and recommendations to minimize a reoccurrence of the incident. *(section 4.13.1.6)*

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Jordan Cove Energy Project L.P.	Docket Nos.	CP17-495-000
Pacific Connector Gas Pipeline, LP		CP17-494-000

(Issued March 19, 2020)

GLICK, Commissioner, *dissenting*:

1. I dissent from today's order because it violates both the Natural Gas Act[1] (NGA) and the National Environmental Policy Act[2] (NEPA). Rather than wrestling with the Project's[3] significant adverse impacts, today's order makes clear that the Commission will not allow these impacts to get in the way of its outcome-oriented desire to approve the Project.[4]

2. As an initial matter, the Commission once again refuses to consider the consequences its actions have for climate change. Although neither the NGA nor NEPA permit the Commission to assume away the impact that constructing and operating the LNG Terminal and Pipeline will have on climate change, that is precisely what the Commission is doing here. In today's order authorizing the Project, pursuant to both section 3 and section 7 of the NGA, the Commission continues to treat climate change differently than all other environmental impacts. The Commission steadfastly refuses to assess whether the impact of the Project's greenhouse gas (GHG) emissions on climate change is significant, even though it quantifies the GHG emissions caused by the

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[1] 15 U.S.C. §§ 717b, 717f (2018).

[2] National Environmental Policy Act of 1969, 42 U.S.C. §§ 4321 *et seq.*

[3] Today's order authorizes the construction and operation of the Jordan Cove LNG export terminal (LNG Terminal) pursuant to NGA section 3, 15 U.S.C. § 717b (2018), and the new Pacific Connector interstate natural gas pipeline (Pipeline) pursuant to NGA section 7, *id.* § 717f. I will refer to those projects collectively as the Project.

[4] The Commission previously denied Pacific Connector Gas Pipeline, L.P. an NGA section 7 certificate because it did not show that the Pipeline was needed and, at the same time, denied Jordan Cove an NGA section 3 certificate because it had no natural gas supply without the Pacific Connector pipeline. *See Jordan Cove Energy Project, L.P.*, 154 FERC ¶ 61,190 (2016).

Project's construction and operation.[5] That refusal to assess the significance of the Project's contribution to the harm caused by climate change is what allows the Commission to perfunctorily conclude that "the environmental impacts associated with the project are "acceptable"[6] and, as a result, conclude that the Project satisfies the NGA's public interest standards.[7] Claiming that a project's environmental impacts are acceptable while at the same time refusing to assess the significance of the project's impact on the most important environmental issue of our time is not reasoned decisionmaking.

3. Moreover, the Commission's public interest analysis does not adequately wrestle with the Project's adverse impacts. The Project will significantly and adversely affect several threatened and endangered species, historic properties, and the supply of short-term housing in the vicinity of the project. It will also cause elevated noise levels during construction and impair visual character of the local community. Although the Commission recites those adverse impacts, at no point does it explain how it considered them in making its public interest determination or why it finds that the Project satisfies the relevant public interest standards notwithstanding those substantial impacts. Simply asserting that the Project is in the public interest without any discussion why is not reasoned decisionmaking.

I. The Commission's Public Interest Determinations Are Not the Product of Reasoned Decisionmaking

4. The NGA's regulation of LNG import and export facilities "implicate[s] a tangled web of regulatory processes" split between the U.S. Department of Energy (DOE) and the Commission.[8] The NGA establishes a general presumption favoring the import and export of LNG unless there is an affirmative finding that the import or export "will not be

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[5] *Jordan Cove Energy Project L.P.*, 170 FERC ¶ 61,202, at P 259 (2020) (Certificate Order); Final Environmental Impact Statement at Tables 4.12.1.3-1, 4.12.1.3-2, 4.12.1.4-1 & 4.12.1.4-2 (EIS).

[6] Certificate Order, 170 FERC ¶ 61,202 at P 294; EIS at ES-19. *But see* Certificate Order, 169 FERC ¶ 61,131 at PP 155, 220-223, 237, 242, 253, 256 (noting that the environmental impacts of the Project would be significant with respect to several federally listed threatened and endangered species, visual character in the vicinity of the LNG Terminal, short-term housing in Coos County, historic properties along the Pipeline route, and noise levels in Coos County).

[7] Certificate Order, 170 FERC ¶ 61,202 at P 294.

[8] *Sierra Club v. FERC*, 827 F.3d 36, 40 (D.C. Cir. 2016) (*Freeport*).

consistent with the public interest."[9] Section 3 of the NGA provides for two independent public interest determinations: One regarding the import or export of LNG itself and one regarding the facilities used for that import or export.

5. DOE determines whether the import or export of LNG is consistent with the public interest, with transactions among free trade countries legislatively deemed to be "consistent with the public interest."[10] The Commission evaluates whether "an application for the siting, construction, expansion, or operation of an LNG terminal" is itself consistent with the public interest.[11] Pursuant to that authority, the Commission must approve a proposed LNG facility unless the record shows that the facility would be inconsistent with the public interest.[12] Today's order fails to satisfy that standard in multiple respects.

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[9] 15 U.S.C. § 717b(a); *see EarthReports, Inc. v. FERC*, 828 F.3d 949, 953 (D.C. Cir. 2016) (citing *W. Va. Pub. Servs. Comm'n v. Dep't of Energy*, 681 F.2d 847, 856 (D.C. Cir. 1982) ("NGA [section] 3, unlike [section] 7, 'sets out a general presumption favoring such authorization.'")). Under section 7 of the NGA, the Commission approves a proposed pipeline if it is shown to be consistent with the public interest, while under section 3, the Commission approves a proposed LNG import or export facility unless it is shown to be inconsistent with the public interest. *Compare* 15 U.S.C. § 717b(a) *with id.* § 717f(a), (e).

[10] 15 U.S.C. § 717b(c). The courts have explained that, because the authority to authorize the LNG exports rests with DOE, NEPA does not require the Commission to consider the upstream or downstream GHG emissions that may be indirect effects of the export itself when determining whether the related LNG export facility satisfies section 3 of the NGA. *See Freeport*, 827 F.3d at 46-47; *see also Sierra Club v. FERC*, 867 F.3d 1357, 1373 (D.C. Cir. 2017) (*Sabal Trail*) (discussing *Freeport*). Nevertheless, NEPA requires that the Commission consider the direct GHG emissions associated with a proposed LNG export facility. *See Freeport*, 827 F.3d at 41, 46.

[11] 15 U.S.C. § 717b(e). In 1977, Congress transferred the regulatory functions of NGA section 3 to DOE. DOE, however, subsequently delegated to the Commission authority to approve or deny an application for the siting, construction, expansion, or operation of an LNG terminal, while retaining the authority to determine whether the import or export of LNG to non-free trade countries is in the public interest. *See EarthReports*, 828 F.3d at 952-53.

[12] *See Freeport*, 827 F.3d at 40-41.

A. The Commission's Public Interest Determination Does Not Adequately Consider Climate Change

6. In making its public interest determination, the Commission examines a proposed facility's impact on the environment and public safety. A facility's impact on climate change is one of the environmental impacts that must be part of a public interest determination under the NGA.[13] Nevertheless, the Commission maintains that it need not consider whether the Project's contribution to climate change is significant in this order because it lacks a means to do so—or at least so it claims.[14] However, the most troubling part of the Commission's rationale is what comes next. Based on this alleged inability to assess the significance of the Project's impact on climate change, the Commission still concludes that all of the Project's environmental impacts would be "acceptable."[15] Think about that. The Commission is simultaneously stating that it cannot assess the significance of the Project's impact on climate change[16] while concluding that all environmental impacts are acceptable to the public interest.[17] That is unreasoned and an abdication of our responsibility to give climate change the "hard look" that the law demands.[18]

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[13] *See Sabal Trail*, 867 F.3d at 1373 (explaining that the Commission must consider a pipeline's direct and indirect GHG emissions because the Commission may "deny a pipeline certificate on the ground that the pipeline would be too harmful to the environment"); *see also Atl. Ref. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 391 (1959) (holding that the NGA requires the Commission to consider "all factors bearing on the public interest").

[14] Certificate Order, 170 FERC ¶ 61,202 at P 262; EIS at 4-4-850.

[15] Certificate Order, 170 FERC ¶ 61,202 at P 294.

[16] *Id.* P 262; EIS at 4-4-850 ("[W]e are unable to determine the significance of the Project's contribution to climate change.").

[17] Certificate Order, 170 FERC ¶ 61,202 at P 294 (stating that the environmental impacts are acceptable and further concluding that the Jordan Cove LNG Terminal is not inconsistent with the public interest and that the Pacific Connector Pipeline is required by the public convenience and necessity.)

[18] *See, e.g.*, *Myersville Citizens for a Rural Cmty., Inc. v. FERC*, 783 F.3d 1301, 1322 (D.C. Cir. 2015) (explaining that agencies cannot overlook a single environmental consequence if it is even "arguably significant"); *see also Michigan v. EPA*, 135 S. Ct. 2699, 2706 (2015) ("Not only must an agency's decreed result be within the scope of its lawful authority, but the process by which it reaches that result must be logical and

7. It also means that the Project's impact on climate change does not play a meaningful role in the Commission's public interest determination, no matter how often the Commission assures us that it does. Using the approach in today's order, the Commission will always conclude that a project will not have a significant environmental impact irrespective of that project's actual GHG emissions or those emissions' impact on climate change. If the Commission's conclusion will not change no matter how many GHG emissions a project causes, those emissions cannot, as a logical matter, play a meaningful role in the Commission's public interest determination. A public interest determination that systematically excludes the most important environmental consideration of our time is contrary to law, arbitrary and capricious, and not the product of reasoned decisionmaking.

8. The failure to meaningfully consider the Project's GHG emissions is all-the-more indefensible given the volume of GHG emissions at issue in this proceeding. The Project will directly release over 2 million tons of GHG emissions per year.[19] The Commission recognizes that climate change is "driven by accumulation of GHG in the atmosphere through combustion of fossil fuels (coal, petroleum, and natural gas), combined with agriculture, clearing of forests, and other natural sources"[20] and that the "GHG emissions from the construction and operation of the projects will contribute incrementally to climate change."[21] In light of this undisputed relationship between anthropogenic GHG emissions and climate change, the Commission must carefully consider the Project's contribution to climate change when determining whether the Project is consistent with the public interest—a task that it entirely fails to accomplish in today's order.

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rational." (internal quotation marks omitted)); *Motor Vehicle Mfrs. Ass'n, Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (explaining that agency action is "arbitrary and capricious if the agency has . . . entirely failed to consider an important aspect of the problem, [or] offered an explanation for its decision that runs counter to the evidence before the agency").

[19] Certificate Order, 170 FERC ¶ 61,202 at P 259; EIS at Tables 4.12.1.3-1, 4.12.1.3-2, 4.12.1.4-1 & 4.12.1.4-2 (estimating the Project's direct and indirect emissions from construction and operation, including vessel traffic).

[20] EIS at 4-849.

[21] Certificate Order, 170 FERC ¶ 61,202 at P 262.

B. The Commission's Consideration of the Project's Other Adverse Impacts Is Also Arbitrary and Capricious

9. In addition, the Project is expected to have a significant adverse effect on threatened and endangered species, including whale, fish, and bird species,[22] historic properties along the pipeline route,[23] and short-term housing in Coos County.[24] Indeed, the Project will adversely affect more than 20 different Federally-listed threatened or endangered species.[25] It will also cause harmful noise levels in the area[26] and impair the visual character of the surrounding community.[27] Although the Commission discloses the adverse impacts throughout the EIS and mentions them in today's order,[28] it does not appear that they meaningfully factor into the Commission's public interest analysis.

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[22] *Id.* PP 220-223.

[23] *Id.* P 253; EIS at 4-683. Following the completion of some land surveys, the Commission states that at least 20 sites along the Pipeline route are eligible historic properties and cannot be avoided. EIS at 5-9 ("Constructing and operating the Project would have adverse effects on historic properties under Section 106 of the [National Historic Preservation Act].").

[24] Certificate Order, 170 FERC ¶ 61,202 at PP 242; EIS at 4-631– 4-635 (finding that the construction of the Project may have significant effects on short-term housing in Coos County, Oregon, which could include potential displacement of existing and potential residents, as well as tourists and other visitors); *see also* Certificate Order, 170 FERC ¶ 61,202 at P 279 (further concluding that these impacts would more acutely impact low-income households).

[25] Certificate Order, 170 FERC ¶ 61,202 at PP 222-223. Furthermore, the Commission asserts that it would authorize the Project to proceed on the basis of its adverse impact on threatened and endangered species only if that impact would jeopardize the continued existence of the specific. EIS at 4-378. As a logical matter, if the Commission will not consider denying a certificate unless it causes the relevant species to extinct, then any sub-extinction level adverse impacts cannot meaningfully factor into the Commission's public interest determination.

[26] EIS at 4-717– 4-721. The Commission finds that pile driving associated with LNG Terminal construction occurring 20 hours per day for two years would result in a significant impact on the local community.

[27] Certificate Order, 170 FERC ¶ 61,202 at P 237.

[28] *Id.* PP 155, 220-223, 237, 242, 253, 256 (noting that the environmental impacts of the Project would be significant with respect to several federal-listed threatened and

10. The Commission notes that the Project may provide various benefits, such as jobs and economic stimulus for the region, and weighs those benefits against adverse economic interests.[29] I certainly recognize that public benefits should be considered in the public interest determination. But reasoned decisionmaking requires that the Commission do more than simply point to the benefits of the Project and assert that the Project satisfies the relevant public interest standard, especially where, as here, the Project will also have considerable adverse impacts. Instead, the Commission must weigh the Project's benefits and all adverse impacts, including those on the environment, if it is to reach a reasoned decision.[30]

11. The Sierra Club's protest makes this very point, contending that environmental impacts "must be incorporated into the balancing . . . of the public interest."[31] In response, the Commission asserts its "balancing of adverse impacts and public benefits is not an environmental analysis process, but rather an economic test."[32] Given that statement, and the absence of any effort in today's order to explain why the Project satisfies the relevant public interest standards despite the significant environmental impacts,[33] the only rational conclusion is that those substantial environmental impacts do not meaningfully factor into the Commission's application of the public interest. The courts, however, have been clear that the Commission must consider "all factors bearing on the public interest."[34] Accordingly, the Commission's refusal to consider

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endangered species, visual character in the vicinity of the LNG Terminal, short-term housing in Coos County, historic properties along the Pipeline route, and noise levels in Coos County).

[29] *Id.* P 94 (concluding that "benefits the Pacific Connector Pipeline will provide outweigh the adverse effects on economic interests.").

[30] That is particularly important when it comes to the Commission's section 7 authorization of the Pipeline because it conveys eminent domain authority, 15 U.S.C. § 717f(h) (2018), and roughly a quarter of the private landowners have not reached easement agreements, meaning that, upon issuance of the certificate, they may be subject to condemnation proceedings.

[31] Sierra Club's October 26, 2017 Protest at 6.

[32] Certificate Order, 170 FERC ¶ 61,202 at P 92.

[33] Although today's order identifies several significant adverse environmental impacts, the Commission concludes that these environmental impacts are "acceptable considering the public benefits" without any explanation of how the benefits outweigh the substantial adverse impacts. *See id.* P 294.

[34] *See Sabal Trail*, 867 F.3d at 1373 (explaining that the Commission may "deny a

environmental impacts as part of its public interest analysis is inconsistent with the NGA and arbitrary and capricious.

II. The Commission Fails to Satisfy Its Obligations under NEPA

12. The Commission's NEPA analysis of the Project's GHG emissions is similarly flawed. In order to evaluate the environmental consequences of the Project under NEPA, the Commission must consider the harm caused by its GHG emissions and "evaluate the 'incremental impact' that those emissions will have on climate change or the environment more generally."[35] As noted, the operation of the Project will emit more than 2 million tons of GHG emissions per year.[36] Although quantifying the Project's GHG emissions is a necessary step toward meeting the Commission's NEPA obligations, listing the volume of emissions alone is insufficient.[37] As an initial matter, identifying the consequences that those emissions will have for climate change is essential if NEPA is to play the disclosure and good government roles for which it was designed. The Supreme Court has explained that NEPA's purpose is to "ensure[] that the agency, in reaching its decision, will have available, and will carefully consider, detailed information concerning significant environmental impacts" and to "guarantee[] that the relevant information will

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pipeline certificate on the ground that the pipeline would be too harmful to the environment"); *see also Atl. Ref. Co.*, 360 U.S. at 391 (holding that the NGA requires the Commission to consider "all factors bearing on the public interest").

[35] *Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1216 (9th Cir. 2008); *WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41, 51 (D.D.C. 2019) (explaining that the agency was required to "provide the information necessary for the public and agency decisionmakers to understand the degree to which [its] decisions at issue would contribute" to the "impacts of climate change in the state, the region, and across the country").

[36] Certificate Order, 170 FERC ¶ 61,202 at P 258; EIS at Tables 4.12.1.3-1, 4.12.1.3-2, 4.12.1.4-1 & 4.12.1.4-2 (estimating the Project's direct and indirect emissions from the Project's construction and operation, including vessel traffic associated with the LNG Terminal).

[37] *See Ctr. for Biological Diversity*, 538 F.3d at 1216 ("While the [environmental document] quantifies the expected amount of CO_2 emitted . . . , it does not evaluate the 'incremental impact' that these emissions will have on climate change or on the environment more generally."); *Klamath-Siskiyou Wildlands Ctr. v. Bureau of Land Mgmt.*, 387 F.3d 989, 995 (9th Cir. 2004) ("A calculation of the total number of acres to be harvested in the watershed is a necessary component . . . , but it is not a sufficient description of the actual environmental effects that can be expected from logging those acres.").

be made available to the larger audience that may also play a role in both the decisionmaking process and the implementation of that decision."[38] It is hard to see how hiding the ball by refusing to assess the significance of the Project's climate impacts is consistent with either of those purposes.

13. In addition, under NEPA, a finding of significance informs the Commission's inquiry into potential ways of mitigating environmental impacts.[39] An environmental review document must "contain a detailed discussion of possible mitigation measures" to address adverse environmental impacts.[40] "Without such a discussion, neither the agency nor other interested groups and individuals can properly evaluate the severity of the adverse effects" of a project, meaning that an examination of possible mitigation measures is necessary to ensure that the agency has taken a "hard look" at the environmental consequences of the action at issue.[41]

14. The Commission responds that it need not determine whether the Project's contribution to climate change is significant because "[t]here is no universally accepted methodology" for assessing the harms caused by the Project's contribution to climate change.[42] But the lack of a single consensus methodology does not prevent the Commission from adopting *a* methodology, even if it is not universally accepted. The Commission could, for example, select one methodology to inform its reasoning while also disclosing its potential limitations or the Commission could employ multiple methodologies to identify a range of potential impacts on climate change. In refusing to assess a project's climate impacts without a perfect model for doing so, the Commission

[38] *Dep't of Transp. v. Pub. Citizen*, 541 U.S. 752, 768 (2004) (citing *Robertson v. Methow Valley Citizens Coun.*, 490 U.S. 332, 349 (1989)).

[39] 40 C.F.R. § 1502.16 (2019) (requiring an implementing agency to form a "scientific and analytic basis for the comparisons" of the environmental consequences of its action in its environmental review, which "shall include discussions of . . . [d]irect effects and their significance.").

[40] *Robertson*, 490 U.S. at 351.

[41] *Id.* at 352.

[42] EIS at 4-850 (stating that "there is no universally accepted methodology to attribute discrete, quantifiable, physical effects on the environment to Project's incremental contribution to GHGs" and "[w]ithout the ability to determine discrete resource impacts, we are unable to determine the significance of the Project's contribution to climate change."); *see also* Certificate Order, 170 FERC ¶ 61,202 at P 262 ("The Commission has also previously concluded it could not determine whether a project's contribution to climate change would be significant.").

sets a standard for its climate analysis that is higher than it requires for any other environmental impact.

15. Indeed, the record in this proceeding provides exactly the type of methodology that the Commission has previously suggested would permit it to make a significance determination. Throughout the course of the last year, the Commission has justified its refusal to consider the significance of a project's GHG emissions on the basis that it could not "find any GHG emission reduction goals established either at the federal level or by the [state]."[43] As the Commission explained in discussing the LNG export facility it most recently approved: "Without either the ability to determine discrete resource impacts or an established target to compare GHG emissions against, we are unable to determine the significance of the Project's contribution to climate change."[44]

16. But Oregon has an "established target to compare GHG emissions against." The State has a legislative goal of reducing GHG emissions 10 percent below 1990 levels by 2020 and 75 percent below 1990 levels by 2050.[45] That is exactly the type of goal that the Commission has previously suggested would provide a framework for establishing significance. Today's order recognizes the state's reduction goals and acknowledges that the Project's GHG emissions would "represent 4.2 percent and 15.3 percent of Oregon's 2020 and 2050 GHG goals, respectively"[46]—*i.e.*, the Project alone would account for almost an eighth of the total state-wide emissions permissible under Oregon law in 2050.

17. But today's order then moves the goal posts once again. Notwithstanding its previous statements that a federal or state climate goal could provide a benchmark to evaluate GHG emissions, the Commission now takes the position that those benchmarks are insufficient because they are not "objective."[47] The Commission, however, provides

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[43] *See, e.g.*, Certificate Order, 170 FERC ¶ 61,202 at P 262 (citing *Rio Grande LNG, LLC*, 170 FERC ¶ 61,046 (2020)). The Commission's order in *Rio Grande* adopted the conclusion that the Commission has "not been able to find any GHG emission reduction goals established either at the federal level or by the [state]. Without either the ability to determine discrete resource impacts or an established target to compare GHG emissions against, we are unable to determine the significance of the Project's contribution to climate change." Final Environmental Impact Statement, Docket No. CP16-454-000, at 4-482 (Apr. 26, 2019).

[44] Final Environmental Impact Statement, Docket No. CP16-454-000 at 5-22.

[45] *See* Certificate Order, 170 FERC ¶ 61,202 at P 260.

[46] *Id.* P 261.

[47] *Id.* P 262.

no justification for its change of heart or its newest excuse for ignoring the significance of the Project's contribution to climate change. As I have previously explained, simply adding the word "objective" does not provide a reasoned basis for refusing to assess significance.[48]

18. It is clear what is going on. The Commission is at pains to avoid having to say that a project's GHG emissions or the impact of those emissions on climate change is significant. After all, it is only when it comes to climate change (and, as noted, only now) that the Commission claims to need an "objective" measure to evaluate significance. The Commission often relies on percentage comparisons when assessing the significance of other environmental impacts. It is only when it comes to climate change that the Commission suddenly gets cold feet about using percentages to determine significance and demands the type of "objective" standard that it does not require anywhere else.

19. In any case, even without a formal tool or methodology, the Commission can consider all factors and determine, quantitatively or qualitatively, whether the Project's GHG emissions will have a significant impact on climate change. After all, that is precisely what the Commission does in other aspects of its environmental review, where the Commission makes several significance determinations based on subjective assessments of the extent of the Project's impact on the environment.[49] The Commission's refusal to similarly analyze the Project's impact on climate change is arbitrary and capricious.

20. And even if the Commission were to determine that the Project's GHG emissions are significant, that is not the end of the analysis. Instead, as noted above, the Commission could blunt those impacts through mitigation—as the Commission often does with regard to other environmental impacts. The Supreme Court has held that an environmental review must "contain a detailed discussion of possible mitigation measures" to address adverse environmental impacts.[50] As noted above, "[w]ithout such a discussion, neither the agency nor other interested groups and individuals can properly evaluate the severity of the adverse effects."[51]

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[48] *Rio Grande LNG, LLC*, 170 FERC ¶ 61,046 (Glick, Comm'r, dissenting at P 22).

[49] *See, e.g.*, EIS at 4-184, 4-619–4-620, 4-645 (concluding that there will be no significant impact on vegetation, Tribal subsistence practices, and marine vessel traffic).

[50] *Robertson*, 490 U.S. at 351.

[51] *Id.* at 351-52; *see also* 40 C.F.R. § 1508.20 (2019) (defining mitigation); *id.* § 1508.25 (including in the scope of an environmental impact statement mitigation

21. Consistent with this obligation, the EIS discusses mitigation measures to ensure that the Project's adverse environmental impacts (other than its GHG emissions) are reduced to less-than-significant levels.[52] And throughout today's order, the Commissions uses its broad conditioning authority under section 3 and section 7 of the NGA[53] to implement these mitigation measures, which support its public interest finding.[54] For example, the Commission uses this broad conditioning authority to mitigate the impact on short-term housing in Coos County caused by the influx of workers during construction of the LNG Terminal and Pipeline. The Commission concludes that the influx of workers will not only create a short-term rental shortage during the peak tourist season, but this impact would be acutely felt by low-income households.[55] To mitigate this significant impact, the Commission requires Jordan Cove to designate a Construction Housing Coordinator to address these housing concerns. Despite this use of our conditioning authority to mitigate adverse impacts, the Project's climate impacts continue to be treated differently, as the Commission refuses to identify any potential climate mitigation measures or discuss how such measures might affect the magnitude of the Project's impact on climate change.[56]

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measures).

[52] *See, e.g.*, EIS at 4-656 (discussing mitigation required by the Commission to address motor vehicle traffic impacts from the Project).

[53] 15 U.S.C. § 717b(e)(3)(A); *id.* § 717f(e); Certificate Order, 170 FERC ¶ 61,202 at P 293 ("[T]he Commission has the authority to take whatever steps are necessary to ensure the protection of environmental resources . . . , including authority to impose any additional measures deemed necessary.").

[54] *See* Certificate Order, 170 FERC ¶ 61,202 at P 293 (explaining that the environmental conditions ensure that the Project's environmental impacts are consistent with those anticipated by the environmental analysis).

[55] *Id.* P 279.

[56] Commissioner McNamee implies that, as part of a mitigation mechanism, I want the Commission to consider imposing a carbon tax or a cap-and-trade like system. Certificate Order, 170 FERC ¶ 61,202 (McNamee, Comm'r, concurring at P 59). That is a red herring. To my knowledge, no one has suggested that the Commission can impose a carbon tax or something similar under NGA section 3. My point is that the Commission could consider discrete measures that offset the adverse effects of the Project itself, just like it does for a host of other adverse environmental impacts. For example, the project developer could purchase renewable energy credits equal to the Project's electricity consumption or it could plant trees sufficient to sequester the Project's GHG emissions. Tailored programs that offset the actual emissions from the

22. Finally, the Commission's refusal to seriously consider the significance of the impact of the Project's GHG emissions is even more mystifying because NEPA "does not dictate particular decisional outcomes."[57] NEPA "'merely prohibits uninformed—rather than unwise—agency action.'"[58] The Commission could find that a project contributes significantly to climate change, but that it is nevertheless in the public interest because its benefits outweigh its adverse impacts, including on climate change. In other words, taking the matter seriously—and rigorously examining a project's impacts on climate change—does not necessarily prevent any of my colleagues from ultimately concluding that a project satisfies the relevant public interest standard.

For these reasons, I respectfully dissent.

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Richard Glick
Commissioner

Project are a far cry from a comprehensive emissions-trading scheme and have much in common with other forms of mitigation routinely required by the Commission, including the mitigation contained in this order.

[57] *Sierra Club v. U.S. Army Corps of Engineers*, 803 F.3d 31, 37 (D.C. Cir. 2015).

[58] *Id.* (quoting *Robertson*, 490 U.S. at 351).

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Jordan Cove Energy Project L.P. Docket Nos. CP17-495-000
Pacific Connector Gas Pipeline, LP CP17-494-000

(Issued March 19, 2020)

McNAMEE, Commissioner, *concurring*:

1. Today's order authorizes Jordan Cove Energy Project L.P. (Jordan Cove) to site, construct, and operate a new liquefied natural gas (LNG) export terminal (Jordan Cove LNG Terminal) in Coos County, Oregon, and issues Pacific Connector Gas Pipeline, LP (Pacific Connector) a certificate of public convenience and necessity to construct and operate its proposed Pacific Connector Pipeline in Klamath, Jackson, Douglas, and Coos Counties, Oregon (together, the Project).[1]

2. These NGA authorizations are two of many federal permits that the applicants must receive to begin construction, including a Clean Water Act section 401 water quality certification and a Coastal Zone Management Act federal consistency determination. Although Congress enacted the NGA, Clean Water Act, and Coastal Zone Management Act using its Commerce Clause power, each have separate statutory requirements and constructs that provide for a unique balance between Congress' constitutional authority to regulate interstate commerce with the States' authority to preserve their own interests.

3. Congress enacted the Clean Water Act to protect national water quality. To balance national and State interests, Congress required the Administrator of the U.S. Environmental Protection Agency (EPA) to establish national standards and preserved certain roles for States, including the ability to set water quality standards for discharges that are more stringent than federal requirements.

4. Congress enacted the Coastal Zone Management Act to preserve, protect, develop, and restore national coastlines and delegated authority to the federal government, state governments, and local governments. Among other authorities, Congress provided States "with a limited opportunity to review applications to ensure they are consistent with state regulations, and, in doing so, grant[ed] states 'a conditional veto over federally licensed or permitted projects.'"[2] Congress, however, made that veto subject to review by the Secretary of Commerce who may overturn a State's decision if the Secretary finds that

[1] *Jordan Cove Energy Project L.P.*, 170 FERC ¶ 61,202 (2020).

[2] *Weaver's Cove Energy, LLC v. Rhode Island Coastal Res. Mgmt. Council*, 589 F.3d 458, 462 (1st Cir. 2009) (internal citations omitted).

"the activity is consistent with the objectives of [the Act] or is otherwise necessary in the interest of national security."[3]

5. As for the NGA, and as I discuss further below, Congress enacted the Act to provide access to natural gas and to direct the Commission to fill in the regulatory void left open by the courts and the Dormant Commerce Clause.[4] Unlike the Clean Water Act or the Coastal Zone Management Act, Congress did not articulate in the NGA a federal-state partnership to regulate the sale and transportation of natural gas in foreign and interstate commerce. Rather, Congress gave the Commission exclusive authority to regulate such transactions and preserved State authority to regulate the local distribution of natural gas, natural gas production, and natural gas gathering. Furthermore, Congress preserved to the States various authorities under the Coastal Zone Management Act, Clean Air Act, and Clean Water Act.[5] Thus, today's authorizations in no way negate Oregon Department of Environmental Quality's (Oregon DEQ) denial without prejudice of the applicants' Clean Water Act section 401 water quality certification application or Oregon Department of Land Conservation and Development's (Oregon DLCD) objection to the federal consistency determination. Indeed, the Commission's conditional authorizations do not permit the applicants to begin construction until they show evidence of obtaining the other federal authorizations or waiver thereof.[6]

6. However, Oregon DEQ and Oregon DLCD's determinations do not control the Commission's NGA sections 3 and 7 authorizations for the Project. NGA section 3 requires the Commission to authorize the siting, construction, and operation of an export or import facility unless the facility is not consistent with the public interest.[7] NGA

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[3] 16 U.S.C. § 1456(c)(3)(A) (2018).

[4] *See also Weaver's Cove Energy, LLC*, 589 F.3d at 461 ("The NGA was originally passed in the 1930s to facilitate the growth of the energy-transportation industry . . . .").

[5] 15 U.S.C. § 717(b); *id.* § 717b(d); *Panhandle E. Pipe Line Co. v. Pub. Serv. Comm'n of Ind.*, 332 U.S. 507, 520 (1947) ("The Natural Gas Act created an articulate legislative program based on a clear recognition of the respective responsibilities of the federal and state regulatory agencies. It does not contemplate ineffective regulation at either level. We have emphasized repeatedly that Congress meant to create a comprehensive and effective regulatory scheme, complementary in its operation to those of the states and in no manner usurping their authority.").

[6] *Jordan Cove Energy Project L.P.*, 170 FERC ¶ 61,202 at Environmental Conditions 11 and 27.

[7] 15 U.S.C. § 717b(a) (2018); *see also West Virginia Pub. Serv. Comm'n v. U.S. Dep't of Energy*, 681 F.2d 847, 856 ("[S]ection 3 sets out a general presumption favoring such authorization, by language which requires approval of an application unless there is

section 7 requires the Commission to issue a certificate of public convenience and necessity for the construction and operation of interstate natural gas pipeline facilities when the Commission finds those facilities are required by the present or future public convenience and necessity.[8] By placing the authority to make these determinations with the Commission, Congress requires the Commission to consider national interests.[9]

7. While States' interests may inform the Commission's determinations, at times, the national interest may conflict with a State's interest; in those cases, the Commission may find that the national interest outweighs the State's interest. The Commission exercises its authority under the NGA, which Congress enacted pursuant to its power under the Commerce Clause. The Commerce Clause emerged as the Founders' response to the ruinous effects resulting from state regulation, tariffs, and protectionism occurring under the Articles of Confederation and giving rise to the Constitution itself.[10] In Federalist No. 42, Publius explained the necessity of the Constitution and the Commerce Clause, stating "[t]he defect of power in the existing Confederacy to regulate the commerce between its several members [has] been clearly pointed out by experience."[11] Similarly,

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an express finding that the proposed activity would not be consistent with the public interest.").

[8] 15 U.S.C. § 717f(e) (2018).

[9] *Kansas v. Fed. Power Comm'n*, 206 F. 690, 705 (8th Cir. 1953) (". . . . Congress has vested the power in the Federal Commission to regulate in the national interest the charges natural gas companies may make for the gas they sell in interstate commerce for resale . . . ."); *Kern River Gas Transmission Co. v. Clark Cnty, Nev.*, 747 F. Supp. 1110 (Dec. 3, 1990) ("The very fact that Congress saw fit to provide a statutory scheme for authorizing 'Certificates of Public Convenience and Necessity' through the FERC pursuant to the Natural Gas Act indicates that there are substantial national interests at stake.").

[10] *Nat'l Fed'n of Indep. Bus. v. Sebelius,* 567 U.S. 519, 599-600 (2012) ("The Commerce Clause, it is widely acknowledged, 'was the Framer's response to the central problem that gave rise to the Constitution itself.' Under the Articles of Confederation, the Constitution's precursor, the regulation of commerce was left to the States. This scheme proved unworkable, because the individual States, understandably focused on their own economic interests, often failed to take actions critical to the success of the Nation as a whole."); *Gonzalez v. Raich*, 545 U.S. 1, 16 (2005) ("The Commerce Clause emerged as the Framers' response to the central problem giving rise to the Constitution itself: the absence of any federal commerce power under the Articles of Confederation.").

[11] James Madison, *The Federalist No. 42 in The Federalist Papers,* 267 (C. Rossiter ed. 1961).

Congress recognized this tension when amending the NGA to provide certificate holders eminent domain authority.[12]

8. Considering the constitutional structure of our government, the NGA and other acts of Congress, as well as the facts in this case, I agree with today's order that the LNG Terminal is not inconsistent with the public interest and the pipeline is required by the public convenience and necessity.[13] These determinations, consistent with the NGA, are based on the national interest, but with serious and heavy consideration of the potential impacts of the Project on affected local communities, States, and environmental resources. I also agree that today's order complies with the National Environmental Policy Act (NEPA). After taking the necessary hard look at the Project's impacts on environmental and socioeconomic resources, the order finds that the Project's environmental impacts are acceptable considering the public benefits that will be provided by the Project.[14] Further, the Commission quantified and considered greenhouse gas (GHG) emissions that are directly associated with the construction and operation of the Project,[15] consistent with the holding in *Sierra Club v. FERC* (*Sabal Trail*).[16]

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[12] *Thatcher v. Tennessee Gas Transmission Co.*, 180 F.2d 644, 647 (5th Cir. 1950) ("Implicit in the provisions of the statute are the facts, among others, that vast reserves of natural gas are located in States of our nation distant from other States which have no similar supply, but do have a vital need of the product; and that the only way this natural gas can be feasibly transported from one State to another is by means of a pipe line. None of the means of transportation by water, land or air, to which mankind has successively become accustomed, suffices for the movement of natural gas. Consideration of the facts, and the legislative history, plan and scope of the Natural Gas Act, and the judicial consideration and application the Act has received, leaves us in no doubt that the grant by Congress of the power of eminent domain to a natural gas company, within the terms of the Act, and which in all of its operations is subject to the conditions and restrictions of the statute, is clearly within the constitutional power of Congress to regulate interstate Commerce.").

[13] *Jordan Cove Energy Project L.P.*, 170 FERC ¶ 61,202 at PP 296-97.

[14] *Id.* P 294.

[15] *Id.* PP 258-62; Environmental Impact Statement (EIS) at 4-701, 4-704, and 4-706.

[16] 867 F.3d 1357 (D.C. Cir. 2017). This case is commonly referred to as "Sabal Trail" because the Sabal Trail Pipeline is one of the three pipelines making up the Southeast Market Pipelines Project.

9. Although I fully support this order, I also write separately to address what I perceive to be a misinterpretation of the Commission's authority under the NGA and NEPA. There have been contentions that the NGA authorizes the Commission to deny a certificate application based on the environmental effects that result from upstream gas production,[17] that the NGA authorizes the Commission to establish measures to mitigate GHG emissions, and that the Commission violates the NGA and NEPA by not determining whether GHG emissions significantly affect the environment. I disagree.

10. A close examination of the statutory text and foundation of the NGA demonstrates that the Commission does not have the authority under the NGA or NEPA to deny a pipeline certificate application based on the environmental effects of upstream gas production, nor does the Commission have the authority to unilaterally establish measures to mitigate GHGs emitted by LNG or pipeline facilities. Further, the Commission has no objective basis to determine whether GHG emitted by LNG or pipeline facilities will have a significant effect on climate change nor the authority to establish its own basis for making such a determination.

11. It is my intention that my discussion of the statutory text and foundation will assist the Commission, the courts, and other parties in their arguments regarding the meaning of the "public convenience and necessity" and the Commission's consideration of a project's effect on climate change in NGA section 3 and 7 proceedings. Further, my review of appellate briefs filed with the court and the Commission's orders suggests that the court may not have been presented with the arguments I make here. Before I offer my arguments, it is important that I further expound on the current debate.

I. <u>Current debate</u>

12. When acting on a NGA section 3 permit or NGA section 7 certificate application, the Commission has two primary statutory obligations under the NGA and NEPA. The NGA requires the Commission to determine whether proposed NGA section 3 facilities "will not be consistent with the public interest"[18] and whether proposed NGA section 7

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[17] Parties previously raised this argument for NGA section 3 applications. The courts, however, have found that the Commission cannot act on information related to the natural gas commodity in considering NGA section 3 permits. *See EarthReports, Inc. v. FERC*, 828 F.3d 949 (D.C. Cir. 2016) (holding that the Commission reasonably declined to consider upstream domestic natural gas production as an indirect effect of the project); *Sierra Club v. FERC*, 827 F.3d 36, 47 (D.C. Cir. 2016) ("[T]he Commission's NEPA analysis did not have to address the indirect effects of the anticipated *export* of natural gas.").

[18] 15 U.S.C. § 717b(a) (2018).

facilities are required by the "present or future public convenience and necessity."[19] NEPA, and the Council on Environmental Quality's (CEQ) implementing regulations, require that the Commission take a "hard look" at the direct,[20] indirect,[21] and cumulative[22] effects of a project. Recently, there has been much debate concerning what factors the Commission can consider in determining whether a NGA section 7 proposed project is in the "public convenience and necessity," and whether the effects related to upstream natural gas production are indirect effects of a certificate application as defined by NEPA.[23]

13. Equating NGA section 7's "public convenience and necessity" standard with a "public interest" standard, my colleague has argued that NGA section 7 requires the Commission to weigh GHGs emitted from the project facilities and related to upstream natural gas production.[24] In support of his contention, my colleague has cited the holding in *Sabal Trail* and dicta in *Atlantic Refining Co. v. Public Service Commission of State of New York* (*CATCO*).[25] In both NGA section 3 and 7 proceedings, my colleague has argued that the Commission must determine whether GHG emissions have a significant impact on climate change in order for climate change to "play a meaningful role in the

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[19] *Id.* § 717f(e).

[20] Direct effects are those "which are caused by the action and occur at the same time and place." 40 C.F.R. § 1508.8(a) (2019).

[21] Indirect effects are those "caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable." 40 C.F.R. § 1508.8(b) (2019). The U.S. Supreme Court held that NEPA requires an indirect effect to have "a reasonably close causal relationship" with the alleged cause; "a 'but for' causal relationship is insufficient to make an agency responsible for a particular effect under NEPA and the relevant regulations." *Dep't of Transp. v. Pub. Citizen*, 541 U.S. 752, 767 (2004).

[22] Cumulative effects are those "which result[] from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions." 40 C.F.R. § 1508.7 (2019).

[23] As noted in footnote 17, this issue has been settled by the courts for NGA section 3 applications. *See supra* note 17.

[24] *Cheyenne Connector, LLC*, 168 FERC ¶ 61,180, at P 10 (2019) (Glick, Comm'r, dissenting) (Cheyenne Connector Dissent).

[25] *Id.* P 4 n.7 (citing *CATCO*, 360 U.S. 378, 391 (1959)). The case *Atlantic Refining Co. v. Public Service Commission of State of New York* is commonly known as "*CATCO*" because the petitioners were sometimes identified by that name.

Commission's public interest determination."[26] And he has argued that by not determining the significance of those emissions, the "public interest determination [] systematically excludes the most important environmental consideration of our time" and "is contrary to law, arbitrary and capricious" and is not "the product of reasoned decisionmaking."[27]

14. He has asserted that the Commission could use the Social Cost of Carbon or its own expertise to determine whether GHG emissions will have a significant effect on climate change.[28] Further, he has contended that the Commission could mitigate any GHG emissions in the event that it made a finding that the GHG emissions had a significant impact on climate change.[29]

15. Several recent cases before the United States Court of Appeals for the D.C. Circuit have also considered the Commission's obligations under NGA section 7 and NEPA as they apply to what environmental effects the Commission is required to consider under NEPA.[30] In *Sabal Trail*, the D.C. Circuit vacated and remanded the Commission's order issuing a certificate for the Southeast Market Pipelines Project, finding that the Commission inadequately assessed GHGs emitted from downstream power plants in its EIS for the project.[31] The court held that the downstream GHG emissions resulting from burning the natural gas at the power plants were a reasonably foreseeable indirect effect of authorizing the project and, at a minimum, the Commission should have estimated those emissions.

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[26] Cheyenne Connector Dissent P 6.

[27] *Id.*

[28] *Id.* PP 13-14.

[29] *Id.* P 16.

[30] The courts have not explicitly opined on whether the Commission is required to determine whether GHG emissions will have a significant impact on climate change or whether the Commission must mitigate GHG emissions. The D.C. Circuit, however, has suggested that the Commission is not required to determine whether GHG emissions are significant. *Appalachian Voices v. FERC*, 2019 WL 847199, *2 (D.C. Cir. Feb. 19, 2019) (unpublished) ("FERC provided an estimate of the upper bound of emissions resulting from end-use combustion, and it gave several reasons why it believed petitioner's preferred metric, the Social Cost of Carbon, is not an appropriate measure of project-level climate change impacts and their significance under NEPA or the Natural Gas Act. That is all that is required for NEPA purposes.").

[31] *Sabal Trail*, 867 F.3d 1357.

16. Further, the *Sabal Trail* court found the Commission's authorization of the project was the legally relevant cause of the GHGs emitted from the downstream power plants "because FERC could deny a pipeline certificate on the ground that the pipeline would be too harmful to the environment."[32] The court stated the Commission could do so because, when considering whether pipeline applications are in the public convenience and necessity, "FERC will balance 'the public benefits against the adverse effects of the project,' *see Minisink Residents for Envtl. Pres. & Safety v. FERC*, 762 F.3d 97, 101-02 (D.C. Cir. 2014) (internal quotation marks omitted), including adverse environmental effects, *see Myersville Citizens for a Rural Cmty. v. FERC*, 783 F.3d 1301, 1309 (D.C. Cir. 2015)."[33] Relying on its finding that the Commission could deny a pipeline on environmental grounds, the court distinguished *Sabal Trail* from the Supreme Court's holding in *Public Citizen,* where the Court held "when the agency has no *legal* power to prevent a certain environmental effect, there is no decision to inform, and the agency need not analyze the effect in its NEPA review"[34] and the D.C. Circuit's decision in *Sierra Club v. FERC* (*Freeport*), where it held "that FERC had *no legal authority to prevent* the adverse environmental effects of natural gas exports."[35]

17. Based on these findings, the court concluded that "greenhouse-gas emissions are an indirect effect of authorizing this project, which FERC could reasonably foresee, and which the agency has legal authority to mitigate."[36] The court also held "the EIS for the Southeast Market Pipelines Project should have either given a quantitative estimate of the downstream greenhouse emissions . . . or explained more specifically why it could not have done so."[37] The court impressed that "[it did] not hold that quantification of greenhouse-gas emissions is required *every* time those emissions are an indirect effect of an agency action" and recognized that "in some cases quantification may not be feasible."[38]

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[32] *Id.* at 1373.

[33] *Id.*

[34] *Sabal Trail*, 867 F.3d at 1372 (citing *Pub. Citizen*, 541 U.S. at 770) (emphasis in original).

[35] *Id.* at 1373 (citing *Freeport*, 827 F.3d 36, 47 (D.C. Cir. 2016)) (emphasis in original).

[36] *Id.* at 1374 (citing 15 U.S.C. § 717f(e)).

[37] *Id.*

[38] *Id.* (emphasis in original).

18. More recently, in *Birckhead v. FERC*,[39] the D.C. Circuit commented in dicta on the Commission's authority to consider downstream emissions. The court stated that because the Commission could "'deny a pipeline certificate on the ground that the pipeline would be too harmful to the environment, the agency is the legally relevant cause of the direct and indirect environmental effects of pipelines it approves'—even where it lacks jurisdiction over the producer or distributor of the gas transported by the pipeline."[40] The court also examined whether the Commission was required to consider environmental effects related to upstream gas production, stating it was "left with no basis for concluding that the Commission acted arbitrarily or capriciously or otherwise violated NEPA in declining to consider the environmental impacts of upstream gas production."[41]

19. I respect the holding of the court in *Sabal Trail* and the discussion in *Birckhead*, and I recognize that the *Sabal Trail* holding is binding on the Commission. However, I respectfully disagree with the court's finding that the Commission can, pursuant to the NGA, deny a pipeline based on environmental effects stemming from the production and use of natural gas, and that the Commission is therefore required to consider such environmental effects under the NGA and NEPA.[42]

20. The U.S. Supreme Court has observed that NEPA requires an indirect effect to have "a reasonably close causal relationship" with the alleged cause.[43] Whether there is a reasonably close causal relationship depends on "the underlying policies or legislative intent" of the agency's organic statute "to draw a manageable line between those causal changes that may make an actor responsible for an effect and those that do not."[44] Below, I review the text of the NGA and subsequent acts by Congress to demonstrate that the "public convenience and necessity" standard in the NGA is not so broad as to include environmental effects of upstream natural gas production, and that the Commission cannot be responsible for those effects. I focus on upstream gas production, and not

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[39] 925 F.3d 510 (D.C. Cir. 2019).

[40] *Id.* at 519 (citing *Sabal Trail*, 867 F.3d at 1373) (internal quotations omitted).

[41] *Id.* at 518.

[42] Though the D.C. Circuit's holding in *Sabal Trail* is binding on the Commission, it is not appropriate to expand that holding through the dicta in *Birckhead* so as to establish new authorities under the NGA and NEPA. The Commission is still bound by the NGA and NEPA as enacted by Congress, and interpreted by the U.S. Supreme Court and the D.C. Circuit. Our obligation is to read the statutes and case law in harmony. This concurrence articulates the legal reasoning by which to do so.

[43] *Metro. Edison Co. v. People Against Nuclear Energy*, 460 U.S. 766, 774 (1983)

[44] *Id.* at 774 n.7.

downstream use, because the Pacific Connector will be transporting gas to the LNG Terminal and the Commission has quantified and considered the GHGs emitted by the terminal facilities. Further, the Commission is not required to consider effects related to the commodity for NGA section 3 applications.[45]

21. As for GHGs emitted from LNG or pipeline facilities themselves, I believe that the Commission can consider such emissions in its NGA determination and is required to consider them in its NEPA analysis. As I set forth below, however, the Commission cannot unilaterally establish measures to mitigate GHG emissions, and there currently is no suitable method for the Commission to determine whether GHG emissions are significant.

II. The NGA does not permit the Commission to deny a certificate application based on environmental effects related to upstream natural gas production

22. To interpret the meaning of "public convenience and necessity," we must begin with the text of the NGA.[46] I recognize that the Commission[47] and the courts have equated the "public convenience and necessity" standard with "all factors bearing on the public interest."[48] However, the phrase "all factors bearing on the public interest" does

[45] *See supra* note 17. The analysis presented here regarding the Commission's limitations to consider GHG emissions for upstream production is generally applicable to downstream use, as well. Because the issue of downstream GHG emissions involving an LNG export facility is not at issue in this proceeding and has been resolved by the courts, it is not discussed in this concurrence. For a full discussion of this issue see my concurrence in *Adelphia*. *Adelphia Gateway, LLC*, 169 FERC ¶ 61,220 (2019) (McNamee, Comm'r, concurring).

[46] 15 U.S.C. § 717f(e) (2018). *See infra* PP 48-54. It is noteworthy that the phrase "public interest" is not included in NGA section 7(c)(1)(A) (requiring pipelines to have a certificate) or NGA section 7(e) (requiring the Commission to issue certificates). Rather, these provisions use the phrase "public convenience and necessity." NGA section 7(c)(1)(B) does refer to public interest when discussing how the Commission can issue a temporary certificate in cases of emergency. *Id.* § 717f(c)(1)(B). Congress is "presumed to have used no superfluous words." *Platt v. Union Pac. R.R. Co.*, 99 U.S. 48, 58 (1878); *see also U.S. ex rel. Totten v. Bombardier Corp.*, 380 F.3d 488, 499 (D.C. Cir. 2004) ("It is, of course, a 'cardinal principle of statutory construction that a statute ought, upon the whole, to be so construed that, if it can be prevented, no clause, sentence, or word shall be superfluous, void, or insignificant.'" (citing *Alaska Dep't of Envtl. Conservation v. EPA*, 540 U.S. 461, n.13 (2004))).

[47] *See, e.g.*, *North Carolina Gas Corp.*, 10 FPC 469, 475 (1950).

[48] *CATCO*, 360 U.S. at 391 ("This is not to say that rates are the only factor bearing on the public convenience and necessity, for § 7(e) requires the Commission to

not mean that the Commission has "broad license to promote the general public welfare"[49] or address greater societal concerns. Rather, the courts have stated that the words must "take meaning from the purposes of regulatory legislation."[50] The Court has made clear that statutory language "cannot be construed in a vacuum. It is a fundamental canon of statutory construction that the words of a statute must be read in their context and with a view to their place in the overall statutory scheme."[51] The Court has further instructed that one must "construe statutes, not isolated provisions."[52]

23. Indeed, that is how the Court in *CATCO* – the first U.S. Supreme Court case including the "all factors bearing on the public interest" language – interpreted the phrase "public convenience and necessity." In that case, the Court held that the public convenience and necessity requires the Commission to closely scrutinize initial rates *based on the framework and text* of the NGA.[53]

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evaluate all factors bearing on the public interest."). The Court never expounded further on that statement.

[49] *NAACP v. FERC*, 425 U.S. 662, 669 (1976).

[50] *Id.*; *see also Office of Consumers' Counsel v. FERC*, 655 F.2d 1132, 1147 (D.C. Cir. 1980) ("Any such authority to consider all factors bearing on the 'public interest' must take into account what the 'public interest' means in the context of the Natural Gas Act. FERC's authority to consider all factors bearing on the public interest when issuing certificates means authority to look into those factors which reasonably relate to the purposes for which FERC was given certification authority. It does not imply authority to issue orders regarding any circumstance in which FERC's regulatory tools might be useful.").

[51] *Davis v. Mich. Dep't of Treasury*, 489 U.S. 803, 809 (1989).

[52] *Graham Cty. Soil & Water Conservation Dist. v. U.S. ex rel. Wilson*, 559 U.S. 280, 290 (2010) (quoting *Gustafson v. Alloyd Co.*, 513 U.S. 561, 568 (1995)).

[53] *CATCO*, 360 U.S. 378, 388-91. The Court stated "[t]he Act was so framed as to afford consumers a complete, permanent and effective bond of protection from excessive rates and charges." *Id.* at 388. The Court found that the text of NGA sections 4 and 5 supported the premise that Congress designed the Act to provide complete protection from excessive rates and charges. *Id.* ("The heart of the Act is found in those provisions requiring . . . that all rates and charges 'made, demanded, or received' shall be 'just and reasonable.'"); *id.* at 389 ("The overriding intent of the Congress to give full protective coverage to the consumer as to price is further emphasized in § 5 of the Act . . . ."). The Court recognized that the Commission's role in setting initial rates was a critical component of providing consumers complete protection because "the delay incident to determination in § 5 proceedings through which initial certificated rates are reviewable

24. Following this precedent, the phrase "public convenience and necessity" must therefore be read within the overall statutory scheme of the NGA. As set forth below, construing the NGA *as a statute* demonstrates that Congress determined the public interest required (i) the public to have access to natural gas and (ii) economic regulation of the transportation and sale of natural gas to protect such public access.

A. The text of the NGA does not support denying a certificate application based on the environmental effects of upstream natural gas production

1. NGA section 1(a)—limited meaning of "public interest"

25. Section 1 of the NGA sets out the reason for its enactment. NGA section 1(a) states, "[a]s disclosed in reports of the Federal Trade Commission [(FTC)] made pursuant to S. Res. 83 (Seventieth Congress, first session) and other reports made pursuant to the authority of Congress, it is declared that the business of transporting and selling natural gas for ultimate distribution to the public *is affected with a public interest,* and that Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the *public interest*."[54]

26. A review of the FTC Report referred to in NGA section 1 demonstrates that the NGA was enacted to counter activities that would limit the public's access to natural gas and subject the public to abusive pricing. Specifically, the FTC Report states "[a]ll communities and industries within the capacity and reasonable distance of existing or future transmission facilities should be assured a natural-gas supply and receive it at fair, nondiscriminatory prices."[55]

27. The FTC Report further states "[a]ny proposed Federal legislation should be premised, in part at least, on the fact that natural gas is a valuable, but limited, natural resource in Nation-wide demand, which is produced only in certain States and limited areas, and the conservation, production, transportation, and distribution of which,

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appears nigh interminable" and "would provide a windfall for the natural gas company with a consequent squall for the consumers," which "Congress did not intend." *Id.* at 389-90.

[54] 15 U.S.C. § 717(a) (2018) (emphasis added).

[55] FEDERAL TRADE COMMISSION, UTILITY CORPORATIONS FINAL REPORT OF THE FEDERAL TRADE COMMISSION TO THE SENATE OF THE UNITED STATES PURSUANT TO SENATE RESOLUTION NO. 83, 70TH CONGRESS, 1ST SESSION ON ECONOMIC, CORPORATE, OPERATING, AND FINANCIAL PHASES OF THE NATURAL-GAS-PRODUCING, PIPE-LINE, AND UTILITY INDUSTRIES WITH CONCLUSIONS AND RECOMMENDATIONS NO. 84-A at 609 (1936) (FTC Report), https://babel.hathitrust.org/cgi/pt?id=ien.35556021351598&view=1up&seq=718.

therefore, under proper control and regulation, are matters charged with high national public interest."[56]

28. The text of NGA section 1(a) and its reference to the FTC Report make clear that "public interest" is directly linked to ensuring the public's access to natural gas through regulating its transport and sale. Moreover, the NGA is designed to promote the "public interest" primarily through economic regulation. This is apparent in the text of the NGA and by its reference to the FTC Report that identifies the concern with monopolistic activity that would limit access to natural gas.[57]

29. Therefore, there is no textual support in NGA section 1 for the claim that the Commission may deny a pipeline application due to potential upstream effects of GHG emissions on climate change. But, this is not the end of the analysis. We must also examine the Commission's specific authority under the NGA section 7.

2. NGA section 7—Congress grants the Commission and pipelines authority to ensure the public's access to natural gas

30. Like NGA section 1, the text of NGA section 7 makes clear that its purpose is to ensure that the public has access to natural gas. A review of the various provisions of NGA section 7 make this point evident:

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[56] *Id.* at 611.

[57] 15 U.S.C. § 717(a) (2018) ("Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the public interest"). The limited, economic regulation meaning of "public interest" was clear at the time the NGA was adopted. The NGA's use of the phrase "affected with the public interest" is consistent with the States' use of this phrase when enacting laws regulating public utilities. Historically, state legislatures used the phrase "affected with the public interest" as the basis of their authority to regulate rates charged for the sale of commodities, rendered services, or use of private property. *Munn v. Illinois*, 94 U.S. 113, 125-26 (1876). The Court found that businesses affected with a public interest or "said to be clothed with a public interest justifying some public regulation" include "[b]usinesses, which, though not public at their inception, may be fairly said to have risen to be such and have become subject in consequence to some government regulation." *Charles Wolff Packing Co. v. Court of Indus. Relations*, 262 U.S. 522, 535 (1923). In essence, these businesses became quasi-public enterprises and were determined to have an "indispensable nature." *Id.* at 538. Such a conclusion also meant that if these businesses were not restrained by the government, the public could be subject to "the exorbitant charges and arbitrary control to which the public might be subjected without regulation." *Id.*

- Section 7(a) authorizes the Commission to "direct a natural-gas company to extend or improve its transportation facilities, to establish physical connection of its transportation facilities with the facilities of, and sell natural gas . . . to the public . . . ."[58] The Commission has stated that "[s]ection 7(a) clearly established the means whereby the Commission could secure *the benefits* of gas service for certain communities, markets and territories adjacent to those originally established by the gas industry, where in the public interest."[59]

- Section 7(b) requires Commission approval for a natural gas pipeline company to "abandon all or any portion of its facilities subject to the jurisdiction of the Commission, or any service rendered by means of such facilities."[60] That is, Congress considered access to natural gas to be so important that it even prohibited natural gas pipeline companies from abandoning service without Commission approval.

- Section 7(c)(1)(B) authorizes the Commission to "issue a temporary certificate in cases of emergency, to assure maintenance of adequate service or to serve particular customers, without notice or hearing, pending the determination of an application for a certificate."[61] The underlying presumption of this section is that the need for natural gas can be so important that the Commission can issue a certificate without notice and hearing.

- Section 7(e) states "a certificate *shall* be issued" when a project is in the public convenience and necessity,[62] leaving the Commission no discretion after determining a project meets the public convenience and necessity standard.

- Section 7(h) grants the pipeline certificate holder the powers of the sovereign to "exercise of the right of eminent domain in the district court of

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[58] 15 U.S.C. § 717f(a) (2018).

[59] *Arcadian Corp. v. Southern Nat. Gas Co.*, 61 FERC ¶ 61,183, at 61,676 (1992) (emphasis added). The Commission's analysis in this regard was unaffected by the opinion in *Atlanta Gas Light Co. v. FERC*, 140 F.3d 1392 (11th Cir. 1998) (vacating the Commission's 1991 and 1992 orders on other grounds).

[60] 15 U.S.C. § 717f(b) (2018).

[61] *Id.* § 717f(c)(1)(B).

[62] *Id.* § 717f(e) (emphasis added).

> the United States."[63] By granting the power of eminent domain, Congress made clear the importance of ensuring that natural gas could be delivered from its source to the public by not allowing traditional property rights to stand in the way of pipeline construction. Furthermore, the sovereign's power of eminent domain must be for a public use[64] and Congress considered natural gas pipelines a public use.

31. Each of these textual provisions illuminate the ultimate purpose of the NGA: to ensure that the public has access to natural gas because Congress considered such access to be in the public interest.[65] To now interpret "public convenience and necessity" to mean that the Commission has the authority to deny a certificate for a pipeline due to upstream emissions because the pipeline may result in access to, and the use of, natural gas would radically rewrite the NGA and undermine its stated purpose.

3. NGA section 1(b) and section 201 of the Federal Power Act (FPA)—authority over environmental effects related to upstream natural gas production reserved to States

32. Statutory text also confirms that control over the physical environmental effects related to upstream natural gas production are squarely reserved for the States. NGA section 1(b) provides that "[t]he provisions of this chapter . . . shall not apply to any other transportation or sale of natural gas or to the local distribution of natural gas or to the facilities for such distribution or to the production or gathering of natural gas."[66]

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[63] *Id.* § 717f(h).

[64] *Miss. & Rum River Boom Co. v. Patterson*, 98 U.S. 403, 406 (1878) ("The right of eminent domain, that is, the right to take private property for public uses, appertains to every independent government.").

[65] This interpretation is also supported by the Commission's 1999 Certificate Policy Statement. *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227, 61,743 (1999), *clarified*, 90 FERC ¶ 61,128, *further clarified*, 92 FERC ¶ 61,094 (2000) (Certificate Policy Statement) ("[I]t should be designed to foster competitive markets, protect captive customers, and avoid unnecessary environmental and community impacts *while serving increasing demands for natural gas*.") (emphasis added); *id.* at 61,751 ("[T]he Commission is urged to authorize new pipeline capacity to meet an anticipated increase in demand for natural gas . . . .").

[66] 15 U.S.C. § 717(b) (2018); *see Pennzoil v. FERC*, 645 F.2d 360, 380-82 (5th Cir. 1981) (holding that FERC lacks the power to even interpret gas purchase agreements between producers and pipelines for the sale of gas that has been removed from NGA jurisdiction).

33. U.S. Supreme Court precedent and legislative history confirm that the regulation of the physical upstream production of gas is reserved for the States. The Court has observed that Congress enacted the NGA to address "specific evils" related to non-transparent rates for the interstate transportation and sale of natural gas and the monopoly power of holding companies that owned natural gas pipeline company stock.[67] The Court has also found that Congress enacted the NGA to

> fill the regulatory void created by the Court's earlier decisions prohibiting States from regulating interstate transportation and sales for resale of natural gas, while at the same time leaving undisturbed the recognized power of the States to regulate all in-state gas sales directly to consumers. Thus, the NGA "was drawn with meticulous regard for the continued exercise of state power, not to handicap it any way."[68]

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[67] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 610 ("state commissions found it difficult or impossible to discover what it cost interstate pipe-line companies to deliver gas within the consuming states"); *id.* ("[T]he investigations of the Federal Trade Commission had disclosed the majority of the pipe-line mileage in the country used to transport natural gas, together with an increasing percentage of the natural gas supply for pipe-line transportation, had been acquired by a handful of holding companies."). Senate Resolution 83, which directed the FTC to develop the report that the NGA is founded on, also demonstrates that Congress was only concerned with consumer protection and monopoly power. The resolution directed the FTC to investigate capital assets and liabilities of natural gas companies, issuance of securities by the natural gas companies, the relationship between company stockholders and holding companies, other services provided by the holding companies, adverse impacts of holding companies controlling natural gas companies, and potential legislation to correct any abuses by holding companies. FTC Report at 1.

[68] *Gen. Motors Corp. v. Tracy*, 519 U.S. 278, 292 (1997) (internal citations omitted) (quoting *Panhandle*, 332 U.S. 507, 516-22)); *see also Nw. Cent. Pipeline v. State Corp. Comm'n*, 489 U.S. 493, 512 (1989) ("The NGA 'was designed to supplement state power and to produce a harmonious and comprehensive regulation of the industry. Neither state nor federal regulatory body was to encroach upon the jurisdiction of the other.'" (quoting *Panhandle*, 332 U.S. at 513)); *Panhandle*, 332 U.S. at 520 (In recognizing that the NGA articulated a legislative program recognizing the respective responsibilities of federal and state regulatory agencies, the Court noted that the NGA does not "contemplate ineffective regulation at either level as Congress meant to create a comprehensive and effective regulatory scheme, complementary in its operation to those of the states and in no manner usurping their authority."). Congress continued to draw the NGA with meticulous regard to State power when it amended the NGA in 1954 to add the Hinshaw pipeline exemption so as "to preserve state control over local distributors who purchase gas from interstate pipelines." *Louisiana Power & Light Co. v.*

34. In *Transco*,[69] the Court also recognized that "Congress did not desire that an important aspect of this field be left unregulated."[70] Thus, the Court held that where congressional authority is not explicit and States cannot practicably regulate a given area, the Commission can consider the issue in its public convenience and necessity determination.[71]

35. Based on this rule, and legislative history,[72] the *Transco* Court found that in its public convenience and necessity determination, the Commission appropriately considered whether the end-use of the gas in a non-producing state was economically wasteful as there was a regulatory gap and no State could be expected to control how gas is used in another State.[73] The Court also impressed that

> The Commission ha[d] not attempted to exert its influence over such "*physically*" wasteful practices as improper well spacing and the flaring of unused gas which result in the entire loss of gas and are properly of concern to the producing State; nor has the Commission attempted to regulate the "economic" aspects of gas used within the producing State.[74]

36. In contrast, there is no legislative history to support the Commission considering environmental effects related to upstream natural gas production. Furthermore, the field of environmental regulation of production activities is not one that has been left unregulated. Unlike in *Transco*, States can reasonably be expected to regulate air emissions from upstream natural gas production: "air pollution control at its source is the primary responsibility of States and local governments."[75] The Clean Air Act vests States with authority to issue permits to regulate stationary sources related to upstream activities.[76] In addition, pursuant to their police powers, States have the ability to

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Fed. Power Comm'n, 483 F.2d 623, 633 (5th Cir. 1973).

[69] *Transco*, 365 U.S. 1 (1961).

[70] *Id.* at 19.

[71] *Id.* at 19-20.

[72] *Id.* at 10-19.

[73] *Id.* at 20-21.

[74] *Id.* at 20 (emphasis added).

[75] 42 U.S.C. § 7401 (2018).

[76] *Id.* § 7661e ("Nothing in this subchapter shall prevent a State, or interstate permitting authority, from establishing additional permitting requirements not

regulate environmental effects related to upstream natural gas production within their jurisdictions.[77]

37. Some may make the argument that "considering" the environmental effects related to upstream production is hardly "regulating" such activities. I disagree. For the Commission to consider such effects would be an attempt to exert influence over States' regulation of physical upstream natural gas production, which the Court in *Transco* suggested would be encroaching upon forbidden ground. If, for example, the Commission considered and denied a certificate based on the GHG emissions released from production activities, the Commission would be making a judgment that such production is too harmful for the environment and preempting a State's authority to decide whether and how to regulate upstream natural gas production. Such exertion of influence is impermissible: "when the Congress explicitly reserves jurisdiction over a matter to the states, as here, the Commission has no business considering how to 'induc[e] a change [of state] policy' with respect to that matter."[78]

38. Hence, there is no jurisdictional gap in regulating GHG emissions for the Commission to fill. The NGA reserves authority over upstream natural gas production to the States, and States can practicably regulate GHGs emitted by those activities. And, even if there were a gap that federal regulation could fill, as discussed below, it is nonsensical for the Commission to attempt to fill a gap that Congress has clearly meant for the EPA to occupy.[79] Therefore, because GHG emissions from upstream natural gas production are not properly of concern to the Commission, the Commission cannot deny a certificate application based on such effects.

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inconsistent with this chapter."). The Act defines "permitting authority" as "the Administrator or the air pollution control agency authorized by the Administrator to carry out a permit program under this subchapter." *Id.* § 7661.

[77] *Huron Portland Cement Co. v. Detroit*, 362 U.S. 440, 442 (1960) ("Legislation designed to free from pollution the very air that people breathe clearly falls within the exercise of even the more traditional concept of what is compendiously known as the police power.").

[78] *Altamont Gas Transmission Co. v. FERC*, 92 F.3d 1239, 1248 (D.C. Cir. 1996); *see ANR Pipeline Co. v. FERC*, 876 F.2d 124, 132 (D.C. Cir. 1989) ("We think it would be a considerable stretch from there to say that, in certifying transportation that is necessary to carry out a sale, the Commission is required to reconsider the very aspects of the sale that have been assessed by an agency specifically vested by Congress with authority over the subject.").

[79] *See infra* PP 60-64.

B. Denying a pipeline based on upstream environmental effects would undermine other acts of Congress

39. Since enactment of the NGA and NEPA, Congress has enacted additional legislation promoting the production and use of natural gas and limiting the Commission's authority over the natural gas commodity. Each of these legislation enactments indicates that the Commission's authority over upstream natural gas production has been further limited by Congress. Arguments that the Commission can rely on the NGA's public convenience and necessity standard and NEPA to deny a pipeline application so as to prevent upstream gas production would undermine these acts of Congress.

1. Natural Gas Policy Act of 1978

40. Determining that federal regulation of natural gas limited interstate access to the commodity, resulting in shortages and high prices, Congress passed the Natural Gas Policy Act of 1978 (NGPA). The NGPA significantly deregulated the natural gas industry.[80] Importantly, NGPA section 601(c)(1) states, "[t]he Commission may not deny, or condition the grant of, any certificate under section 7 of the Natural Gas Act based upon the amount paid in any sale of natural gas, if such amount is deemed to be just and reasonable under subsection (b) of this section."[81]

41. Besides using price deregulation to promote access to natural gas, Congress gave explicit powers to the President to ensure that natural gas reached consumers. NGPA section 302(c) explicitly provides, "[t]he President may, by order, require any pipeline to transport natural gas, and to construct and operate such facilities for the transportation of natural gas, as he determines necessary to carry out any contract authorized under subsection (a)."[82] Similarly, the NGPA gave authority to the Secretary of Energy to promote access to natural gas.[83]

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[80] Generally, the NGPA limited the Commission's authority over gas that is not transported in interstate commerce, new sales of gas, sales of gas and transportation by Hinshaw pipelines, and certain sales, transportation and allocation of gas during certain gas supply emergencies. *See, e.g.*, NGPA sections 601(a)(1)(A)-(D), 15 U.S.C. § 3431(a)(1)(A)-(D) (2018).

[81] *Id.* § 3431(c)(1) (2018). In addition, section 121(a) provides, "the provisions of subtitle A respecting the maximum lawful price for the first sale of each of the following categories of natural gas shall, except as provided in subsections (d) and (e), cease to apply effective January 1, 1985." 15 U.S.C. § 3331(a), *repealed by* the Wellhead Decontrol Act of 1989, Pub. L. 101-60 § 2(b), 103 Stat. 157 (1989).

[82] *Id.* § 3362.

[83] *See id.* § 3391(a) ("[T]he Secretary of Energy shall prescribe and make effective

42. There can be no doubt about the plain language of the NGPA: the Court observed that Congress passed the NGPA to "promote gas transportation by interstate and intrastate pipelines."[84] Furthermore, the NGPA was "intended to provide investors with adequate incentive to develop new sources of supply."[85]

2. Powerplant and Industrial Fuel Use Act of 1978

43. With respect to natural gas as a fuel source for electric generation, in 1987 Congress repealed sections of the Powerplant and Industrial Fuel Use Act of 1978 (Fuel Use Act),[86] which had restricted the use of natural gas in electric generation so as to conserve it for other uses. With the repeal of the Fuel Use Act, Congress made clear that natural gas could be used for electric generation and that the regulation of the use of natural gas by power plants unnecessary.[87]

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a rule . . . which provides . . . no curtailment plan of an interstate pipeline may provide for curtailment of deliveries for any essential agricultural use . . . ."); *id.* § 3392(a) ("The Secretary of Energy shall prescribe and make effective a rule which provides that notwithstanding any other provisions of law (other than subsection (b)) and to the maximum extent practicable, no interstate pipeline may curtail deliveries of natural gas for any essential industrial process or feedstock use. . . ."); *id.* § 3392(a) ("The Secretary of Energy shall determine and certify to the Commission the natural gas requirements (expressed either as volumes or percentages of use) of persons (or classes thereof) for essential industrial process and feedstock uses (other than those referred to in section 3391(f)(1)(B))."); *id.* § 3393(a) ("The Secretary of Energy shall prescribe the rules under sections 3391 and 3392 of this title pursuant to his authority under the Department of Energy Organization Act to establish and review priorities for curtailments under the Natural Gas Act.").

[84] *Gen. Motors Corp. v. Tracy*, 519 U.S. at 283 (quoting 57 Fed. Reg. 13271 (Apr. 16, 1992)).

[85] *Pub. Serv. Comm'n of State of N.Y. v. Mid-Louisiana Gas Co.*, 463 U.S. 319, 334 (1983).

[86] 42 U.S.C. § 8342, *repealed by* Pub. L. 100-42, § 1(a), 101 Stat. 310 (1987).

[87] The Commission need not look any further than the text of the statutes to determine its authority. In the case of the repeal of the Fuel Use Act, the legislative history is informative as to Congress's reasoning. *See* H.R. Rep. 100-78 *2 ("By amending [Fuel Use Act], H.R. 1941 will remove artificial government restrictions on the use of oil and gas; allow energy consumers to make their own fuel choices in an increasingly deregulated energy marketplace; encourage multifuel competition among oil, gas, coal, and other fuels based on their price, availability, and environmental merits; preserve the 'coal option' for new baseload electric powerplants which are long-lived and

3. Natural Gas Wellhead Decontrol Act of 1989

44. If there were any remaining doubt that the Commission has no authority to consider the upstream production of natural gas and its environmental effects, such doubt was put to rest when Congress enacted the Wellhead Decontrol Act.[88] In this legislation, Congress specifically removed the Commission's authority over the upstream gas production.[89]

45. But the Wellhead Decontrol Act was not merely about deregulating upstream natural gas production. Congress explained that the reason for deregulating natural gas at the wellhead was important to ensuring that end users had access to the commodity. The Senate Committee Report for the Decontrol Act stated "the purpose (of the legislation) is to promote competition for natural gas at the wellhead *to ensure consumers an adequate and reliable supply of natural gas at the lowest reasonable price*."[90] Similarly, the House Committee Report to the Decontrol Act noted, "[a]ll sellers must be able to reasonably reach the highest-bidding buyer in an increasingly national market. All buyers must be free to reach the lowest-selling producer, and obtain shipment of its gas to them on even terms with other suppliers."[91] The House Committee Report also stated the Commission's "current competitive 'open access' pipeline system [should be]

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use so much fuel; and provide potential new markets for financially distressed oil and gas producers."); *id.* *6 ("Indeed, a major purpose of this bill is to allow individual choices and competition and fuels and technologies . . . ."); *see also* President Ronald Reagan's Remarks on Signing H.R. 1941 Into Law, 23 WEEKLY COMP. PRES. DOC. 568, (May 21, 1987) ("This legislation eliminates unnecessary restrictions on the use of natural gas. It promotes efficient production and development of our energy resources by returning fuel choices to the marketplace. I've long believed that our country's natural gas resources should be free from regulatory burdens that are costly and counterproductive.").

[88] Pub. L. 101-60, 103 Stat. 157 (1989).

[89] The Wellhead Decontrol Act amended NGPA section 601(a)(1)(A) to read, "[f]or purposes of section 1(b) of the Natural Gas Act, the provisions of the Natural Gas Act and the jurisdiction of the Commission under such Act shall not apply to any natural gas solely by reason of any first sale of such natural gas." 15 U.S.C. § 3431(a)(1)(A), *amended by*, Pub. L. 101-60 § 3(a)(7)(A), 103 Stat. 157 (1989). *United Distrib. Cos. v. FERC*, 88 F.3d 1105, 1166 (D.C. Cir. 1996) ("That enactment contemplates a considerably changed natural gas world in which regulation plays a much reduced role and the free market operates at the wellhead.").

[90] S. Rep. No. 101-39 at 1 (emphasis added).

[91] H.R. Rep. No. 101-29 at 6.

maintained."[92] With this statement, the House Committee Report was referencing Order No. 436 in which the Commission stated that open access transportation "is designed to remove any unnecessary regulatory obstacles and to facilitate transportation of gas to any end user that requests transportation service."[93]

4. Energy Policy Act of 1992

46. In the Energy Policy Act of 1992 (EPAct 1992), Congress also expressed a preference for providing the public access to natural gas. EPAct section 202 states, "[i]t is the sense of the Congress that natural gas consumers and producers, and the national economy, are best served by a competitive natural gas wellhead market."[94]

47. The NGA, NGPA, the repeal of the Fuel Use Act, the Wellhead Decontrol Act, and EPAct 1992 each reflect Congressional mandates to promote the production, transportation, and use of natural gas. None of these acts, and no other law, including NEPA, modifies the presumption in the NGA to facilitate access to natural gas. And, it is not for the Commission to substitute its judgment for that of Congress in determining energy policy.

C. "Public convenience and necessity" does not support consideration of environment effects related to upstream natural gas production

48. In addition to considering the text of the NGA as a whole and subsequent-related acts, we must interpret the phrase "public convenience and necessity" as used when enacted. As discussed below, "public convenience and necessity" has always been understood to mean "need" for the service. To the extent the environment is considered, such consideration is limited to the effects stemming from the construction and operation of the proposed facilities and is not as broad as some would believe.[95]

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[92] *Id.* at 7.

[93] *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 436, 50 Fed. Reg. 42,408, 42,478 (Oct. 18, 1985) (Order No. 436).

[94] Pub. L. No. 102-486, 106 Stat. 2776 (1992).

[95] Some will cite the reference to environment in footnote 6 in *NAACP v. FPC* to argue that the Commission can consider the environmental effects of upstream gas production. *NAACP v. FERC*, 425 U.S. 662, 670 n.6. The Court's statement does not support that argument. The Court states that the environment could be a subsidiary purpose of the NGA and FPA by referencing FPA section 10, which states the Commission shall consider whether a hydroelectric project is best adapted to a comprehensive waterway by considering, among other things, the proposed *hydroelectric project's effect* on the adequate protection, mitigation, and enhancement of fish and wildlife. Nothing in the Court's statement or the citation would support the consideration

49. When Congress enacted the NGA, the phrase "public convenience and necessity" was a term of art used in state and federal public utility regulation.[96] In 1939, one year after the NGA's enactment, the Commission's predecessor agency, the Federal Power Commission, defined public convenience and necessity as "a public need or benefit without which the public is inconvenienced to the extent of being handicapped in the pursuit of business or comfort or both, without which the public generally in the area involved is denied to its detriment that which is enjoyed by the public of other areas similarly situated."[97] To make such showing, the Commission required certificate applicants to demonstrate that the public needed its proposed project, the applicant could perform the proposed service, and the service would be provided at reasonable rates.[98]

50. To the extent that public convenience and necessity included factors other than need, they were limited and directly related to the proposed facilities, not upstream effects related to the natural gas commodity. Such considerations included the effects on pipeline competition, duplication of facilities, and social costs, such as misuse of eminent domain and environmental impacts resulting from the creation of the right-of-way or service.[99] For example, the Commonwealth of Massachusetts considered environmental impacts resulting from the creation of the right-of-way and service in denying an application to build a railroad along a beach. The Commonwealth found that "the demand for train service was held to be outweighed by the fact the beach traversed 'will cease to be attractive when it is defaced and made dangerous by a steam railroad.'"[100]

51. The Commission's current guidance for determining whether a proposed project is in the public convenience and necessity is consistent with the historic use of the term. As

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of upstream impacts under the NGA.

[96] William K. Jones, *Origins of the Certificate of Public Convenience and Necessity: Developments in the States, 1870-1920*, 79 COLUM. L. REV. 426, 427-28 (1979) (Jones).

[97] *Kan. Pipe Line & Gas Co.*, 2 FPC 29, 56 (1939).

[98] *See* Order No. 436, at 42,474 (listing the requirements outlined in *Kan. Pipe Line & Gas Co.*: "(1) they possess a supply of natural gas adequate to meet those demands which it is reasonable to assume will be made upon them; (2) there exist in the territory proposed to be served customers who can reasonably be expected to use such natural-gas service; (3) the facilities for which they seek a certificate are adequate; (4) the costs of construction of the facilities which they propose are both adequate and reasonable; (5) the anticipated fixed charges or the amount of such fixed charges are reasonable; and (6) the rates proposed to be charged are reasonable.")

[99] Jones at 428.

[100] *Id.* at 436.

outlined in its 1999 Certificate Policy Statement, the Commission implements an economic balancing test that is focused on whether there is a need for the facilities and adverse economic effects stemming from the construction and operation of the proposed facilities themselves. The Commission designed its balancing test "to foster competitive markets, protect captive customers, and avoid unnecessary environmental and community impacts while serving increasing demands for natural gas."[101] The Commission also stated that its balancing test "provide[s] appropriate incentives for the optimal level of construction and efficient customer choices."[102] To accomplish these objectives, the Commission determines whether a project is in the public convenience and necessity by balancing the public benefits of the project against the adverse economic impacts on the applicant's existing shippers, competitor pipelines and their captive customers, and landowners.[103]

52. Although the Certificate Policy Statement also recognizes the need to consider certain environmental issues related to a project, it makes clear that the environmental impacts to be considered are related to the construction and operation of the pipeline itself and the creation of the right-of-way.[104] As noted above, it is the Commission's objective to avoid *unnecessary* environmental impacts, meaning to route the pipeline to avoid environmental effects where possible and feasible, not to prevent or mitigate environmental effects from upstream natural gas production. This is confirmed when one considers that, if the project had unnecessary adverse environmental effects, the Commission would require the applicant to reroute the pipeline: "If the environmental analysis following a preliminary determination indicates a preferred route other than the one proposed by the applicant, the earlier balancing of the public benefits of the project against its adverse effects would be reopened to take into account the adverse effects on landowners who would be affected by the changed route."[105]

53. Further, the Certificate Policy Statement provides, "[i]deally, an applicant will structure its proposed project to avoid adverse economic, competitive, environmental, or other effects on the relevant interests from the construction of the new project."[106] And

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[101] Certificate Policy Statement, 88 FERC ¶ at 61,743.

[102] *Id.*

[103] *Id.*

[104] *See also Ctr. for Biological Diversity v. U.S. Army Corps of Eng'rs*, 941 F.3d 1288, 1299 (11th Cir. 2019) ("Regulations cannot contradict their animating statutes or manufacture additional agency power.") (citing *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 125-26 (2000)).

[105] Certificate Policy Statement, 88 FERC ¶ at 61,749.

[106] *Id.* at 61,747.

that is what occurred in this case. Pacific Connector revised its route crossing the Pacific Crescent Trail to reduce the amount of Forest Service lands affected and reduce impacts on northern-spotted owl critical and suitable habitat.[107] Further, Pacific Connector rerouted the pipeline to avoid areas that posed moderate to high potential landslide risk. These examples are consistent with the NGA's and Certificate Policy Statement's focus on environmental impacts related to the construction and operation of the pipeline itself and the creation of the right-of-way.[108]

54. In sum, the meaning of "public convenience and necessity" does not support weighing the public need for the project against effects related to upstream natural gas production.

D. NEPA does not authorize the Commission to deny a certificate application based on emissions from upstream gas production

55. The text of the NGA, and the related subsequent acts by Congress, cannot be revised by NEPA or CEQ regulations to authorize the Commission to deny a certificate application based on effects from upstream gas production.

56. The courts have made clear that NEPA does not expand a federal agency's substantive or jurisdictional powers.[109] Nor does NEPA repeal by implication any other statute.[110] Rather, NEPA is a merely procedural statute that requires federal agencies to take a "hard look" at the environmental effects of a proposed action before acting on it.[111]

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[107] Final EIS at 3-49.

[108] *Id.* at 4-24.

[109] *Nat. Res. Def. Council, Inc. v. EPA*, 822 F.2d 104, 129 (D.C. Cir. 1987) ("NEPA, as a procedural device, does not work a broadening of the agency's substantive powers. Whatever action the agency chooses to take must, of course, be within its province in the first instance.") (citations omitted); *Cape May Greene, Inc. v. Warren*, 698 F.2d 179, 188 (3d Cir. 1986) ("The National Environmental Policy Act does not expand the jurisdiction of an agency beyond that set forth in its organic statute."); *Gage v. U.S. Atomic Energy Comm'n*, 479 F.2d 1214, 1220 n.19 (D.C. Cir. 1973) ("NEPA does not mandate action which goes beyond the agency's organic jurisdiction."); *see also Flint Ridge Dev. Co. v. Scenic Rivers Ass'n of Okla.*, 426 U.S. 776, 788 (1976) ("where a clear and unavoidable conflict in statutory authority exists, NEPA must give way").

[110] *U.S. v. Students Challenging Regulatory Agency Procedures*, 412 U.S. 669, 694 (1973).

[111] *Vt. Yankee Nuclear Power Corp. v. Nat. Res. Def. Council, Inc.*, 435 U.S. 519, 558 (1978) ("NEPA does set forth significant substantive goals for the Nation, but its mandate to the agencies is essentially procedural.").

NEPA also does not require a particular result. In fact, the Supreme Court has stated, even if a NEPA analysis identifies an environmental harm, the agency can still approve the project.[112]

57. Further, CEQ's regulations on indirect effects cannot make the GHG emissions from upstream production part of the Commission's public convenience and necessity determination under the NGA. As stated above, an agency's obligation under NEPA to consider indirect environmental effects is not limitless. Indirect effects must have "a reasonably close causal relationship" with the alleged cause, and that relationship is dependent on the "underlying policies or legislative intent."[113] NEPA requires such reasonably close causal relationship because "inherent in NEPA and its implementing regulations is a 'rule of reason,'"[114] which "recognizes that it is pointless to require agencies to consider information they have no power to act on, or effects they have no power to prevent."[115] Thus, "where an agency has no ability to prevent a certain effect due to its limited statutory authority over the relevant actions, the agency cannot be considered a legally relevant 'cause' of the effect."[116]

58. The Commission has no power to deny a certificate for effects related to the upstream production of natural gas. As explained above, the Commission's consideration of adverse environmental effects is limited to those effects stemming from the

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[112] *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 350 (1989) ("Although these procedures are almost certain to affect the agency's substantive decision, it is now well settled that NEPA itself does not mandate particular results, but simply prescribes the necessary process.").

[113] *Metro. Edison Co. v. People Against Nuclear Energy*, 460 U.S. 766, 774 n.7 (1983).

[114] *Pub. Citizen*, 541 U.S. at 767.

[115] *Ctr. for Biological Diversity*, 941 F.3d at 1297; *see also Town of Barnstable v. FAA*, 740 F.3d 681, 691 (D.C. Cir. 2014) ("NEPA's 'rule of reason' does not require the FAA to prepare EIS when it would 'serve no purpose.'").

[116] *Pub. Citizen,* 541 U.S. at 770; *see also Town of Barnstable*, 740 F.3d at 691 ("Because the FAA 'simply lacks the power to act on whatever information might be contained in the [environmental impact ('EIS')],' NEPA does not apply to its no hazard determinations.") (internal citation omitted); *Ohio Valley Envtl. Coal. v. Aracoma Coal Co.*, 556 F.3d 177, 196-97 (4th Cir. 2009) (finding that the U.S. Army Corps of Engineers (Corps) was not required to consider the valley fill projects because "[West Virginia Department of Environmental Protection], and not the Corps, [had] 'control and responsibility' over all aspects of the valley fill projects beyond the filling of jurisdictional waters.").

construction and operation of the pipeline facility and the related right-of-way. For the Commission to deny a pipeline based on GHGs emitted from upstream gas production would be contrary to the text of the NGA and subsequent acts by Congress. The NGA reserves such considerations for the States, and the Commission must respect the jurisdictional boundaries set by Congress. Suggesting that the Commission can consider such effects not only risks duplicative regulation but in fact defies Congress.

III. The NGA does not contemplate the Commission establishing mitigation for GHG emissions from LNG or pipeline facilities

59. My colleague has also suggested that the Commission should require the mitigation of GHG emissions from the authorized LNG and pipeline facilities and the upstream production of natural gas transported on those facilities. I understand his suggestions as proposing a carbon emissions fee, offsets or tax (similar to the Corps' compensatory wetland mitigation program), technology requirements (such as scrubbers or electric-powered compressor units),[117] or emission caps. Some argue that the Commission can require such mitigation under NGA section 3(e)(3)(A) or NGA section 7(e). NGA section 3(e)(3)(A) provides, "the Commission may approve an application . . . in whole or part, with such modifications and upon such terms and conditions as the Commission find necessary or appropriate."[118] NGA section 7(e) provides "[t]he Commission shall have the power to attach to the issuance of the certificate . . . such reasonable terms and conditions as the public convenience and necessity may require."[119]

60. I disagree. The Commission cannot interpret NGA section 3(e) or section 7(e) to allow the Commission to unilaterally establish measures to mitigate GHG emissions because Congress, through the Clean Air Act, assigned the EPA and the States exclusive authority to establish such measures. Congress designated the EPA as the expert agency "best suited to serve as primary regulator of greenhouse gas emissions," [120] not the Commission.

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[117] It is also important to consider the impact on reliability that would result from requiring electric-compressor units on a gas pipeline. In the event of a power outage, a pipeline with electric-compressor units may be unable to compress and transport gas to end-users, including power plants and residences for heating and cooking.

[118] 15 U.S.C. § 717b(3)(e)(3)(A) (2018).

[119] *Id.* § 717f(e).

[120] *American Elec. Power Co., Inc. v. Conn.*, 564 U.S. 410, 428 (2011).

61. The Clean Air Act establishes an all-encompassing regulatory program, supervised by the EPA to deal comprehensively with interstate air pollution.[121] Congress entrusted the Administrator of the EPA with significant discretion to determine appropriate emissions measures. Congress delegated the Administrator the authority to determine whether pipelines and other stationary sources endanger public health and welfare; section 111 of the Clean Air Act directs the Administrator of the EPA "to publish (and from time to time thereafter shall revise) a list of categories of stationary sources. He shall include a category of sources in such list if in *his judgment* it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare"[122] and to establish standards of performance for the identified stationary sources.[123] The Clean Air Act requires the Administrator to conduct complex balancing when determining a standard of performance, taking into consideration what is technologically achievable and the cost to achieve that standard.[124]

62. In addition, the Clean Air Act allows the Administrator to "distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing such standards."[125] The Act also permits the Administrator, with the consent of the Governor of the State in which the source is to be located, to waive its requirements "to encourage the use of an innovative technological system or systems of continuous emission reduction."[126]

63. Congress also intended that states would have a role in establishing measures to mitigate emissions from stationary sources. Section 111(f) notes that "[b]efore promulgating any regulations . . . or listing any category of major stationary sources . . . the Administrator shall consult with appropriate representatives of the Governors and of State air pollution control agencies."[127]

64. Thus, the text of the Clean Air Act demonstrates it is improbable that NGA section 3(e)(3)(A) or NGA section 7(e) allow the Commission to establish GHG emission standards or mitigation measures out of whole cloth. To argue otherwise would defeat

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[121] *See id.* at 419.

[122] 42 U.S.C. § 7411(b)(1)(A) (2018).

[123] *Id.* § 7411(b)(1)(B).

[124] *Id.* § 7411(a)(1).

[125] *Id.* § 7411(a)(2).

[126] *Id.* § 7411(j)(1)(A).

[127] *Id.* § 7411(f)(3).

the significant discretion and complex balancing that the Clean Air Act entrusts in the EPA Administrator, and would eliminate the role of the States.

65. Furthermore, to argue that the Commission may use its NGA conditioning authority to establish GHG emission mitigation—a field in which the Commission has no expertise—and address climate change—an issue that has been subject to profound debate across our nation for decades—is an extraordinary leap. The Supreme Court's "major rules" canon advises that agency rules on issues that have vast economic and political significance must be treated "with a measure of skepticism" and require Congress to provide clear authorization.[128] The Court has articulated this canon because Congress does not "hide elephants in mouseholes"[129] and "Congress is more likely to have focused upon, and answered, major questions, while leaving interstitial matters to answer themselves in the course of the statute's daily administration."[130]

66. Courts would undoubtedly treat with skepticism any attempt by the Commission to mitigate GHG emissions. Congress has introduced climate change bills since at least 1977,[131] over four decades ago. Over the last 15 years, Congress has introduced and failed to pass 70 legislative bills to reduce GHG emissions—29 of those were carbon emission fees or taxes.[132] For the Commission to suddenly declare such climate

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[128] *Util. Air Regulatory Grp. v. EPA*, 573 U.S. 302, 324 (2014); *Brown & Williamson,* 529 U.S. at 160 ("Congress could not have intended to delegate a decision of such economic and political significance to an agency in so cryptic a fashion."); *see also Gonzales v. Oregon*, 546 U.S. 243, 267-68 (2006) (finding regulation regarding issue of profound debate suspect).

[129] *Whitman v. American Trucking Ass.,* 531 U.S. 457, 468 (2001).

[130] *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 12, 159 (quoting Justice Breyer, *Judicial Review of Questions of Law and Policy*, 38 ADMIN. L. REV. 363, 370 (1986)); *see also* Abbe R. Gluck & Lisa Schultz Bressman, *Statutory Interpretation from the Inside—An Empirical Study of Congressional Drafting, Delegation, and the Canons: PART I*, 65 STAN. L. REV. 901, 1004 (2013) ("Major policy questions, major economic questions, major political questions, preemption questions are all the same. Drafters don't intend to leave them unresolved.").

[131] National Climate Program Act, S. 1980, 95th Cong. (1977).

[132] CONGRESSIONAL RESEARCH SERVICE, MARKET-BASED GREENHOUSE GAS EMISSION REDUCTION LEGISLATION: 108TH THROUGH 116TH CONGRESSES at 3 (Oct. 23, 2019), https://fas.org/sgp/crs/misc/R45472.pdfhttps://fas.org/sgp/crs/misc/R45472.pdf. Likewise, the CEQ issued guidance on the consideration of GHG emissions in 2010, 2014, 2016, and 2019. None of those documents require, let alone recommend, that an agency establish a carbon emissions fee or tax.

mitigation power resides in the long-extant NGA and that Congress's efforts were superfluous strains credibility. Establishing a carbon emissions fee or tax, or GHG mitigation out of whole cloth would be a major rule, and Congress has made no indication that the Commission has such authority.

67. Some may make the argument that the Commission can develop mitigation measures without establishing a standard. I disagree. Establishing mitigation measures requires determining how much mitigation is required – i.e., setting a limit, or establishing a standard, that quantifies the amount of GHG emissions that will adversely affect the human environment. Some may also argue that the Commission has unilaterally established mitigation in other contexts, including wetlands, soil conservation, and noise. These examples, however, are distinguishable. Congress did not exclusively assign the authority to establish avoidance or restoration measures for mitigating effects on wetlands or soil to a specific agency. The Corps and the EPA developed a wetlands mitigation bank program pursuant to section 404 of the Clean Water Act.[133] Congress endorsed such mitigation.[134] As for noise, the Clean Air Act assigns the EPA Administrator authority over determining the level of noise that amounts to a public nuisance and requires federal agencies to consult with the EPA when its actions exceed the public nuisance standard.[135] The Commission complies with the Clean Air Act by requiring project noise levels in certain areas to not exceed 55 dBA Ldn, as required by EPA's guidelines.[136]

68. Accordingly, there is no support that the Commission can use its NGA section 3(e) or section 7(e) authority to establish measures to mitigate GHG emissions from proposed LNG or pipeline facilities or from upstream gas production.[137]

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[133] 33 U.S.C. § 1344 (2018).

[134] *See* Water Resources Development Act, Pub. L. 110-114, § 2036(c), 121 Stat. 1041, 1094 (2007); National Defense Authorization Act, Pub. L. 108-136, § 314, 117 Stat. 1392, 1430 (2004); Transportation Equity Act for the 21st Century, Pub. L. 105-178, § 103 (b)(6)(M), 112 Stat. 107, 133 (1998); Water Resources Development Act of 1990, Pub. L. 101-640, § (a)(18)(C), 104 Stat. 4604, 4609 (1990).

[135] 42 U.S.C. § 7641(c) ("In any case where any Federal department or agency is carrying out or sponsoring any activity resulting in noise which the Administrator determines amounts to a public nuisance or is otherwise objectionable, such department or agency shall consult with the Administrator to determine possible means of abating such noise.").

[136] *See Williams Gas Pipelines Cent., Inc.*, 93 FERC ¶ 61,159, at 61,531-52 (2000).

[137] In addition, requiring a pipeline to mitigate emissions from upstream gas

IV. The Commission has no reliable objective standard for determining whether GHG emissions significantly affect the environment

69. My colleague has argued that the Commission violates the NGA and NEPA by not determining the significance of GHG emissions that are effects of a project.[138] He has challenged the Commission's explanation that it cannot determine significance because there is no standard for determining the significance of GHG emissions.[139] He has argued that the Commission can adopt the Social Cost of Carbon[140] to determine whether GHG emissions are significant or rely on its own expertise as it does for other environmental resources, such as vegetation, wildlife, or open land.[141] He has suggested that the Commission does not make a finding of significance in order to deceptively find that a project is in the public convenience and necessity.

70. I disagree. The Social Cost of Carbon is not a suitable method for determining whether GHG emissions that are caused by a proposed project will have a significant effect on climate change, and the Commission has no authority or objective basis using its own expertise to make such determination.

A. Social Cost of Carbon is not a suitable method to determine significance

71. The Commission has found, and I agree, that the Social Cost of Carbon is not a suitable method for the Commission to determine significance of GHG emissions.[142] Because the courts have repeatedly upheld the Commission's reasoning,[143] I will not restate the Commission's reasoning here.

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production would not be "a reasonable term or condition as the public convenience and necessity may require." 15 U.S.C. § 717f(e) (2018). It would be unreasonable to require a pipeline to mitigate an effect it has no control over. Further, as discussed above, emissions from upstream gas production are not relevant to the NGA's public convenience and necessity determination.

[138] Cheyenne Connector PP 2, 7.

[139] *Id.* P 12.

[140] *Id.* P 13.

[141] *Adelphia Gateway, LLC*, 169 FERC ¶ 61,220 at P 10 (Glick, Comm'r, dissenting).

[142] *Fla. Se. Connection, LLC*, 162 FERC ¶ 61,233, at P 48 (2018).

[143] *Appalachian Voices*, 2019 WL 847199, *2; *EarthReports, Inc.*, 828 F.3d 949, 956; *Sierra Club v. FERC*, 672 F. App'x 38, (D.C. Cir. 2016); *see also Citizens for a*

72. However, I will address the suggestion that the Social Cost of Carbon can translate a project's impact on climate change into "concrete and comprehensible terms" that will help inform agency decision-makers and the public at large.[144] The Social Cost of Carbon, described as an estimate of "the monetized damages associated with an incremental increase in carbon emissions in a given year,"[145] may appear straightforward. On closer inspection, however, the Social Cost of Carbon and its calculated outputs are not so simple to interpret or evaluate.[146] When the Social Cost of Carbon estimates that one metric ton of CO_2 costs $12 (the 2020 cost using a discount rate of 5 percent),[147] agency decision-makers and the public have no objective basis or benchmark to determine whether that cost is significant. Bare numbers standing alone simply *cannot* ascribe significance.

Healthy Cmty. v. U.S. Bureau of Land Mgmt., 377 F. Supp. 3d 1223, 1239-41 (D. Colo. 2019) (upholding the agency's decision to not use the Social Cost of Carbon); *WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41, 77-79 (D.D.C. 2019) (upholding the agency's decision to not use the Social Cost of Carbon); *High Country Conservation Advocates v. U.S. Forest Serv.*, 333 F. Supp. 3d 1107, 1132 (D. Colo. 2018) ("[T]he *High Country* decision did not mandate that the Agencies apply the social cost of carbon protocol in their decisions; the court merely found arbitrary the Agencies' failure to do so without explanation.").

[144] Cheyenne Connector Dissent P 13.

[145] Interagency Working Group on the Social Cost of Greenhouse Gases, *Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory impact Analysis – Under Executive Order 12866* at 1 (Aug. 2016), https://www.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf (2016 Technical Support Document).

[146] In fact, the website for the Climate Framework for Uncertainty Negotiation and Distribution (FUND) – one of the three integrated assessment models that the Social Cost of Carbon uses – states "[m]odels are often quite useless in unexperienced hands, and sometimes misleading. No one is smart enough to master in a short period what took someone else years to develop. Not-understood models are irrelevant, half-understood models are treacherous, and mis-understood models dangerous." FUND-Climate Framework for Uncertainty, Negotiation and Distribution, http://www.fund-model.org/ (LAST VISITED NOV. 18, 2019).

[147] *See* 2016 Technical Support Document at 4. The Social Cost of Carbon produces wide-ranging dollar values based upon a chosen discount rate, and the assumptions made. The Interagency Working Group on Social Cost of Greenhouse Gases estimated in 2016 that the Social Cost of one ton of carbon dioxide for the year 2020 ranged from $12 to $123. *Id.*

B. <u>The Commission has no authority or objective basis to establish its own framework</u>

73. Some argue that the lack of externally established targets does not relieve the Commission from establishing a framework or targets on its own. Some have suggested that the Commission can make up its own framework, citing the Commission's framework for determining return on equity (ROE) as an example. However, they overlook the fact that Congress designated the EPA, not the Commission, with exclusive authority to determine the amount of emissions that are harmful to the environment. In addition, there are no available resources or agency expertise upon which the Commission could reasonably base a framework or target.

74. As I explain above, Congress enacted the Clean Air Act to establish an all-encompassing regulatory program, supervised by the EPA to deal comprehensively with interstate air pollution. Section 111 of the Clean Air Act directs the Administrator of the EPA to identify stationary sources that "in his judgment cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare"[148] and to establish standards of performance for the identified stationary sources.[149] Thus, the EPA has exclusive authority for determining whether emissions from pipeline facilities will have a significant effect on the environment.

75. Further, the Commission is not positioned to unilaterally establish a standard for determining whether GHG emissions will significantly affect the environment when there is neither federal guidance nor an accepted scientific consensus on these matters.[150] This inability to find an acceptable methodology is not for a lack of trying. The Commission

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[148] 42 U.S.C. § 7411(b)(1)(A) (2018).

[149] *Id.* § 7411(b)(1)(B).

[150] The Council on Environmental Quality's 2019 Draft Greenhouse Gas Guidance states, "[a]gencies need not undertake new research or analysis of potential climate effects and may rely on available information and relevant scientific literature." CEQ, *Draft National Environmental Policy Act Guidance on Consideration of Greenhouse Gas Emissions*, 84 Fed. Reg. 30,097, 30,098 (June 26, 2019); *see also* CEQ FINAL GUIDANCE FOR FEDERAL DEPARTMENTS AND AGENCIES ON CONSIDERATION OF GREENHOUSE GAS EMISSIONS AND THE EFFECTS OF CLIMATE CHANGE IN NATIONAL ENVIRONMENTAL POLICY ACT REVIEWS at 22 (Aug. 1, 2016) ("agencies need not undertake new research or analysis of potential climate change impacts in the proposed action area, but may instead summarize and incorporate by reference the relevant scientific literature"), https://ceq.doe.gov/docs/ceq-regulations-and-guidance/nepa_final_ghg_guidance.pdf.

reviews the climate science, state and national targets, and climate models that could inform its decision-making.[151]

76. Moreover, assessing the significance of project effects on climate change is unlike the Commission's determination of ROE. Establishing ROE has been one of the core functions of the Commission since its inception under the FPA as the Federal Power Commission.[152] And, setting ROE has been an activity of state public utility commissions, even before the creation of the Federal Power Commission.[153] The Commission's methodology is also founded in established economic theory.[154] In contrast, assessing the significance of GHG emissions is not one of the Commission's core missions and there is no suitable methodology for making such determination.

77. It has been argued that the Commission can establish its own methodology for determining significance, pointing out that the Commission has determined the significance of effects on vegetation, wildlife, and open land using its own expertise and without generally accepted significance criteria or a standard methodology.

78. I disagree. As an initial matter, it is important to note that when the Commission states it has no suitable methodology for determining the significance of GHG emissions, the Commission means that it has no objective basis for making such finding. The Commission's findings regarding significance for vegetation, wildlife, and open land have an objective basis. For example for vegetation, the Commission determined the existing vegetation in the project area by using information made available by the U.S. Forest Service, U.S. Bureau of Land Management, Oregon Department of Fish and Wildlife, and Oregon Natural Heritage Program.[155] The Commission determined the project's effect on vegetation by considering the existing vegetation, by using the

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[151] *Fla. Se. Connection, LLC*, 162 FERC ¶ 61,233, at P 36; *see also WildEarth Guardians*, 738 F.3d 298, 309 (D.C. Cir. 2013) ("Because current science does not allow for the specificity demanded by the Appellants, the BLM was not required to identify specific effects on the climate in order to prepare an adequate EIS.").

[152] *Hope*, 320 U.S. 591 (1944); *FPC v. Nat. Gas Pipeline Co. of America*, 315 U.S. 575 (1942).

[153] *See, e.g., Willcox v. Consol. Gas Co.*, 212 U.S. 19, 41 (1909) (finding New York State must provide "a fair return upon the reasonable value of the property at the time it is being used for the public.").

[154] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 166 FERC ¶ 61,207 (2019) (describing the Commission's use of the Discounted Cash Flow model that was originally developed in the 1950s as a method for investors to estimate the value of securities).

[155] Final EIS at 4-150 to 4-155, 4-163 to 4-165.

applicant's materials to quantify the amount of acres that will be temporarily impacted by construction and permanently impacted by operation, and by considering the mitigation and restoration activities that Jordan Cove and Pacific Connector will implement, including *BLM and Forest Service Compensatory Mitigation Plan and Amendment*, *Late Successional Reserves Crossed by the PGCP Project*, and planting of Douglas firs.[156] Based on this information demonstrating that affected vegetation is widespread in the vicinity of the project and the measures that the applicants will implement, the Commission made a reasoned finding that the Project's impacts on vegetation will not be significant. The Commission conducted a similar evaluation of wildlife and open land.

79. In contrast, the Commission has no reasoned basis to determine whether a project has a significant effect on climate change. To assess a project's effect on climate change, the Commission can only quantify the amount of project emissions and compare that number to national emissions to calculate a percentage of national emissions. That calculated number cannot inform the Commission on climate change effects caused by the project, e.g., increase of sea level rise, effect on weather patterns, or effect on ocean acidification. Nor are there acceptable scientific models that the Commission may use to attribute every ton of GHG emissions to a physical climate change effect.

80. Without adequate support or a reasoned target, the Commission cannot ascribe significance to particular amounts of GHG emissions. To do so would not only exceed our agency's authority, but would risk reversal upon judicial review. Courts require agencies to "consider[] the relevant factors and articulate[] a rational connection between the facts found and the choice made."[157] Simply put, stating that an amount of GHG emissions appears significant without any objective support fails to meet the agency's obligations under the Administrative Procedure Act (APA).

V. Conclusion

81. As in other cases, I have carefully considered the facts, record and the law.[158] Under the NGA, the Commission considers local and state interests, but ultimately is

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[156] *Id.* 4-156 to 4-158, 4-165 to 4-173.

[157] *City of Tacoma v. FERC*, 460 F.3d 53, 76 (D.C Cir. 2006) (quoting *Ariz. Cattle Growers' Ass'n v. FWS*, 273 F.3d 1229, 1235-36 (9th Cir. 2001)); *see also American Rivers v. FERC*, 895 F.3d 32, 51 (D.C. Cir. 2018) (". . . the Commission's NEPA analysis was woefully light on reliable data and reasoned analysis and heavy on unsubstantiated inferences and *non sequiturs*") (italics in original); *Found. for N. Am. Wild Sheep v. U.S. Dep't of Agr.*, 681 F.2d 1172, 1179 (9th Cir. 1982) ("The EA provides no foundation for the inference that a valid comparison may be drawn between the sheep's reaction to hikers and their reaction to large, noisy ten-wheel ore trucks.").

[158] The views of the State of Oregon are particularly important and I have considered the letter issued by Oregon DLCD. As discussed in the order, the issues

required to consider the national interest when making its final determination. I fully support the Commission's order that the LNG Project is not inconsistent with the public interest and that the pipeline is required by the public convenience and necessity.

82. This concurrence is intended to assist the Commission, courts, and other parties in their consideration of the Commission's obligations under the NGA and NEPA. The Commission cannot act *ultra vires* and claim more authority than the NGA provides it, regardless of the importance of the issue sought to be addressed.[159] The NGA provides the Commission no authority to deny a certificate application based on the environmental effects from upstream gas production. Congress enacted the NGA, and subsequent legislation, to ensure the Commission provided public access to natural gas. Further, Congress designed the NGA to preserve States' authority to regulate the physical effects from upstream gas production, and did not leave that field unregulated. Congress simply did not authorize the Commission to judge whether upstream production will be too environmentally harmful.

83. Nor does the Commission have the ability to establish measures to mitigate GHG emissions. Pursuant to the Clean Air Act, Congress exclusively assigned that authority to the EPA and the States. Finally, the Commission has no objective basis for determining whether GHG emissions are significant that would satisfy the Commission's APA obligations and survive judicial review.

84. I recognize that some believe the Commission should do more to address climate change. The Commission, an energy agency with a limited statutory authority, is not the appropriate authority to establish a new regulatory regime.

For these reasons, I respectfully concur.

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Bernard L. McNamee
Commissioner

raised were already considered in the EIS or specifically addressed in the order. *Jordan Cove Energy Project L.P.*, 170 FERC ¶ 61,202 at P 156.

[159] *Office of Consumers' Counsel*, 655 F.2d at 1152 ("[A]ppropriate respect for legislative authority requires regulatory agencies to refrain from the temptation to stretch their jurisdiction to decide questions of competing public priorities whose resolution properly lies with Congress.").

Document Content(s)

171 FERC ¶ 61,136
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Richard Glick, Bernard L. McNamee,
and James P. Danly.

Jordan Cove Energy Project L.P. — Docket Nos. CP17-495-001
Pacific Connector Gas Pipeline, LP — CP17-494-001

ORDER ON REHEARING AND STAY

(Issued May 22, 2020)

1. On March 19, 2020, the Commission issued an order pursuant to section 3 of the Natural Gas Act (NGA)[1] and Part 153 of the Commission's regulations[2] authorizing Jordan Cove Energy Project L.P. (Jordan Cove) to site, construct, and operate a liquefied natural gas (LNG) export terminal and associated facilities (Jordan Cove LNG Terminal) in unincorporated Coos County, Oregon (Authorization Order).[3] The Commission also authorized, pursuant to NGA section 7[4] and Parts 157 and 284 of the Commission's regulations,[5] Pacific Connector Gas Pipeline, LP (Pacific Connector) to construct and operate a new interstate natural gas pipeline system (Pacific Connector Pipeline) in Klamath, Jackson, Douglas, and Coos Counties, Oregon.

2. On April 17, 2020, the Commission received requests for rehearing from Jordan Cove and Pacific Connector, the Cow Creek Band of Umpqua Tribe of Indians (Cow Creek Band), and the Klamath Tribes. On April 20, 2020, the Commission received requests for rehearing from the Confederated Tribes of the Coos, Lower Umpqua, and Siuslaw Indians (collectively, Confederated Tribes); Citizens for Renewables, Inc.,

[1] 15 U.S.C. § 717b (2018).

[2] 18 C.F.R. pt. 153 (2019).

[3] *Jordan Cove Energy Project L.P.*, 170 FERC ¶ 61,202 (2020) (Authorization Order).

[4] 15 U.S.C. § 717f (2018).

[5] 18 C.F.R. pt. 157 (2019).

Citizens Against LNG, and Jody McCaffree (collectively, Jody McCaffree); Oregon Department of Energy, Oregon Department of Environmental Quality, Oregon Department of Fish and Wildlife, and Oregon Department of Land Conservation and Development (collectively, State of Oregon); the Natural Resources Defense Council (NRDC); and, jointly, Sierra Club, Niskanen Center (on behalf of Bill Gow, Sharon Gow, Neal C. Brown Family LLC, Wilfred E. Brown, Elizabeth A. Hyde, Barbara L. Brown, Pamela Brown Ordway, Chet N. Brown, Evans Schaff Family LLC, Deb Evans, Ron Schaff, Stacey McLaughlin, Craig McLaughlin, Richard Brown, Twyla Brown, Clarence Adams, Stephany Adams, Will McKinley, Wendy McKinley, Frank Adams, Lorraine Spurlock, Toni Woolsey, Alisa Acosta, Gerrit Boshuizen, Cornelis Boshuizen, Robert Clarke, John Clarke, Carol Munch, Ron Munch, Mitzi Sulffridge, James Dahlman, John Dahlman), the Western Environmental Law Center, the Klamath Tribes, Center for Biological Diversity, Oregon Wild, Rogue Riverkeeper, Pacific Coast Federation of Fishermen's Associations, Institute for Fisheries Resources, Greater Good Oregon, Friends of Living Oregon Waters, Surfrider Foundation, Oregon Women's Land Trust, Oregon Shores Conservation Coalition, League of Women's Voters of Coos County, League of Women's Voters of Umpqua County, League of Women's Voters of Rouge Valley, League of Women's Voters of Klamath County, Rogue Climate, Umpqua Watersheds, Waterkeeper Alliance, Coast Range Forest Watch, Cascadia Wildlands, Oregon Physicians for Social Responsibility, Hair on Fire Oregon, Citizens for Renewables, Citizens Against LNG, Francis Eatherington, Janet Hodder, Michael Graybill, and Natural Resources Defense Council (collectively, Sierra Club). On April 21, 2020, the Commission received a late request for rehearing and stay from Kenneth E. Cates, Kristine Cates, James Davenport, Archina Davenport, David McGriff, Emily McGriff, Andrew Napell, Dixie Peterson, Paul Washburn, and Carol Williams. NRDC and Sierra Club also requested to stay the Authorization Order until the Commission acts on rehearing.

3. As discussed below, we deny and grant rehearing in part, and deny the stay requests as moot.

I. Background

4. The Jordan Cove LNG Terminal is designed to produce a nominal capacity of up to 7.8 million metric tonnes per annum (MTPA) of LNG for export.[6] The project facilities will include: gas inlet and gas conditioning facilities; five liquefaction trains, each with a nominal capacity of 1.56 MTPA, for a total nominal capacity of 7.8 MTPA; two full-containment LNG storage tanks, each with a net capacity of approximately 160,000 cubic meters (m^3); a marine slip, including one LNG carrier loading berth

[6] Authorization Order, 170 FERC ¶ 61,202 at P 7.

capable of accommodating LNG carriers with a cargo capacity of 89,000 m^3 to 217,000 m^3;[7] and support systems.[8]

5. Construction of the Jordan Cove LNG Terminal will affect about 577 acres of land, and mitigation associated with the project is anticipated to impact about 778 additional acres of land.[9] Once construction is complete, operation of the Jordan Cove LNG Terminal will require the use of approximately 200 acres, across two parcels—Ingram Yard and the South Dunes Site—which are connected by a one-mile-long Access Utility Corridor.[10] The main LNG production facilities will be located on the Ingram Yard parcel, while the interconnection with the Pacific Connector Pipeline will be located on the South Dunes Site parcel.[11]

6. In December 2011, Jordan Cove received authorization from the Department of Energy, Office of Fossil Energy (DOE/FE) to export annually up to 438 billion cubic feet (Bcf) per year equivalent of natural gas in the form of LNG to countries with which the United States has a Free Trade Agreement (FTA);[12] and, in March 2014, Jordan Cove received conditional authorization to export annually up to 292 Bcf equivalent to non-FTA countries.[13] On February 6, 2018, Jordan Cove filed an application with DOE/FE to

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[7] We note that Jordan Cove is only authorized by the U.S. Coast Guard to receive vessels with nominal capacities of up to 148,000 m^3. Final EIS at 4-91.

[8] Authorization Order, 170 FERC ¶ 61,202 at PP 8-11.

[9] *Id.* P 12.

[10] *Id.*

[11] Fort Chicago LNG II U.S. L.P., an affiliate of Jordan Cove, currently owns 295 acres of land at the terminal site. Jordan Cove will acquire the use of the remaining lands through easements or leases.

[12] *Jordan Cove Energy Project, L.P.*, FE Docket No. 11-127-LNG, Order No. 3041 (December 7, 2011). The 2011 FTA authorization stated that the 30-year term of the authorization would commence on the earlier of the date of the first export or December 7, 2021; and, the 2014 non-FTA, 20-year authorization required Jordan Cove to commence operations within seven years of the date of the authorization (i.e., by March 24, 2021).

[13] *Jordan Cove Energy Project, L.P.*, FE Docket No. 12-32-LNG, Order No. 3413 (March 24, 2014). These authorizations were associated with Jordan Cove's previously-proposed export terminal, in Docket No. CP13-483-000. As explained in the Authorization Order, the Commission denied that proposal, along with Pacific Connector's previously proposed pipeline project (Docket No. CP13-492-000), on

amend its FTA and non-FTA authorizations to modify the quantity of LNG Jordan Cove is authorized to export (reflecting changes Jordan Cove made to its proposed facilities and additional engineering analysis) and to "re-set the dates by which [Jordan Cove] must commence exports."[14] Specifically, Jordan Cove requested to reduce the approved export volume to FTA countries from 438 Bcf per year equivalent to 395 Bcf per year equivalent, and to increase the approved export volume to non-FTA countries from 292 Bcf equivalent to 395 Bcf equivalent.[15] In July 2018, DOE/FE amended Jordan Cove's FTA authorization in accordance with Jordan Cove's request.[16] Jordan Cove's requested amendment of its non-FTA authorization remains pending before the DOE/FE.[17]

7. The Pacific Connector Pipeline is designed to provide up to 1,200,000 dekatherms per day (Dth/d) of firm natural gas transportation service from interconnects with existing natural gas pipeline systems near Malin, Oregon, to the Jordan Cove LNG Terminal, for liquefaction and export.[18] The Pacific Connector Pipeline will include approximately 229 miles of 36-inch-diameter natural gas pipeline, a new 62,200-horsepower (hp) compressor station, three new meter stations, and appurtenant facilities.[19] The Pacific

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March 11, 2016. Authorization Order, 170 FERC ¶ 61,202 at P 5 (citing *Jordan Cove Energy Project, L.P.*, 154 FERC ¶ 61,190, *reh'g denied*, 157 FERC ¶ 61,194 (2016) (2016 Order)).

[14] Jordan Cove's February 6, 2018 Amendment Application filed in FE Docket Nos. 11-127-LNG and 12-32-LNG at 3-5.

[15] Assuming a gas density of 0.7 kg/m^3, 395 Bcf/year is 7.84 MTPA.

[16] *Jordan Cove Energy Project, L.P.*, FE Docket No. 11-127-LNG, Order No. 3041-A (July 20, 2018). According to the amended authorization, Jordan Cove is authorized to export up to 395 Bcf equivalent to FTA countries for a 30-year term beginning on the earlier date of the first export or July 20, 2028. All other obligations, rights, and responsibilities established in the December 2011 authorization remain in effect.

[17] Jordan Cove's amended application to export LNG to non-FTA nations is pending before the DOE/FE in FE Docket No. 12-32-LNG.

[18] Authorization Order, 170 FERC ¶ 61,202 at P 15.

[19] *Id.*

Connector Pipeline is 95.8% subscribed under two executed precedent agreements with Jordan Cove for 1,150,000 Dth/d at a negotiated rate.[20]

II. Procedural Matters

A. The Authorization Order was Procedurally Valid

8. NRDC claims that the Authorization Order is procedurally invalid, as it was issued after the Commission had already, during a February 20, 2020 open meeting held under the Government in the Sunshine Act, voted, 2-to-1, to substantively deny the project.[21] NRDC states that Commission regulations permit items to be struck from the Commission meeting "without vote or notice,"[22] but that the Commission failed to strike the then-proposed draft from the agenda or make a request to otherwise hold in abeyance the projects' review until a later date, before casting a vote.[23] NRDC contends that the Commission "must explain how its actions did not result in a substantive denial of Jordan Cove on February 20, 2020."[24]

9. NRDC's arguments rest on a misunderstanding of Commission practice and procedure. The Commission, an independent agency that consists of up to five members,[25] acts through its written orders,[26] which are issued following a favorable vote of the majority.[27] At the February 20, 2020 open meeting, the Commission voted 2-to-1 to reject

[20] The first precedent agreement relates to service during commissioning of the Jordan Cove LNG Terminal and the second is a long-term precedent agreement relating to service once the terminal has achieved commercial operation. Authorization Order, 170 FERC ¶ 61,202 at P 17; Pacific Connector Application at 16-17.

[21] NRDC Rehearing Request at 99 (citing 5 U.S.C. § 552b (2018)).

[22] *Id.* at 102 (citing 18 C.F.R. § 375.204(b) (2019)).

[23] *Id.* at 103.

[24] *Id*. at 104.

[25] *See* 16 U.S.C. § 792 (2018); 18 C.F.R. § 376.102 (2019).

[26] *See, e.g.*, *Indianapolis Power & Light Co.*, 48 FERC ¶ 61,040, at 61,203 & n.29 ("The Commission speaks through its orders."), *order on reh'g*, 49 FERC ¶ 61,328 (1989).

[27] 42 U.S.C. 7171 (2018) ("Actions of the Commission shall be determined by a majority vote of the members present.").

an order drafted by Commission staff through the Commission's usual internal practice, that would have authorized the project.[28] Because the Commission rejected the proposed order, and therefore no action was taken on Jordan Cove and Pacific Connector's applications, they remained pending.[29] NRDC is correct that the proposed draft order was not "struck" from the open meeting agenda under the Commission's regulations; however, the Commission was under no obligation to do so.[30] In addition, the fundamental requirement that an agency "disclose the basis"[31] for its decision aptly demonstrates the flaw in NRDC's suggested result: the Commission could not lawfully discharge its responsibilities by voting to deny Jordan Cove and Pacific Connector's applications for the project without issuing an order or opinion disclosing its basis for doing so.

B. Late Motion to Intervene

10. On March 27, 2020, Cow Creek Band filed an untimely motion to intervene in the Jordan Cove LNG Terminal proceeding. Cow Creek Band also filed a request for rehearing in both the Jordan Cove LNG Terminal and Pacific Connector Pipeline proceedings. The Commission has explained that "[w]hen late intervention is sought after the issuance of a dispositive order, the prejudice to other parties and burden upon

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[28] NRDC recognizes both that, at the February 20, 2020 meeting, the Commissioners had before them a proposed "order to approve the Project," and that a Commission vote "substantively approves or denies *orders* as proposed." NRDC Rehearing Request at 101-102 (emphasis added). Thus, even under NRDC's logic, the Commission voted to deny, i.e., not to issue, the proposed order, which was an order to *approve* the project

[29] *See MidAmerican Energy Holdings Co.*, 118 FERC ¶ 61,003, at 61,009 n.45 (2007) ("The Commission, a five-member agency . . . acts through its written orders . . . . Phrased differently, in the absence of such orders, including before it has issued such orders, the Commission cannot be said to have acted.").

[30] *See* 18 C.F.R. § 375.204(b). Nor was it necessary for the Commission to change the "subject matter" of the meeting in advance. NRDC Request for Rehearing at 100 (citing 18 C.F.R. § 375.204(a)(4)(i)-(ii) (2018)). The subject matter did not change. *See* Sunshine Act Meeting Notice (Feb. 13, 2020), https://www.ferc.gov/CalendarFiles/20200213175606-sunshine.pdf.

[31] *See, e.g.*, *FPC v. United Gas Pipe Line Co.*, 393 U.S. 71, 73 (1968) ("Before the courts can properly review agency action, the agency must disclose the basis of its order and 'give clear indication that it has exercised the discretion with which Congress has empowered it' . . . .") (citing *Phelps Dodge Corp. v. NLRB*, 313 U.S. 177, 197 (1941)).

the Commission of granting the late intervention may be substantial."[32] In such circumstances, movants bear a higher burden to demonstrate good cause for the granting of late intervention,[33] and generally it is Commission policy to deny late intervention at the rehearing stage.[34]

11. Here, Cow Creek Band explains that although it timely intervened in the Pacific Connector Pipeline proceeding,[35] it did not realize that the Commission would rule on the Jordan Cove LNG Terminal and the Pacific Connector Pipeline in the same order.[36] Thus, it requests party status in the Jordan Cove LNG Terminal proceeding because it realizes the full impact of the order on the Tribe.

12. As stated above, it is Commission policy to deny late intervention at the rehearing stage.[37] Allowing an intervention at the rehearing stage in the proceeding would delay, prejudice, and place additional burdens on the Commission and the certificate holder.[38] Thus, we deny Cow Creek Band's late motions to intervene and reject its rehearing

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[32] *Nat'l Fuel Gas Supply Corp.*, 139 FERC ¶ 61,037 (2012) (*National Fuel*). *See,* e.g., *Fla. Gas Transmission Co.*, 133 FERC ¶ 61,156 (2010).

[33] *See Cal. Dep't of Water Res. & the City of Los Angeles*, 120 FERC ¶ 61,057, at n.3 (2007), *reh'g denied*, 120 FERC ¶ 61,248, *aff'd sub nom. Cal. Trout & Friends of the River v. FERC*, 572 F.3d 1003 (9th Cir. 2009).

[34] *See PennEast Pipeline Co.*, 162 FERC ¶ 61,279 (2018) (denying two motions for late intervention and rejecting requests for rehearing filed 20 and 27 days after the Commission issued a certificate order for the PennEast Project); *Tenn. Gas Pipeline Co., L.L.C.*, 162 FERC ¶ 61,013, at P 10 (2018) (*Tennessee Gas*) (denying late motions to intervene and rejecting requests for rehearing filed two weeks and thirteen months after the Commission issued a certificate order for the Connecticut Expansion Project); *NationalFuel*, 139 FERC ¶ 61,037 (denying a late motion to intervene and request for rehearing filed 30 days after the Commission issued a certificate order for the Northern Access Project).

[35] *See* Cow Creek Band October 23, 2017 Motion to Intervene in Docket No. CP17-494-000.

[36] Cow Creek Band Late Motion to Intervene in Docket No. CP17-495-000.

[37] *See supra* note 34.

[38] *National Fuel*, 139 FERC ¶ 61,037 at P 18 ("When late intervention is sought after the issuance of a dispositive order, the prejudice to other parties and burden upon the Commission of granting the late intervention may be substantial.").

request to the extent it deals with the Jordan Cove terminal. We note that Cow Creek Band filed a timely, unopposed motion to intervene in the Pacific Connector Pipeline proceeding; thus, we are addressing its timely request for rehearing as to that proposal in this order. Further, Cow Creek Band's rehearing request as to the Jordan Cove LNG Terminal raises several of the same cultural resource issues raised by other parties, which are addressed below.

C. Late Requests for Rehearing

13. Pursuant to section 19(a) of the NGA, an aggrieved party must file a request for rehearing within 30 days after the issuance of the Commission's order.[39] Under the Commission's regulations, read in conjunction with section 19(a), the deadline to seek rehearing was 5:00 pm U.S. Eastern Time, April 20, 2020.[40] Kenneth E. Cates, Kristine Cates, James Davenport, Archina Davenport, David McGriff, Emily McGriff, Andrew Napell, Dixie Peterson, Paul Washburn, and Carol Williams failed to meet this deadline. Because the 30-day rehearing deadline is statutorily based, it cannot be waived or extended, and their requests must be rejected as late.[41] Nevertheless, these individuals'

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[39] 15 U.S.C. § 717r(a) (2018) ("Any person, State, municipality, or State commission aggrieved by an order issued by the Commission in a proceeding under this act to which such person, State, municipality, or State commission is a party may apply for a rehearing within thirty days after the issuance of such order"). The Commission has no discretion to extend this deadline. *See, e.g.*, *Transcontinental Gas Pipe Line Co.*, 161 FERC ¶ 61,250, at P 10 n.13 (2017) (collecting cases).

[40] Rule 2007 of the Commission's Rules of Practice and Procedure provides that when the time period prescribed by statute falls on a weekend, the statutory time period does not end until the close of the next business day. *See* 18 C.F.R. § 385.2007(a)(2) (2019). The Commission's business hours are "from 8:30 a.m. to 5:00 p.m.," and filings – paper or electronic – made after 5:00 p.m. will be considered filed on the next regular business day. *See* 18 C.F.R. §§ 375.101(c), 2001(a)(2) (2019).

[41] *See Annova Common Infrastructure, LLC*, 170 FERC ¶ 61,140, at P 6 (2020) (dismissing a request for rehearing received by the Commission at 5:45 p.m., after the 5:00 p.m. on the day of the filing deadline); *Tex. LNG Brownsville, LLC*, 170 FERC ¶ 61,139, at P 7 (2020) (dismissing a request for rehearing received by the Commission at 5:48 p.m., after the 5:00 p.m. on the day of the filing deadline); *Atl. Coast Pipeline, LLC*, 164 FERC ¶ 61,110, at P 12 (2018) (dismissing requests for rehearing received at 5:02 p.m. and 10:19 p.m., after 5:00 p.m. on the day of the filing deadline); *NEXUS Gas Transmission, LLC*, 164 FERC ¶ 61,054, at P 12 (2018) (dismissing a request for rehearing received by the Commission at 9:29 p.m., after the 5:00 p.m. on the day of the filing deadline). Here, the rehearing request was received at 7:54 p.m. on April 20, so that it was considered filed on April 21, one day too late.

arguments are addressed below as their rehearing request "incorporate[s] by reference all arguments, facts, and authorities cited in the Request for Rehearing and Stay of Order filed today in this cause by Sierra Club . . . ."[42]

D. <u>Party Status</u>

14. Under NGA section 19(a) and Rule 713(b) of the Commission's Rules and Practice and Procedure, only a party to a proceeding is eligible to request rehearing of a final Commission decision.[43] Any person seeking to become a party must file a motion to intervene pursuant to Rule 214 of the Commission's Rules of Practice and Procedure.[44] The Niskanen Center, Neal C. Brown Family LLC, Wilfred Brown, Chet N. Brown, and Twyla Brown never sought to intervene in either the Jordan Cove LNG Terminal or Pacific Connector Pipeline proceedings and they may not join in the rehearing request filed by Sierra Club. Further, Elizabeth A. Hyde, Richard Brown, Alisa Acosta, and James Dahlman never sought to intervene in the Jordan Cove LNG Terminal proceeding; accordingly, they may not join in the rehearing request filed by Sierra Club as to the that proceeding.[45]

E. <u>Deficient Rehearing Request</u>

15. The NGA requires that a request for rehearing set forth the specific grounds on which it is based.[46] Additionally, Rule 713 of Commission's regulations provide that requests for rehearing must "[s]tate concisely the alleged error in the final decision" and "include a separate section entitled 'Statement of Issues,' listing each issue in a separately enumerated paragraph" that includes precedent relied upon.[47] Any issue not so listed will

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[42] Kenneth E. Cates et al. Rehearing Request at 1. In addition, as noted below the Commission does not permit rehearing requests to incorporate by reference arguments from other filings. *Infra* PP15, 17.

[43] 15 U.S.C. § 717f(a) (2018); 18 C.F.R. § 385.713(b) (2019).

[44] 18 C.F.R. § 385.214(a)(3) (2019).

[45] On April 13, 2020, Mark Sheldon filed a request for rehearing and stay of the Authorization Order. On May 5, 2020, the Commission issued a notice rejecting Mr. Sheldon's request for rehearing and stay because he is not a party to the proceedings. *See* 15 U.S.C. § 717r(a) (2018); 18 C.F.R. §§ 385.212(a)(2), 385.214 (2019).

[46] 15 U.S.C. § 717r(a).

[47] 18 C.F.R. § 385.713 (2019).

be deemed waived.[48] Consistent with these requirements, the Commission "has rejected attempts to incorporate by reference arguments from a prior pleading because such incorporation fails to inform the Commission as to which arguments from the referenced pleading are relevant and how they are relevant."[49]

16. Klamath Tribes' April 17, 2020 request for rehearing is deficient because it fails to include a Statement of Issues section separate from its arguments, as required by Rule 713 of the Commission's Rules of Practice and Procedure. Accordingly, we dismiss Klamath Tribes' rehearing request. However, we note that Klamath Tribes joined Sierra Club's request for rehearing, which raises the same issues and is addressed below.

17. The rehearing petitions filed by Klamath Tribes, Cow Creek Band, Confederated Tribes, and Ms. McCaffree attempt to incorporate by reference arguments made in prior pleadings, other requests for rehearing, or the dissent to the Authorization Order.[50] As noted above, this is improper and we will not consider such arguments. To the extent the arguments incorporated by reference are properly raised in other requests for rehearing, they are addressed below.

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[48] *Id.* § 385.713(c)(2) (2019).

[49] *San Diego Gas & Elec. Co. v. Sellers of Market Energy*, 127 FERC ¶ 61,269, at P 295 (2009). *See Tenn. Gas Pipeline Co., L.L.C.*, 156 FERC ¶ 61,007, at P 7 (2016) ("the Commission's regulations require rehearing requests to provide the basis, in fact and law, for each alleged error including representative Commission and court precedent. Bootstrapping of arguments is not permitted."). *See also ISO New England, Inc.*, 157 FERC ¶ 61,060, at P 4 (2016) (explaining that the identical provision governing requests for rehearing under the Federal Power Act "requires an application for rehearing to 'set forth specifically the ground or grounds upon which such application is based,' and the Commission has rejected attempts to incorporate by reference grounds for rehearing from prior pleadings"); *Alcoa Power Generating, Inc.*, 144 FERC ¶ 61,218, at P 10 (2013) ("The Commission, however, expects all grounds to be set forth in the rehearing request, and will dismiss any ground only incorporated by reference.") (citations omitted).

[50] Klamath Tribes Rehearing Request at 1 (incorporating by reference arguments made in Sierra Club's request for rehearing); Cow Creek Band Rehearing Request at 8 (incorporating by reference arguments made in prior comments); Confederated Tribes Rehearing Request at 14-15 (incorporating by reference arguments made in prior comments and the dissent to the Authorization Order); McCaffree Rehearing Request at 7, 34 (incorporating by reference arguments made in in prior comments; the State of Oregon's, Sierra Club's, and the Confederated Tribes' requests for rehearing; and the dissent to the Authorization Order).

F. Answer

18. On May 5, 2020, Jordan Cove and Pacific Connector filed a motion for leave to answer and answer to the requests for rehearing. Rule 713(d)(1) of the Commission's Rules of Practice and Procedure prohibits answers to a request for rehearing.[51] Accordingly, we reject Jordan Cove's and Pacific Connector's filing.

G. Evidentiary Hearing

19. Sierra Club asserts that the Commission must hold an evidentiary hearing to resolve substantial disputed issues regarding the conclusion that the project is in the public interest, and the alleged lack of completed studies, data gaps and lack of information on impacts to local and regional businesses, water quality and quantity impacts, greenhouse gas (GHG) impacts, and health and safety impacts.[52] Sierra Club contends that an evidentiary hearing would allow the Commission to fully meet its obligations under the NGA, National Environmental Policy Act (NEPA), and the Fifth Amendment to the U.S. Constitution.[53]

20. An evidentiary, trial-type hearing is necessary only where there are material issues of fact in dispute that cannot be resolved on the basis of the written record.[54] No party has raised a material issue of fact that the Commission cannot resolve on the basis of the written record. As demonstrated by the discussion below, the existing written record provides a sufficient basis to resolve the issues relevant to this proceeding. The Commission has done all that is required by giving interested parties an opportunity to participate through evidentiary submission in written form.[55] Further, we disagree with Sierra Club's cursory statement that an evidentiary hearing is required to enable the Commission to meet its obligations under the NGA, NEPA, and the Fifth Amendment. Sierra Club is obligated to "set forth specifically the ground or grounds upon which" its request for rehearing is based.[56] Simply making blanket allegations that the Commission violated the law without

[51] 18 C.F.R. § 385.713(d)(1) (2019).

[52] Sierra Club Rehearing Request at 44-45.

[53] *Id.* at 45.

[54] *See, e.g.*, *S. Union Gas Co. v. FERC*, 840 F.2d 964, 970 (D.C. Cir. 1988); *Dominion Transmission, Inc.*, 141 FERC ¶ 61,183, at P 15 (2012).

[55] *Moreau v. FERC*, 982 F.2d 556, 568 (D.C. Cir. 1993).

[56] 15 U.S.C. § 717r(a) (2018). *See also Constellation Energy Commodities Group, Inc. v. FERC*, 457 F.3d 14, 22 (D.C. Cir. 2006) ("Each quoted passage states a conclusion; neither makes an argument. Parties are required to present their arguments to

any explanation or analysis does not meet this requirement. Accordingly, we affirm the Authorization Order's denial of Sierra Club's request for a trial-type evidentiary hearing.[57]

21. We disagree with Sierra Club's contention that we did not act on Stacey McLaughlin's request for additional procedures.[58] In the Authorization Order, the Commission found that implementing additional procedures was not needed or appropriate: "this order reviews both the non-environmental and environmental issues associated with the proposals."[59] We agree.

III. Stay Request

22. Sierra Club requests that the Commission stay the Authorization Order pending issuance of an order on rehearing.[60] NRDC joins Sierra Club's request for a stay, arguing that by issuing the Authorization Order in the midst of the COVID-19 pandemic, the Commission unnecessarily exposed affected landowners to immediate, irreparable injury through eminent domain condemnation actions, requiring them to divert their attention to ensure that they protect their legal rights due to mandatory filing deadlines under the NGA.[61] On May 5, 2020, Jordan Cove and Pacific Connector filed an answer to the requests for stay. This order addresses and denies Sierra Club's and NRDC's requests for rehearing; accordingly, we dismiss the requests for stay as moot.

IV. Discussion

A. Natural Gas Act

1. Denial of an Identical Application in 2016

23. Petitioners assert that the Commission's approval of the projects in the Authorization Order, after denying an "identical" project application in 2016, was arbitrary and capricious

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the Commission in such a way that the Commission knows 'specifically … the ground on which rehearing [i]s being sought.'").

[57] Authorization Order, 170 FERC ¶ 61,202 at P 26.

[58] Sierra Club Rehearing Request at 44.

[59] Authorization Order, 170 FERC ¶ 61,202 at P 28.

[60] Sierra Club Rehearing Request at 107, 110.

[61] NRDC Rehearing Request at 106.

without a more substantial justification.[62] NRDC states that the "*only* material difference between the 'new' Project and the Project denied in 2016 is that Pacific Connector conducted an Open Season in which it received *no creditworthy bids*[.]"[63]

24. The Authorization Order explained in detail how the proposal approved in the Authorization Order differed from the proposal denied in the 2016 Order in several key aspects.[64] As the Commission explained in the Authorization Order, the 2016 Order "denied Pacific Connector's proposal because Pacific Connector, by failing to provide precedent agreements or sufficient other evidence of need, failed to demonstrate market support for its proposal."[65] Pacific Connector sought rehearing of the 2016 Order, in an attempt to reopen the record to provide evidence of market demand for the project, in the form of precedent agreements for approximately 77% of the project's capacity, which had been entered into less than a month after the issuance of the 2016 Order.[66] The Commission declined to reopen the record, finding that Pacific Connector had not met the "heavy burden" required to justify reopening a proceeding; specifically, the Commission found that Pacific Connector had not identified any "extraordinary circumstances" that would overcome an agency's interest in finality, as Pacific Connector had sufficient time during the life of the proceeding to demonstrate market demand for the project.[67] Significantly, however, the Commission reiterated the finding in the 2016 Order that the denial was without prejudice to Jordan Cove and Pacific Connector submitting an application in the future, "should the companies show a market need for these services in the future."[68]

25. This is precisely what Pacific Connector and Jordan Cove provided in the instant proceeding. As the Commission explained in the Authorization Order, Pacific Connector provided evidence that it had entered into a long-term precedent agreement with Jordan

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[62] *Id.* at 9-11; State of Oregon Rehearing Request at 43-49; McCaffree Rehearing Request at 10.

[63] NRDC Rehearing Request at 13 (emphasis in original).

[64] Authorization Order, 170 FERC ¶ 61,202 at P 35 (citing 2016 Order, 157 FERC ¶ 61,194 at P 29).

[65] *Id.* P 35.

[66] 2016 Order, 157 FERC ¶ 61,194 at P 13.

[67] *Id.* P 17.

[68] *Id.* P 27 (quoting *Jordan Cove Energy Project, L.P.*, 154 FERC ¶ 61,160 at P 48).

Cove for approximately 96% of the project's capacity, which, as discussed below, is sufficient evidence of market demand for the project.[69] Accordingly, the petitioners' requests for rehearing on this matter are denied.

2. Principal Place of Business

26. Ms. McCaffree states that the Commission erred in finding that Jordan Cove and Pacific Connector's principal place of business is Houston, Texas.[70] The Commission's regulations pertaining to applications under section 3 of the NGA require applicants to indicate the "town or city where the applicant's principal office is located."[71] Similarly, the Commission's regulations for applications under section 7 of the NGA require applicants to set forth their principal place of business.[72] The Authorization Order stated that Jordan Cove and Pacific Connector are both Delaware limited partnerships, each with its principal place of business in Houston, Texas, which was what was indicated in the application.[73]

27. Ms. McCaffree contends that Portland, Oregon, is the location where Jordan Cove and Pacific Connector direct, control, and coordinate the project entities' activities and claims that Portland, Oregon, is the applicants' principal place of business.[74] There is no statutory, regulatory, or policy requirement that binds an applicant's principal place of business to the place from which it expects to direct, control, and/or coordinate project activities. Moreover, Ms. McCaffree has not provided any support for the claim that

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[69] Authorization Order, 170 FERC ¶ 61,202 at PP 64-65; Pacific Connector Application at 15. Petitioners cite to *F.C.C. v. Fox Television Stations, Inc.*, 556 U.S. 502 (2009), to support their argument that although the Commission may "change its position, it must provide a substantial justification when the new position rests upon factual findings that contradict the prior position." NRDC Rehearing Request at 14; State of Oregon Rehearing Request at 43. As we explained above, the facts of the 2016 case are substantially different to the facts presented here. In the present case, Pacific Connector provided precedent agreements for service—agreements that were notably lacking from the 2016 case until after the Commission issued its order denying the project, leading the Commission to deny the proposal.

[70] McCaffree Rehearing Request at 36.

[71] 18 C.F.R. § 153.7(a)(3) (2019).

[72] 18 C.F.R. § 157.6(b)(1) (2019).

[73] Authorization Order, 170 FERC ¶ 61,202 at P 4.

[74] McCaffree Rehearing Request at 36.

project activities would not be directed, controlled, and/or coordinated from Houston, Texas. Jordan Cove and Pacific Connector attested in their application that their principal office is in Houston, Texas, and Ms. McCaffree has provided no support for her claims to the contrary. Moreover, the place of business was not a material matter in the Authorization. Accordingly, the request for rehearing on this issue is denied.

3. Need for the Pacific Connector Pipeline

28. Several petitioners allege that in the Authorization Order, the Commission failed to demonstrate that the Pacific Connector Pipeline is required by the public convenience and necessity.[75] Specifically, petitioners asserted that: (1) Pacific Connector's precedent agreements with Jordan Cove are not an adequate indicator of need for the pipeline;[76] (2) the Commission improperly ignored evidence that there was no domestic market demand for the transportation of natural gas on the Pacific Connecter Pipeline;[77] and (3) the Commission improperly stated that the Pacific Connector would provide public benefits to American natural gas producers when the gas to be transported on the pipeline would be produced in Canada.[78]

29. First, petitioners assert that is in inappropriate for the Commission to rely on Pacific Connector's precedent agreements with Jordan Cove as evidence of the public need for the project.[79] Sierra Club takes issue with the Commission's policy of not "look[ing] behind" precedent agreements, asserting that this policy is arbitrary and capricious, particularly in instances, such as this, where precedent agreements have been entered into with only one affiliate buyer, subscribing capacity for a "speculative" project.[80] Petitioners also argue that the Commission erred in assessing the public benefits of Pacific Connector's precedent agreements with Jordan Cove, as those precedent agreements were "for export," and no public benefits would be derived from

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[75] NRDC Rehearing Request at 17-35; Sierra Club Rehearing Request at 5-18; State of Oregon Rehearing Request at 46-49; McCaffree Rehearing Request at 8-9.

[76] NRDC Rehearing Request at 17-30; Sierra Club Rehearing Request at 5-13; State of Oregon Rehearing Request at 46-47; McCaffree Rehearing Request at 8-9.

[77] NRDC Rehearing Request at 31-35.

[78] *Id.* at 31; Sierra Club Rehearing Request at 15-18; State of Oregon Rehearing Request at 47-49.

[79] NRDC Rehearing Request at 17-30; Sierra Club Rehearing Request at 5-13; State of Oregon Rehearing Request at 42-47.

[80] Sierra Club Rehearing Request at 7.

the service provided, and that it would otherwise be inappropriate to credit export capacity in the Commission's public convenience and necessity analysis, under the U.S. Court of Appeals for the D.C. Circuit's opinion in *City of Oberlin v. FERC*.[81] Further, petitioners allege, beside the precedent agreements, additional evidence indicates that there is a lack of market for the Pacific Connector Pipeline, as no market exists for LNG to be exported from the Jordan Cove LNG Terminal.[82]

30. We affirm the Commission's finding in the Authorization Order that precedent agreements are significant evidence of demand for a project.[83] As the court stated in *Minisink Residents for Environmental Preservation & Safety v. FERC*, and again in *Myersville Citizens for a Rural Community, Inc. v. FERC*, nothing in the Certificate Policy Statement or in any precedent construing it suggests that the policy statement requires, rather than permits, the Commission to assess a project's benefits by looking

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[81] NRDC Rehearing Request at 22-31 (citing *City of Oberlin, Ohio v. FERC*, 937 F.3d 599, 605 (D.C. Cir. 2019) (*City of Oberlin*)); Sierra Club Rehearing Request at 12-19 (same); State of Oregon Rehearing Request at 46-47 (same); McCaffree Rehearing Request at 8 (same).

[82] NRDC Rehearing Request at 31-35; McCaffree Rehearing Request at 8.

[83] Authorization Order, 170 FERC ¶ 61,202 at P 61 (citing *Minisink Residents for Envtl. Pres. & Safety v. FERC*, 762 F.3d 97, 110 n.10 (D.C. Cir. 2014) (*Minisink*); *Sierra Club v. FERC*, 867 F.3d 1357, 1379 (D.C. Cir. 2017) (affirming Commission reliance on preconstruction contracts for 93% of project capacity to demonstrate market need)); *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227, at 61,748 (1999), *clarified*, 90 FERC ¶ 61,128, *further clarified*, 92 FERC ¶ 61,094 (2000) (Certificate Policy Statement) (precedent agreements, though no longer required, "constitute significant evidence of demand for the project")); *Twp. of Bordentown v. FERC*, 903 F.3d 234, 263 (3d Cir. 2018) ("As numerous courts have reiterated, FERC need not 'look[] beyond the market need reflected by the applicant's existing contracts with shippers.'") (quoting *Myersville Citizens for a Rural Cmty., Inc. v. FERC*, 183 F.3d 1291, 1301, 1311 (D.C. Cir. 2015) (*Myersville*)); *Appalachian Voices v. FERC*, No. 17-1271, 2019 WL 847199 at *1 (D.C. Cir. Feb.19, 2019) (unpublished) (precedent agreements are substantial evidence of market need); *see also Midship Pipeline Co., LLC*, 164 FERC ¶ 61,103, at P 22 (2018) (long-term precedent agreements for 64 percent of the system's capacity is substantial demonstration of market demand); *PennEast Pipeline Co., LLC*, 164 FERC ¶ 61,098, at P 16 (2018) (affirming that the Commission is not required to look behind precedent agreements to evaluate project need); *NEXUS Gas Transmission, LLC*, 160 FERC ¶ 61,022, at P 41 (2017), *order on reh'g*, 164 FERC ¶ 61,054 (2018), *aff'd in relevant part*, *City of Oberlin*, 937 F.3d at 605 (finding need for a new pipeline system that was 59% subscribed).

beyond the market need reflected by the applicant's precedent agreements with shippers.[84] As stated in the Authorization Order, approximately 96% of the Pacific Connector's capacity has been subscribed by Jordan Cove under precedent agreements, one of which is a long-term precedent agreement.[85] Thus, there is sufficient evidence in the record to support our finding that the service to be provided by the pipeline is needed.[86]

31. NRDC asserts that the Commission's finding that Pacific Connector's precedent agreements with Jordan Cove are sufficient evidence of demand for the project is inconsistent with its denial of an application to construct a pipeline in *Independence Pipeline Company.*[87] NRDC argues that that the facts in *Independence* are "remarkably similar" to those here, and states that because Pacific Connector "had every ability and reason to enter into precedent agreements at least seven years ago" and yet only entered into precedent agreements after the Commission denied Pacific Connector and Jordan Cove's application in 2016, that we should look upon the precedent agreements in this proceeding with suspicion.[88]

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[84] *Minisink*, 762 F.3d at 110 n.10; *see also Myersville*, 183 F.3d at 1311. Further, Ordering Paragraph (G) of the Authorization Order requires Pacific Connector to file a written statement affirming that it has executed contracts for service at the levels provided for in their precedent agreement prior to commencing construction. Authorization Order, 170 FERC ¶ 61,202 at ordering para. (G).

[85] Authorization Order, 170 FERC ¶ 61,202 at PP 17, 65. The other precedent agreement relates to service during commissioning of the Jordan Cove LNG terminal. *Id.* P 17.

[86] *See, e.g., Midship Pipeline Co., LLC*, 164 FERC ¶ 61,103 at P 22 (long-term precedent agreements for 64% of the system's capacity is substantial demonstration of market demand); *NEXUS Gas Transmission, LLC*, 160 FERC ¶ 61,022 at P 41, *order on reh'g*, 164 FERC ¶ 61,054, *aff'd in relevant part*, *City of Oberlin*, 937 F.3d at 605 (finding need for a new pipeline system that was 59% subscribed); *Elba Express Co., L.L.C.*, 155 FERC ¶ 61,293, at P 8 (2016) (granting partial waiver where five of six shippers executed contracts, representing approximately 58% of the project's capacity); *Dominion Transmission Inc.*, 136 FERC ¶ 61,031, at P 8 (2011) (granting partial waiver where shippers executed contracts representing approximately 75% of the project's capacity).

[87] 89 FERC ¶ 61,283 (1999) (*Independence*).

[88] NRDC Rehearing Request at 17-22.

32. NRDC's argument misapplies the reasoning in *Independence* and inappropriately disregards the factual differences between these two proceedings. As an initial matter, the "remarkable similarities" NRDC points to are almost entirely between the *Independence* proceeding and the 2016 proceeding.[89] As explained in the Authorization Order, in *Independence*, the Commission denied Independence's application construct to an interstate natural gas pipeline after finding that Independence failed to provide contractual evidence of market support for the project, and was only able to present the required contractual evidence by creating an affiliate shipper and entering into a precedent agreement with it on the eve of a Commission-imposed deadline to present the required evidence.[90] NRDC asserts that circumstances here are similar to the *Independence* proceeding because in 2016 the Commission denied Pacific Connector's application for similarly failing to demonstrate contractual evidence of market demand for the project, and Pacific Connector only presented evidence of demand for the project after the Commission had indicated it would deny the application.[91]

33. The Authorization Order explained that here, unlike either the *Independence* or Jordan Cove/Pacific Connector 2016 proceedings, Pacific Connector's current application included signed precedent agreements, including a long-term precedent agreement with Jordan Cove for 96% of the Pacific Connector Pipeline's capacity, something we find significant, and sufficient, evidence of demand for the project.[92] Thus, as demonstrated in the Authorization Order, *Independence* is inapposite here.[93]

34. Finally, NRDC's unsupported argument that the Commission must look upon Pacific Connector's precedent agreements with Jordan Cove with skepticism because Pacific Connector could have entered into these agreements any time in the last "four" or "seven" years, and therefore the precedent agreements likely were created only to falsify evidence of market demand,[94] is similarly without merit, and is rejected.[95]

[89] *Id.* at 18-19.

[90] Authorization Order, 170 FERC ¶ 61,202 at P 63.

[91] NRDC Rehearing Request at 17-22.

[92] Authorization Order, 170 FERC ¶ 61,202 at P 63.

[93] *Id.*

[94] NRDC Rehearing Request at 19-21.

[95] Because Commission findings as to the facts must be supported by substantial evidence to be considered conclusive, 15 U.S.C. § 717r(b) (2018), the Commission

35. Regardless, petitioners argue that the Commission should look beyond the need for transportation of natural gas in interstate commerce evidenced by the precedent agreements in this proceeding and make a judgement based on how the gas will be used after it is delivered at the end of the pipeline and the interstate transportation is completed.[96] However, under Commission policy, if there are precedent or service agreements, the Commission does not, and need not, make judgments about the needs of individual shippers[97] or ultimate end use of the commodity, and we see no justification to make an exception to that policy here.

36. NRDC and the State of Oregon[98] argue that the Authorization Order is inconsistent with the D.C. Circuit's ruling in *City of Oberlin.*[99] NRDC asserts that the D.C. Circuit "held that contracts for the export of gas cannot be factored into a Section 7 public convenience and necessity review[.]"[100] NRDC misreads the D.C. Circuit's holding in *City of Oberlin*, which was that the Commission must fully explain why "it is lawful to credit precedent agreements with foreign shippers serving foreign customers toward a finding that an interstate pipeline is required by the public," not that doing so is unlawful.[101] In compliance with the D.C. Circuit's directive in *City of Oberlin*, the Authorization Order did precisely this.[102] Nonetheless, we provide additional explanation below.

37. As an initial matter, the D.C. Circuit's directive in *City of Oberlin* is not directly implicated here. As noted, the D.C. Circuit directed the Commission to explain why "it is lawful to credit precedent agreements with foreign shippers servicing foreign

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cannot accept unsupported arguments.

[96] McCaffree Rehearing Request at 8-9; State of Oregon Rehearing Request at 43-47; Sierra Club Rehearing Request at 9-11; NRDC Rehearing Request at 9-34.

[97] Certificate Policy Statement, 88 FERC at 61,744 (citing *Transcontinental Gas Pipe Line Corp.*, 82 FERC ¶ 61,084, at 61,316 (1998)).

[98] NRDC Rehearing Request at 22-31; State of Oregon Rehearing Request at 46-47.

[99] 937 F.3d 599.

[100] NRDC Rehearing Request at 22.

[101] *City of Oberlin*, 937 F.3d 599, 607.

[102] *See* Authorization Order, 170 FERC ¶ 61,202 at PP 84-86.

customers . . . ."[103] In this case, Pacific Connector has provided precedent agreements with Jordan Cove, a domestic shipper, to transport gas in interstate commerce to the Jordan Cove LNG Terminal and it cannot operate without the gas to be delivered via the pipeline.

38. We also find that it is appropriate for the Commission to give credit to the precedent agreements in this case for transportation of gas that the shipper intends to liquefy for export. To determine whether the Commission may give credit to the precedent agreements in this case, we turn to the text of the statute. NGA section 7(e) requires the Commission to issue a certificate if the Commission finds that the applicant's proposal "is or will be required by the present or future public convenience and necessity."[104] The courts have stated that the Commission must consider "all factors bearing on the public interest,"[105] Petitioners cite no precedent, and we are aware of none, to suggest that the Commission should exclude Pacific Connector's precedent agreements from that broad assessment.

39. On the contrary, as we stated in the Authorization Order, Congress directed, in NGA section 3(c), that the importation or exportation of natural gas from or to "a nation with which there is in effect a free trade agreement requiring national treatment for trade in natural gas, shall be deemed to be consistent with the public interest, and applications for such importation or exportation shall be granted without modification or delay."[106] In addition, NGA section 3(a) requires the approval of export to any country unless the proposed exportation "will not be consistent with the public interest."[107] The D.C. Circuit has found that the language in NGA section 3(a) demonstrates that "NGA § 3, unlike § 7, 'sets out a general presumption favoring such authorization.'"[108] While these provisions of the NGA are not directly implicated by Pacific Connector's application under NGA section 7(c), they do inform our determination that the proposed pipeline is

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[103] *City of Oberlin*, 937 F.3d 599, 607.

[104] *Id.* 717f(e).

[105] *Atl. Refining Co. v. Pub. Serv. Comm'n of State of N.Y.*, 360 U.S. 378, 391 ("This is not to say that rates are the only factor bearing on the public convenience and necessity, for § 7(e) requires the Commission to evaluate all factors bearing on the public interest.").

[106] 15 U.S.C. § 717b(c) (2018).

[107] *Id.* § 717b(a).

[108] *EarthReports, Inc. v. FERC*, 828 F.3d 949, 953 (2016) (citing *W. Va. Pub. Servs. Comm'n v. Dep't of Energy*, 681 F.2d 847, 856 (D.C. Cir. 1982).

in the public convenience and necessity because it will support the public interest of exporting natural gas to FTA countries. We therefore find that it is permissible for the Commission to consider precedent agreements with LNG export facilities as one of the factors bearing on the public interest in its public convenience and necessity determination.

40. We also disagree with the parties' argument that the Commission cannot credit the precedent agreements because the contracts will "purely benefit foreign customers."[109] We view transportation service for all shippers as providing domestic public benefits, and do not weigh various prospective end uses differently for the purpose of determining need. This includes shippers transporting gas in interstate commerce for eventual export, since such transportation will provide domestic public benefits, including: contributing to the development of the gas market, in particular the supply of reasonably-priced gas; adding new transportation options for producers, shippers, and consumers; boosting the domestic economy and the balance of international trade; and supporting domestic jobs in gas production, transportation, and distribution, and domestic jobs in industrial sectors that rely on gas or support the production, transportation, and distribution of gas.

41. In this case, the Authorization Order stated the Pacific Connector will provide additional capacity to transport gas out of the Rocky Mountain production area and that one of the Pacific Connector Pipeline's primary interconnects, Ruby Pipeline, "extend[s] from Wyoming to Oregon, delivering gas from the Rocky Mountain production area to west coast markets."[110] Furthermore, as discussed above, the production and sale of domestic gas contributes to the growth of the economy and supports domestic jobs in gas production, transportation, and distribution. These are valid domestic public benefits of the Pacific Connector Pipeline, which do not require us to distinguish between gas supplies that will be consumed domestically and those that will be consumed abroad.[111]

42. In addition, looking at the situation broadly, gas imports and exports benefit domestic markets; thus, contracts for the transportation of gas that will be imported or exported are appropriately viewed as indicative of a domestic public benefit. The North American gas market has numerous points of export and import, with volumes changing constantly in response to changes in supply and demand, both on a local scale, as local distribution companies' and other users' demand changes, and on a regional or national

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[109] NRDC Rehearing Request 23.

[110] Authorization Order, 170 FERC ¶ 61,202 at PP 47, 85.

[111] Accordingly, despite Ms. McCaffree's contention, the Pacific Connector pipeline is not a "section 3 pipeline." *See* Authorization Order, 170 FERC ¶ 61,202 at PP 48-51.

scale, as the market shifts in response to weather and economic patterns.[112] Any constraint on the transportation of domestic gas to points of export risks negating the efficiency and economy the international trade in gas provides to domestic consumers.

43. Sierra Club next claims that it is inappropriate for the Commission to rely on Pacific Connector's precedent agreements where they have been entered into with only one affiliate buyer.[113] Affiliation with a project sponsor does not lessen a shipper's need for capacity and its contractual obligation to pay for its subscribed service.[114] "[A]s long as the precedent agreements are long term and binding, we do not distinguish between pipelines' precedent agreements with affiliates or independent marketers in establishing market need for a proposed project."[115] We find that the relationship between Jordan Cove and Pacific Connector will neither lessen Pacific Connector's need for capacity nor diminish Jordan Cove's obligation to pay for its capacity under the terms of its contract.[116] When considering applications for new certificates, the Commission's sole

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[112] *See, e.g.*, U.S. Energy Information Administration (EIA), *Colorado State Profile and Energy Estimates* (updated March 12, 2019), https://www.eia.gov/state/analysis.php?sid=CO#55 (describing Colorado as the seventh-largest natural gas producing state in the nation, with minimal natural gas storage capacity, and transporting gas to the west coast); EIA, *Natural Gas Weekly Update*, October 24, 2018, https://www.eia.gov/naturalgas/weekly/ archivenew_ngwu/2018/10_25/ (pipeline explosion in Canada leads to lower U.S. gas imports and higher regional prices).

[113] Sierra Club Rehearing Request at 7.

[114] *See Mountain Valley Pipeline, LLC*, 161 FERC ¶ 61,043, at P 45 (2017), *order on reh'g*, 163 FERC ¶ 61,197, at P 90 (2018), *aff'd, Appalachian Voices v. FERC*, No. 17-1271, 2019 WL 847199, at *3 (D.C. Cir. Feb. 19, 2019) (*Mountain Valley*). *See also, e.g.*, *Greenbrier Pipeline Co., LLC*, 101 FERC ¶ 61,122, at P 59 (2002), *reh'g denied*, 103 FERC ¶ 61,024 (2003).

[115] *Millennium Pipeline Co. L.P.*, 100 FERC ¶ 61,277, at P 57 (2002) (*Millennium*) (citing *Tex. E. Transmission Corp.*, 84 FERC ¶ 61,044 (1998)). *See also City of Oberlin*, 937 F.3d at 605 (finding petitioners' argument that precedent agreements with affiliates are not the product of arms-length negotiations without merit, because the Commission explained that there was no evidence of self-dealing and stated that the pipeline would bear the risk of unsubscribed capacity); *Myersville Citizens for a Rural Community, Inc. v. FERC*, 783 F.3d 1301, 1311 (D.C. Cir. 2015) (*Myersville*) (rejecting argument that precedent agreements are inadequate to demonstrate market need).

[116] Further, without compelling record evidence, we will not speculate on the motives of a regulated entity or its affiliate.

concerns regarding affiliates of the pipeline as shippers is whether there may have been undue discrimination against a non-affiliate shipper.[117] Here, the Commission did not find[118] any evidence of impropriety or self-dealing to indicate anti-competitive behavior or affiliate abuse. We affirm that determination.

44. Finally, NRDC contends that additional evidence, particularly signals in the LNG market, suggest that the Pacific Connector Pipeline is not needed.[119] Unlike under NGA section 7, the Commission does not assess market need for LNG exports under NGA section 3. Rather, as we have explained previously, DOE has exclusive jurisdiction over commodity exports, and issues inherent in that decision.[120] And here, as noted in the Authorization Order, DOE has already determined that Jordan Cove's exportation of 438 Bcf per year of domestically-produced natural gas to free trade nations is consistent with the public interest. Therefore, no further analysis by the Commission regarding market need for LNG is required or permitted.

4. The Public Interest Determination for the Jordan Cove LNG Terminal

45. Petitioners assert that the Commission erred in finding that the Jordan Cove LNG Terminal is consistent with the public interest. Specifically, petitioners state that the Jordan Cove LNG Terminal is not consistent with the public interest, as: (1) its only source of gas (the Pacific Connector Pipeline) is not required by the public convenience and necessity;[121] (2) Jordan Cove failed to demonstrate a market need for its LNG (as it did in 2016);[122] and (3) the Commission improperly relied on the economic benefits of the exportation of LNG as a commodity in its determination that Jordan Cove is in the public interest.[123]

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[117] *See* 18 C.F.R. § 284.7(b) (2019) (requiring transportation service to be provided on a non-discriminatory basis).

[118] Authorization Order, 170 FERC ¶ 61,202 at PP 76-77.

[119] NRDC Rehearing Request at 31-35.

[120] *Rio Grande LNG, LLC*, 170 FERC ¶ 61,046, at n.26 (2020).

[121] NRDC Rehearing Request at 35-36.

[122] McCaffree Rehearing Request at 8-9.

[123] State of Oregon Rehearing Request at 27-29.

46. NRDC, citing to the Commission's 2016 denial of Pacific Connector and Jordan Cove's previous proposals, again argues that Jordan Cove cannot be consistent with the public interest because there is no need for the Pacific Connector Pipeline, the Jordan Cove LNG Terminal's sole source of natural gas.[124] As demonstrated in the Authorization Order[125] and above,[126] the Pacific Connector Pipeline is required by the public convenience and necessity; therefore, this argument fails.

47. Additionally, Ms. McCaffree's assertion that the Jordan Cove LNG Terminal is not consistent with the public interest due to an "unrealistic assessment of market demand"[127] similarly fails. As we discussed above, while it is outside of the Commission's NGA section 3 authority to assess market demand for LNG exports, we view the DOE's approval of Jordan Cove's application to export LNG to FTA nations as sufficient evidence of market demand.[128]

48. The State of Oregon asserts that the Commission cannot disclaim jurisdiction over the export of the LNG commodity pursuant to section 3 of the NGA, while also relying on the benefits of those exports, including "benefits to the local and regional economy" and "the provision of new market access for natural gas producers" in determining the Jordan Cove LNG Terminal is consistent with the public interest.[129] The State of Oregon is mistaken. As the Commission stated in the Authorization Order, and as acknowledged by the State of Oregon, section 3 of the NGA does not provide the Commission any authority to approve or disapprove the import or export of LNG.[130] The Commission, in assessing whether or not the construction and operation of the Jordan Cove LNG Terminal would be consistent with the public interest, does not examine economic claims relating to the exportation of the commodity of natural gas, which are within DOE's exclusive jurisdiction, nor did the Commission rely on these claims in determining that the siting, construction, and operation of the Jordan Cove LNG Terminal was not inconsistent with the public interest. While the Commission acknowledged the economic

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[124] NRDC Rehearing Request at 35-36.

[125] Authorization Order, 170 FERC ¶ 61,202 at PP 294.

[126] *See supra* PP 28-47.

[127] McCaffree Rehearing Request at 8-9.

[128] *See supra* P 44.

[129] State of Oregon Rehearing Request at 27-29.

[130] Authorization Order, 170 FERC ¶ 61,202 at P 32; *see* 15 U.S.C. § 717b (2018); State of Oregon Rehearing Request at 28-29.

benefits of the proposal, the Commission's determination examined other factors, including the prior use of the site, the mitigation of environmental impacts, as well as PHMSA's Letter of Determination that the siting of the LNG terminal would comply with federal safety standards.[131]

5. Open Season for Capacity Subject to a Right of First Refusal

49. As part of its application, Pacific Connector filed a *pro forma* open-access tariff applicable to services provided on its proposed pipeline. Pacific Connector proposed open season procedures if capacity posted for bidding is subject to a right of first refusal (ROFR). Section 284.221(d)(2) of the Commission's regulations gives eligible shippers a regulatory right to request an open season to potentially avoid pre-granted abandonment of their ROFR capacity.[132]

50. Pacific Connector's proposed General Terms and Conditions (GT&C) section 10.4 states that "[Pacific Connector] may … hold an open season for capacity that is subject to a [Right of First Refusal], no earlier than eighteen (18) Months prior to the termination or expiration date or potential termination date for the eligible Service Agreement."[133] The Commission concluded that the proposed 18-month period would not be consistent with the 6- to 12- month period that the Commission in *Transcontinental Gas Pipe Line Corporation* found to be a reasonable period before a contract ends for a shipper to notify the pipeline company whether the shipper wants to renew its contract.[134] The Commission directed Pacific Connector to revise its open season process for ROFR capacity to be consistent with the timeframe in *Transco I*.[135]

51. On rehearing, Jordan Cove and Pacific Connector object to this directive and renew the proposal to begin the open season for ROFR capacity up to 18 months prior to the end date of a shipper's existing service agreement.[136] Jordan Cove and Pacific Connector state that potential customers at the Jordan Cove LNG Terminal will not contract for liquefaction services without assurance of a corresponding contract for

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[131] Authorization Order, 170 FERC ¶ 61,202 at P 40-43.

[132] 18 C.F.R. § 284.221(d)(2) (2019).

[133] Authorization Order, 170 FERC ¶ 61,202 at P 127.

[134] *Id.* at P 128 (quoting *Transcontinental Gas Pipe Line Corporation*, 103 FERC ¶ 61,295, at P 20 (2003) (*Transco I*)).

[135] Authorization Order, 170 FERC ¶ 61,202 at P 128.

[136] Jordan Cove and Pacific Connector Rehearing Request at 18-24.

pipeline capacity, demonstrating a need to synchronize the contracting processes.[137] Because the market demands of the Jordan Cove LNG Terminal require it to contract for liquefaction capacity more than 12 months in advance, they explain the open season for ROFR capacity on the pipeline must also begin more than 12 months in advance.[138] They assert that this mismatch in timing will materially and adversely impact both the LNG Terminal's and the Pipeline's ability to execute contracts for their services.[139]

52. We grant rehearing and approve Pacific Connector's proposed GT&C section 10.4 of its *pro forma* tariff. There are various competing interests to consider in determining how soon before contract termination the ROFR process must be completed.[140] An existing shipper with ROFR capacity may have an interest in making a final decision close to the time that its contract terminates, giving the shipper an opportunity to decide whether and how much of its capacity to retain, not only in light of the current market value of the capacity as shown by the third party bids in the open season, but also in light of a current assessment of the existing shipper's capacity needs.[141] A third party bidder may have an interest in knowing whether it has obtained the capacity well before the existing shipper's contract terminates.[142] A winning third party bidder may need time to finalize any business arrangements that are premised on obtaining the capacity before it commences service.[143] As Jordan Cove states, the market demands of its LNG terminal require it to contract for capacity more than one year in advance,[144] and liquefaction agreements currently require customers to exercise extension options at least three years in advance.[145] Similarly, Pacific Connector's service agreements with its customers will include optional extension periods that must be exercised three years in advance, to mirror the timeframe when Jordan Cove and Pacific Connector would expect to begin

[137] *Id.* at 19-20.

[138] *Id.* at 20-21.

[139] *Id.* at 21.

[140] *Dominion Transmission, Inc.*, 111 FERC ¶ 61,135, at P 17 (2005).

[141] *Transco I*, 103 FERC ¶ 61,295 at PP 19-20.

[142] *Dominion Transmission, Inc.*, 111 FERC ¶ 61,135 at P 17.

[143] *Id.*

[144] Jordan Cove and Pacific Connector Rehearing Request at 20-21.

[145] *Id.*

remarketing capacity at the LNG terminal and on the pipeline.[146] The unique relationship between an interstate pipeline that predominantly serves an LNG terminal and that terminal is different than the domestic natural gas pipeline market, and therefore supports a different balance of interests between existing shippers and potential third party bidders. Therefore, we conclude that Pacific Connector's proposal to retain the flexibility to start the bidding process for ROFR capacity as much as 18 months before the termination or expiration date, or the potential termination date, of a contract is reasonable. Accordingly, the Commission grants rehearing and accepts Pacific Connector's proposed 18-month outer limit in GT&C section 10.4.

6. Eminent Domain

53. On rehearing, Sierra Club and the State of Oregon argue that the Commission has failed to satisfy the requirements of the Fifth Amendment of the U.S. Constitution, and the NGA, by granting the power of eminent domain through the Authorization Order.[147] Sierra Club contends that the Authorization Order: (1) erred by determining that a finding of public convenience and necessity under the NGA is the equivalent to the finding of "public use" required by the Fifth Amendment;[148] (2) improperly provided for eminent domain authority in a conditioned certificate;[149] (3) failed to condition the use of eminent domain upon final Commission staff review of residential construction plans;[150] (4) violated the due process rights of landowners;[151] and (5) failed to preclude the use of "quick take" procedures.[152] The State of Oregon also contend that the Authorization Order failed to adequately assess a "public use."[153]

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[146] *Id.* at 21.

[147] Sierra Club Rehearing Request at 19, 30-37; State of Oregon Rehearing Request at 12, 43.

[148] Sierra Club Rehearing Request at 19, 31-34.

[149] *Id.* at 30-34.

[150] *Id.* at 35.

[151] *Id.* at 42.

[152] *Id.* at 35-37.

[153] State of Oregon Rehearing Request at 12.

54. The Authorization Order explained that the Commission itself does not confer eminent domain powers.[154] Under NGA section 7, the Commission has jurisdiction to determine if the construction and operation of proposed interstate pipeline facilities are in the public convenience and necessity.[155] Once the Commission makes that determination and issues a natural gas company a certificate of public convenience and necessity, it is NGA section 7(h) that authorizes that certificate holder to acquire the necessary land or property to construct the approved facilities by exercising the right of eminent domain if it cannot acquire the easement by an agreement with the landowner.[156] The D.C. Circuit has held that "[t]he Commission does not have the discretion to deny a certificate holder the power of eminent domain."[157]

55. The Fifth Amendment to the Constitution provides that private property may not be taken for public use without just compensation.[158] We affirm that, having determined that the Pacific Connector Pipeline serves the public convenience and necessity, we are not required to make a separate finding that the project serves a "public use" in order for a certificate holder to pursue condemnation proceedings in U.S. District Court or a state court pursuant to the NGA section 7(h).[159] The U.S. Supreme Court has explained that "legislatures are better able [than courts] to assess what public purposes should be advanced by an exercise of the taking power."[160] Here, Congress articulated in the NGA

[154] Authorization Order, 170 FERC ¶ 61,202 at P 87.

[155] 15 U.S.C. § 717f(e) (2018).

[156] Authorization Order, 170 FERC ¶ 61,202 at P 97 (citing 15 U.S.C. § 717f(h) (2018)).

[157] *Midcoast Interstate Transmission, Inc. v. FERC*, 198 F.3d 960, 973 (D.C. Cir. 2000) (*Midcoast Interstate*).

[158] U.S. CONST. amend. V.

[159] *See Atl. Coast Pipeline, LLC*, 161 FERC ¶ 61,042, at P 79 (2017). *See also, e.g.*, *Midcoast Interstate*, 198 F.3d at 973 (holding that Commission's determination that pipeline "serve[d] the public convenience and necessity" demonstrated that it served a "public purpose" for Fifth Amendment purposes).

[160] *Hawaii Hous. Auth. v. Midkiff*, 467 U.S. 229, 244 (1984) ("Thus, if a legislature, state or federal, determines there are substantial reasons for an exercise of the taking power, courts must defer to its determination that the taking will serve a public use."); *Nat'l R.R. Passenger Corp. v. Bos. & Me. Corp.*, 503 U.S. 407, 422-23 (1992) ("We have held that the public use requirement of the Takings Clause is coterminous with the regulatory power, and

its position that "transporting and selling natural gas for ultimate distribution to the public is affected with a public interest, and that Federal regulation in matters relating to the transportation of natural gas and the sale thereof in interstate and foreign commerce is necessary in the public interest."[161] Neither Congress nor any court has suggested that there was a further test,[162] beyond the Commission's determination under NGA section 7(e),[163] that a proposed pipeline was required by the public convenience and necessity, such that certain certificated pipelines furthered a public use, and thus were entitled to use eminent domain, while others did not.[164] The D.C. Circuit has confirmed that the Commission's public convenience and necessity finding necessarily satisfies the Fifth Amendment's public use requirement.[165]

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that the Court will not strike down a condemnation on the basis that it lacks a public use so long as the taking "is rationally related to a conceivable public purpose. . . . ").

[161] 15 U.S.C. § 717(a) (2018).

[162] *Cf.* Sierra Club Rehearing Request at 20-21 (arguing that no court has held that economic benefit alone is adequate to support a public use determination) (citing, e.g., *Kelo v. City of New London*, 545 U.S. 469, 479-80 (2015) (upholding a city's use of eminent domain to implement economic development plan)).

[163] *Id.* § 717f(e).

[164] *See*, *e.g.*, *N. Border Pipeline Co. v. 86.72 Acres of Land*, 144 F.3d 469, 470–71 (7th Cir. 1998) (under the Natural Gas Act, "issuance of the certificate [of public convenience and necessity] to [pipeline] carries with it the power of eminent domain to acquire the necessary land when other attempts at acquisition prove unavailing"); *Maritimes & Ne. Pipeline, L.L.C. v. Decoulos*, 146 F. App'x 495, 498 (1st Cir. 2005) (noting that once a certificate of public convenience and necessity is issued by FERC, and the pipeline is unable to acquire the needed land by contract or agreement with the owner, the only issue before the district court in the ensuing eminent domain proceeding is just compensation for the taking); *Rockies Exp. Pipeline LLC v. 4.895 Acres of Land, More or Less*, 734 F.3d 424, 431 (6th Cir. 2013) (rejecting landowner's claim for damages from eminent domain taking by pipeline as an impermissible collateral attack on the essential fact findings made by the Commission in issuing the certificate order authorizing the pipeline); *E. Tennessee Nat. Gas Co. v. Sage*, 361 F.3d 808, 823 (4th Cir. 2004) (affirming district court's determination that the certificate of public convenience and necessity issued by FERC gave the pipeline the right to exercise eminent domain and thus an interest in the landowners' property).

[165] *See Mid Coast Interstate Transmission, Inc. v. FERC*, 198 F.3d 960, 973 (D.C. Cir. 2000); *see also* Authorization Order, 170 FERC ¶ 61,202 at P 99.

56. Sierra Club challenges this conclusion on rehearing and argues that such a determination was rejected in *City of Oberlin*.[166] Sierra Club contends that the Authorization Order failed to properly balance the potential use of eminent domain against the project's public benefits.[167] Sierra Club's cite to *City of Oberlin* is inapplicable here. There, the D.C. Circuit concluded, given the fact that NGA section 7 authorizes the use of eminent domain, that the Commission had not provided sufficient explanation for why it is lawful to credit precedent agreements with foreign shippers serving customers toward a finding that a pipeline is required by the public convenience and necessity.[168] Here, we affirm the Authorization Order's finding that the Pacific Connector Pipeline is in the public convenience and necessity,[169] a determination which, as discussed above,[170] provides an explanation that the court's sought in *City of Oberlin*.

57. Consistent with the Certificate Policy Statement, the need for and benefits derived from the project are balanced against the adverse impacts on landowners.[171] Here, the Commission balanced the concerns of all interested parties and did not give undue weight to the interests of any particular party. Approximately 43.7% of Pacific Connector's pipeline rights-of-way will be collocated or adjacent to existing powerline, road, and pipeline corridors.[172] Approximately 82 miles of the total pipeline right-of-way are on public land (federal or state-owned land), and the remaining 147 miles are on privately owned land.[173] Of those 147 miles, 60 miles are held by timber companies.[174] On July 29, 2019, Pacific Connector stated that it had negotiated easement agreements from 72 percent of private, non-timber landowners (representing 75% of the mileage from such landowners) and 93% of timber company landowners (representing 92% of the mileage from timber companies). Pacific Connector engaged in public outreach during the

[166] Sierra Club Rehearing Request at 19-20 (citing *City of Oberlin*, 937 F.3d 599.

[167] *Id.*

[168] *City of Oberlin*, 937 F.3d at 607.

[169] Authorization Order, 170 FERC ¶ 61,202 at P 89.

[170] *See supra* PP 37-44.

[171] Certificate Policy Statement, 88 FERC at 61,744. *See also National Fuel*, 139 FERC ¶ 61,037 at P 12.

[172] Pacific Connector's September 18, 2019 Revised Plan of Development at 8.

[173] Final EIS at Table 4.7.2.1-1.

[174] Pacific Connector's July 29, 2019 Land Statistics Update.

Commission's pre-filing process, working with interested stakeholders, soliciting input on route concerns, and assessing route alternatives to address concerns and impacts on landowners and communities.

58. We affirm the Authorization Order's rejection of the argument that issuing a conditional certificate violates the Fifth Amendment.[175] As a certificate holder under section 7(h) of the NGA, Pacific Connector can commence eminent domain proceedings in a court action if it cannot acquire property rights by negotiation. Pacific Connector will not be allowed to construct any facilities on such property unless and until a court authorizes acquisition of the property through eminent domain and there is a favorable outcome on all outstanding requests for necessary approvals. Further, Pacific Connector will be required by the court in any eminent domain proceeding to compensate landowners for any property rights it acquires.[176]

59. Sierra Club contends that the Authorization Order failed to condition the use of eminent domain upon Commission staff review of final residential construction plans.[177] Under section 7(h) of the NGA, once a natural gas company obtains a certificate of public convenience and necessity it may exercise the right of eminent domain in a U.S. District Court or a state court, regardless of the status of other authorizations for the project.[178] Any additional measures requested by Sierra Club are unnecessary because the Authorization Order appropriately ensures adequate Commission oversight of construction. For instance, Environmental Condition 5 provides that the authorized facility locations shall be as shown in the Final EIS, as supplemented by filed site plans and alignment sheets, and shall include the route variations identified in the order and conditions and must be filed with the Secretary prior to the start of construction.[179] Environmental Condition 5 also states that "Pacific Connector's exercise of eminent domain authority . . . must be consistent with these authorized facilities and locations."[180] Further, the Authorizing Order notes that Jordan Cove and Pacific Connector shall follow the construction procedures and mitigation measures described in their respective applications and supplemental filings and as identified or modified in the Final EIS and Authorizing Order, unless they receive approval in writing from the Director of the

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[175] Authorization Order, 170 FERC ¶ 61,202 at P 101.

[176] *Id.*

[177] Sierra Club Rehearing Request at 35.

[178] 15 U.S.C. § 717f(h).

[179] Authorization Order, 170 FERC ¶ 61,202 at app., envtl. condition 5.

[180] *Id.*

Office of Energy Projects for the use of a modification.[181] The Authorization Order also requires Jordan Cove and Pacific Connector to file implementation plans describing how each will implement those construction procedures prior to commencing construction for review and written approval.[182]

60. Sierra Club further contends that the Authorization Order violates the Due Process Clause of the U.S. Constitution because it alleges not all affected landowners were provided a sufficient notice prior to the taking of their property.[183] Sierra Club appears to conflate the process by which landowners are provided notice that an application for a pipeline certificate is pending at the Commission and their ability to comment on the EIS or the certificate application, and the Due Process rights due to landowners in an eminent domain proceeding in a court. The Commission has no authority to set the notice requirements applicable to eminent domain proceedings. As to the Commission's proceedings, we note that the Commission's regulations require NGA section 7 applicants to demonstrate that they have made "a good faith effort to notify all affected landowners . . . ."[184] Pacific Connector has satisfied this requirement.[185] As explained in the Authorization Order, eminent domain power conferred on Pacific Connector under the NGA "requires the company to go through the usual condemnation process, which calls for an order of condemnation and a trial determining just compensation prior to the taking of private property."[186] Further, "if and when the company acquires a right of way through any [landowner's] land, the landowner will be entitled to just compensation, as established in a hearing that itself affords due process."[187]

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[181] Authorization Order, 170 FERC ¶ 61,202 at app., envtl. condition 1.

[182] Authorization Order, 170 FERC ¶ 61,202 at app., envtl. condition 7.

[183] Sierra Club Rehearing Request at 42-43.

[184] 18 C.F.R. § 157.6(d) (2019).

[185] Pacific Connection October 23, 2017 Updated Landowner List.

[186] Authorization Order, 170 FERC ¶ 61,202 at PP 95-96 (citing *Appalachian Voices v. FERC*, No. 17-1271, 2019 WL 847199, at *2 (unpublished) (quoting *Transwestern Pipeline Co., LLC v. 17.19 Acres of Prop. Located in Maricopa Cnty.*, 550 F.3d 770, 774 (9th Cir. 2008))).

[187] *Id.* (quoting *Del. Riverkeeper Network v. FERC*, 895 F.3d 102, 110 (D.C. Cir. 2018)).

61. Finally, Sierra Club argues that the Commission should prohibit "quick take" procedures.[188] "Quick-take" procedures are established by the judiciary as one method for carrying out the right of eminent domain. While Sierra Club alleges various constitutional infirmities with quick-take procedures as a category,[189] the Commission's has no authority to direct courts how to conduct their proceedings.

7. Balancing of Adverse Impacts

62. Multiple petitioners contend that the Authorization Order violates sections 3 and 7 of the NGA by failing to take into account the adverse environmental impacts of the projects in determining that the projects are consistent with the public interest.[190] Petitioners assert that the Authorization Order's public interest determination does not take into account the project's impacts on threatened and endangered species, wildlife, landowners and communities; petitioners further assert that the public interest determination errs by not considering GHG emissions attributable to the project.[191] Petitioners contend that in addition to failing to account for environmental impacts, the public interest determination overestimates the need for and benefits of the projects.[192]

63. Regarding the Authorization Order's public convenience and necessity determination for the Pacific Connector Pipeline under section 7 of the NGA, the petitioners misunderstand the nature of the balancing required by the Certificate Policy Statement. The Certificate Policy Statement's balancing of adverse impacts and public benefits is an economic test, not an environmental analysis.[193] Only when the benefits outweigh the adverse effects on the economic interests will the Commission proceed to consider the environmental analysis where other interests are addressed.[194] If a project

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[188] Sierra Club Rehearing Request at 35-37.

[189] *Id.* at 36 (citing *Knick v. Twp. of Scott, Penn.*, 139 S.Ct. 2162 (2019)).

[190] Sierra Club Rehearing Request at 22-24; NRDC Rehearing Request at 36-43; State of Oregon Rehearing Request at 29, 46; McCaffree Rehearing Request at 10.

[191] NRDC Rehearing Request at 36-43.

[192] McCaffree Rehearing Request at 10-11, Sierra Club Rehearing Request at 22-24; State of Oregon Rehearing Request at 47-48.

[193] *National Fuel*, 139 FERC ¶ 61,037 at P 12.

[194] Certificate Policy Statement, 88 FERC at 61,745.

satisfies the requirements of the Certificate Policy Statement, a Commission order will consider both economic and environmental issues.

64. In any event, we find that, contrary to the petitioners' assertions, threatened and endangered species,[195] wildlife,[196] landowner and community impacts,[197] and GHG emissions[198] are addressed adequately in the Final EIS, considered in the Authorization Order, and addressed, as necessary, below. Further, as discussed above, we find that there is significant evidence of demand for the project.[199] The Authorization Order found that if the Pacific Connector Pipeline is constructed and operated as described in the Final EIS, the environmental impacts are acceptable considering the public benefits of the project, and determined that the Pacific Connector Pipeline was required by the public convenience and necessity.[200] We affirm this finding.

65. In the Authorization Order, the Commission determined that the Jordan Cove LNG Terminal was not inconsistent with the public interest based on *all* information in the record, including information presented in the Final EIS.[201] Although the Final EIS identifies some adverse environmental impacts, the Commission found that the Jordan Cove LNG Terminal, if constructed and operated as described in the Final EIS with required conditions, is an environmental acceptable action and, consequently, based on all other factors discussed in the Authorization Order, the Jordan Cove LNG Terminal is not inconsistent with the public interest.[202] We affirm that decision.

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[195] Final EIS at 4-317 to 4-391; *see also infra* PP 217-228.

[196] Final EIS at 4-185 to 4-235; *see also infra* PP 169-179.

[197] Final EIS at 4-420 to 4-686; *see also infra* PP 180-194.

[198] Final EIS at 4-697 to 4-706, 4-849 to 4-851; *see also infra* PP 232-254.

[199] *See supra* PP 28-48.

[200] Authorization Order, 170 FERC ¶ 61,202 at P 294.

[201] *Id.*

[202] Authorization Order, 170 FERC ¶ 61,202 at P 294.

V. Environmental Analysis

A. Procedural Issues

1. The Draft EIS Satisfied NEPA Requirements

66. NRDC and Sierra Club argue that the Draft EIS was missing so much relevant information that it "precluded meaningful public participation in the NEPA process."[203] NRDC states that the Draft EIS lacked "critical information" including staff's Biological Assessment, mitigation plans, as well as studies and authorizations from other agencies, including ongoing agency consultation.[204] Sierra Club asserts that the Commission "chose to rush through the NEPA process" leaving out sufficient information to analyze alternatives to the Pacific Connector Pipeline, as well as the pipeline's potential impacts on residential wells, and other environmental resources areas.[205] Petitioners contend that the Commission's consideration of comments after the close of the comment period on the Final EIS is insufficient to account for the missing information in the Draft EIS, as it did not lead to the same amount of public participation,[206] and the Final EIS does not benefit from responses to these comments.[207] As a result, Sierra Club calls for the Commission to issue a revised Draft EIS, with a new opportunity for comment.[208]

67. We disagree that the Draft EIS did not satisfy NEPA. The Draft EIS is a draft of the agency's proposed Final EIS and, as such, its purpose is to elicit suggestions for change.[209] A draft is adequate when it allows for "meaningful analysis" and "make[s] every effort to disclose and discuss" "major points of view on the environmental impacts."[210] Although NRDC and Sierra Club identified that some information was

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[203] NRDC Rehearing Request at 56-58; Sierra Club Rehearing Request at 37-41.

[204] NRDC Rehearing Request at 56.

[205] Sierra Club Rehearing Request at 39-40.

[206] *Id.* at 41.

[207] NRDC Rehearing Request at 57.

[208] Sierra Club Rehearing Request at 41.

[209] *City of Grapevine v. U.S. Dep't of Transp.*, 17 F.3d 1502, 1507 (D.C. Cir. 1994) (*City of Grapevine*).

[210] 40 C.F.R. § 1502.9(a) (2019); *see also Nat'l Comm. for the New River v. FERC*, 373 F.3d 1323, 1328 (D.C. Cir. 2004) (*New River*) (holding that the Commission's Draft EIS was adequate even though it did not have a site-specific

missing from the Draft EIS, they have not demonstrated that this renders the Draft EIS inadequate by these standards. Nor have NRDC or Sierra Club shown that "omissions in the [Draft EIS] left the public unable to make known its environmental concerns about the project's impact."[211]

68. NRDC and Sierra Club err in claiming that the Draft EIS, the Final EIS, or Authorization Order, were required to include complete, finalized mitigation plans.[212] The Supreme Court has held "that NEPA does not require a fully developed plan detailing what steps *will* be taken to mitigate adverse environmental impacts . . . ."[213] Here, as the Commission stated in the Authorization Order, Commission staff published a Final EIS that identifies baseline conditions for all relevant resources.[214] Later-filed mitigation plans will not present new environmentally-significant information nor pose substantial changes to the proposed action that would otherwise require a supplemental EIS. Moreover, as we have explained in other cases, practicalities require the issuance of certificate authorizations before completion of certain reports and studies because large projects, such as this, take considerable time and effort to develop.[215] Perhaps more important, their development is subject to many variables whose outcomes cannot be predetermined. And, as the Commission has found elsewhere, in some instances, the certificate holder may need to access property in order to acquire the necessary information.[216] Accordingly, post-certification studies may properly be used to develop

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crossing plan for a major waterway where the proposed crossing method was identified and thus provided "a springboard for public comment").

[211] *Sierra Club, Inc. v. U.S. Forest Serv.*, 897 F.3d 582, 598 (4th Cir. 2018) (rejecting petitioners claim that the Commission's draft environmental impact statement precluded meaningful comment where the applicant had not yet filed an erosion and sediment control plan at the time the draft EIS was published) (citing *New River*, 373 F.3d at 1329).

[212] *See, e.g.*, NRDC Rehearing Request at 56; Sierra Club Rehearing Request at 40-41.

[213] *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 359 (1989) (emphasis in original).

[214] Authorization Order, 170 FERC ¶ 61,202 at P 160.

[215] *See, e.g.*, *Algonquin Gas Transmission, LLC*, 154 FERC ¶ 61,048, at P 94 (2016); *E. Tenn. Natural Gas Co.*, 102 FERC ¶ 61,225, at P 23 (2003), *aff'd sub nom.*, *New River*, 373 F.3d 1323.

[216] *Midwestern Gas Transmission Co.*, 116 FERC ¶ 61,182, at P 92 (2006).

site-specific mitigation measures. It is not unreasonable for the Final EIS to deal with sensitive locations in a general way, leaving specificities of certain resources for later exploration during construction.[217] What is important is that the agency make adequate provisions to assure that the certificate holder will undertake and identify appropriate mitigation measures to address impacts that are identified during construction.[218] We have and will continue to demonstrate our commitment to assuring adequate mitigation.[219]

69. Moreover, while the Draft EIS serves as "a springboard for public comment,"[220] any information that is filed after the comment period is available in the Commission's public record, including through its electronic database, eLibrary.[221] Further, the Authorization Order noted that comments filed on the Draft EIS were addressed in the Final EIS "to the extent practicable,"[222] and comments on the Final EIS were addressed in the Authorization Order.

70. To the extent Sierra Club and Ms. McCaffree claim that the Commission was required to issue a revised Draft EIS, they are mistaken.[223] As the Supreme Court has stated, "an agency need not supplement an EIS every time new information comes to light after the EIS is finalized."[224]

71. NEPA requires the revision or supplement of a draft (or final) EIS only where the agency makes "substantial changes in the proposed action," or if there are "significant new circumstances or information relevant to environmental concerns."[225] Sierra Club has not demonstrated that either of these scenarios occurred. The Final EIS analyzes the relevant environmental information and recommended environmental conditions. In the

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[217] *Mojave Pipeline Co.*, 45 FERC ¶ 63,005, at 65,018 (1988).

[218] *Id.*

[219] *Id.*

[220] *See Robertson*, 490 U.S. at 349.

[221] The eLibrary system offers interested parties the option of receiving automatic notification of new filings.

[222] Authorization Order, 170 FERC ¶ 61,202 at n.266.

[223] Sierra Club Rehearing Request at 41; McCaffree Rehearing Request at 15.

[224] *Marsh v. Oregon Natural Resources Council*, 490 U.S. 360, 373 (1989).

[225] 40 C.F.R. § 1502.9(c)(1) (2019).

Authorization Order, we adopted the recommended environmental conditions and further responded to comments, including those filed after the Final EIS.[226] In short, the Commission's procedures, consistent with NEPA and the NGA, allowed the public a meaningful opportunity to comment and resulted in an informed Commission decision.

72. NRDC contends that the Commission improperly issued the Draft EIS and Final EIS prior to completing consultation with the National Marine Fisheries Service (NMFS), Indian tribes, and the Oregon State Historic Preservation Office (SHPO), among other agencies and entities.[227] NRDC argues that the Commission's failure to complete the consultation process for inclusion in either the Draft or Final EIS "falls short of reasoned decision making under NEPA" and fails to promote "active public involvement and access to information" as required by NEPA.[228] Sierra Club claims that the Commission should have gathered all information before issuing a Draft EIS.[229]

73. Both the Draft and Final EIS contain extensive discussion regarding the potential impacts on federally-listed threatened and endangered species, marine mammals[230] and cultural resources.[231] As we explain above and in other cases,[232] practicalities require the issuance of orders before completion of certain reports and studies because large projects, such as this, take considerable time and effort to develop. Accordingly, the Commission's process "to the fullest extent possible,"[233] reflects the integration of the Commission's Draft EIS with the NMFS and SHPO consultation processes. As courts have recognized, NEPA's requirements are essentially procedural;[234] if the agency's

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[226] Authorization Order, 170 FERC ¶ 61,202 at P 293.

[227] NRDC Rehearing Request at 57.

[228] *Id.* (citing *Price Road Neighborhood Ass'n v. U.S. Dept. of Transp.*, 113 F.3d 1505, 1511 (9th Cir. 1997)).

[229] Sierra Club Rehearing Request at 41.

[230] *See* Draft EIS at 4-229 to 4-309; Final EIS at 4-235 to 4-317.

[231] *See* Draft EIS at 4-632 to 4-655; Final EIS at 4-663 to 4-686.

[232] *See*, *e.g.*, *Weaver's Cove Energy*, *LLC*, 114 FERC ¶ 61,058, at PP 108-115 (2006); *Islander E. Pipeline Co*., 102 FERC ¶ 61,054, at PP 41-44 (2003).

[233] 40 C.F.R. § 1502.9(a) (2019).

[234] *Vt. Yankee Nuclear Power Corp. v. Natural Res. Def. Council*, Inc., 435 U.S. 519, 558 (1978) (*Vermont Yankee*).

decision is fully informed and well-considered, the Commission has satisfied its NEPA responsibilities.[235] The Commission's approach is fully consistent with NEPA, as affirmed in *National Committee for New River v. FERC*,[236] where the D.C. Circuit recognized that "if every aspect of the project were to be finalized before any part of the project could move forward, it would be difficult, if not impossible, to construct the project."[237]

B. <u>Conditional Certificates</u>

74. Several petitioners allege that the Commission's conditional authorization of the projects pending receipt of all applicable federal and state approvals, including the Coastal Zone Management Act (CZMA),[238] the Clean Water Act (CWA),[239] and the Clean Air Act (CAA),[240] is unlawful.[241]

75. Under Environmental Conditions 11 and 27 of the Authorization Order, Jordan Cove and Pacific Connector cannot commence construction of any project facilities without first filing documentation either that they have received "all applicable authorizations required under federal law," including under the CZMA, CWA, and CAA, or that such authorizations have been waived.[242] This conditional authorization is a reasonable exercise of the Commission's broad authority to condition certificates for interstate pipelines on "such reasonable terms and conditions as the public convenience

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[235] *Natural Res. Def. Council, Inc. v. Hodel*, 865 F.2d 288, 294 (D.C. Cir. 1988).

[236] 373 F.3d 1323 (D.C. Cir. 2004).

[237] *Id*. at 1329 (quoting *E. Tenn. Natural Gas Co.*, 102 FERC ¶ 61,225 at P 25) (internal quotations omitted).

[238] 16 U.S.C. § 1456(c)(3)(A) (2018).

[239] 33 U.S.C. § 1341(a)(1) (2018).

[240] 42 U.S.C. § 7401 et seq. (2018).

[241] With regard to the CZMA, *see, e.g.*, Confederated Tribes Rehearing Request at 31-33; State of Oregon Rehearing Request at 25-26; Sierra Club Rehearing Request at 25-27. With regard to the CWA, *see, e.g.*, McCaffree Rehearing Request at 12-13, 17-18; State of Oregon Rehearing Request at 14-24; Sierra Club Rehearing Request at 25-27. With regard to the CAA, *see, e.g.*, State of Oregon Rehearing Request at 24.

[242] Authorization Order, 170 FERC ¶ 61,202, app., envtl. conditions 11, 27.

and necessity may require."[243] As discussed in the Authorization Order and in more detail below, the Commission's practice of issuing conditional certificates has consistently been affirmed by courts as lawful.[244]

1. <u>Coastal Zone Management Act</u>

76. As noted by the petitioners, the CZMA provides in pertinent part that that "[n]o license or permit shall be granted by [a] Federal agency until the state or its designated agency has concurred with the applicant's certification" that "the proposed activity complies with the enforceable policies of the state's approved [coastal management] program and that such activity will be conducted in a manner consistent with the program."[245]

77. The Jordan Cove LNG Terminal and a portion of the Pacific Connector Pipeline will be constructed within a designated coastal zone, and accordingly, the projects are subject to a consistency review under the CZMA.[246] As stated in the Authorization Order, on April 11, 2019, Jordan Cove and Pacific Connector submitted joint CZMA certification to the Oregon Department of Land Conservation and Development (Oregon DLCD).[247] On February 19, 2020, Oregon DLCD objected to the applicants' consistency certification on the basis that the applicants have not established consistency with specific

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[243] 15 U.S.C. § 717f(e); *see also, e.g.*, *ANR Pipeline Co. v. FERC*, 876 F.2d 124, 129 (D.C. Cir. 1989) (noting the Commission's "extremely broad" conditioning authority).

[244] Authorization Order, 170 FERC ¶ 61,202 at P 192 (citing *Del. Riverkeeper Network v. FERC*, 857 F.3d 388, 399 (D.C. Cir. 2017) (upholding Commission's approval of a natural gas project conditioned on securing state certification under section 401 of the Clean Water Act); *see also Myersville*, 783 F.3d at 1320-21 (upholding the Commission's conditional approval of a natural gas facility construction project where the Commission conditioned its approval on the applicant securing a required federal CAA air quality permit from the state); *Pub. Utils. Comm'n. of State of Cal. v. FERC*, 900 F.2d 269, 282 (D.C. Cir. 1990) (holding the Commission had not violated NEPA by issuing a certificate conditioned upon the completion of the environmental analysis)).

[245] 16 U.S.C. § 1456(c)(3)(A) (2018).

[246] Authorization Order, 170 FERC ¶ 61,202 at P 230.

[247] *Id.* P 231.

enforceable policies of the Oregon Coastal Management Program and that they are not supported by adequate information.[248]

78. The Commission noted in the Authorization Order that Oregon DLCD's objection appeared to be without prejudice and that the objection could be appealed to the U.S. Secretary of Commerce.[249] Accordingly, the Authorization Order required, in Environmental Condition 27, that prior to beginning construction, Jordan Cove and Pacific Connector must file a determination of consistency with the Coastal Zone Management Plan issued by the State of Oregon.[250] The Commission also explained in the Authorization Order that the Commission's practice of issuing conditional certificates has consistently been upheld by courts and that Jordan Cove and Pacific Connector would not be permitted to begin construction until they receive all necessary authorizations.[251]

79. Petitioners allege that our conditional authorization of the projects was unlawful and that the Commission is prohibited from approving the projects until the state has provided a concurrence with the consistency determination pursuant to the CZMA.[252] In addition, Sierra Club contends that requiring compliance with the CZMA prior to issuance of a notice permitting construction to begin, as opposed to issuance of the Authorization Order, limits the state's ability to participate in the process or impose meaningful conditions on projects.[253] Sierra Club further argues that issuance of a conditional authorization for these particular projects was inappropriate given that the

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[248] *Id.*

[249] *Id.* The CZMA provides that, when a state objects to a consistency certification, the applicant may appeal the objection to the Secretary of Commerce by filing a notice of appeal within 30 days of receipt of the objection. Following the appeal, the Secretary of Commerce may override a state objection to a consistency certification. 16 U.S.C. § 1456(c)(3)(A) (2018).

[250] Authorization Order, 170 FERC ¶ 61,202 at P 231 & app., envtl. condition 27.

[251] *Id.* PP 191-192 & app., envtl. condition 11.

[252] Confederated Tribes Rehearing Request at 32-33; Cow Creek Rehearing Request at 26-28 (addressing Cow Creek's arguments as to the Pacific Connector Pipeline); Sierra Club Rehearing Request at 25-27; State of Oregon Rehearing Request at 25-26; McCaffree Rehearing Request at 11-12.

[253] Sierra Club Rehearing Request at 26.

state had already objected to the CZMA consistency certifications.[254] Additionally, Ms. McCaffree states that because Oregon DLCD found that the projects' impacts violated the state's coastal program, the Commission cannot ignore and must consider those effects in making its determination.[255] Last, in their request for rehearing, Jordan Cove and Pacific Connector request clarification that Environmental Condition 27 could be satisfied if they submit a determination by the Secretary of Commerce that the activity is consistent with the objectives of the CZMA or is otherwise necessary in the interest of national security.[256]

80. As we explained above and in the Authorization Order, the Commission's practice of issuing conditional certificates has consistently been affirmed by courts as lawful,[257] including specifically the Commission's issuance of certificates conditioned on future state approval pursuant to the CZMA.[258] The Commission's approach is a practical response to the reality that it may be impossible for an applicant to obtain all approvals necessary to construct and operate a project in advance of the Commission's issuance of its certificate without unduly delaying a project.[259]

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[254] *Id.* at 26-27.

[255] McCaffree Rehearing Request at 12, 15-17.

[256] Jordan Cove and Pacific Connector Rehearing Request at 25-27.

[257] *See supra* P 76 & note 244.

[258] Authorization Order, 170 FERC ¶ 61,202 at P 192 (citing *Del. Dep't. of Nat. Res. & Envtl. Control v. FERC*, 558 F.3d 575, 578-79 (D.C. Cir. 2009) (holding Delaware suffered no concrete injury from the Commission's conditional approval of a natural gas terminal construction despite statutes requiring states' prior approval because the Commission conditioned its approval of construction on the states' prior approval)). Confederated Tribes contends that the court's decision in *Mountain Rhythm Res. v. FERC*, 302 F.3d 958 (9th Cir. 2002) undermines the Commission's interpretation of its conditional approval authority under the Natural Gas Act. But that case is inapposite: there, the court addressed whether the Commission reasonably relied on maps created by the National Oceanic and Atmospheric Administration in determining that a project was in a coastal zone. *Id.* at 965.

[259] Authorization Order, 170 FERC ¶ 61,202 at P 192 (citing *Broadwater Energy LLC*, 124 FERC ¶ 61,225, at P 59 (2008) (*Broadwater*); *Crown Landing LLC*, 117 FERC ¶ 61,209, at P 26 (2006) (*Crown Landing*); *Millennium*, 100 FERC ¶ 61,277 at PP 225-231).

81. Moreover, as we have previously explained, we see "no inherent conflict between the CZMA . . . and the NGA given the Commission's multi-faceted duties regarding LNG importation, the flexibility provided by implementing regulations issued by other agencies, and the courts' practical and reasonable decisions allowing statutes to operate together successfully."[260] Further,

> [f]or the Commission to deny NGA section 3 authorization . . . because a state's certification or concurrence under the CZMA . . . is pending at the state level or on appeal in a state or federal court . . . would require [a project proponent] to begin again the complex, time-consuming, and expensive application process when and if the CZMA . . . issues are resolved. This would be needlessly inefficient and contrary to the energy needs of our nation. Our practice of approving projects with conditions precluding construction pending the applicant's compliance with the CZMA . . . is far more consistent with both Congressional expectations and relevant agency regulations.[261]

82. We also disagree with Sierra Club's contention that this practice limits a state's ability to participate in the process. As stated previously and throughout the Authorization Order, the applicants must receive all necessary approvals, including authorizations federally delegated to the states, (or evidence of waiver thereof) prior to beginning construction.[262] Accordingly, the Authorization Order does not narrow the state's authorities delegated to it under the relevant statutes.[263]

83. Nor do we find that issuance of a conditional authorization in this case was inappropriate given that the state had objected to the consistency determination. In *Broadwater Energy LLC*, the Commission rejected similar arguments that it should vacate or withdraw its authorizations for the Broadwater Pipeline and Broadwater Energy import terminal because the State of New York objected to the project proponents' consistency determination shortly after the Commission issued its authorization order.[264] The Commission explained in its rehearing order that it was not required to vacate the

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[260] *Crown Landing*, 117 FERC ¶ 61,209 at P 27.

[261] *Id*. P 29.

[262] Authorization Order, 170 FERC ¶ 61,202, app., envtl. condition 11.

[263] *See Broadwater*, 124 FERC ¶ 61,225 at P 58.

[264] *Id.* P 66.

approval because the project proponent had appealed the state's finding to the Secretary of Commerce and the Commission would not authorize construction unless the state's objection was overridden.[265] On March 16, 2020, Jordan Cove and Pacific Connector appealed to the Secretary of Commerce.[266]

84. Relatedly, pursuant to Jordan Cove and Pacific Connector's request, we clarify that if the Secretary of Commerce overrides the state's determination, filing the Secretary's decision would satisfy Environmental Condition 27. The CZMA is a federal statute, implementation of which has been delegated to the states to make the concurrence determination in the first instance. Pursuant to the language of the CZMA, the Secretary of Commerce retains authority to override a state's decision.[267]

85. Last, we note, contrary to Ms. McCaffree's claim, that the Commission fully considered the environmental effects associated with the projects in the Authorization Order, including those effects that were the basis for Oregon DLCD's objections. For clarity, in multiple instances, the Authorization Order notes the Oregon DLCD's concerns, so that the state's analysis could be contrasted with that of the Commission.[268]

2. <u>Clean Water Act</u>

86. Section 401(a)(1) of the CWA provides that an applicant for a federal license to conduct an activity that "may result in any discharge into the navigable waters" must obtain a water quality certification from the state and, further, that "[n]o license or permit shall be granted until the certification required by the section has been obtained or has

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[265] *Id.*

[266] *See* Jordan Cove and Pacific Connector's April 3, 2020 Notice of Appeal filed in Docket Nos. CP17-494-000 and CP17-495-000.

[267] 16 U.S.C. § 1456(c)(3)(A) (2018) ("No license or permit shall be granted by the Federal agency until the state or its designated agency has concurred with the applicant's certification or until, by the state's failure to act, the concurrence is conclusively presumed*, unless the Secretary, on his own initiative or upon appeal by the applicant, finds, after providing a reasonable opportunity for detailed comments from the Federal agency involved and from the state, that the activity is consistent with the objectives of this chapter or is otherwise necessary in the interest of national security*.") (emphasis added).

[268] *See, e.g.*, Authorization Order, 170 FERC ¶ 61,202 at P 206, n.414.

been waived …" and "[n]o license or permit shall be granted if certification has been denied … ."[269]

87. The State of Oregon, Jordan Cove, and Pacific Connector dispute whether and when Oregon DEQ received Jordan Cove's and Pacific Connector's requests for water quality certifications with regard to Commission-jurisdictional activities.[270] On May 6, 2019, Oregon DEQ issued a denial of Jordan Cove's and Pacific Connector's requests for certification, which Oregon DEQ linked to a subset of activities under the jurisdiction of the U.S. Army Corps of Engineers (Army Corps).[271] Oregon DEQ issued the denial without prejudice and specifically allowed Jordan Cove and Pacific Connector to reapply.[272]

88. In the Authorization Order, the Commission explained that Jordan Cove and Pacific Connector will be unable to exercise the authorizations to construct and operate the projects until they receive all necessary authorizations, including under the CWA, or provide evidence of waiver.[273] The Commission explained that such conditional authorization is permitted, citing *Delaware Riverkeeper Network v. FERC*, which upheld the Commission's use of conditional authorizations before other authorizations under federal law are complete.[274]

89. On rehearing, the State of Oregon offers two reasons to distinguish the court's decision in *Delaware Riverkeeper Network v. FERC*.[275] First, the State of Oregon maintains that before the Commission issued its Authorization Order, Oregon DEQ had already timely denied the requests for certification, the applicants had not appealed, and

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[269] 33 U.S.C. § 1341(a)(1) (2018).

[270] *E.g.*, State of Oregon Rehearing Request at 18 (asserting that Oregon DEQ received applications for a 401 certification for activities to be authorized by the Corps but not for activities to be authorized by the Commission); Oregon DEQ May 7, 2019 Denial of 401 Water Quality Certification at 3 (same).

[271] Oregon DEQ May 7, 2019 Denial of 401 Water Quality Certification at 3.

[272] *Id.* at 3, 85.

[273] Authorization Order, 170 FERC ¶ 61,202 at PP 191-192 & app., envtl. condition 11.

[274] 857 F.3d 388 (D.C. Cir. 2017); *see* Authorization Order, 170 FERC ¶ 61,202 at P 192, n.371.

[275] State of Oregon Rehearing Request at 18-19.

the applicants had not re-applied.[276] Sierra Club takes a similar position, adding that Jordan Cove and Pacific Connector have not made any serious effort to satisfy Environmental Condition 11 because they have not indicated when or if they will re-apply for certification.[277] Ms. McCaffree states that the Commission has failed its obligation to assess and determine whether, given the projects' adverse impacts, obtaining the section 401 certification is feasible.[278]

90. Second, the State of Oregon asserts that Environmental Condition 11 fails to assure the result that the court relied upon in *Delaware Riverkeeper Network v. FERC*, i.e., that there will be no activity that may result in any discharge into the navigable waters before a valid water quality certification or a waiver is in place, because the Authorization Order granted Pacific Connector's request for a blanket construction certificate [279] Oregon DEQ asserts that the Commission's regulations presume that an activity under a blanket construction certificate complies with the CWA if the certificate-holder adheres to Commission staff's *Upland Erosion Control, Revegetation, and Maintenance Plan* (Plan) and *Wetland and Waterbody Construction and Mitigation Procedures* (Procedures) or an approved project-specific alternative.[280] The State of Oregon contends that although the Plan and Procedures are designed to reduce or mitigate discharges to waters, they do not prohibit discharges and they do not substitute for effluent limitations or water quality standards overseen by the state under the CWA.[281] The State of Oregon similarly states that Environmental Condition 11's prohibition on "commencing construction … including any tree-felling or ground-disturbing activities" neither prevents discharges from existing conveyances such as the use of existing stormwater systems, road culverts, herbicide application, and other point sources nor does it prevent the discharge from the removal of riparian vegetation in the form of increased heat loading to streams.[282]

91. There is no material distinction between the Authorization Order and the Commission's prior conditional order reviewed and upheld in *Delaware Riverkeeper*

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[276] *Id.* at 19.

[277] Sierra Club Rehearing Request at 26-27.

[278] McCaffree Rehearing Request at 12-13, 17-18.

[279] State of Oregon Rehearing Request at 20.

[280] *Id.* (citing 18 C.F.R. § 157.206(b)(3)(iv) (2019)).

[281] *Id.* at 20.

[282] *Id.* at 21-22.

Network v. FERC. At the time of the Commission's Authorization Order, Oregon DEQ had denied the requests for water quality certification, the applicants had not appealed, and the applicants had not indicated when or if they will re-apply. Jordan Cove and Pacific Connector were free to choose whether to pursue their interests by appealing the denials, by re-applying, or by presenting evidence of waiver directly to the Commission to obtain further authorization to commence construction.[283] On April 21, 2020, Jordan Cove and Pacific Connector filed a petition for a declaratory order from the Commission seeking a finding that Oregon DEQ waived the section 401 certification requirement by failing to act by the deadline in section 401.[284] The Commission will respond to Jordan Cove's and Pacific Connector's petition in a separate order in new sub-docket numbers CP17-494-003 and CP17-495-003.[285]

92. We disagree with the State of Oregon's contention that granting Pacific Connector's request for a blanket certificate could result in an activity that may cause a discharge into the navigable waters before it obtains a valid water quality certification or a waiver thereof. The Commission's blanket certificate regulations include environmental conditions that require pipeline companies, prior to commencing construction, to comply with numerous environmental laws enforced by other agencies to ensure that sensitive environmental areas will not be adversely impacted by any

[283] *See Millennium Pipeline Co., L.L.C. v. Seggos*, 860 F.3d 696, 700 (D.C. Cir. 2017). The courts have explained that "[o]nce the Clean Water Act's requirements have been waived, the Act falls out of the equation." *Id.* at 700. If the state has failed to act by the deadline in section 401, the state's later denial of the request has "no legal significance." *Id.* at 700-01 (declining the project sponsor's request that the court set a deadline for agency action, explaining that after waiver "there is nothing left for the [agency] ... to do" and "the [agency's] decision to grant or deny would have no legal significance"); *see also Weaver's Cove Energy, LLC v. R.I. Dep't of Envtl. Mgmt.*, 524 F.3d 1330, 1333 (D.C. Cir. 2008) (explaining that after waiver, states' preliminary decisions under section 401 "would be too late in coming and therefore null and void"). Accordingly, a state's denial of certification does not preclude an applicant from later initiating a proceeding to find waiver. *Constitution Pipeline Co., LLC*, 169 FERC ¶ 61,199, at P 8 (2019).

[284] Jordan Cove and Pacific Connector, Petition for Declaratory Order, Docket Nos. CP19-494-003, CP17-495-003 (filed April 21, 2020); *see* 33 U.S.C. § 1341(a)(1) (2018) ("If the State, interstate agency, or Administrator, as the case may be, fails or refuses to act on a request for certification, within a reasonable period of time (which shall not exceed one year) after receipt of such request, the certification requirements of this subsection shall be waived with respect to such Federal application.").

[285] *See Notice of Petition for Declaratory Order*, 85 Fed. Reg. 27,736 (May 11, 2020).

construction activities, including activities under the automatic provisions, that will involve ground disturbance or changes to operational air and noise emissions.[286] Specifically, section 157.206(b)(2)(i) of our regulations would require Pacific Connector to be in compliance with the CWA and its implementing regulations and plans before acting under its blanket certificate.[287] As noted by the State of Oregon,[288] Pacific Connector could show compliance with section 157.206(b)(2)(i) if it adheres to Commission staff's current Plan and Procedures,[289] which require the project sponsor to apply for and obtain an individual or generic CWA section 401 water quality certification or waiver thereof, prior to commencing any activity under the blanket certificate.[290] Accordingly, we dismiss the State of Oregon's argument because Pacific Connector must be compliant with the CWA before it can perform any activity under its blanket certificate.[291]

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[286] 18 C.F.R. § 157.206(b) (2019) (requiring a company planning to undertake construction activities under its Part 157 blanket certificate to obtain any necessary permits or approvals needed pursuant to "following statutes and regulations or compliance plans developed to implement these statutes": the Clean Water Act, Clean Air Act, National Historic Preservation Act, Archeological and Historic Preservation Act, Coastal Zone Management Act, Endangered Species Act, Wild and Scenic Rivers Act, National Wilderness Act, National Parks and Recreation Act, the Magnuson-Stevens Fishery Conservation and Management Act, and executive orders requiring evaluation of the potential effects of actions on floodplains and wetlands).

[287] 18 C.F.R. § 157.206(b)(2)(i) (2019); *see* Office of Energy Projects, *Guidance Manual for Environmental Report Preparation*, Vol. I at 7-1 to 7-12 (Feb. 2017) (discussing the regulatory structure for activities under blanket certificates), https://www.ferc.gov/industries/gas/enviro/guidelines/guidance-manual-volume-1.pdf.

[288] State of Oregon Rehearing Request at 21.

[289] 18 C.F.R. § 157.206(b)(3)(iv) (2019).

[290] Commission's *Upland Erosion Control, Revegetation and Maintenance Plan* (May 2013) https://www.ferc.gov/industries/gas/enviro/plan.pdf. (Plan); Commission's *Wetland and Waterbody Construction and Mitigation Procedures* at 7 (May 2013), https://www.ferc.gov/industries/gas/enviro/guidelines/wetland-pocket-guide.pdf (Procedures).

[291] If Pacific Connector cannot demonstrate compliance with CWA section 401 prior to performing an activity under its blanket certificate, then Pacific Connector must seek a new case-specific NGA section 7 certificate for that activity. *See, e.g.*, *Kern River Gas Transmission Co.*, 98 FERC ¶ 62,040, at 64,071 (2002) (project sponsor requested case-specific NGA section 7 certificate for its project because it could not ensure

93. Turning to the State of Oregon's argument that Environmental Condition 11 is inadequate because it only requires that Jordan Cove and Pacific Connector file documentation about authorizations required under federal law (or evidence of waiver thereof) but does not expressly require that the Commission or the Director of the Office of Energy Projects affirmatively determine that the authorizations are valid or determine that waiver has occurred.[292] The State of Oregon is concerned that Environmental Condition 11 gives no indication about the standard or process to determine waiver and that there would be no final order to challenge if the state wishes to contest the validity of filed documentation.[293]

94. Pursuant to Environmental Condition 11 and other conditions, Jordan Cove and Pacific Connector may not commence construction until they first receive written authorizations from the Director of the Commission's Office of Energy Projects. The Director will only authorize the commencement of construction when the applicants have demonstrated compliance with all applicable conditions.[294] Should Jordan Cove and Pacific Connector file documentation to satisfy Environmental Condition 11, these filings will appear in the Commission's online eLibrary as part of the public record for this proceeding. Any authorization to commence construction is a final agency action, and a party aggrieved by such a decision can pursue rehearing under section 19 of the NGA.[295] At that time, a party may challenge the applicants' compliance with Environmental Condition 11 and may challenge the Director's stated reasoning and conclusions. Here Jordan Cove and Pacific Connector have now petitioned for a declaratory order on the question of waiver.[296] Any person that intervened in the proceedings under NGA section 3 and section 7 is already a party to the proceeding for the petition.[297] The

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consistency with the Endangered Species Act, as required by section 157.206(b)(2)(vi) of the Commission's regulations); *El Paso Natural Gas Co*, 94 FERC ¶ 61,403, at 62,501 (2001) (project sponsor requested case-specific NGA section 7 certificate for its project because it could not ensure consistency with the National Historic Preservation Act, as required by section 157.206(b)(2)(iii) of the Commission's regulations).

[292] State of Oregon Rehearing Request at 21.

[293] *Id.*

[294] *See, e.g.*, Authorization Order, 170 FERC ¶ 61,202 at P 293.

[295] 15 U.S.C. § 717r (2018).

[296] *See Notice of Petition for Declaratory Order* (May 5, 2020) (Docket Nos. CP17-494-003, CP17-495-003).

[297] *Id*. at 1 n.1.

Commission's response to the petition will be subject to rehearing. Finally, petitioners assert that the conditional authorization undermines state authority under the CWA. The State of Oregon contends that the statement in the NGA that "nothing in this Act affects the rights of States" under the CWA,[298] includes the significant right to issue a water quality certification before the relevant federal license or permit.[299] The State of Oregon emphasizes Congress's "clearly stated intent" to avoid the inefficient outcome that a state's later denial will nullify the Commission's authorization or that a state's later certification, which may include terms and conditions that affect the design or siting of a facility, will force the applicant to return to the Commission to amend its authorization.[300] Sierra Club asserts that requiring compliance with the CWA prior to issuance of an order authorizing the start of construction, as opposed to issuance of the Authorization Order, limits the state's ability to participate in the process or to impose meaningful conditions on projects.[301] Ms. McCaffree asserts that the Commission cannot overrule the state's denial and cannot waive federal CWA standards.[302]

95. As is true with respect to the CZMA, the Commission's conditional authorization does not undermine state authority under the CWA and does not limit a state's ability to participate in the process. The practice of issuing conditional authorizations for natural gas projects, when necessary, is a safeguard against inefficient outcomes. The Commission's approach is a practical response to the reality that it may be impossible for an applicant to obtain all approvals necessary to construct and operate a project in advance of the Commission's issuance of its certificate without unduly delaying a project.[303] This approach is far more consistent with both Congressional expectations and relevant agency regulations than if the Commission failed to make timely decisions on matters related to its NGA jurisdiction that will inform project sponsors and other licensing agencies, as well as

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[298] State of Oregon at 23 (quoting section 3(d) of the NGA, 15 U.S.C. § 717b(d) (2018)).

[299] *Id.* at 23.

[300] *Id.* at 23-24.

[301] *Id.* at 23-24; Sierra Club Rehearing Request at 26.

[302] McCaffree Rehearing Request at 12, 17.

[303] Authorization Order, 170 FERC ¶ 61,202 at P 192 (citing *Broadwater*, 124 FERC ¶ 61,225 at P 59; *Crown Landing*, 117 FERC ¶ 61,209 at P 26; *Millennium*, 100 FERC ¶ 61,277 at PP 225-231).

the public.[304] The conditioned Authorization Order fully protects the authority delegated to Oregon under the CWA. It requires that the applicants receive the necessary state approval, or prove waiver, prior to construction and the resulting impacts to the navigable waters in the state. The conditioned Authorization Order does not impact any substantive determinations that need to be made by Oregon DEQ under the CWA. Oregon DEQ retains full authority to grant or deny the specific requests. The Commission has no authority to modify or reject the terms and conditions imposed by a state's water quality certification, and the Commission has no authority to overrule a state's denial absent waiver.[305]

3. Clean Air Act

96. The State of Oregon argues that the Commission could not issue the Authorization Order until applicants obtained a pre-construction authorization, known as an Air Contaminant Discharge Permit, pursuant to Title V of the Clean Air Act.[306] The State of Oregon also claims that Environmental Condition 11 is inadequate because it should have required that the applicants receive all necessary federal authorizations, including the Clean Air Act Title V Operating Permit, needed for operation of the projects before either begins operation.[307]

97. The Commission appropriately conditioned its authorization on Jordan Cove and the Pacific Connector obtaining required federal authorizations. Jordan Cove and Pacific Connector indicated that they would obtain the Air Contaminant Discharge Permit before beginning construction.[308] As discussed, the Commission may issue conditional

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[304] *See e.g.*, *Broadwater*, 124 FERC ¶ 61,225 at P 59; *Crown Landing*, 117 FERC ¶ 61,209 at P 29.

[305] *E.g., City of Tacoma, Wash. v. FERC*, 460 F.3d 53, 67-68 (D.C. Cir. 2006) ("FERC's role is limited to awaiting, and then deferring to, the final decision of the state. Otherwise, the state's power to block the project would be meaningless. … If the question regarding the state's section 401 certification is not the application of state water quality standards but compliance with the terms of section 401, then FERC must address it."); *accord Am. Rivers, Inc. v. FERC*, 129 F.3d 99, 107-111 (2d Cir. 1997).

[306] State of Oregon Rehearing Request at 24.

[307] *Id.* at 24-25.

[308] *See* Final EIS at 1-25.

authorizations,[309] courts have specifically affirmed the Commission's issuance of certificates conditioned on future state approval pursuant to the Clean Air Act.[310]

98. We decline to adopt the State of Oregon's request that the Commission condition any authorization to commence service on Jordan Cove's future Title V Operating Permit.[311] As discussed in the Final EIS, under the CAA, an application to the State of Oregon for this permit is due one year after the source commences operation.[312]

C. The Projects' Purposes and Reasonable Alternatives

1. The EIS's Purpose and Need Statement

99. NRDC argues that the Commission violated NEPA because it deferred to Jordan Cove's and Pacific Connector's definitions for the projects' purposes and needs in the Final EIS.[313] NRDC contends that the Commission must take "a hard look at the factors relevant" to the projects' purpose and need and cannot automatically adopt Jordan Cove's and Pacific Connector's definitions such that the projects are a foregone conclusion.[314] NRDC acknowledges that the NGA's public interest determinations and NEPA's purpose and need statement differ, but contends that the purpose and need statement in the Final EIS should be informed by the underlying statutory review being conducted, which is to balance public benefits against adverse consequences.[315] NRDC argues that, by adopting

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[309] *See supra* P 76 & note 244.

[310] *Myersville*, 783 F.3d at 1320-21 (upholding the Commission's conditional approval of a natural gas facility construction project where the Commission conditioned its approval on the applicant securing a required federal Clean Air Act air quality permit from the state).

[311] The State of Oregon requires Title V facilities to obtain a Standard Air Containment Discharge Permit prior to commencing construction; in addition, any facility that triggers Prevention of Significant Deterioration permitting, such as the Jordan Cove LNG Terminal and the Pacific Connector Pipeline, must also obtain a Title V Operating Permit. *See* Final EIS at 4-689.

[312] *Id.* at 4-689.

[313] NRDC Rehearing Request at 46.

[314] *Id*. at 46-47 (citing *Nat'l Parks Conservation Ass'n v. Bureau of Land Management*, 606 F.3d 1058, 1071 (9th Cir. 2010)).

[315] *Id.* at 47.

private interests, the Commission's purpose and need statement was so narrow to preclude consideration of a reasonable range of alternatives.[316]

100. An agency's statement of purpose and need in an EIS is evaluated under a reasonableness standard.[317] Under this standard, agencies are afforded considerable discretion to define the purpose and need statement for a project,[318] but that statement may not be so narrow to preclude otherwise reasonable alternatives such that "the EIS would become a foreordained formality."[319] The nature of the proposed federal action must also be informed both by "the project sponsor's goals," as well as "the goals that Congress has set for the agency."[320] Accordingly, under the NGA and NEPA, the Commission's purpose in assessing a project proposed under section 3 or 7 of the NGA is "*whether* to adopt an applicant's proposal and, if so, to what degree," not to engage in energy resource or natural gas transportation planning.[321]

101. As discussed in the Authorization Order, the Commission appropriately relied on the general objectives of the projects' applicants.[322] The Final EIS states that the Jordan Cove LNG Terminal will export natural gas supplies from existing natural gas transmission systems to overseas markets, particularly Asia, and the Pacific Connector Pipeline will connect the existing Gas Transmission Northwest, LLC and Ruby Pipeline LLC systems with the proposed terminal.[323] Such a statement, which explains where the

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[316] *Id.* at 47, 55.

[317] *See, e.g.*, *Friends of Se.'s Future v. Morrison*, 153 F.3d 1059, 1067 (9th Cir. 1998) (stating that while agencies are afforded "considerable discretion to define the purpose and need of a project," agencies' definitions will be evaluated under the rule of reason); *see also City of Alexandria v. Slater*, 198 F.3d 862, 867 (D.C. Cir. 1999).

[318] *See City of Angoon v. Hodel*, 803 F.2d 1016 (9th Cir. 1986).

[319] *Citizens Against Burlington, Inc. v. Busey*, 938 F.2d 190, 196 (D.C. Cir. 1991)).

[320] *Sierra Club v. U.S. Forest Serv.*, 897 F.3d at 598 (quoting *All. for Legal Action v. FAA*, 69 F. App'x 617, 622 (4th Cir. 2003)).

[321] *See Theodore Roosevelt Conservation P'ship v. Salazar*, 661 F.3d 66, 73 (D.C. Cir. 2011); *see also* 15 U.S.C. §§ 717b, 717f (2018); Authorization Order, 170 FERC ¶ 61,202 at P 186 (citing *Citizens Against Burlington, Inc. v. Busey*, 938 F.2d at 191).

[322] Authorization Order, 170 FERC ¶ 61,202 at P 186.

[323] Final EIS at 1-6.

gas originates and where it is delivered, is permissible as it allows the agency to consider a sufficiently wide range of alternatives to be considered.[324]

102. NRDC argues that the Commission only gave serious consideration to the applicants' proposals because it improperly adopted the applicants' purposes in contravention of its duties to consider the public interest under the NGA.[325] NRDC cites *National Parks and Conservation Association v. Bureau of Land Management*[326] for support but in that case the BLM drafted its purpose and need statement for a private land exchange in such narrow terms that it foreordained approval of the land exchange.[327] In contrast, our approval of the projects, as proposed by Jordan Cove and Pacific Connector, was not preordained. The Commission considered the no-action alternative, system alternatives, LNG terminal site alternatives, and pipeline route alternatives and variations, and balanced numerous environmental factors in the Final EIS. As discussed throughout this order and the Authorization Order, the Commission used this analysis in the Final EIS to conditionally approve environmentally acceptable actions, and even adopt a route variation, consistent with its public interest criteria under sections 3 and 7 of the NGA.

2. Alternatives

a. No-Action Alternative

103. NRDC and Sierra Club argue that the Final EIS fails to offer a genuine "no action" alternative because the Final EIS states that under the no-action alternative, exports of LNG from one or more other LNG export facilities may occur.[328] Under the no-action alternative the Commission would deny the requested applications under sections 3 and 7 of the NGA. The Authorization Order explained that under the no-action alternative, the proposed actions would not occur and the environment would not be affected.[329] Contrary to NRDC's claims, the Final EIS also details baseline environmental resources

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[324] *See Sierra Club v. U.S. Forest Serv.*, 897 F.3d at 598-99 (upholding the Commission's statement of purpose and need for a natural gas pipeline to run through national forest).

[325] NRDC Rehearing Request at 55.

[326] 606 F.3d 1058, 1072.

[327] *Id.* at 1072.

[328] NRDC Rehearing Request at 48-51; Sierra Club Rehearing Request at 39.

[329] Authorization Order, 170 FERC ¶ 61,202 at P 187 (citing Final EIS at ES-5, 3-4).

before describing the environmental impacts of various alternatives.[330] "[M]erely because a 'no action' proposal is given a brief discussion does not suggest that it has been insufficiently addressed."[331] The Final EIS ultimately did not recommend the no action alternative because that alternative would not meet the projects' purposes and needs.[332] Moreover, no other existing LNG terminal in the region could export LNG, a similar terminal facility may be built to meet the demand for export. This could lead to impacts at other locations and would not result in significant environmental benefits.[333]

b. System and Site Alternatives

104. Petitioners next allege that the Commission failed to take a hard look at alternatives. When an agency is tasked to decide whether to adopt a private applicant's proposal, and if so, to what degree, a reasonable range of alternatives to the proposal includes rejecting the proposal, adopting the proposal, or adopting the proposal with some modification.[334] Reasonable alternatives are defined as those alternatives "that are technically and economically practical or feasible and meet the purpose and need of the proposed action."[335] The Commission enjoys broad discretion in evaluating alternatives and utilizing its expertise to balance competing interests.[336] Indeed, "[e]ven if an agency has conceded that an alternative is environmentally superior, it nevertheless may be entitled under the circumstances not to choose that alternative."[337] As discussed herein,

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[330] *Id.* (citing Final EIS at 4-1 to 4-852).

[331] *Headwaters, Inc. v. Bureau of Land Mgmt*, 914 F.2d 1174, 1181 (9th Cir.1990). *See Or. Natural Res. Council v. Lyng*, 882 F.2d 1417, 1423 n.5 (1989) ("The fact that the description of the no-action alternative is shorter than those of the other proposals does not necessarily indicate that the no-action alternative was not considered seriously. It may only reveal that the forest service believed that the concept of a no-action plan was self-evident while the specific timber sale plans needed explanation.").

[332] Final EIS at 3-5.

[333] *Id.*

[334] *See Theodore Roosevelt Conservation P'ship*, 661 F.3d at 72-74.

[335] 43 C.F.R. § 46.420(b) (2019).

[336] *Minisink*, 762 F.3d at 111. *See also Myersville*, 783 F.3d at 1324 (deferring to agency's rejection of a pipeline loop alternative that would eliminate the emissions associated with the proposed compressor station but would disturb more land).

[337] *Myersville*, 783 F.3d at 1324.

the Final EIS takes a hard look at alternatives, including the no action alternative, system alternatives, LNG terminal site alternatives, and pipeline route alternatives and variations.

i. The Existing LNG Storage Alternatives

105. NRDC argues that the Commissions improperly dismissed as an alternative the use of any of the four LNG storage facilities in Oregon and Washington that are connected to natural gas systems, because these facilities were not designed to export LNG and therefore would require significant modifications to meet the projects' purpose.[338] NRDC contends that the Commission failed to assess whether modifications at these facilities would be technically or economically feasible.[339]

106. As discussed in the Final EIS, Commission staff considered whether the four peak shaving LNG storage plants could meet the terminal's objectives, but determined that modifying these plants was not technically or economically practical or feasible.[340] Because the plants are not designed to export LNG, they would require significant modifications; the facilities needed to export LNG do not exist and the storage tanks are too small to meet the project's goals. On review, NRDC argues that the Commission should have provided a more detailed discussion, but CEQ regulations only require a brief discussion of why an alternative was eliminated[341] and NRDC fails to establish that this determination was erroneous.

ii. The Humboldt Bay Site Alternative

107. NRDC next argues that the Commission improperly dismissed the Humboldt Bay site alternative because its environmental impacts would be similar to the terminal and those of any connecting pipeline would be similar to the proposed route.[342] NRDC claims the Final EIS does not provide any information to determine whether the Humboldt Bay site would provide a significant environmental advantage or disadvantage, as there could be numerous routes and locations that may appear similar on their surface

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[338] NRDC Rehearing Request at 52.

[339] *Id.* at 53.

[340] Final EIS at 3-5.

[341] 40 C.F.R. § 1502.14(a) (2019).

[342] NRDC Rehearing Request at 52.

but may offer significant environmental advantages or disadvantages upon deeper evaluation.[343]

108. The Final EIS examines whether the nearest deepwater port, Humboldt Bay in California, was a feasible alternative site for the proposed action.[344] The Final EIS summarizes Commission staff's consideration of potential site locations, parcel availability, land use, and general environmental impacts. Commission staff identified the Samoa Peninsula within Humboldt Bay as generally available for coastal-dependent industry development.[345] The Samoa Peninsula includes open land, BLM-managed recreation land, public beaches, former and current industrial land, numerous residences, an elementary school, coastal shrub and wooded vegetation, and coastal dunes. Based on the characteristics of the existing navigational channels within Humboldt Bay as described in the Final EIS, dredging impacts are expected to be similar or greater to those at the proposed site.[346] Given the presence of these resources on or adjacent to the peninsula, and the presence of several communities located across the shipping channel, a 200-acre LNG terminal located in Humboldt Bay would likely result in impacts similar to or greater than the proposed project.

109. With regard to an associated pipeline, Commission staff estimated that the pipeline distance between Malin, Oregon and Humboldt Bay would be approximately 200 miles.[347] Similar to the proposed route, this route would use existing roads and utility rights-of-way, would maximize use of open lands and ridgelines, and would reduce the crossing of extremely mountainous terrain. Based on staff's desktop analysis, assuming a nominal 95-foot-wide construction right-of-way, an approximate 200-mile-long pipeline route would affect about 2,300 acres of land, 286 fewer acres than the proposed route.[348]

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[343] *Id.* at 54.

[344] Final EIS at 3-10.

[345] *Id.*

[346] *Id.*

[347] *Id.* This estimate was based on a route originating near Malin, Oregon proceeding due west along the Oregon-California border, turning southwest north of Dorris, California and generally following highway 97, before turning due west near Mt. Hebron, California to Yreka, California, and then proceeding in a southwest direction to just south of Weitchpec, California, continuing southwesterly to a location about 10 miles east of Eureka, California, and finally proceeding west to Humboldt Bay. *Id.*

[348] The proposed pipeline construction right-of-way is approximately 229 miles long, not including temporary extra work areas, contractor and pipe storage yards, access

A pipeline from Malin to Humboldt Bay would cross at least 110 miles of forested and mountainous terrain, resulting in impacts of about 1,265 acres, 394.3 acres fewer than the proposed route.[349] This alternative pipeline route would also cross a similar number of major waterbodies.

110. Based on these estimates, Commission staff expected the terminal site at Humboldt Bay would not offer any environmental advantages and the associated pipeline would offer only minor environmental advantages compared to the proposed terminal location and pipeline route. Therefore, the alternative would not offer a significant environmental advantage over the proposed action. As stated in the Final EIS, staff does not recommend adopting an alternative that is environmentally comparable or results in minor advantages but merely shifts the projects impacts from one set of landowners to another.[350]

111. In addition, we also find based on a review of the record that this alternative is not feasible. According to Jordan Cove, the bay lacks an available parcel or combination of parcels equaling the approximately 200 acres needed for an LNG terminal site.[351] Accordingly, we affirm Commission staff's determination concerning the Humboldt Bay Site alternative in the Final EIS.

iii. <u>Alternative Slip and Berth Size</u>

112. Sierra Club contends that the Commission should have considered alternatives that would have reduced the size of the proposed slip and berth to the minimum necessary to accommodate the largest carriers that the terminal is authorized to use.[352] Sierra Club notes that Jordan Cove will dredge the terminal slip to accommodate LNG carriers as large as 217,000 m^3 in capacity, but the largest carrier visiting the terminal is expected to be 148,000 m^3 in capacity.[353] Sierra Club claims that it appears that 148,000 m^3 carriers are roughly 15 percent shorter in length and have lower drafts than 217,000 m^3

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roads, and aboveground facilities, and would impact approximately 2,586 acres of land. *Id.* at 4-437.

[349] The approved route, including the incorporation of the Blue Ridge Variation, would impact 1,659.3 acres of mountainous and forested terrain. *Id.* at 3-28, 4-437.

[350] *Id.* at 3-3.

[351] Jordan Cove DEIS Comments at Attachment A, 4 (July 5, 2019).

[352] Sierra Club Rehearing Request at 45-47.

[353] *Id.* at 46.

carriers.[354] Sierra Club acknowledges that the Final EIS indicates that the Coast Guard confirmed that the proposed slip width is needed for safety purposes, but the Commission failed to fully explain this determination and otherwise ignored slip length.[355]

113. The lengths, widths, and drafts of the existing LNG carrier fleet vary depending on design and manufacturer. These variations in ship size occur across all carrier types, even among carriers with similar LNG storage capacities. The Coast Guard indicated that is the waterway is suitable to receive LNG carriers with up to 148,000 m^3 nominal capacities.[356] Based on publicly and privately available data on LNG carriers currently operating in the global market, the difference in length between the carriers of this nominal capacity and vessels with capacities of 217,000 m^3 is between approximately 60 and 85 feet (6-8%), and the respective difference in drafts is about 2.5 feet. Setting aside other site-specific factors including channel and tidal characteristics in which affect slip design, reducing the slip length by up to 85 feet and the depth by 2.5 feet would reduce the slip size by less than two acres[357] and the volume of excavated soil by about 6,300 yards,[358] neither of which would result in a significant environmental advantage when compared to the proposed action.[359] Therefore, based on this minor difference in vessel lengths and drafts, and resulting environmental impacts, staff determined, and we agree, that an alternative slip design assessment would not offer a significant environmental advantage over the proposed action.

iv. Eliminating the Emergency Lay Berth Alternative

114. Sierra Club next argues that the Commission failed to explore an alternative that omitted the proposed emergency vessel lay berth from the slip, which provides a place to

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[354] *Id.*

[355] *Id.* (citing app. R, pt. 3, SA2-389).

[356] Final EIS at 4-91.

[357] Commission staff calculated this figure using the following formula: reduced slip length (85 feet) x proposed slip width (800 feet) = 68,000 $feet^2$ / 43,560 $feet^2$ per acre = 1.6 acres.

[358] Commission staff calculated this figure using the following formula: reduced slip area (68,000 $feet^2$) x reduced depth of excavation (2.5 feet) = 170,000 cubic feet / 27 cubic feet per yard = 6,296 yards.

[359] The proposed slip size is 52 acres. *See* Resource Report 1 at 33. The slip will also result in 3.8 million cubic yards of dredged material. EIS at 2-17.

store a disabled carrier.[360] Sierra Club questions whether this feature is needed, and states that no other LNG terminal in the United States includes a lay berth.[361]

115. Jordan Cove indicated that, in response to U.S. Coast Guard concerns, it included the emergency lay berth to mitigate the scenario where a temporarily non-operational LNG carrier needed to be berthed during a port call.[362] The Coast Guard assists the Commission in evaluating whether an applicant's proposed waterway would be suitable for LNG marine vessel traffic;[363] accordingly, the Commission defers to the Coast Guard as the recognized safety experts on the need for the lay berth to ensure safe operations.

116. Moreover, we note that eliminating the lay berth would not reduce the overall slip size or result in a significant environmental advantage. The lay berth and operational berth are both located on either side of a U-shaped slip. Although the lay berth is located within the slip, it does not actually enlarge the slip. Thus, eliminating the lay berth would not reduce the overall slip size, which in turn would not significantly reduce the environmental impact of the project. An alternative that does not reduce an environmental impact would not result in a significant environmental advantage when compared to the proposed project component. Finally, any reduction in the slip width to eliminate a lay berth would negatively impact safely docking LNG vessels.[364]

v. <u>The Shoreline Berth Alternative</u>

117. Sierra Club alleges that the Commission improperly eliminated the "shoreline berth" or shoreside berth, because it would require more acres of dredging, and, therefore, not offer a significant environmental advantage.[365] Sierra Club argues that the Commission ignored the volume of dredged material, the needed depth of dredging, and the changes to the river floor.[366] Moreover, Sierra Club asserts that eliminating the alternative based on dredging alone ignores the extensive excavation, spoil disposal, and

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[360] Sierra Club Rehearing Request at 48.

[361] *Id.*

[362] Jordan Cove Resource Report 1 at 11.

[363] Final EIS at 4-739.

[364] *Id.* at Appendix R, pt. 3, SA2-389.

[365] Sierra Club Rehearing Request at 48-49.

[366] *Id.* at 49.

hydrologic and biological impacts associated with the slip.[367] Sierra Club also argues that the Commission should have considered the shoreline berth sized for 148,000 m^3 carriers.[368]

118. The Commission fully considered the shoreline berth and appropriately eliminated the alternative on multiple grounds.[369] The EIS determined that a shoreside berth alternative would not result in a significant environmental advantage because it would require essentially the same amount of in-water dredging than the proposed configuration and may require additional dredging for the second emergency lay berth.[370] Smaller berths, sized for 148,000 m^3 carriers, may reduce the amount of dredging slightly,[371] but this decrease would not result in a significant environmental advantage. Contrary to Sierra Club's claim that the Final EIS only considers dredging when eliminating the alternative, the Final EIS also eliminates the alternative due to safety and reliability concerns.[372] The shoreline berth alternative would place docked LNG carriers in the direct path of other vessel traffic navigating north up the river along an outside bend in the channel and put the carrier in danger of collision from other vessels.[373] As required by NEPA, the Final EIS examines this alternative but eliminated it from further consideration due to these safety and environmental impacts. Accordingly, we find that the Final EIS appropriately eliminates this alternative.

vi. <u>The Waste Heat Recovery Alternative</u>

119. Sierra Club argues that the Commission should have considered alternatives that would require Jordan Cove to use waste heat to generate all electricity needed for the terminal.[374] Operating the LNG terminal would require approximately 39.2 megawatts

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[367] *Id.*

[368] *Id.*

[369] Final EIS at 3-16 to 3-17.

[370] *Id.* at 3-16.

[371] *See supra* at P 113.

[372] Final EIS at 3-16 to 3-17.

[373] *Id.*

[374] Sierra Club Rehearing Request at 50.

(MW) (holding mode) and 49.5 MW (loading mode) of electricity.[375] As Sierra Club acknowledges, Jordan Cove will already use waste heat to generate a portion of electricity at the terminal.[376] Jordan Cove will operate three, 30-MW steam turbine generators to provide 24.4 MW of power and an auxiliary boiler when two or more heat steam recovery generators are offline for maintenance.[377] Steam for use by the steam turbine generators will be generated by heat recovery steam generators, using exhaust from the LNG refrigerant compression gas turbine drivers.[378] Jordan Cove will supply the remaining 15 to 26 MW of electricity using a connection with the local power grid.[379] Sierra Club asks that the Commission consider using gas turbine exhaust energy as a fuel source alternative, but, as discussed, Jordan Cove already plans to use this technology to generate electricity.[380] Commission staff determined, and we agree, that supplying all facility power through waste heat is not feasible.

c. **Pipeline Route Alternatives**

120. Ms. McCaffree argues that the Commission failed to consider reasonable route alternatives that she previously raised. In her request, Ms. McCaffree fails to describe these routes and instead cites accession numbers to exhibits to previous comments.[381] As discussed, the Commission has rejected attempts to incorporate by reference arguments from a prior pleading because such incorporation fails to inform the Commission as to which arguments from the referenced pleading are relevant and how they are relevant.[382] Accordingly, we dismiss her request.[383]

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[375] Final EIS at 2-8.

[376] Sierra Club Rehearing Request at 50.

[377] Jordan Cove Resource Report 1 at 32; May 2, 2019 Supplemental Filing at 6; Jordan Cove Application at 7.

[378] Jordan Cove Resource Report 1 at 27-28, 32.

[379] Final EIS at 2-8.

[380] Sierra Club Rehearing Request at 50.

[381] McCaffree Rehearing Request at 34.

[382] *See supra* PP 15, 17.

[383] Moreover, Ms. McCaffree's cited submissions during the NEPA process do not describe or clearly show her preferred alternatives.

D. Connected Actions

121. Ms. McCaffree states that the Commission failed to analyze the Port of Coos Bay's proposed Coos Bay Section 408/204(f) Channel Modification as a connected action together with Jordan Cove's proposals in a single EIS.[384] As noted in the Final EIS, the Port of Coos Bay is in the engineering and design phase for several proposed activities that make up the proposed Coos Bay Section 408/204(f) Channel Modification to improve navigation efficiency, reduce shipping transportation costs, and facilitate the shipping industry's transition to larger, more efficient vessels.[385] The Port of Coos Bay would dredge 15.5 million cubic yards of material from several miles of the channel over the course of three years.[386] The Port of Coos Bay's planned Channel Modification must be authorized by the Corps, which is preparing a separate EIS.[387]

122. Pursuant to CEQ regulations, "connected actions" include actions that: (a) automatically trigger other actions, which may require an EIS; (b) cannot or will not proceed without previous or simultaneous actions; or (c) are interdependent parts of a larger action and depend on the larger action for their justification.[388] Connected actions "are closely related and therefore should be discussed in the same impact statement."[389] In evaluating whether multiple actions are, in fact, connected actions, courts have employed a "substantial independent utility" test, which the Commission finds useful for determining whether the three criteria for a connected action are met. The test is articulated variously as "whether one project will serve a significant purpose even if a

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[384] McCaffree Rehearing Request at 29-31.

[385] Final EIS at 4-832, tbl.4.14-2 n.b/.

[386] *Id.* at 4-836.

[387] *Id.*

[388] 40 C.F.R. § 1508.25(a)(1) (2019).

[389] *Id.*

second related project is not built"[390] or whether "each of two projects would have taken place with or without the other."[391]

123. Ms. McCaffree asserts that the Coos Bay Section 408/204(f) Channel Modification is largely dependent upon funding from Jordan Cove and that Jordan Cove may substantially increase its exports because the Channel Modification will enable more vessel traffic.[392] Based on these assertions, Ms. McCaffree concludes that without the Jordan Cove LNG Terminal, the Coos Bay Section 408/204(f) Channel Modification has no independent utility and would not exist, and that without the Channel Modification, the Jordan Cove LNG Terminal might not support a final investment decision and would not likely be built.[393]

124. Ms. McCaffree's allegations of mutual benefit do not prove that the Jordan Cove LNG Terminal and the Coos Bay Section 408/204(f) Channel Modification are connected actions under NEPA. On May 10, 2018, the Coast Guard issued a revised Letter of Recommendation indicating that the Coos Bay Federal Navigation Channel as it is currently maintained would "be considered suitable for accommodating the type and frequency of LNG marine traffic associated with [the Jordan Cove LNG Terminal]."[394] On November 7, 2018, the Coast Guard confirmed that vessel transit simulation studies conducted by Jordan Cove demonstrated that Jordan Cove could use any class of LNG carrier with physical dimensions equal to or smaller than those observed during the simulated transits.[395] The Port of Coos Bay has an independent interest in the benefits

[390] *Coal. on Sensible Transp., Inc. v. Dole*, 826 F.2d 60, 69 (D.C. Cir. 1987). *See also O'Reilly v. U.S. Army Corps of Eng'rs*, 477 F.3d 225, 237 (5th Cir. 2007) (defining independent utility as whether one project "can stand alone without requiring construction of the other [projects] either in terms of the facilities required or of profitability").

[391] *Earth Island Inst. v. U.S. Forest Serv.*, 351 F.3d 1291, 1305 (9th Cir. 2003) (internal citation omitted).

[392] McCaffree Rehearing Request at 30. Ms. McCaffree contends that the entrance to the Charleston Harbor along the vessel route is 0.3 feet too shallow to allow an LNG tanker with a loaded draft of 40 feet to safely transit unless the Channel Project widens and deepens the channel to accommodate a safety-related 10% under-keel clearance. *Id.* at 25-26.

[393] *Id.* at 30-31.

[394] Final EIS at 1-15; 4-749 to 4-750.

[395] *Id.* at 1-15, 4-749 to 4-750.

from the Coos Bay Section 408/204(f) Channel Modification, such as facilitating the shipping industry's transition to larger, more efficient vessels,[396] because the number of calls at the port by deep-draft vessels has declined from more than 300 per year in the late 1980s to about 200 in the late 2000s to just over 40 in 2015.[397] Based on these circumstances, we conclude that the Jordan Cove LNG Terminal and the Coos Bay Section 408/204(f) Channel Modification will each serve a significant purpose even if the other is not built and that each of two projects would have taken place with or without the other. Because these projects have substantial independent utility, they are not connected actions under NEPA.

125. We note that the Final EIS does consider potential impacts from the Coos Bay Section 408/204(f) Channel Modification in the Final EIS' discussion of cumulative impacts.[398] As discussed in the Final EIS, these impacts are temporary, and none amount to significant environmental impacts.[399] Ms. McCaffree takes no issue with this analysis.

E. Environmental Justice

1. Identifying Environmental Justice Populations

126. Executive Order 12898 requires that specified federal agencies make achieving environmental justice part of their missions by identifying and addressing, as appropriate, disproportionately high and adverse human or environmental health effects of their programs, policies, and activities on minorities and low income populations (environmental justice populations).[400] The Commission is not one of the specified

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[396] *Id.* at 4-832, tbl.4.14-2 n.b/.

[397] *Id.* at 4-653.

[398] *Id.* at 4-828, 4-830 tbl.4.14-2, 4-834 to 4-837, 4-840 to 4-841, 4-843, 4-844, 4-847, 4-851.

[399] *Id.*

[400] Exec. Order No. 12898 §§ 1-101, 6-604, 59 Fed. Reg. 7629, at 7629, 7632 (Feb. 11, 1994). Identification of a disproportionately high and adverse impact on a minority or low-income population "does not preclude a proposed agency action from going forward, nor does it necessarily compel a conclusion that a proposed action is environmentally unsatisfactory." Council on Environmental Quality, *Environmental Justice: Guidance Under the National Environmental Policy Act*, at 10 (1997) (CEQ 1997 Environmental Justice Guidance), https://www.epa.gov/environmentaljustice/ceq-environmental-justice-guidance-under-national-environmental-policy-act; Federal Interagency Working Group for Environmental Justice and NEPA Committee, *Promising Practices for EJ Methodologies in NEPA Reviews*, at 38 (2016) (quoting same),

agencies, and the provisions of Executive Order 12898 are not binding on this Commission. Nonetheless, in accordance with our usual practice, the Final EIS addresses environmental justice issues.[401] An agency's choice among reasonable analytical methodologies for an environmental justice analysis is entitled to deference.[402]

127. Consistent with guidance from the Council on Environmental Quality (CEQ) and the EPA, Commission staff analyzed the presence of minority and/or low-income populations; and whether impacts on human health or the environment would be disproportionately high and adverse for minority and low-income populations and appreciably exceed impacts on the general population or other comparison group.[403] NRDC asserts that the Final EIS undertakes a flawed methodology at both steps.[404]

128. To identify potential environmental justice populations that could be affected by geographic proximity to the project, Commission staff selected an area of analysis for the Jordan Cove LNG Terminal extending out a 3-mile radius from the center of the terminal site[405] and an area of analysis for the pipeline consisting of the 19 census tracts that would be crossed by the pipeline route and another census tract within 1 mile of the route.[406] Commission staff used information from EPA's Environmental Justice Mapping and Screening Tool (EJSCREEN) about low income and minority populations to inform its assessment of the potential presence of environmental justice communities in the chosen areas of analysis.[407] The Final EIS acknowledges that larger and more

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https://www.epa.gov/sites/production/files/2016-08/documents/nepa_promising_practices_document_2016.pdf.

[401] *See* Final EIS at 4-622 to 4-629 & 4-646 to 4-650.

[402] *Sierra Club v. FERC*, 867 F.3d at 1368 (quoting *Cmtys. Against Runway Expansion, Inc. v. FAA*, 355 F.3d 678, 689 (D.C. Cir. 2004)).

[403] Final EIS at 4-623 (citing CEQ 1997 Environmental Justice Guidance and EPA, *Final Guidance For Incorporating Environmental Justice Concerns In EPA's NEPA Compliance Analysis*, at §§ 3.2.1-3.2.2. (1998), https://www.epa.gov/sites/production/files/2015-02/documents/ ej_guidance_nepa_epa0498.pdf (EPA 1998 Environmental Justice Guidance)).

[404] NRDC Rehearing Request at 88-92.

[405] Final EIS at 4-623.

[406] *Id.* at 4-646.

[407] *Id.* at 4-623, 4-647 to 4-649.

populated geographic areas can have the effect of masking or diluting the presence of concentrations of environmental justice populations.[408] Commission staff addressed this problem by separately reviewing data for the 10 identified census tracts fully or partially located within 3 miles of the areas that would be disturbed during construction of the LNG terminal.[409] The Final EIS finds that low-income and minority environmental populations are present within 3 miles of the Jordan Cove LNG Terminal and along portions of the Pacific Connector Pipeline route, including the census tract where the Klamath Compressor Station will be located.[410]

129. NRDC claims that the Commission failed to recognize the limits of the EJSCREEN tool.[411] NRDC points to the EPA's disclaimer that the EJSCREEN tool is "a pre-decision screening tool, and was not designed to be the basis for agency decision making or determinations regarding the existence or absence of EJ concerns."[412]

130. As described above, Commission staff appropriately used the EJSCREEN tool as a pre-decision screening tool to assess the potential presence of environmental justice populations within Commission staff's chosen areas of analysis. The Final EIS and the Commission did not use the EJSCREEN tool as the sole basis for agency decision making or determinations regarding the existence or absence of environmental justice concerns. NRDC cites to an earlier comment addressing the EJSCREEN tool,[413] but such incorporation by reference is improper and is dismissed.[414]

131. NRDC criticizes the Final EIS for providing other demographic indicators from EJSCREEN besides minority populations and income—i.e., linguistic isolation, education, and age—as "context" without explaining whether this information plays any role in the analysis.[415]

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[408] *Id.* at 4-623.

[409] *Id.*

[410] *Id.* at 4-626 to 4-627, 4-647 to 4-648.

[411] NRDC Rehearing Request at 99.

[412] *Id.* (quoting EPA, *EJSCREEN: Technical Documentation* 9 (Aug. 2017)).

[413] *Id.* (citing NRDC July 5, 2019 Comments on the Draft EIS, attachment 1 (report of Dr. Ryan Emanuel)).

[414] *See supra* P 15.

[415] NRDC Rehearing Request at 93.

132. We disagree with NRDC's assertion that this information creates confusion and ambiguity.[416] The additional data in EJSCREEN are considered potential indicators of vulnerable populations.[417] The Final EIS appropriately provides this information to give the Commission and the public a more complete understanding of the populations potentially affected by the project, even if the additional demographic indicators do not directly inform the required environmental justice analysis under Executive Order 12898.

133. NRDC contends that the approach in the Final EIS to combine all minority populations together treats people of color as interchangeable, conflates distinct environmental justice concerns, and produces flawed results.[418] NRDC states that the approach fails to account for discrete minority populations that are too small to constitute a minority environmental justice population but are nonetheless large relative to the overall population of that minority group in the statewide reference community in Oregon.[419] NRDC points to the Native American population as an example, and NRDC asserts that the Final EIS' methodology leaves no way to detect other minority groups that would be similarly overlooked by the Final EIS' methodology.[420]

134. We disagree that the approach used in the Final EIS to identify minority environmental justice populations was flawed. NRDC cites no authority for its criticism of the combined treatment of all minority populations. As noted in the Final EIS, the implementing guidance documents for Executive Order 12898 support the chosen approach. These guidance documents define a minority environmental justice population to be a population where the minority population comprises more than 50% of the total population or comprises "a meaningfully greater share" than an appropriate reference community.[421] A minority population exists if there is "more than one minority group

[416] *Id.*

[417] Final EIS at 4-623.

[418] NRDC Rehearing Request at 92.

[419] *Id.*

[420] *Id.*

[421] EIS at 4-622, 4-625; CEQ 1997 Environmental Justice Guidance at 25; EPA 1998 Environmental Justice Guidance at 15; Federal Interagency Working Group for Environmental Justice and NEPA Committee, *Promising Practices for EJ Methodologies in NEPA Reviews* at 21-25 (2016)). Consistent with recent guidance that the "meaningfully greater" analysis "requires use of a reasonable, subjective threshold (e.g., ten or twenty percent greater than the reference community)," Commission staff applied a threshold of 20% in the Final EIS analysis. Final EIS at 4-625 n.205 (quoting

present and the minority group percentage, as calculated by aggregating all minority persons, meets one of the above-stated thresholds."[422] Thus the approach to aggregate minority populations increases the likelihood that an agency will determine a given population to be a minority environmental justice population and will then undertake additional review for disproportionate impacts.[423] Although Native Americans comprise a small share of the local population, the Final EIS treats Tribal populations as an environmental justice population with the potential to be disproportionately affected by the construction and operation of the LNG terminal and pipeline due to scoping comments, Tribal involvement during the review process, and their history and culture.[424] This extension of the environmental justice analysis does not indicate that the general methodology was flawed and instead shows that staff considered factors other than EJSCREEN when determining environmental justice populations. NRDC does not identify any other minority group that may have been improperly overlooked by the Final EIS' methodology, and we are aware of none.

135. NRDC states that although the Final EIS acknowledges that unique issues affect the Native American population, this does not inform the Final EIS' analysis of disproportionate impacts, which extends only to a discussion of low-income environmental justice populations.[425] NRDC states that the Final EIS did not and could not disclose information necessary for a reader to understand and to provide informed comment about the Jordan Cove LNG Terminal's impact on Native Americans and cultural resources because the Commission's consultations with Native American communities and with the Oregon SHPO remain pending.[426]

136. The discussion of Native American populations in the environmental justice section of the Final EIS appropriately acknowledges the potential for these populations to be disproportionately affected but concluded that this potential would be similar to that

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Federal Interagency Working Group for Environmental Justice and NEPA Committee, *Promising Practices for EJ Methodologies in NEPA Reviews* at 25 (2016)).

[422] Final EIS at 4-622 (quoting CEQ 1997 Environmental Justice Guidance at 26).

[423] Although the minority population reported in the FEIS is an aggregate, the EJSCREEN-census reports allowed Commission staff to review individual minority populations and we determined that "sub-groups" were not distinctive requiring further designation, with the exception of Native Americans.

[424] *Id.* at 4-626, 4-649.

[425] NRDC Rehearing Request at 93.

[426] *Id.*

described for low-income populations.[427] For Native American populations, unlike other environmental justice populations, Commission staff appropriately consulted with Native American tribes under section 106 of the National Historic Preservation Act (NHPA).[428] For this reason, the Final EIS in the environmental justice section directs the reader to the other portions of the Final EIS that discuss consultations with Indian tribes, the potential project-related impacts on cultural and other resources that may be important to tribes, and the Commission staff's recommended conditions to mitigate those impacts.[429] NRDC cites no requirement that the Final EIS discuss all of these matters in one location, and there is no such requirement.

2. Identifying Disproportionately High and Adverse Impacts

137. NRDC takes issue with the conclusions in the Final EIS that even the projects' greatest anticipated impacts (to visual resources, noise, and housing supply) would not result in disproportionately high and adverse impacts to environmental justice populations.[430]

138. The Final EIS anticipates that the Jordan Cove LNG Terminal's moderate to high visual impacts will affect residents in census tracts 4 and 5.03.[431] Data for the narrower census block groups[432] within these census tracts revealed that although census tract 4 as a whole had not been identified as a potential low-income population, one of the portions of census tract 4 subject to visual impacts would meet the definition of a low-income population.[433] The visual impacts at the relevant location would be moderate rather than

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[427] Final EIS at 4-629, 4-649.

[428] *See infra* PP 150-162 (discussing cultural resources).

[429] Final EIS at 4-629, 4-649 to 4-650.

[430] NRDC Rehearing Request 90-91 (citing Final EIS at 4-627 to 4-629; 4-469 to 4-650).

[431] Final EIS at 4-628.

[432] Census block groups are statistical divisions of census tracts, generally defined to contain between 600 and 3,000 people. A census block group consists of clusters of census blocks, the smallest geographic area that the Census Bureau uses to tabulate decennial data. Federal Interagency Working Group for Environmental Justice and NEPA Committee, *Promising Practices for EJ Methodologies in NEPA Reviews* at 22 n.10 (2016); *id.* at 23 n.11.

[433] Final EIS at 4-628 n.209.

high.[434] Data for the census block groups revealed the opposite for census tract 5.03: although census tract 5.03 as a whole had been identified as a potential low-income population, the portion of census tract 5.03 subject to visual impacts would not meet the definition of a low income population.[435] The Final EIS concludes that visual impacts on low-income populations in all affected residential areas would not be disproportionately high and adverse when compared to other affected residents.[436]

139. The Final EIS anticipates that the Jordan Cove LNG Terminal's significant construction noise impacts will potentially affect residents in census tracts 4, 5.02, and 5.03.[437] Data for the narrower census block groups within these census tracts reveals that the portions of the census tracts near the shorelines, i.e., the portions subject to the greatest construction noise impacts, do not meet the definition of a low-income population.[438] The Final EIS concludes that noise impacts on low-income populations in affected residential areas would not be disproportionately high and adverse when compared to other affected residents.[439]

140. The Final EIS anticipates that the pipeline's construction and operation impacts, such as emissions from construction equipment, increased dust and noise, and increased local traffic, would not significantly affect the environment, would be temporary and localized, and with mitigation in place are not expected to result in high and adverse human health or environmental effects on any nearby communities.[440] The Final EIS acknowledges the presence of environmental justice populations in the census tracts crossed by the pipeline route and concludes that "the likelihood that these potential environmental justice and vulnerable populations [including tribal populations] will be disproportionately affected relative to other populations in the census tracts crossed by the pipeline is low."[441]

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[434] *Id.* at 4-628.

[435] *Id.* at 4-628 n.209.

[436] *Id.* at 4-628.

[437] *Id.*

[438] *Id.* at 4-628 n.210.

[439] *Id.* at 4-628.

[440] *Id.* at 4-649.

[441] *Id.* at 4-649 and 4-650.

141. NRDC asserts that the Final EIS provides no explanation why it uses the broader scale of a census tract to identify environmental justice populations near the LNG terminal and pipeline but pivots to use the narrower scale of census block groups to analyze the LNG terminal's potential disproportionate impact on the identified populations.[442] NRDC perceives a risk that the Commission's analysis can obscure the project's true effects on marginalized populations.[443] Because the Final EIS does not pivot to use census block groups to analyze the Pacific Connector Pipeline's potential disproportionate impacts to environmental justice communities, NRDC criticizes the different methodology as arbitrary and capricious.[444] NRDC states that census tracts in sparsely populated areas encompass larger land areas which, when incorporated into the environmental justice analysis, may lead to skewed results that mask the demographic and socioeconomic makeup of the populations living in closest proximity to the project, which matters for the potential disproportionate impact.[445] NRDC states that the Final EIS's failure to tailor its methodology to account for this methodological flaw renders the entire environmental justice analysis erroneous.[446]

142. The Final EIS reasonably tailors its methodology at each step of the environmental justice inquiry for each set of project activities and impacts. An agency's choice among reasonable analytical methodologies for an environmental justice analysis is entitled to deference.[447] At step one for both projects, the Final EIS uses the broader census tract, consistent with relevant guidance,[448] to identify potential environmental justice

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[442] NRDC Rehearing Request at 93-94.

[443] *Id.* at 94.

[444] *Id.* at 96-98.

[445] *Id.* at 96-98.

[446] *Id.* at 98.

[447] *Sierra Club v. FERC*, 867 F.3d at 1368 (quoting *Cmtys. Against Runway Expansion, Inc. v. FAA*, 355 F.3d at 689).

[448] *E.g.*, CEQ 1997 Environmental Justice Guidance at 26 ("the appropriate unit of geographic analysis may be a governing body's jurisdiction, a neighborhood, a census tract, or other similar unit that is chosen so as to not artificially dilute or inflate the affected minority population."); EPA 1998 Environmental Justice Guidance at 15 (same); Federal Interagency Working Group for Environmental Justice and NEPA Committee, *Promising Practices for EJ Methodologies in NEPA Reviews* at 27 (2016) ("Select an appropriate geographic unit of analysis (e.g., block group, census tract) for identifying low-income populations in the affected environment.").

populations.[449] At step two for the LNG terminal, the Final EIS rationally narrows the geographic scale using census block groups to more closely match the area of the visual and noise impacts that the Final EIS anticipates to pose high and adverse effects on human health or the environment.[450] Populations beyond this narrower area cannot possibly experience visual and noise impacts, so the composition of the broader populations is not relevant to the Commission's analysis. NRDC offers no support for its speculation that the Commission's closer analysis at step two for the LNG terminal could have obscured the project's true effects on marginalized populations.

143. The different methodology at step two for the pipeline was not arbitrary and capricious. It was not necessary for the Final EIS to narrow the geographic scale below the census tract because the Final EIS anticipates that the pipeline would pose no high and adverse effects on human health or the environment.[451] The Final EIS explains generally that a pipeline's impacts differ from a discrete facility, for which impacts are generally concentrated in one location, because a pipeline sequentially establishes or expands a narrow corridor often over long distances passing near populations with a variety of social and economic characteristics.[452] The Final EIS explains specifically that impacts from the Pacific Connector Pipeline will be localized, temporary, and mitigated.[453] The Final EIS explains that the pipeline route mostly crosses rural regions with low population densities, avoids towns and cities, and mostly follows the ridges through the mountains. NRDC offers no support for its speculation that the approach in the Final EIS masked the demographic and socioeconomic makeup of any population living in closest proximity to the pipeline and thus masked the potential disproportionate impact. And we find no support for this claim.

144. NRDC contends that the conclusions in the Final EIS that the LNG terminal's visual impacts on low-income populations would be "moderate"[454] and that both visual impacts and construction noise impacts "would not be disproportionately high and adverse when compared to other affected residents"[455] are conclusory statements that,

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[449] Final EIS at 4-625 to 4-627; 4-646 to 4-649.

[450] *Id.* at 4-627 to 4-628.

[451] *Id.* at 6-469.

[452] *Id.*

[453] *Id.*

[454] *Id.* at 4-628.

[455] *Id.*

without further analysis, do not satisfy NEPA and the Administrative Procedure Act (APA).[456] In a similar vein, NRDC asserts that the conclusion in the Final EIS that for the pipeline the likelihood of a disproportionate impact is low does not appear to be based on a qualitative or quantitative analysis of the data.[457] NRDC states that the Final EIS fails to recognize that equal exposure across differing populations can lead to disproportionate impacts to the environmental justice populations given pre-existing inequities.[458]

145. We disagree that the conclusions in the Final EIS are unsupported or improperly limited. The Final EIS explicitly acknowledges that step two of the review methodology addresses the questions whether a project's impact on human health or the environment would be disproportionately high and adverse for environmental justice communities and would appreciably exceed impacts on the general population or other comparison group.[459] To the latter question, there is no evidence in the record that the LNG terminal and pipeline would be sited, constructed, or operated in ways that unequally distribute exposure pathways, environmental consequences, and the resulting impacts[460] upon environmental justice populations and appreciably exceed impacts on the general population or a comparison group. We acknowledge that the apparently equal distribution of exposure pathways and environmental consequences, even if the resulting impacts would not be high to the broader affected population, can result in disproportionately high and adverse impacts to environmental justice populations.[461] But there is no basis to conclude, and NRDC offers none, that the identified low-income

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[456] NRDC Rehearing Request at 94.

[457] *Id.* at 98.

[458] *Id.* at 98-99.

[459] Final EIS at 4-623, 4-646.

[460] *See* Federal Interagency Working Group for Environmental Justice and NEPA Committee, *Promising Practices for EJ Methodologies in NEPA Reviews* at 29 (2016) (parsing terminology, an impact is the adverse or beneficial result of exposure pathways or other environmental consequence of the proposed action).

[461] *See, e.g.*, Federal Interagency Working Group for Environmental Justice and NEPA Committee, *Promising Practices for EJ Methodologies in NEPA Reviews* at 39 (2016) (suggesting that agencies recognize that even where a project's impact "appears to be identical to both the affected general population and the affected minority populations and low-income populations," the impact might be amplified by population-specific factors, "e.g., unique exposure pathways, social determinants of health, community cohesion," making the impact disproportionately high and adverse).

environmental justice populations have a special sensitivity to the LNG terminal's significant visual resource impacts and construction noise or have a special sensitivity to the pipeline's localized, temporary, and mitigated impacts, such that a disproportionately high and adverse impact might result. The special sensitivity of the Native American population, as the only identified minority environmental justice population potentially affected by the projects, is addressed in other portions of the Final EIS, as noted in the environmental justice section of the Final EIS.[462] Accordingly, we deny rehearing and find that the Commission engaged in a hard look at environmental justice to satisfy NEPA and explained the reasoning for its conclusions to satisfy the APA.

F. Noise

146. Jordan Cove and Pacific Connector seek clarification about the deadlines to take steps, if necessary, to control operating noise at the pipeline's Klamath Compressor Station.[463] Under Environmental Condition 34 of the Authorization Order, Pacific Connector must file a noise survey shortly after placing the Klamath Compressor Station into service. Pacific Connector may also be required to file a second noise survey for the Klamath Compressor Station shortly after placing all liquefaction trains at the Jordan Cove LNG Terminal into service. The results of either noise survey could trigger further steps to control the operating noise at the compressor station. Environmental Condition 34 states:

> Pacific Connector shall file a noise survey with the Secretary no later than 60 days after placing the Klamath Compressor Station in service. If a full load condition noise survey is not possible, Pacific Connector shall provide an interim survey at the maximum possible horsepower load and provide the full load survey no later than 60 days after all liquefaction trains at the LNG Terminal are fully in service. If the noise attributable to the operation of all of the equipment at the Klamath Compressor Station under interim or full horsepower load conditions exceeds an Ldn of 55 dBA at any nearby NSAs, *Pacific Connector shall file a report on what changes are needed and shall install the additional noise controls to meet the level within 1 year of the in-service date.* Pacific Connector shall confirm compliance with the above requirement by filing a second noise survey with the

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[462] Final EIS at 4-629, 4-649 to 4-650 (providing cross-references to sections 4.9 and 4.11 of the EIS).

[463] Jordan Cove and Pacific Connector Rehearing Request at 28-31; Authorization Order, 170 FERC ¶ 61,202 at P 257; *id.* app., envtl. condition 34.

> Secretary no later than 60 days after it installs the additional noise controls.[464]

147. Jordan Cove and Pacific Connector request that the Commission clarify that the deadline to file a report on what changes are needed and to install additional noise controls "within 1 year of the in-service date" refers to the two separate in-service dates that inform the deadlines for the two noise surveys: (1) the placement of the Klamath Compressor Station in service and (2) the later placement of all liquefaction trains at the Jordan Cove LNG Terminal fully in service.[465]

148. We grant clarification. We agree that the reference to the in-service date is ambiguous, as described above. The Commission intended to require that Pacific Connector complete further steps to control the operating noise at the Klamath Compressor Station, if necessary, within one year of the in-service date that immediately preceded the noise survey showing an exceedance of the Commission's noise threshold. The Commission modifies Environmental Condition 34 to read:

> Pacific Connector shall file a noise survey with the Secretary no later than 60 days after placing the Klamath Compressor Station in service. If a full load condition noise survey is not possible, Pacific Connector shall provide an interim survey at the maximum possible horsepower load and provide the full load survey no later than 60 days after all liquefaction trains at the LNG Terminal are fully in service. If the noise attributable to the operation of all of the equipment at the Klamath Compressor Station under interim or full horsepower load conditions exceeds an Ldn of 55 dBA at any nearby NSAs, Pacific Connector shall file a report on what changes are needed and shall install the additional noise controls to meet the level within 1 year of the in-service date *that immediately preceded the noise survey showing an exceedance.* Pacific Connector shall confirm compliance with the above requirement by filing a second noise survey

[464] Authorization Order, 170 FERC ¶ 61,202, app., envtl. condition 34 (emphasis added).

[465] Jordan Cove and Pacific Connector Rehearing Request at 28. Jordan Cove and Pacific Connector note that the pipeline would go into service 18 months before the LNG terminal and would gradually increase flow as the LNG terminal is commissioned. *Id.* at 29.

with the Secretary no later than 60 days after it installs the additional noise controls.

G. Cultural Resources

149. Petitioners contend that the Commission erred in issuing the Authorization Order while a number of issues pertaining to cultural resources remain unresolved.[466] Specifically, petitioners state that the Commission could not take a "hard look" at the projects' impacts to cultural resources because "cultural resource surveys are not yet complete for the Jordan Cove LNG Terminal or the Pacific Connector Pipeline."[467]

150. We disagree that the Final EIS for the projects is based on inadequate information. Although the Commission must consider and study environmental issues before approving a project, it does not require a definitive resolution of all environmental concerns before approving a project. NEPA does not require completion of every study or aspect of an analysis before an agency can issue a Final EIS and the courts have held that an agency does not need perfect information before it takes any action.[468]

151. The Authorization Order acknowledges that the Commission has not yet completed NHPA consultation;[469] consultation with Indian tribes, the Oregon SHPO, and other applicable agencies is still ongoing.[470] The Final EIS recommends, and Environmental Condition 30 of the Authorization Order states that the applicants may not begin construction of facilities or use of any staging, storage, temporary work areas, and new or to-be-improved access roads until: (1) the applicants file the remaining cultural resource survey reports, site evaluations and monitoring reports (as necessary), a revised ethnographic study, final Historic Properties Management Plans for both projects, a final

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[466] Confederated Tribes Rehearing Request at 18-22; Cow Creek Band Rehearing Request at 11-15; NRDC Rehearing Request at 93; Sierra Club Rehearing Request at 27-29; McCaffree Rehearing Request at 28.

[467] Confederated Tribes Rehearing Request at 18; Cow Creek Band Rehearing Request at 8-11.

[468] *U.S. Dep't of the Interior v. FERC*, 952 F.2d 538, 546 (D.C. Cir. 1992); *State of Ala. v. Andrus*, 580 F.2d 465, 473 (D.C. Cir. 1978), *vacated in part sub. nom.*, *W. Oil & Gas Ass'n v. Ala.*, 439 U.S. 922 (1978) ("NEPA cannot be 'read as a requirement that complete information concerning the environmental impact of a project must be obtained before action may be taken.'") (citation omitted).

[469] Authorization Order, 170 FERC ¶ 61,202 at P 252; Final EIS at 4-684 to 4-686.

[470] Authorization Order, 170 FERC ¶ 61,202 at P 252; Final EIS at 5-9.

Unanticipated Discovery Plan, and comments from the SHPO, interested Indian tribes, and applicable federal land-managing agencies; (2) the Advisory Council on Historic Preservation (Advisory Council) is afforded an opportunity to comment on the undertaking; and (3) Commission staff reviews and approves all cultural resources reports, studies, and plans, and notifies the applicants in writing that treatment plans may be implemented and/or construction may proceed.[471]

152. The Authorization Order further acknowledges that cultural resource surveys are not yet complete for the Jordan Cove LNG Terminal or the Pacific Connector Pipeline.[472] However, surveys that the applicants have completed identified cultural sites that the applicants must monitor during construction or otherwise mitigate prior to construction.[473] In addition, if the applicants cannot avoid identified cultural sites, the applicants must conduct further studies and testing.[474]

153. The Authorization Order explains that the Final EIS concludes that construction and operation of the projects would have adverse effects on historic properties, but that an agreement document, discussed further below, would be developed with the goal of resolving those impacts.[475]

1. <u>Issuance of Certificate Order Prior to Completing Section 106 Consultation</u>

154. Petitioners contend that issuing the Authorization Order prior to completing a finalized Memorandum of Agreement (MOA) pursuant to the NHPA, an Unanticipated Discovery Plan, and all cultural surveys is inconsistent with the requirements of the NHPA and NEPA.[476] Confederated Tribes and Cow Creek Band also express concern about issuing the Authorization Order prior to completing consultation, stating that that approach does not meet the requirement to take a hard look at cultural resources;

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[471] Authorization Order, 170 FERC ¶ 61,202 at app., envtl. condition 30.

[472] Authorization Order, 170 FERC ¶ 61,202 at P 251; Final EIS at 4-678 to 4-683 and 5-9.

[473] Authorization Order, 170 FERC ¶ 61,202 at P 251, app., envtl. condition 30; Final EIS at 5-9.

[474] Authorization Order, 170 FERC ¶ 61,202 at P 251; Final EIS at 5-9.

[475] Authorization Order, 170 FERC ¶ 61,202 at P 253; Final EIS at 5-9.

[476] Sierra Club Rehearing Request at 27-28; Confederated Tribes Rehearing Request at 18-22; Cow Creek Band Rehearing Request at 15-19.

challenge the adequacy of the consultation completed; and contend that instead of entering an MOA, the Commission should have pursued a Programmatic Agreement.[477] Ms. McCaffree argues that the Authorization Order should not have been issued prior to completing the Historic Properties Management Plan, and in particular, that the order should have considered impacts to the McCullough Bridge.[478] Confederated Tribes contend that the updates to the ethnographic survey should have been completed prior to the issuance of the Authorization Order and that the cultural resources surveys should have been completed earlier in the review process.[479] Similarly, NRDC contends that because the Commission has not completed consultation under NHPA, the Authorization Order's consideration of environmental justice concerns is insufficient.[480]

155. The Commission has previously affirmed that a conditional certificate could be issued prior to completion of cultural resource surveys and consultation procedures required under NHPA because construction activities would not commence until surveys and consultation are complete,[481] consistent with the D.C. Circuit's decision in *City of Grapevine, Tex. v. Dep't of Transp.*, holding that the FAA properly conditioned approval of a runway project upon the applicant's subsequent compliance with the NHPA.[482] The prohibition on construction in the Authorization Order's Environmental Condition 30 ensures that there can be no effect on historic properties until there has been full compliance with the NHPA.[483]

156. With respect to the potential impacts to McCullough Bridge, we note that table L-14 of the Final EIS states that the bridge was listed on the National Register of Historic Places in 2005 and is located within or adjacent to the Pacific Connector Area of

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[477] Confederated Tribes Rehearing Request at 15, 22, 25, 27, 29; Cow Creek Rehearing Request at 4-7, 15-24.

[478] McCaffree Rehearing Request at 28.

[479] Confederated Tribes Rehearing Request at 15, 18.

[480] NRDC Rehearing Request at 93.

[481] *See generally Iroquois Gas Transmission System, L.P.*, 53 FERC ¶ 61,194, at 61,758-64 (1990).

[482] 17 F.3d at 1509 (upholding the agency's conditional approval because it was expressly conditioned on the completion of section 106 process).

[483] *See City of Grapevine*, 17 F.3d at 1509 (upholding Federal Aviation Administration's approval of a runway conditioned upon the applicant's completion of compliance with the NHPA).

Potential Effect (APE) but concludes that Pacific Connector will avoid the site by horizontal directional drilling. Accordingly, we find that further consultation with respect to the McCullough Bridge will not be required.

157. The Commission's approach appropriately respects the integration of the various requirements for natural gas infrastructure, including the NGA, the NHPA, and NEPA. We believe this approach is consistent with the court's conclusion in *Mid States Coalition for Progress v. Surface Transportation Board* that while "an agency may not require consultation in lieu of taking its own 'hard look' at the environmental impact of a project, we do not believe that NEPA is violated when an agency, after preparing an otherwise valid Final EIS, imposes consultation requirements in conjunction with other mitigating conditions."[484]

158. Finally, the Commission will complete consultation and enter into an agreement with Oregon SHPO, the Advisory Council, the applicants, federal land-managing agencies, and consulting Indian tribes to resolve any adverse impacts to historic properties prior to authorizing construction.[485] We disagree that we must complete consultation under the NHPA prior to analyzing the environmental justice impacts of a proposed project; and, petitioners cite no requirement under the NHPA that mandates this result.

2. <u>Traditional Cultural Property Historic District</u>

159. Jordan Cove and Pacific Connector assert that the Authorization Order erred in failing to undertake an independent review of the Oregon SHPO's finding of eligibility with respect to the proposed Traditional Cultural Property (TCP) historic district nominated by Confederated Tribes for listing in the National Register of Historic Places.[486] According to the petitioners, the Commission's acceptance of the Oregon SHPO's findings without an independent assessment amounts to a failure of reasoned decision-making. Petitioners also raise concerns about the Oregon SHPO's process for determining eligibility and identified some specific substantive issues with the TCP

[484] 345 F.3d 520, 554 (8th Cir. 2003).

[485] *See* Authorization Order, 170 FERC ¶ 61,202 at P 259 (citing Final EIS at 5-9). Commission staff's draft agreement document was characterized as a draft MOA. In accordance with the Advisory Council's January 15, 2020 Comments on the draft MOA, the final agreement document will be characterized as a Programmatic Agreement. *See* Advisory Council's January 15, 2020 Comment on the MOA at 25-26.

[486] Jordan Cove and Pacific Connector Rehearing Request at 5-17.

nomination. Relatedly, Confederated Tribes asks for clarification on the grounds for the TCP eligibility determination.[487]

160. For the purposes of conducting environmental review for the certificate proceeding, staff determined that the TCP nomination met the eligibility criteria spelled out in 36 C.F.R. § 60.4 (2019). The Authorization Order explained that when the Commission determines if a property is eligible for listing on the National Register for Historic Properties, it does so in consultation with the SHPO, and that generally, the Commission agrees with the opinions of the SHPO on findings of eligibility.[488] In this case, that consultation has yet to conclude. The Authorization Order noted that the National Park Service rejected the SHPO's nomination of the TCP as property eligible for listing.[489] However, the National Park Service stated that its rejection was based on procedural grounds and substantive deficiencies that the SHPO could cure if it resubmits the eligibility determination for the TCP.[490]

161. The Authorization Order specified that in making an eligibility determination, the Oregon SHPO considered arguments against the nomination raised by Jordan Cove and others.[491] Further, Commission staff acknowledged the objections to the nomination in the draft agreement document sent to the consulting parties for review on December 13, 2019.[492] Notwithstanding the fact that, as noted above, consultation with all parties on this issue is ongoing, we affirm our decision to agree with the eligibility determination made by the SHPO.

H. Vessel Traffic

162. Ms. McCaffree asserts that the Commission failed to sufficiently consider the suitability of the Coos Bay Channel for vessel traffic to and from the Jordan Cove LNG Terminal, and failed to appropriately condition the order so as to require Jordan Cove's compliance with Coast Guard's requirements, as laid out in Coast Guard's May 10, 2018

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[487] Confederate Tribes Rehearing Request at 38-45.

[488] Authorization Order, 170 FERC ¶ 61,202 at P 283.

[489] *Id.* P 282.

[490] Oregon Parks and Recreation Department, State Historic Preservation Office July 26, 2019 Letter at 3-9 (containing National Park Service July 2, 2019 eligibility determination letter).

[491] *Id.* P 282.

[492] *Id.*

Letter of Recommendation.[493] Ms. McCaffree argues that, without ensuring Jordan Cove complies with Coast Guard's Letter of Recommendation, the Coos Bay Channel is not a suitable waterway for the vessel traffic that would result from construction and operation of the Jordan Cove LNG Terminal.[494] Ms. McCaffree further states that because the Coos Bay Channel is narrow, operation of the Jordan Cove LNG Terminal, including vessel traffic, poses significant safety risks.[495]

163. As Commission staff stated in the Final EIS, "[t]he Coast Guard exercises regulatory authority over LNG marine vessels[.]"[496] Accordingly, the Commission has no authority to approve, disapprove, or otherwise condition the Coast Guard's finding of whether or not a waterway is suitable to handle the vessel traffic attributable to an LNG terminal. As the Commission noted in the Authorization Order, on May 10, 2018, the Coast Guard "issued a Letter of Recommendation, indicating the Coos Bay Channel would be suitable for accommodating the type and frequency of LNG marine traffic associated with the Jordan Cove LNG Terminal."[497] Similarly, the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) has authority to determine whether or not the siting of LNG facilities complies with federal safety standards.[498] While the Commission incorporates these determinations into assessing the safety risks associated with a proposed LNG terminal, it does not have the authority to make these determinations itself. If Ms. McCaffree has concerns regarding the Coast Guard's Letter of Recommendation or Waterway Suitability Assessment for the Coos Bay Channel, she may file those concerns with the Coast Guard. Further, Environmental Condition 35 and 125 of the Authorization Order requires Jordan Cove and Pacific Connector to provide documentation that they have complied with DOT regulations and that the U.S. Coast Guard determines appropriate measures have been put into place by Jordan Cove or other appropriate parties prior to initial site preparation and commencement of construction, respectively.[499]

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[493] McCaffree Rehearing Request at 25-28.

[494] *Id.*

[495] *Id.* at 27-28.

[496] Final EIS at 7-744.

[497] Authorization Order, 170 FERC ¶ 61,202 at P 264.

[498] *Id.* P 265.

[499] *Id.* at app., envtl. conditions 35 and 125.

I. State and Local Economic Impacts

164. Ms. McCaffree and the State of Oregon contend that the Commission failed to adequately consider negative state and local economic impacts to housing availability and cost, the tourism and recreation industry, the Dunes National Recreation area and Scenic Adventure Coast, commercial fishing, the commercial crab fishery, and recreational fishing.[500]

165. We believe we did consider these impacts in the Authorization Order. In considering socioeconomic impacts of the project, the Authorization Order acknowledged that construction of the Jordan Cove LNG Terminal and Pacific Connector Pipeline would impact socioeconomic resources including tourism, recreation, and fishing, and would cause significant impacts (additional usage) on short-term housing in Coos County.[501] The limited short-term housing availability that would occur as a result of construction of the projects could also affect tourism, as visitors would have to compete with construction workers for housing.[502] The projects could also affect supplemental subsistence activities, commercial fishing, and commercial oyster farms, but these impacts would not be significant.[503] The likelihood of the pipeline resulting in a long-term decline in property values is low.[504] The Authorization Order also found that the projects will provide direct employment opportunities for local workers, support other local and state services and industries, and generate local, state, and federal tax revenues.[505]

166. With respect to concerns raised about commercial and recreational fishing and crab fisheries, the Final EIS finds that increased sedimentation from dredging is not expected to result in long-term or population-wide effects on crabs.[506] The Authorization

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[500] McCaffree Rehearing Request at 14; State of Oregon Rehearing Request at 32-33.

[501] Authorization Order, 170 FERC ¶ 61,202 at P 239; Final EIS at 4-652.

[502] Final EIS at 4-619, 4-644, and 4-652.

[503] *Id.* at 4-619 to 4-621, 4-644 to 4-645, 5-8.

[504] *See* Final EIS at 4-635. The Final EIS acknowledges that it is not possible to ascertain from the limited information available whether property values near the Jordan Cove LNG Terminal would be affected. *Id.* at 4-614.

[505] *Id.* at 4-614 to 4-616 and 4-635 to 4-639.

[506] Final EIS at 4-621.

Order also explains that the Final EIS finds that the spatial restrictions will not significantly affect recreational and commercial fisheries as the restrictions would be in place for approximately 20 to 30 minutes, similar to the timeframe for other deep-draft vessels using the channel.[507] Finally, the Authorization Order also notes that the Final EIS considers project impacts on recreation and tourism and found the impacts would be short-term and temporary.[508] We find that state and local economic impacts have been adequately addressed in the Authorization Order and Final EIS and deny rehearing on this issue.

J. Vegetation

167. The State of Oregon contends that the Final EIS does not sufficiently analyze the Pacific Connector Pipeline's impacts to oak woodland, juniper woodland, and shrub steppe, or provide sufficient mitigation measures for these impacts.[509]

168. We disagree. The Final EIS provides a detailed accounting of the impacts to forested, woodland, and shrubland vegetation, including both juniper and oak woodlands, as well as shrubland, from construction and operation of the Pacific Connector Pipeline.[510] As detailed in the Final EIS, construction of the Pacific Connector Pipeline would result in impacts to approximately: 108 acres of western juniper (and Ponderosa pine) woodland, 126 acres of white oak forest and woodland, and 305 acres of shrubland.[511] These impacts account for only approximately 2.6%, 3.0%, and 7.3% of the Pacific Connector Pipeline's total vegetation impacts, respectively.[512] Operation of the Pacific Connector Pipeline would impact approximately 30 acres of western juniper and Ponderosa pine forest and woodland, 27 acres of white oak and Ponderosa pine woodland, and 87 acres of shrubland.[513] Impacts on vegetation include temporary and permanent loss, potential revegetation challenges, a potential increase in noxious weeds and invasive species, forest

[507] Authorization Order, 170 FERC ¶ 61,202 at n.503; Final EIS at 4-620.

[508] Authorization Order, 170 FERC ¶ 61,202 at PP 234-236.

[509] State of Oregon Rehearing Request at 51, 75.

[510] Final EIS at 4-167 to 4-170, tbl.4.4.2.4-1, 4.4.2.4-2.

[511] *Id.* at 4-167 to 4-168, tbl.4.4.2.4-1 (pp.). For context, the Jordan Cove and Pacific Connector projects are anticipated to impact over 4,600 acres of vegetation. *Id.* at 5-4.

[512] *Id.*

[513] *Id.* at 4-168 to 4-170, tbl.4.4.2.4-1.

fragmentation, and edge effects.[514] The Final EIS does not identify oak or juniper woodland, and identified only minimal (less than one acre) amounts of shrubland in the Jordan Cove LNG Terminal area.[515] The Final EIS further discusses Pacific Connector's mitigation measures to reduce impacts to vegetation and restore disturbed areas, including (but not limited to) measures to decrease forest fragmentation, and Pacific Connector's *Erosion Control and Revegetation Plan*, *Leave Tree Protection Plan*, *Integrated Pest Management Plan*, *Fire Prevention and Suppression Plan*, and the *Soil Prevention Containment and Countermeasures Plan*.[516] In addition, the Final EIS notes that while these measures would be applied along the entire route of the Pacific Connector Pipeline, the Forest Service and the BLM would require additional measures to further reduce impacts to vegetation on federal lands.[517] Accordingly, the Final EIS[518] and the Authorization Order[519] appropriately concluded that the impacts to vegetation would not be significant. We affirm this finding.

K. Wildlife

169. NRDC asserts that the Final EIS' analysis of the projects' impacts on wildlife failed to satisfy NEPA.[520] Specifically, NRDC contends that that the Final EIS does not appropriately consider impacts to bald eagles, migratory birds, and whales.[521]

170. NRDC states that the Final EIS' analysis of impacts to bald eagles was insufficient, and that the Authorization Order should have included a condition specifically requiring Jordan Cove and Pacific Connector file evidence of having obtained a permit pursuant to the Bald and Golden Eagle Protection Act (Eagle Act).[522] NRDC requests that the Commission clarify that Jordan Cove and Pacific Connector may

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[514] *Id.* at 4-165 to 4-166.

[515] *Id.* at 4-153, 4-156.

[516] *Id.* at 4-171 to 4-173.

[517] *Id.* at 4-173.

[518] *Id.* at 5-4.

[519] Authorization Order, 170 FERC ¶ 61,202 at P 211.

[520] NRDC Rehearing Request at 75-87.

[521] *Id.* at 75.

[522] *Id.* at 76 (citing 16 U.S.C. § 668c (2018)).

not commence construction until they obtain an Eagle Act permit from FWS, or presents evidence that FWS found such a permit was not needed.[523]

171. Contrary to NRDC's claims, the Final EIS provides a sufficient accounting of bald eagles in the vicinity of the projects, as well as an analysis of potential impacts to bald eagles from construction and operation of the projects.[524] The Final EIS states that the draft *Migratory Bird Conservation Plan* incorporates FWS' recommended spatial buffers for bald eagle nests in the vicinity of the Pacific Connector Pipeline to reduce these potential impacts.[525] In addition, as stated in the Final EIS, the Commission has entered into an MOU with FWS to promote best practices to avoid and reduce impacts on birds, including the bald eagle, and Jordan Cove and Pacific Connector continue to work with FWS under the Eagle Act.[526] As discussed above, the fact that Jordan Cove and Pacific Connector are still working with FWS in compliance with the Eagle Act does not render staff's issuance of the Final EIS, or of the Commission's Authorization Order unlawful or inappropriate.[527] Further, we find clarifying the Authorization Order in the manner requested by NRDC to be unnecessary. As NRDC notes, Environmental Condition 11 of the Authorization Order requires Jordan Cove and Pacific Connector to present documentation that they have obtained all necessary federal approvals, or evidence of waiver thereof, prior to commencing construction.[528] This includes the Eagle Act.

172. NRDC asserts that the Commission's determination that the project would not significantly affect migratory birds is "premature and irrational" because Jordan Cove's and Pacific Connector's draft *Migratory Bird Conservation Plan* is not finalized, and consultation with FWS to finalize the plan is ongoing.[529] NRDC further claims that the assessment of impacts to migratory birds must be revised in light of the Department of

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[523] *Id.* at 76-77.

[524] Final EIS at 4-188, 4-203 to 4-208.

[525] *Id.* at tbl.4.5.1.2-8 (4-226).

[526] *Id.* at 4-198, 4-227; 1-23.

[527] *See supra* P 75.

[528] NRDC Rehearing Request at 77 (citing Authorization Order, 170 FERC ¶ 61,202 at app., envtl. cond. 11).

[529] *Id.* at 78.

the Interior's changing perspective of the reach of the Migratory Bird Treaty Act (MBTA).[530]

173. As stated above, reliance on a draft mitigation plan is appropriate.[531] As noted in the Final EIS, FWS has authority under the MBTA to protect migratory birds;[532] and, similar to a Biological Opinion, the Commission may rely on FWS' determination of compliance with the MBTA, as well as its interpretation of the MBTA.[533] The Final EIS lists the various types of migratory birds in the vicinity of the projects[534] and assesses the potential impacts of the projects on these species.[535] Commission staff determined that although migratory birds would be affected by construction and operation of the projects (primarily from habitat modification), Jordan Cove's and Pacific Connector's proposed mitigation measures such as clearing vegetation outside the fledging period, surveying and removal of raptor nests, and additional avoidance, minimization, and mitigation measures in the final *Migratory Bird Conservation Plan*, would adequately reduce impacts and that construction and operation of the projects would not significantly impact migratory birds.[536] We affirm this finding.

174. NRDC disputes the findings in the Final EIS regarding the impacts of construction and operation of the Jordan Cove LNG Terminal on Southern Resident orcas and gray whales.[537] NRDC asserts that the Final EIS incorrectly assessed the impacts to Southern Resident orcas from ship strikes and impacts to the orcas' prey population and foraging habitat, and states that the Final EIS underestimated the gray whale population in the vicinity of Coos Bay.[538]

175. The Final EIS finds that, based on available resources, Southern Resident orcas make rare use of the Coos Bay area, and that gray whales are found in the area "only on

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[530] *Id.* at 78-80.

[531] *See supra* P 167.

[532] *See* NRDC's Rehearing Request at 78-80; Final EIS at 1-13.

[533] *See infra* PP 223.

[534] *Id.* at 4-187 to 4-190.

[535] *Id.* at 4-196 to 4-198, 4-224 to 4-227.

[536] *Id.*

[537] NRDC Rehearing Request at 80-85.

[538] *Id.*

an occasional basis."[539] Accordingly, Commission staff determined that the risk of ship strikes on either of these species is "very low."[540] Commission staff determined that construction and operation of the Jordan Cove LNG Terminal was not likely to adversely affect either the Southern Resident orca or the gray whale, due to the low numbers of whales in the area, the lack of impacts to prey species from construction and operation of the project, the measures included in the *Marine Mammal Monitoring Plan*, (including a commitment to stop pile driving activities when whales are found in Coos Bay), and a determination that the project would not adversely modify proposed critical habitat for the Southern Resident orca, or have any impact on designated critical habitat units.[541] Despite NRDC's assertions, we find that the Final EIS appropriately considers the project's impacts on marine mammals, including the Southern Resident orca and the gray whale. These determinations were affirmed in the National Marine Fisheries Service's Biological Opinion.[542]

176. The State of Oregon contends that impacts to forest habitat were not adequately considered.[543] In support, the State of Oregon notes that the Biological Assessment does not include the Blue Ridge Variation, and that otherwise the Final EIS does not adequately consider impacts to critical habitat for the marbled murrelet and northern spotted owl, asserting that commitments to restrict tree clearing during these species' breeding periods does not mitigate for the impacts to their habitat.[544] The State of Oregon also asserts that the Final EIS does not adequately consider or analyze offsite mitigation for these species.[545]

177. The State of Oregon is incorrect in stating that the Biological Assessment does not consider the Blue Ridge Variation.[546] Appendix R (Alternatives) of the Biological Assessment examined the difference in impacts to listed species from a number of alternatives, including the Blue Ridge Alternative, and ultimately determined that

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[539] Final EIS at 4-330.

[540] *Id.*

[541] Final EIS at 4-332 to 4-334.

[542] *See* NMFS January 10, 2020 Biological Opinion at 3.

[543] State of Oregon Rehearing Request at 73-74.

[544] *Id.*

[545] *Id.* at 74.

[546] State of Oregon Rehearing Request at 50.

incorporating the Blue Ridge Alternative would not result in a change to any of Commission staff's findings.[547] Further, despite the State of Oregon's assertion, Commission staff appropriately considered impacts to the habitat of both the marbled murrelet and the northern spotted owl, as well as all mitigation measures. The Final EIS considered the impacts to habitat for the marbled murrelet and northern spotted owl and discloses the impacts to their habitat, as well as known occupied or presumed occupied sites, for both species.[548] The Final EIS further discusses Pacific Connector's proposed mitigation measures in addition to avoiding tree clearing during each species' breeding season, including replanting trees, funding off-site mitigation, funding a program to reduce corvid predation of marbled murrelet nests, and sponsoring programs on BLM land (such as fire suppression and road decommissioning) intended to benefit the northern spotted owl.[549]

178. Even with these mitigation measures, however, Commission staff ultimately determined that the Pacific Connector Pipeline is likely to adversely affect critical habitat for the marbled murrelet and the northern spotted owl,[550] a determination echoed in FWS' January 31, 2020 Biological Opinion.[551] However, FWS also determined that the Pacific Connector Pipeline is not likely to result in the destruction or adverse modification of critical habitat for the marbled murrelet and the northern spotted owl. In addition, Environmental Condition 24 of the Authorization Order requires Pacific Connector to file, prior to construction, its commitment to adhere with FWS' recommended timing restrictions within threshold distances of marbled murrelet and northern spotted owl stands during construction, operation, and maintenance of the Pacific Connector Pipeline, and Environmental Condition 25 requires Pacific Connector to conduct surveys of all suitable marbled murrelet and northern spotted owl habitat, and file the results of these surveys with the Commission, prior to construction.[552] Therefore, we find that impacts on critical habitat for the marbled murrelet and northern spotted owl have been sufficiently assessed.

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[547] *See* Commission Staff's July 29, 2019 Biological Assessment, Appendix R – Alternatives.

[548] Final EIS at 4-338 to 4-346.

[549] *Id.*

[550] Final EIS at 4-341, 4-345.

[551] *See* FWS' January 31, 2020 Biological Opinion at 104, 166.

[552] Authorization Order, 170 FERC ¶ 61,202 at app., envtl. conds. 24, 25.

179. The State of Oregon also takes issue with Pacific Connector's *Drilling Fluid Contingency Plan for Horizontal Directional Drilling Operations*, asserting that it does not provide sufficient site-specific measures to mitigate for releases of drilling fluids on waterbodies, which the State of Oregon asserts could have adverse impacts on salmonid and other aquatic species.[553] The State of Oregon further contends that the Authorization Order's reliance on the *Drilling Fluid Contingency Plan for Horizontal Directional Drilling Operations* in determining that impacts to surface water resources would not be significant is arbitrary and capricious.[554] The *Drilling Fluid Contingency Plan for Horizontal Directional Drilling Operations* requires mitigation measures proposed by Pacific Connector, but as we discuss in greater detail below, the Final EIS and Authorization Order sufficiently address the potential adverse impacts of HDD,[555] as well as potential impacts to aquatic resources,[556] and determined there would be no significant impacts.

L. Landowner Impacts

180. Sierra Club claims that the Commission failed to properly assess the numerous impacts that construction and operation of the projects would have on "landowners' land use and way of life."[557]

181. First, Sierra Club contends that the Final EIS' analysis of impacts to landowners cannot have been adequate, as it used incorrect data to estimate the number of landowners Pacific Connector Pipeline contacted to negotiated easements.[558] Sierra Club states that the easement numbers relied on in the Authorization Order are based on Pacific Connector's proposed route, and do not reflect the additional landowners Pacific Connector will need to obtain easements from as a result of the Authorization Order approving the modified project route, which incorporates the Blue Ridge Variation.[559]

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[553] State of Oregon Rehearing Request at 50-55.

[554] *Id.* at 53.

[555] *See infra* P 183.

[556] Final EIS at 4-235 to 4-317.

[557] Sierra Club Rehearing Request at 70.

[558] *Id.* at 70-71.

[559] *Id.*

182. As an initial matter, we note that Commission staff's assessment of impacts to landowners is entirely independent of the status of easement negotiations. Sierra Club is correct that incorporating the Blue Ridge Variation into the approved route for the Pacific Connector Pipeline impacts the overall project length, and the number of impacted landowners.[560] Sierra Club fails, however, to demonstrate that the increased project length and number of impacted landowners renders the Final EIS' assessment to landowners inadequate in any way. Pacific Connector is required to obtain access to property necessary for construction and operation of the pipeline, including all impacted landowners along the Blue Ridge Variation, prior to construction. Further, newly affected parcels are subject to Pacific Connector's and the Commission's Plan and Procedures designed to avoid, reduce, and mitigate landowner impacts. We note that Sierra Club does not point to any different types of land uses located along the Blue Ridge Variation, as compared to the proposed route.[561] Thus, Sierra Club fails to demonstrate how the incorporation of the Blue Ridge Alternative into the project route makes the assessment of landowner impacts inadequate.

183. Sierra Club states that the Final EIS and Authorization Order did not sufficiently account for private wells along the route of the Pacific Connector Pipeline.[562] Sierra Club refers to the Final EIS' accounting of seven privately-owned wells within 200 feet of construction of the pipeline "absurd", because it relied on a State of Oregon provided database to research well locations in the state.[563] The Final EIS notes that "[the Oregon Water Resources Department] … maintains a database of water well locations" and that Pacific Connector Pipeline used the "database for their applications to the FERC."[564] The Final EIS further states that there are private wells along the pipeline route "that are exempt from water rights permitting" and that their locations are not currently known.[565] Accordingly the seven private wells identified using the State of Oregon Water Resources Department's database were the wells Pacific Connector was able to identify that were within 200 feet of the pipeline construction right-of-way, and were available using the

[560] *See* Authorization Order, 170 FERC ¶ 61,202 at P 270; Final EIS at 3-24.

[561] The Final EIS identifies the differences in land ownership and number of land parcels in a comparison between the proposed route and the Blue Ridge Variation and identified one residence within 50 feet of the construction right-of-way along the Blue Ridge Variation. *See* Final EIS at 3-28, tbl. 3.4.2.2-1.

[562] Sierra Club Rehearing Request at 71-74.

[563] *Id.* at 72.

[564] Final EIS at 1-36.

[565] *Id.* at 4-81.

database.[566] Sierra Club did not present evidence of any other wells within 200 feet of construction of the pipeline that the Final EIS should, but does not, include in its analysis. The Final EIS acknowledges that Pacific Connector will likely encounter additional wells; therefore, Pacific Connector will request impacted landowners to identify private wells and their uses.[567] The Final EIS further states that Pacific Connector would develop site-specific mitigation measures to prevent impacts to private wells located within 200 feet of construction of the project, which would take into account the use(s) of the well (i.e. irrigation, home use, etc.).[568] Thus, we find that the Final EIS appropriately considers impacts to landowners' wells.

184. Sierra Club further states that Pacific Connector's *Groundwater Supply Monitoring and Mitigation Plan* (Groundwater Supply Plan) is flawed, and that the Final EIS and Authorization Order fail to address these (purported) deficiencies.[569] Specifically, Sierra Club asserts that 1) the Groundwater Supply Plan and the Commission fail to identify wells located on property needed for construction and operation of the Pacific Connector Pipeline; 2) the Groundwater Supply Plan's pre-construction well monitoring requirements are unclear; 3) landowners should not be required to establish that their well has been damaged, rather, Jordan Cove should show they were not responsible; 4) in addition to wells, seeps and springs should be monitored; 5) the well monitoring schedule is inadequate; 6) the Groundwater Supply Plan does not state where the Spill Prevention, Containment, and Countermeasures Plan can be located; and 7) Pacific Connector's commitment to work with landowners in the event groundwater supply is impacted is not explained sufficiently.[570]

185. The Final EIS analyzes the potential impacts to groundwater, including wells, that would occur from construction and operation of the project.[571] As discussed above, all wells that could be identified using the State of Oregon's database were included in the Final EIS, however additional wells may still be encountered, and therefore Pacific Connector will request impacted landowners to identify all wells, and their uses.[572]

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[566] *Id.*

[567] *Id.*

[568] *Id.*

[569] Sierra Club Rehearing Request at 74-77.

[570] *Id.*

[571] Final EIS at 4-35 to 4-36; 4-79 to 4-85.

[572] *See supra* P 183.

Pacific Connector will conduct pre-construction monitoring to identify, and further monitor all groundwater sources, including springs, seeps, and wells.[573] Impacted landowners will also be able to negotiate with Pacific Connector during the easement process to adjust the alignment of the pipeline to increase the distance between the pipeline and groundwater sources, and, if requested, Pacific Connector will conduct post-construction groundwater sampling to determine if groundwater sources were impacted.[574] In the event a groundwater supply is impacted, Pacific Connector would work with the landowner to develop mitigation measures that would satisfy the needs of the individual landowner.[575] As noted in the Final EIS, Pacific Connector's *Spill Prevention, Containment, and Countermeasures Plan* was included in appendices F.2 and G.2 of Resource Report 2 of Pacific Connector's application.[576] The Final EIS determines that impacts to groundwater, including wells, would be temporary, and not significant,[577] and we concur with Commission staff's determination.

186. Sierra Club contends that the Final EIS and Authorization Order fail to address the adverse effects of horizontal directional drilling (HDD), including the risk of sediment and other drilling material being released into aquatic resources (known as a "frac-out") and the impacts such events could have on landowners.[578] Sierra Club is mistaken; the Final EIS notes that Pacific Connector developed a *Drilling Fluid Contingency Plan for Horizontal Directional Drilling Operations* which would be utilized in the event of a frac-out.[579] This contingency plan utilizes measures including the halting of HDD drilling operations, developing site-specific mitigation plans, and if possible, removing the drilling mud from the environment, among other measures.[580] Further, as discussed in the Authorization Order, because Pacific Connector has not yet identified all fluids and additives that would be used during HDD activities, Environmental Condition 18 requires Pacific Connector to file a list of all proposed drilling additives for Commission approval

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[573] Final EIS at 4-83.

[574] *Id.*

[575] *Id.* 4-83.

[576] *Id.*at 2-51.

[577] *Id.* at 4-85.

[578] Sierra Club Rehearing Request at 77.

[579] Final EIS at 4-277.

[580] *Id.*

prior to construction.[581] Therefore, we find the Final EIS and Authorization Order appropriately consider the potential adverse effects of HDD.

187. Sierra Club alleges that the Authorization Order and Final EIS fail to evaluate the negative impact construction and operation will have on property values, as well as other impacts to factors incident to property ownership, including homeowners insurance.[582] Sierra Club asserts that the six studies that Commission staff relied on in determining that there was a low likelihood of a decrease in property values attributable to the Pacific Connector Pipeline are somehow faulty.[583] The Final EIS acknowledges that "the effect a pipeline may have on a property's value depends on many factors, including the size of the tract, the values of adjacent properties, the presence of other utilities, the current value of the land, and the current land use" and further stated that decisions of whether or not to purchase property are generally based on the proposed use of the property rather than subjective valuation due to the presence of a pipeline.[584] Thus, the Final EIS appropriately concludes, based on the studies consulted, that the pipeline is not likely to negatively impact property values.[585] While Sierra Club disagrees with this finding, this disagreement does not show that the Commission's decision-making process was uninformed, or lacking under NEPA. "If supported by substantial evidence, the Commission's findings of fact are conclusive."[586] Further, the Final EIS states that there is no verifiable information, or documented cases indicating the presence of a pipeline complicates a property owner's efforts to obtain homeowners insurance and a mortgage, and Sierra Club fails to present any additional information that would suggest this has, or does, occur.[587]

188. Sierra Club asserts that the Final EIS and Authorization Order fail to assess impacts to visual resources, and how these impacts affect property values.[588] Sierra Club

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[581] Authorization Order, 170 FERC ¶ 61,202 at P 207, app. envtl. cond. 18.

[582] Sierra Club Rehearing Request at 77-79.

[583] *Id.*

[584] Final EIS at 4-635.

[585] *Id.*

[586] *Myersville*, 783 F.3d at 1308 (quoting *B & J Oil & Gas v. FERC*, 353 F.3d 71, 76 (D.C. Cir. 2004) (citing 15 U.S.C. § 717r(b))).

[587] *Id.*

[588] Sierra Club Rehearing Request at 79-80.

further states that the Final EIS does not justify its use of a 5-mile viewshed for assessing visual resource impacts.[589] We disagree. The Final EIS assesses the visual impacts of both the Pacific Connector Pipeline and Jordan Cove LNG Terminal in significant detail, analyzing the short- and long-term visual resource impacts from several different viewsheds, and determines that these impacts would not be significant.[590] The Final EIS identifies the 5-mile viewshed as "the foreground/middleground distance zone as described in the BLM Visual Resource Management (VRM) system, and corresponds to the potential viewing range within which visible aspects of the Project (primarily the cleared right-of-way) are most likely to be noticeable to the casual observer."[591] In the Final EIS, Commission staff recognizes that some "identifiable affected interests", including those who live near a pipeline right-of-way or travel near it frequently, may place a higher value on these resources.[592] We find that the Final EIS sufficiently assessed the potential impacts to visual resources. Sierra Club's concerns regarding property values are fully addressed above.[593]

189. Sierra Club claims that the Final EIS fails to assess the adverse impacts from Pacific Connector using herbicide to maintain its pipeline right-of-way.[594] Sierra Club further contends that there is a not a sufficient monitoring program in place to prevent the spread of invasive species and noxious weeds after construction.[595] The Final EIS states that Pacific Connector will use only approved herbicides and will implement measures to prevent the spread of herbicides, including pausing herbicide treatments when rain is anticipated in the next 24 hours, and the use of buffers to prevent the spread of herbicides to sensitive sites.[596] Sierra Club does not present any evidence of the types of herbicide-related harms it anticipates, outside of landowners' preference to use organic herbicide on their property. In addition, the Final EIS discusses Pacific Connector's *Integrated Pest Management Plan*, which contains measures to prevent the spread of noxious weeds and

[589] *Id.*

[590] Final EIS at 5-587 to 4-601.

[591] *Id.* at 4-588.

[592] *Id.* at 4-608.

[593] *See supra* P 187.

[594] Sierra Club Rehearing Request at 80-82.

[595] *Id.* at 81-82.

[596] Final EIS at 4-176.

invasive species, including the use of herbicides.[597] The Final EIS explains how Pacific Connector would monitor the pipeline right-of-way for infestations of noxious weeds and invasive plant species, and address these infestations if they occur.[598]

190. Sierra Club asserts that the Final EIS and Authorization Order do not sufficiently address how the construction and operation of the Pacific Connector Pipeline will impact landowners' ability to utilize timber on their property.[599] Sierra Club claims that the Final EIS does not address how landowners will be able to continue to cut timber after the pipeline has been constructed.[600] Contrary to Sierra Club's assertions, the Final EIS addresses the project's impacts on timber cutting,[601] explaining that during operation timber operations may continue, and timber operators can cross the right-of-way with "heavy hauling and logging equipment", as long as there is proper coordination with Pacific Connector, and precautions are taken to preserve the integrity of the pipeline.[602] The Final EIS determines that logging operations would not be significantly impacted, nor would the cost of logging significantly increase, although the requirement to coordinate with Pacific Connector may be an inconvenience for some.[603] Accordingly, we find that the Final EIS sufficiently addressed impacts to timber operations.

191. Sierra Club asserts that the effects of the Pacific Connector Pipeline on landowners' planned property improvements are not adequately addressed.[604] Sierra Club states that the construction and operation of the pipeline will negatively impact or otherwise prevent landowners from undertaking plans for improvements on their property.[605] As Sierra Club acknowledges, the Final EIS states that in several instances, landowners and Pacific Connector were able to reach an agreement to modify the

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[597] *Id.* at 4-173 to 4-176.

[598] Final EIS at 4-176.

[599] Sierra Club Rehearing Request at 82-83.

[600] *Id.*

[601] Final EIS at 4-439; 4-443 to 4-446.

[602] *Id.* at 4-439.

[603] *Id.* at 4-446.

[604] Sierra Club Rehearing Request at 83-84.

[605] *Id.*

pipeline route so as to avoid impacts on planned improvements.[606] For instances in which impacts to planned property improvements were unavoidable, determining appropriate compensation for the impacts to the landowners' planned improvement is a matter between the landowner and Pacific Connector.

192. Sierra Club asserts that the "psychological effects on landowners" caused by a project that has been pending for over 15 years, have not been assessed.[607] As the Commission has previously explained, a project's "potential psychological effect on landowners are beyond the scope of NEPA review."[608]

193. Finally, Sierra Club argues that the Final EIS and the Authorization Order fail to address how landowners may resume "normal activities such as timber harvesting" after construction of the pipeline, and that there is "little or no basis" for the conclusion that impacts to land use would not be significant.[609] Sierra Club states that impacts on landowners' water sources, ability to irrigate, impacts from invasive species, insecticide and pesticide spraying, fire mitigation, and "unwanted intrusions" by third parties via the pipeline corridor were not addressed.[610]

194. We address Sierra Club's concerns regarding timber harvesting above.[611] In addition, concerns regarding impacts on water sources,[612] irrigation and agriculture,[613] invasive species,[614] fire mitigation,[615] have been addressed in the Final EIS,

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[606] Final EIS at 4-443.

[607] Sierra Club Rehearing Request at 84.

[608] *S. Natural Gas Co.*, 86 FERC ¶ 61,129, at 61,444 (1999).

[609] Sierra Club Rehearing Request at 84-85.

[610] *Id.* at 85.

[611] *See supra* P 190.

[612] *See supra* PP 183 - 185.

[613] *See, e.g.*, *supra* P 190; Authorization Order, 170 FERC ¶ 61,202 at PP 201, 229; Final EIS at 4-438.

[614] *See*, *e.g., supra* PP 168, 189; Authorization Order, 170 FERC ¶ 61,202 at P 211, envtl. cond. 19; Final EIS at 4-157 to 4-159.

[615] *See, e.g., infra* PP 210 - 211; Authorization Order, 170 FERC ¶ 61,202 at P 211; Final EIS at 4-178 to 4-179, 4-460.

Authorization Order, and herein. As discussed in the Final EIS, Pacific Connector would implement a "Landowner Complaint Resolution Procedure" to enable landowners to register complaints with Pacific Connector, and landowners may further contact the Commission's Dispute Resolution Division if they are not satisfied with Pacific Connector's response to their complaint.[616] As discussed in Environmental Condition 10 in the Authorization Order, the complaint resolution procedure will provide landowners with instructions on how to register complaints regarding environmental mitigation problems or concerns, and will be available to landowners during construction and restoration of the Pacific Connector Pipeline, and two years after the completion of restoration activities.[617] Accordingly, we find this analysis provided sufficient basis for Commission staff's conclusion that land use would not be significantly impacted.[618] That Sierra Club may disagree with our conclusion does not render our analysis insufficient under NEPA.

M. Safety

1. Aviation

195. Sierra Club and Ms. McCaffree assert that neither the Commission nor the Federal Aviation Administration (FAA) assessed the impacts of the Jordan Cove LNG Terminal's thermal plume on aircraft operations at the nearby Southwest Oregon Regional Airport, particularly during takeoff and landing.[619] Petitioners contend that the only assessment of impacts by the agencies was the FAA's determination, in its 2015 memorandum addressing the effects of thermal exhaust plumes, that "thermal exhaust plumes may pose a unique hazard to aircraft" and therefore "are incompatible with airport operations.[620]

196. As petitioners note, the Final EIS acknowledges and incorporates the FAA's 2015 memorandum regarding the risks of thermal exhaust plumes for aviation, particularly that

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[616] Final EIS at 4-441.

[617] Authorization Order, 170 FERC ¶ 61,202 at envtl. cond. 10.

[618] *See* Final EIS 4-420 to 4-552; 5-6.

[619] Sierra Club Rehearing Request at 51-53; McCaffree Rehearing Request at 22-23.

[620] *See* FAA Memorandum (Sept. 24, 2015), https://www.faa.gov/airports/environmental/land_use/media/technical-guidance-assessment-tool-thermal-exhaust-plume-impact.pdf.

they are "incompatible" with airport operations.[621] Petitioners fail, however, to examine the FAA's 2015 memorandum in its entirety. The FAA prepared the memorandum in response to requests for information from state and local governments, as well as airport operators, on the appropriate distance between power plant exhaust stacks and airports.[622] As an initial matter, the memorandum clarifies that the FAA has no regulations protecting airports from plumes and other emissions from exhaust stacks, and only has regulations to limit exhaust stack height near airports.[623] Contrary to the assertions of Sierra Club and Ms. McCaffree, the memorandum was not limited to the FAA's determination that thermal exhaust plumes were incompatible with aviation. A full reading of the FAA's 2015 memorandum demonstrates that, while the FAA did in fact determine that thermal exhaust plumes "*may* pose a unique hazard to aircraft in critical phases of flight" and that accordingly such plumes are "incompatible with airport operations," the FAA also determined that "the overall risk associated with thermal exhaust plumes in causing a disruption of flight is low."[624] The 2015 memorandum further states that any such impact would be highly dependent on a variety of factors, including the proximity of the exhaust stacks to the airport flight path, the size and speed of the aircraft, and local weather patterns (wind, ambient temperatures, atmospheric stratification at the plume site).[625] Thus, in recognition of its lack of regulations regarding thermal exhaust plumes, the low (but present) risk to flight operations that such plumes present, and the variety of factors that must be taken in to account to determine the presence, or severity, of any such risk, the FAA recommended that airports take such plumes in to account.[626]

197. Sierra Club asserts that the 2015 memorandum is "directed at airport sponsors to consider the impact of existing thermal plumes on potential future airports" and that it is inappropriate to expect the Southwest Oregon Regional Airport account for plumes from the new Jordan Cove LNG Terminal.[627] To the contrary, the FAA states that the memorandum was prepared in response to several inquiries and requests "*from airport operators*", and that the FAA-developed "Exhaust-Plume-Analyzer can be an effective tool to assess the impact exhaust plumes may impose on flight operations at an existing

[621] Final EIS at 4-657.

[622] FAA September 24, 2015 Memorandum at 1.

[623] *Id.*

[624] *Id.* at 2.

[625] *Id.*

[626] *Id.*

[627] Sierra Club Rehearing Request at 52.

or proposed site in the vicinity of an airport."[628] Accordingly, it is entirely reasonable, based on the FAA's 2015 memorandum, to expect the Southwest Oregon Regional Airport to take such plumes in to account. The Final EIS, informed by the FAA's 2015 memorandum, determines that thermal exhaust plumes may have an adverse impact on takeoffs and landings, and reiterates the FAA's directive for airports to take these plumes in to account.[629] We find this analysis is sufficient, and encourage Jordan Cove to work with the Southwest Oregon Regional Airport as well as state and local authorities to address concerns regarding the potential impacts of thermal exhaust plumes on aircraft operations.

198. Sierra Club asserts that the Final EIS and Authorization Order fail to sufficiently assess the structural hazards to aviation caused by construction and operation of the Jordan Cove LNG Terminal,[630] stating that the Final EIS and Authorization Order ignore the FAA determination "that [runway 04] will be unusable during instrument flight rule conditions when an LNG tanker is berthed or in transit."[631] Sierra Club further disputes the Authorization Order's determination that impacts to airport operations (including flight delays) would not be significant.[632] In support, Sierra Club cites the Final EIS's conclusion that operation of the Jordan Cove LNG Terminal "could significantly impact" airport operations.[633] As the Commission stated in the Authorization Order, the Final EIS' determination that operating the Jordan Cove LNG Terminal could impact airport operations was based on the FAA's determination that several components of the LNG terminal would be presumed hazards to air navigation.[634] The Authorization Order further explains that, after the issuance of the Final EIS, the FAA completed aeronautical studies, which found that operation of the terminal or docked/transiting LNG tankers

[628] FAA September 24, 2015 Memorandum at 2 (emphasis added).

[629] Final EIS at 4-657.

[630] Sierra Club Rehearing Request at 52-53.

[631] *Id.* (citing FAA's December 23, 2019 "Determination of No Hazard to Air Navigation," Aeronautical Study No. 2017-ANM-5386-OE).

[632] *Id.* at 52.

[633] *Id.*

[634] Authorization Order, 170 FERC ¶ 61,202 at P 244 (citing Final EIS at 4-657; Jordan Cove's May 10, 2018 Response to Commission Staff's April 20, 2018 Data Request).

would not cause a hazard to air navigation.[635] The FAA's determination provided a sufficient basis for the Commission to determine that airport operations would not be significantly impacted.

199. Sierra Club asserts that neither the Commission nor the FAA addressed the aviation hazards posed by "temporary" structures (i.e., cranes) that would be present during construction.[636] The FAA's "Determination of No Hazard to Air Navigation" for onshore equipment at the Jordan Cove LNG Terminal states that the determinations include temporary construction equipment, including cranes.[637] Thus, the FAA took such construction equipment into account when issuing its determinations regarding hazards to air navigation.

200. Ms. McCaffree states that the Final EIS and the Authorization Order do not assess the hazards that would result from Jordan Cove's proposal to dispose of dredged material "in very close proximity to the end" of a runway at the Southwest Oregon Regional Airport, as the location of the dredged material there may attract wildlife, which could create a hazard in the approach or departure airspace.[638] Ms. McCaffree's argument is dismissed as she raises this issue for the first time on rehearing. Ms. McCaffree had ample opportunity to present this argument during the Commission's environmental review process. The Commission looks with disfavor on raising issues for the first time on rehearing that could have been raised earlier, particularly during the NEPA scoping process, in part, because other parties are not permitted to respond to requests for rehearing.[639] Regardless, we note that the Final EIS assesses the potential for mitigation

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[635] *Id.* P 245.

[636] Sierra Club Rehearing Request at 52-53.

[637] Separate FAA determinations can be found at http://oeaaa.faa.gov for Aeronautical Study Nos: 2017-ANM-5386-OE through 2017-ANM-5388-OE; 2017-ANM-5390-OE through 2017-ANM-5418; 2018-ANM-4-OE through 2018-ANM-8-OE; 2018-ANM-718-OE through 2018-ANM-720-OE; 2019-ANM-5196-OE; and 2019-ANM-5197-OE.

[638] McCaffree Rehearing Request at 22-23.

[639] *See Baltimore Gas & Elec. Co.*, 91 FERC ¶ 61,270, at 61,922 (2000) ("We look with disfavor on parties raising on rehearing issues that should have been raised earlier. Such behavior is disruptive to the administrative process because it has the effect of moving the target for parties seeking a final administrative decision."); *Dep't of Transp. v. Pub. Citizen*, 541 U.S. 752, 764 (2004) ("Persons challenging an agency's compliance with NEPA must 'structure their participation so that it ... alerts the agency to the [parties'] position and contentions,' in order to allow the agency to give the issue meaningful consideration.") (quoting *Vermont*, 435 U.S. at 553); *see also Tenn. Gas*

sites near the Southwest Oregon Regional Airport to attract birds to the area. The Final EIS determines that although dredge disposal may attract some birds, the disposal would not substantially alter the composition of wildlife or affect airport operations.[640]

201. Ms. McCaffree asserts that the "FAA did not sign off fully" on its determinations of presumed hazards for certain components of the Jordan Cove LNG Terminal and takes issue with the FAA's eventual determinations of no hazard for these facilities. Ms. McCaffree further argues that it is arbitrary for the Commission to issue the Authorization Order while the applicant(s) complete surveys, studies, and/or consultations.[641] As an initial matter, if Ms. McCaffree contests the FAA's no hazard determinations, she may register her complaints with the FAA; the Commission is not the appropriate venue for resolving the FAA's determinations. Further, Ms. McCaffree does not allege that our reliance on the FAA's determinations is improper, or otherwise undermines our determination regarding the Jordan Cove LNG Terminal's safety impacts. Finally, while Ms. McCaffree does not identify the safety related studies, plans, or consultations that the Commission is allowing Jordan Cove to complete after issuance of the Authorization Order, as we explain above and in the Authorization Order, our practice of issuing conditional certificates has consistently been affirmed by courts as lawful.[642]

2. Safety Determination for Jordan Cove LNG Terminal

202. Ms. McCaffree asserts that the Commission inappropriately "delegated" its duty to consider the safety hazards of operating the Jordan Cove LNG Terminal, pursuant to the federal safety standards contained in Part 193, Subpart B, of Title 49 of the Code of Federal Regulations, and states that PHMSA's September 11, 2019 Letter of Determination that the Jordan Cove LNG Terminal complies with these safety standards was erroneous.[643] Ms. McCaffree further argues that the Commission is "precluded" from relying on PHMSA's Letter of Determination, that the Final EIS fails to adequately respond to safety-related comments, and that the Commission's issuance of a conditional

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Pipeline Co., L.L.C., 162 FERC ¶ 61,167 at P 10; *Nw. Pipeline, LLC*, 157 FERC ¶ 61,093, at P 27 (2016) ("We dismiss the Cemetery's argument that EA's indirect impacts analysis was deficient because the Cemetery raises this argument for the first time on rehearing.").

[640] Final EIS at 4-196.

[641] McCaffree Rehearing Request at 23.

[642] *See supra* P 75.

[643] McCaffree Rehearing Request at 18-21 (citing 49 C.F.R. pt. 93, subpt. B (2019)).

Authorization Order while Jordan Cove continues to demonstrate compliance with PHMSA's Letter of Determination and other safety-related matters is "arbitrary and not otherwise in accord with applicable law."[644]

203. Initially, Ms. McCaffree contends that the Commission is impermissibly "delegating" its duty under the NGA and NEPA to assess whether or not an LNG terminal complies with the federal safety standards.[645] Ms. McCaffree asserts that doing so "usurps the NEPA process" by preventing public participation in the PHMSA proceeding, and seeks to "dissolve" Commission accountability for the safety determination.[646] PHMSA is the federal agency named by Congress for "exercis[ing] authority under the Pipeline Safety Act (49 U.S.C. § 60101, et seq.) to prescribe safety standards for LNG facilities." Accordingly, we do not "delegate" our authority or duty to determine whether an LNG facility complies with these safety standards; rather, the responsibility and authority to make such a determination rests with PHMSA. As noted in the Authorization Order, pursuant to an August 31, 2018 Memorandum of Understanding entered into by PHMSA and the Commission (PHMSA MOU), on September 11, 2018, PHMSA issued a Letter of Determination indicating that the proposed Jordan Cove LNG Terminal complied with federal safety standards in Part 193, Subpart B of PHMSA's regulations.[647]

204. Ms. McCaffree contends that PHMSA's Letter of Determination is insufficient, in that it ignores the risks posed by "unconfined vapor cloud explosions", as well as comments regarding these risks.[648] Ms. McCaffree asserts that Jordan Cove did not use appropriate modeling to demonstrate the risks of vaper cloud explosions and whether or not the hazard from such an explosion would remain within the boundaries of the LNG facility.[649] Ms. McCaffree further argues that PHMSA failed to consider testimony and comments presented to PHMSA on this matter.[650] As a result, Ms. McCaffree contends that the Commission is "precluded" from relying on PHMSA's Letter of Determination.

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[644] *Id.* at 18-21.

[645] *Id.* at 18.

[646] *Id.*

[647] Authorization Order, 170 FERC ¶ 61,202 at P 41.

[648] McCaffree Rehearing Request at 19-20.

[649] *Id.*

[650] *Id.*

205. As an initial matter, if Ms. McCaffree contests PHMSA's Letter of Determination she should raise her concerns with that agency, which is charged with prescribing such minimum safety standards and determining whether or not LNG facilities comply with those standards.[651] Both PHMSA's Letter of Determination and the Final EIS state that Jordan Cove must address the minimum safety standards requirements.[652] Regardless, the Commission finds that the Letter of Determination adequately assesses the potential hazards from vapor cloud explosions, as well as the potential for such explosions to extend beyond the boundary of the Jordan Cove LNG Terminal. The Letter of Determination acknowledges that, based on Jordan Cove's evaluation of hazardous releases (including vapor cloud explosions), these releases would extend "beyond the Jordan Cove LNG Terminal eastern boundary."[653] To prevent such hazardous releases from extending beyond the boundary of the facility, the Letter of Determination states that Jordan Cove proposes to construct a 100-foot-high wall along the eastern boundary to serve as a "thermal radiation shield."[654] PHMSA determined that such a measure would be appropriate, provided Jordan Cove can confirm the effectiveness of the wall, particularly to "withstand the overpressure impact due to a potential vapor cloud explosion scenario from the liquefaction area."[655] Accordingly, it appears that PHMSA appropriately considered the risks of vapor cloud explosions in issuing its Letter of Determination, and the Commission relies on it "as the authoritative determination" of the Jordan Cove LNG Terminal's "ability to comply" with the minimum federal safety standards.[656] Moreover, Ms. McCaffree's assertion that the Commission is somehow "precluded" from relying on PHMSA's Letter of Determination is without merit.

206. Ms. McCaffree asserts that the Final EIS violates NEPA by failing to "adequately" respond to comments on "the potential safety hazards of the Jordan Cove LNG terminal and its associated tanker traffic" and "thwarts" public review by allowing applicants to label information as "Critical Energy Infrastructure Information" (CEII).[657] As discussed in detail above, PHMSA holds the responsibility to determine whether or not an LNG

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[651] *See*, 49 U.S.C. § 60101, *et seq.* (2018); *see also* PHMSA MOU at 2.

[652] Final EIS at 4-741 to 4-742.

[653] *See* Commission Staff's September 24, 2019 Memo filed in Docket No. CP17-495-000 (Containing PHMSA's Letter of Determination) at 3.

[654] *Id.* at 21.

[655] *Id.* at 3, 40.

[656] PHMSA MOU at 2.

[657] McCaffree Rehearing Request 25-28.

facility complies with federal safety standards;[658] however, the Final EIS contains a detailed analysis of the Jordan Cove LNG Terminal's Reliability and Safety based on its process, mechanical, hazard mitigation, security, and geotechnical and structural designs, including how the facility would protect against vapor cloud explosions,[659] and as discussed above, the Final EIS adequately considers tanker traffic impacts from construction and operation of the Jordan Cove LNG Terminal.[660]

207. Further, the Commission does not "thwart" public review and robust analysis of applications by allowing applicants to label information as CEII. The Commission began labeling certain information as CEII after the attacks of September 11, 2001; the Commission's CEII regulations seek to "restrict unfettered public access to [CEII], but still permit those with a need for the information to obtain it in an efficient manner."[661] To prevent overutilization of the CEII designation, the Commission's regulations limit the labeling of CEII to "specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure."[662] Moreover, the Commission's regulations permit any party to a proceeding to request and receive a complete CEII version of a document.[663]

208. Ms. McCaffree contends that the Authorization Order "failed to acknowledge" that PHMSA's Letter of Determination was (inappropriately) conditioned upon Jordan Cove demonstrating to PHMSA that its proposed hazardous release safety measures were effective, and that issuing the Authorization Order prior to Jordan Cove receiving all safety-related determinations was arbitrary.[664] The Authorization Order recognizes that PHMSA conditioned its Letter of Determination on Jordan Cove finalizing its hazardous release mitigation; Environmental Condition 35 of the Authorization Order requires Jordan Cove to file documentation of PHMSA's determination that the final design safety

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[658] *See supra* P 205.

[659] Final EIS at 4-759 to 4-769.

[660] *See supra* PP 162-163.

[661] *See* Critical Energy Infrastructure Information, Order No. 683, 116 FERC ¶ 61,263, at PP 2, 6 (2006).

[662] 18 C.F.R. § 388.113(c)(1) (2019).

[663] *Id.* § 388.113(g)(4) (2019).

[664] McCaffree Rehearing Request at 21.

features comply with federal safety standards prior to initial site preparation.[665] Further, as discussed above and in the Authorization Order, our practice of issuing conditional certifications and authorizations has consistently been affirmed as lawful.[666]

3. <u>Forest Fires</u>

209. Sierra Club argues that the Commission violated NEPA by failing to take a hard look at how pipeline construction and operation, including the temporary and permanent clearing of the right-of-way, will increase the likelihood and severity of forest fires.[667] Sierra Club contends that the pipeline right-of-way will be permanently cleared of large diameter trees and replaced with early seral vegetation that in a wildfire may act like a wick and carry fire along the entire right-of-way, thus spreading fire beyond its "natural" reach.[668]

210. Contrary to Sierra Club's assertion, the Final EIS acknowledges that both pipeline construction and operations could increase the risk of wildfires. Construction and operational activities—such as burning of cleared vegetation, mowing, welding, refueling with flammable liquids, vehicle and equipment use (parking vehicles with hot mufflers or tailpipes on tall dry grass)—could create a wildfire risk, especially during wildfire season.[669] Although the cleared right-of-way may work as a fire break, the presence of the cleared right-of-way could also increase the risk of fires reaching forest crowns.[670] As discussed in the Final EIS, large forest fires including crown fires could occur if small, low-intensity surface fires are ignited within the herbaceous or low shrub cover maintained along the permanent right-of-way. These fires could then spread to ladder fuels near forest edges and ignite the forest's canopy.[671]

211. In response to these risks, Pacific Connector will implement a *Fire Prevention and Suppression Plan*.[672] This plan is consistent with Forest Service and BLM policies and

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[665] Authorization Order, 170 FERC ¶ 61,202 at app., envtl. cond. 35.

[666] *See supra* P 75.

[667] Sierra Club Rehearing Request at 53.

[668] *Id.* at 54.

[669] Authorization Order, 170 FERC ¶ 61,202 at P 211; Final EIS at 4-177 to 4-178.

[670] Final EIS at 4-178.

[671] *Id.* at 4-177 to 4-178.

[672] *Id.* at 4-178, 4-816.

current practices and is designed to identify measures to minimize the chances of a fire starting and spreading from project facilities and to reduce the risk of wildland and structural fire. Although designed for federal lands, the plan would be applicable to the entire pipeline route; regardless of landownership. In addition, the *Erosion Control and Revegetation Plan* requires that residual slash from timber clearing be placed at the edge of the right-of-way and scattered/redistributed across the right-of-way during final cleanup and reclamation according to BLM and Forest Service fuel loading specifications to minimize fire hazard risks.[673]

212. Sierra Club argues that the Commission failed to assess whether fuel breaks (strips or blocks of vegetation that have been altered to slow or control a fire) along the pipeline right-of-way would be effective. Sierra Club acknowledges that fuel breaks can be effective so long as vegetation is maintained and eliminated, but the Commission appears to be letting this vegetation regrow. Sierra Club also points out that such fuel breaks are generally ineffective in the high to extreme fire behavior weather in Southern Oregon along the right-of-way.[674] As discussed, a maintained right-of-way may function as a fire break in certain circumstances; however, contrary to Sierra Club's claim, the Commission is not requiring fuel breaks along the pipeline right-of-way.[675] Therefore, the additional analysis requested by Sierra Club is not necessary.

213. Sierra Club claims that the pipeline may be susceptible to wildfire risks along the right-of-way due to the pipeline's shallow depth, noting that it is unclear whether the pipeline will be buried 18 or 24 inches below the surface.[676] According to Sierra Club, should a rupture occur, a catastrophic wildfire would begin or if already ongoing, be exacerbated beyond control.[677]

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[673] *Id.* at Appendix F.10-Part 2, Erosion Control and Revegetation Plan, 10.

[674] Sierra Club Rehearing Request at 55.

[675] Although the Commission is not requiring fuel breaks along the pipeline right-of-way, integrated stand density fuel breaks, which are designed to reduce the threat of stand replacement fires by reducing stand density, ladder fuels, and incorporating existing openings, have been recommended by BLM and Forest Service as compensatory mitigation on BLM and Forest Service lands off of the pipeline right-of-way. We anticipate that BLM and Forest Service may tier to the EIS when preparing their subsequent site-specific NEPA analyses. Final EIS at 2-35 to 2-39.

[676] *Id.*

[677] *Id.*

214. As Sierra Club suggests, the depth of the pipeline trench varies. DOT regulations require a trench depth of 30 inches in normal soil, 18 inches in consolidated rock, and 48 to 60 inches in agricultural lands.[678] Pacific Connector plans to exceed these minimums where feasible with the goal to trench to a depth of 36 inches in normal soils and up to 24 inches of cover in consolidated rock areas.[679] Sierra Club offers no evidence to suggest that a wildfire is sufficient to overcome the insulating properties of soil or ignite the gas in the subterranean pipeline.

215. Sierra Club next argues that construction and operation of the pipeline will occur during the wildfire season when mechanized and industrial activities are precluded during most daylight hours from late spring to late fall, but the Authorization Order places no fire-related restrictions on the Pacific Connector Pipeline's operations when other activities are precluded.[680] We do not see the need to restrict construction as Sierra Club requests due to Pacific Connector's use of its *Fire Prevention and Suppression Plan*.[681] As discussed, the plan will reduce the risk of fires associated with construction and operation of the pipeline and also includes fire response procedures to be implemented in the event of a fire.[682]

216. Sierra Club also expresses concern that the pipeline's presence will inhibit controlled burns, which help restore forest resilience in wildfire-prone areas, and instead the areas in the vicinity of the pipeline will be managed as "full suppression."[683] However, Sierra Club does not present any evidence to suggest this may be the case. There is no evidence supporting the assertion that the presence of a right-of-way precludes controlled burns. We note that controlled burns may occur over existing rights-of-way with appropriate planning and consultation with pipeline operators. Furthermore, it is speculative to claim that a right-of-way would be managed as "full-suppression." The presence of a right-of-way may affect suppression efforts, but Sierra Club has offered no policy or regulation that a right-of-way prevents suppression or necessitates "full suppression."

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[678] 49 CFR pt. 192 (2019).

[679] Pacific Connector Pipeline Resource Report 1 at 50.

[680] *Id.* at 54-55.

[681] Final EIS at 4-178, 4-816.

[682] *Id.* at 4-178 to 4-179. Although we are not requiring seasonal restrictions, we note that Pacific Connector will only burn slash during the wet season. Final EIS at 4-446.

[683] Sierra Club Rehearing Request at 55.

N. Threatened and Endangered Species

217. Sierra Club contends that the Commission violated the Endangered Species Act (ESA) by: (1) issuing a certificate requiring the Blue Ridge Alternative without consulting with the U.S. Fish and Wildlife Service (FWS) and NMFS (collectively, the Services) regarding that alternative, and (2) relying on Biological Opinions that the Commission had reason to know are flawed.[684]

218. Sierra Club claims that Commission staff's Biological Assessment and the Services' Biological Opinions analyzed and authorized the proposed route and not the Blue Ridge Alternative, which is what the Commission authorized in the Authorization Order.[685] Sierra Club argues that the Blue Ridge Alternative has effects that are "different in scope, scale, and location" than what the Services considered.[686] Accordingly, Sierra Club argues that the ESA requires the Commission to reinitiate consultation with the Services.[687]

219. Commission staff's Biological Assessment states:

> [t]his [Biological Assessment] assesses the [projects] as designed and proposed by the applicant; however, the FERC and the Forest Service have recommended that four route variation be included in the proposed action . . . including . . . the Blue Ridge Variation . . . . Appendix R provides the quantitative differences to listed species that these variations would have compared to the proposed action. As presented in Appendix R, we have concluded that inclusion of these variations into the proposed action would not change the effects determinations presented in this [Biological Assessment].[688]

220. Thus, Commission staff's Biological Assessment did analyze the Blue Ridge Variation, and staff found the Blue Ridge Variation and the proposed route result in the

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[684] *Id.* at 29-30, 56-64.

[685] *Id.* at 29.

[686] *Id.* (citing Authorization Order, 170 FERC ¶ 61,202 at P 270).

[687] *Id.* at 30.

[688] Commission staff's July 2019 Biological Assessment at 3-4 (filed on July 30, 2019).

same effects determinations. Moreover, staff's Biological Assessment expressly stated that the Commission and the Forest Service recommend inclusion of the Blue Ridge Alternative in the proposed action.

221. We acknowledge, however, that although the Biological Opinions state they are based on information included in the Biological Assessment, the Biological Opinions do not explicitly reference the Blue Ridge Alternative. Therefore, we will informally consult with the Services to determine whether the ESA requires any further consultation. If further consultation is required, the Commission will not authorize the applicants to commence construction activities until such consultation is complete, pursuant to Environmental Condition 11.[689]

222. Sierra Club also argues that the Commission violated the ESA by relying on Biological Opinions that the Commission had reason to know are flawed.[690] Generally, Sierra Club contends that the Biological Opinions fail to adequately assess harm to species and that the reinitiation triggers are coextensive with project effects.[691] Specific to FWS's Biological Opinion, Sierra Club argues that FWS' Biological Opinion: (1) failed to adequately explain inconsistencies between the opinion and FWS' recovery plans for the marbled murrelet and northern spotted owl and (2) relied on uncertain mitigation measures.[692] Specific to NMFS's Biological Opinion, Sierra Club claims that NMFS' Biological Opinion: (1) failed to explain its use of surrogates as reinitiation triggers for several species, (2) did not use the best available science, (3) failed to adequately address cumulative effects associated with the projects, and (4) failed to provide incidental take coverage for vessel strikes to whales.[693]

223. Sierra Club discounts the substantive and procedural responsibilities that section 7(a)(2) of the ESA[694] imposes and the interdependence of federal agencies acting under that section. Although a federal agency is required to ensure that its action will not jeopardize the continued existence of listed species or adversely modify their critical habitat, it must do so in consultation with the Services. Because the Services are charged

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[689] Authorization Order, 170 FERC ¶ 61,202 at app., envtl. cond. 11.

[690] Sierra Club Rehearing Request at 56-64.

[691] *Id.*

[692] *Id.* at 56-58.

[693] *Id.* at 58-64.

[694] 6 U.S.C. § 1536(a)(2) (2018).

with implementing the ESA, they are the recognized experts regarding matters of listed species and their habitats, and the Commission may rely on their conclusions.[695]

224. In reviewing whether the Commission may appropriately rely on the Services' Biological Opinions, the relevant inquiry is not whether the documents are flawed, but rather whether the Commission's reliance was arbitrary and capricious.[696] An agency may rely on a Biological Opinion if a challenging party fails to cite new information that the consulting agency did not take into account that challenges the Biological Opinion's conclusions.[697] Here, Sierra Club does not present any new information that the Services did not consider, and, accordingly, the alleged defects do not rise to the level of new information that would cause the Commission to call into question the factual conclusions of the Biological Opinions. We find the Commission appropriately relied on the judgment of the Services—the agencies responsible for providing expert opinion regarding whether authorizing the projects is likely to jeopardize the continued existence of listed species under the ESA. Thus, we reject Sierra Club's argument that our reliance on the Services' Biological Opinions violated the ESA.

225. We note that the cumulative effects that Sierra Club claims NMFS failed to address in in its Biological Opinion (specifically, that the projects will likely result in the development of another LNG terminal and additional pipelines in the area and will likely spur additional industrial development in Coos Bay)[698] are not cumulative effects that must be considered in consultation because they are purely speculative and not reasonably certain to occur.[699]

226. Additionally, regarding take associated with vessel strikes to whales, NMFS explained in its Biological Opinion that "the ESA does not allow NMFS to exempt incidental take of marine mammals where an authorization of the take is required and may be obtained under the [Marine Mammal Protection Act (MMPA).]"[700] As noted in

[695] *City of Tacoma v. FERC*, 460 F.3d 53, 75 (D.C. Cir. 2006) (finding that expert agencies such as FWS have greater knowledge about the conditions that may threaten listed species and are best able to make factual determinations about appropriate measures to protect the species).

[696] *Id.*

[697] *Id.* at 76.

[698] *Id.* at 62-63.

[699] 50 C.F.R. § 402.02 (2019).

[700] NMFS January 10, 2020 Biological Opinion at 53.

the Authorization Order, Jordan Cove's consultation with NMFS regarding impacts on marine mammals is ongoing, and NMFS may issue an incidental take authorization under the MMPA.[701]

227. Ms. McCaffree argues that the Commission violated the ESA because it did not fully assess the projects' impacts, specifically dredging and noise, to snowy plovers and their habitats.[702] Ms. McCaffree claims that the Commission failed to consider "[p]ictures and proof of plovers utilizing the tidal muds that are slated to be destroyed by the development of the LNG marine terminal…."[703]

228. FWS's Biological Opinion analyzed impacts to western snowy plovers, including impacts from dredging and noise.[704] FWS determined that the projects would not jeopardize the continued existence of the species or result in the destruction or adverse modification of its critical habitat;[705] and, in its Incidental Take Statement for western snowy plover, FWS provided four reasonable and prudent measures and nine terms and conditions.[706] The Authorization Order requires Jordan Cove and Pacific Connector to implement the reasonable and prudent measures and adopt the terms and conditions in FWS' Biological Opinion.[707] Accordingly, we find that the Commission satisfied its obligations under the ESA by ensuring that the Commission's action will not jeopardize the continued existence of the western snowy plover or result in the destruction or adverse modification of its habitat.

O. Air Quality

229. The State of Oregon asserts that the Final EIS erroneously claims that the Jordan Cove LNG Terminal and the Pacific Connector Pipeline are not subject to Prevention of Significant Deterioration preconstruction permit requirements under the Clean Air Act because the Jordan Cove LNG Terminal does not exceed relevant PSD requirements.[708]

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[701] Authorization Order, 170 FERC ¶ 61,202 at P 226.

[702] McCaffree Rehearing Request at 28-29.

[703] *Id.* at 29.

[704] FWS January 31, 2020 Revised Biological Opinion at 172-207.

[705] *Id.* at 197.

[706] *Id.* at 203-207.

[707] Authorization Order, 170 FERC ¶ 61,202 at app., envtl. cond. 26.

[708] State of Oregon Rehearing Request at 33.

The State of Oregon indicates that the Jordan Cove LNG Terminal is projected to emit more than two times the Prevention of Significant Deterioration thresholds carbon monoxide and oxides of nitrogen (NOx) for new federal sources, and, if Oregon Department of Environmental Quality (DEQ) determines that the facilities qualify as a major new stationary source, they will be subject to additional control requirements, including Best Available Control Technology to control GHG emissions, which could change the terminal's design and operations.[709] The State of Oregon also argues that Jordan Cove and Pacific Connector have indicated uncertainty about the exact nature of the liquefaction facilities at the terminal and the Klamath Compressor Station,[710] which has prevented DEQ from making a Prevention of Significant Deterioration determination.[711]

230. Under the Prevention of Significant Deterioration program, a listed new "federal major source" that exceeds 100 tons per year or more of any individual regulated pollutant is subject to preconstruction permit requirements, while a non-listed source is subject to these requirements if it has the potential to emit less than the 250 tons per year (tpy) or more of any criteria pollutant.[712] To provide context for project emissions, the Authorization Order and Final EIS state that the terminal must obtain preconstruction review and a permit under Title V of the CAA, but was not subject to Prevention of Significant Deterioration because the terminal is not a listed federal major source and its potential to emit is less than 250 tpy during operations,[713] and made the same determination for the Klamath Compressor Station.[714] However, the State of Oregon retains full authority to grant or deny air quality permits; if the State of Oregon requires that the Jordan Cove LNG Terminal must obtain a Prevention of Significant Deterioration permit, it will be up to Jordan Cove to determine how it wishes to proceed. In addition, the Commission has conditioned our authorization on Jordan Cove's ability to secure all

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[709] *Id.* at 33, 70-71.

[710] The State of Oregon refers to the Klamath Compressor Station near Malin, Oregon, as the Malin Compressor Station. State of Oregon Rehearing Request at 70-71.

[711] *Id.* at 70-71.

[712] *Id.* at 33 (citing OAR 340-200-0020(66)(c)).

[713] Authorization Order, 170 FERC ¶ 61,202 at P 255; EIS at 4-701 to 4-702.

[714] Authorization Order, 170 FERC ¶ 61,202 at P 255; EIS at 4-706.

necessary federal authorizations, including any relevant federal CAA permits obtainable from Oregon DEQ.[715]

231. Finally, Ms. McCaffree argues that the Commission failed to adequately consider tanker emissions as part of the cumulative impacts analysis for air quality.[716] We disagree. The Final EIS fully considers and modeled LNG carrier emissions when assessing the Jordan Cove LNG Terminal's operational air emissions,[717] concluding that the project would not have a significant impact on regional air quality.[718]

P. Climate Change and GHG Emissions

1. Global Warming Potentials

232. NRDC contends that the Commission failed to adequately consider the projects' GHG impacts, alleging that the Commission relied on outdated global warming potentials (GWP) for GHGs when it used the EPA's international GHG reporting rules rather than the Intergovernmental Panel on Climate Change's (IPCC) more recent estimates to analyze the projects' GHG emissions.[719] For methane, NRDC contends that even if the Commission uses EPA's GWP of 25 over a 100-year period, the Commission must also calculate climate impacts using the IPCC's more recent 100-year GWP of 36 and 20-year GWP of 84-87 due to methane's potency over a shorter timeframe and to better correspond to 20- to 30-year natural gas transportation contracts.[720]

233. The Commission appropriately relied on EPA's published global warming potentials, which are the current scientific methodology used for consistency and comparability with other Commission jurisdictional projects as well as emissions estimates in the United States and internationally, including GHG control programs under

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[715] Authorization Order, 170 FERC ¶ 61,202 at app., envtl. cond. 11.

[716] McCaffree Rehearing Request at 32.

[717] Final EIS at 4-701.

[718] *Id.* at 4-707.

[719] NRDC Rehearing Request at 67.

[720] *Id.* at 67-68.

the CAA.[721] As we have explained,[722] we have consistently used EPA's global warming potentials, including time horizons, in order to compare proposals with other projects and with GHG inventories.

2. Indirect, Cumulative, and Connected Greenhouse Gas Emissions

234. NRDC, Sierra Club, and Confederated Tribes contend that the Commission failed to consider the indirect and cumulative impacts associated with the Pacific Connector Pipeline and Jordan Cove LNG Terminal, arguing that the Commission must include the induced upstream production of gas, impacts associated with transport and liquefaction, and downstream consumption of the gas that flows through the pipeline.[723] On upstream emissions, both Sierra Club and NRDC argue that the Commission must consider GHG emissions at the wellhead when the Commission relies, in part, on the pipeline's ability to supply natural gas from supply basins in the U.S. Rocky Mountains and Western Canada as a project benefit.[724] NRDC contends, at the very least, the Commission should be able to calculate upstream emissions using the full capacity of the pipeline.[725] Confederated Tribes argues that the Commission must consider the eventual end use of the natural gas being transported through the Jordan Cove LNG Terminal.[726] Confederated Tribes points out that the downstream combustion of the gas transported by the terminal is not just a "reasonably foreseeable" indirect impact, it is the terminal's entire purpose.[727]

235. NEPA requires agencies to consider indirect impacts that are "caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable."[728]

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[721] Authorization Order, 170 FERC ¶ 61,202 at PP 258-59; Final EIS at 4-687 to 4-694, tbls. 4.12.1.3-1, 4.12.1.3-2, 4.12.1.4-1, & 4.12.1.4-2.

[722] *Dominion Transmission, Inc.*, 158 FERC ¶ 61,029, at P 4 (2017).

[723] NRDC Rehearing Request at 58-59, 60-61; Sierra Club Rehearing Request at 67; Confederated Tribes Rehearing Request at 34.

[724] NRDC Rehearing Request at 69; Sierra Club Rehearing Request at 67-68.

[725] NRDC Rehearing Request at 70.

[726] Confederated Tribes Rehearing Request at 36.

[727] *Id.*

[728] 40 C.F.R. § 1508.8 (2019).

236. As discussed in the Authorization Order, upstream greenhouse gases associated with the gas transported on the Pacific Connecter Pipeline are not an indirect impact for purposes of NEPA.[729] We are unable to identify, based on the record, an incremental increase in natural gas production that is causally related to our action in approving the projects.[730] Although the Commission noted generally the natural gas production areas that will provide natural gas to be transported via the Pacific Connector Pipeline,[731] given the large geographic scope of Western Canada and the U.S. Rocky Mountain production areas, the magnitude of analysis requested would require the Commission to go well beyond "reasonable forecasting." Furthermore, the Commission does not have more detailed information regarding the number, location, and timing of wells, roads, gathering lines, and other appurtenant facilities, nor does it have details about production methods. Thus, there are no available forecasts that would enable the Commission to meaningfully predict production-related impacts, many of which are highly localized. Any estimates of the potential impacts associated with induced unconventional natural gas production arguably related to the Pacific Connector Pipeline would be based on information that is generic in nature, providing upper-bound estimates of upstream effects using general shale gas well information and worst-case scenarios of peak use. The Commission does not find this type of generic estimate to meaningfully inform its decision. Consequently, we continue to find that impacts from upstream production activities do not meet the definition of indirect effects, and therefore they are not mandated to be included in the Commission's NEPA review.[732]

237. NRDC and the Confederated Tribes argue that the Commission must nonetheless examine the full lifecycle climate impacts associated with both projects, including the downstream impacts related to consumption of the gas to be exported from the terminal, because the Pacific Connector Pipeline and Jordan Cove LNG Terminal are a single integrated project.[733] As we explained in the Authorization Order, the courts have explained that, because the authority to authorize the LNG exports rests with DOE; NEPA does not require the Commission to consider the upstream or downstream GHG emissions that may be indirect effects of the export itself when determining whether the

[729] Authorization Order, 170 FERC ¶ 61,202 at P 174.

[730] *Id.*

[731] *Id.* P 47.

[732] *See generally id.* (McNamee, Comm'r, concurrence at PP 22-58) (elaborating on the purpose of the NGA to facilitate the development and access to natural gas, as well as an analysis of consideration of indirect effects under NEPA).

[733] NRDC Rehearing Request at 59; Confederated Tribes Rehearing Request at 36.

related LNG export facility satisfies section 3 of the NGA.[734] These courts agree that the Commission is not the legally relevant cause of these emissions.[735]

238. Sierra Club and NRDC next claim that the Commission must analyze downstream impacts from the terminal because DOE's non-free trade export review is a connected action.[736] Pursuant to CEQ regulations, "connected actions" include actions that: (a) automatically trigger other actions, which may require an EIS; (b) cannot or will not proceed without previous or simultaneous actions; or (c) are interdependent parts of a larger action and depend on the larger action for their justification.[737] As noted above,[738] in evaluating whether multiple actions are, in fact, connected actions, courts have employed a "substantial independent utility" test, asks "whether one project will serve a significant purpose even if a second related project is not built."[739]

239. As required by NGA section 3(c),[740] DOE issued an instant grant of authority to Jordan Cove to export 395 Bcf per year of natural gas to countries with which the United States has an FTA, and this volume is equivalent to Jordan Cove LNG Terminal's nameplate capacity of 7.8 MTPA of LNG.[741] No additional trade authorization is needed for the terminal to operate at its full capacity. Because the terminal already has a significant purpose and could proceed absent the pending authorization for non-FTA nations, the two actions are not connected actions.

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[734] Authorization Order, 170 FERC ¶ 61,202 at P 171 (citing *Sierra Club v. FERC*, 827 F.3d 36 (D.C. Cir. 2016) (Freeport)); *see also Sierra Club v. FERC*, 867 F.3d at 1373 (discussing Freeport).

[735] *See* Freeport, 827 F.3d at 46-47; *Sierra Club v. FERC*, 867 F.3d at 1373.

[736] Sierra Club Rehearing Request at 68-70; NRDC Rehearing Request at 59.

[737] 40 C.F.R. § 1508.25(a)(1) (2019).

[738] *See supra* P 122.

[739] *Coal. on Sensible Transp., Inc. v. Dole*, 826 F.2d at 69. *See also O'Reilly v. U.S. Army Corps of Eng'rs*, 477 F.3d at, 237 (defining independent utility as whether one project "can stand alone without requiring construction of the other [projects] either in terms of the facilities required or of profitability").

[740] 15 U.S.C. § 717b(c) (2018).

[741] Authorization Order, 170 FERC ¶ 61,202 at P 181.

240. Nonetheless, Sierra Club contends that even if the Jordan Cove LNG Terminal does not depend on non-FTA nation authorization, the two actions are connected because the non-FTA nation exports authorization does not have independent utility absent the terminal.[742] But under CEQ's definition of a connected action, the terminal must have an interdependent relationship with the non-FTA nation authorization.[743] Nothing about the Jordan Cove LNG Terminal "triggers" or mandates non-FTA nation authorization and, as discussed, the terminal can proceed without such authorization. Moreover, Sierra Club does not make any showing that the delivery of natural gas to non-FTA nations, as opposed to FTA nations, has differing environmental effects, nor is there any information available as to the end use of the gas to be shipped from the Jordan Cove LNG Terminal.

3. Project Level Climate Impacts

241. Ms. McCaffree claims that the Commission failed to consider and address the projects' GHG impacts on commerce and Gross Domestic Product, as well as impacts of ocean acidification, domoic acid and sea level rise on the biological function of the Coos Estuary.[744] As discussed in the Final EIS and below, the Commission examined various tools to link project GHGs to climate change impacts, but was unable to identify a method for relating GHG emissions to specific resource impacts.[745] However, the EIS identified general climate change impacts in the project area.[746] Currently, there is no accepted methodology to attribute discrete, quantifiable, physical effects on the environment, particularly Coos Bay, or the area's economy to the projects' incremental contribution to GHGs.[747]

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[742] Sierra Club Rehearing Request at 68.

[743] 40 C.F.R. § 1508.25(a)(1) (2019). *See also Del. Riverkeeper Network v. FERC*, 753 F.3d 1304, 1313 (D.C. Cir. 2014) (finding that four pipeline proposals were connected actions because the four projects would result in "a single pipeline" that was "linear and physically interdependent" and because the projects were financially interdependent).

[744] McCaffree Rehearing Request at 32-33.

[745] Final EIS at 4-849.

[746] *Id.*

[747] *See generally* Authorization Order, 170 FERC ¶ 61,202 at P 262.

4. <u>Significance</u>

242. The State of Oregon, NRDC, and Sierra Club argue that the Commission is required by both NEPA and the NGA to assess the significance of the projects' GHG emissions, even if the Commission must develop its own methodology for assessing GHG emissions.[748] NRDC and Sierra Club suggest that the Commission use existing climate models to develop such a methodology.[749] NRDC claims the Commission failed to explain why existing climate models were too large and complex to assess significance, or why more simplistic climate models were not appropriate.[750] Sierra Club also claims that other methodologies could be used to ascribe significance, including tools used by the U.S. Global Change Research Program (USGCRP) to assess impacts.[751]

243. As an initial matter, the Commission discussed the significance of the projects' direct GHG emissions by quantifying those emissions,[752] and those emissions were placed in the context of cumulative emissions from other sources.[753] NEPA requires nothing more.

244. We disagree that the Commission can establish its own methodology for determining the significance of GHG emissions as we do for other resources, such as wetlands or vegetation. The Commission applies standard methodologies and established metrics for assessing the significance of the environmental impacts on these resources. In contrast, here the Commission has no benchmark to determine whether a project has a significant effect on climate change. To assess a project's effect on climate change, the Commission can only quantify the amount of project emissions, but it has no way to then assess how that amount contributes to climate change. For example, that calculated

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[748] State of Oregon Rehearing Request at 35-36, 61-62, 67; NRDC Rehearing Request at 61-64; Sierra Club Rehearing Request at 65-67.

[749] NRDC Rehearing Request at 63-64; Sierra Club Rehearing Request at 66.

[750] NRDC Rehearing Request at 63-64.

[751] *Id.* at 66.

[752] Final EIS at tbl.4.12.1.3-1 (LNG Terminal construction emissions), Table 4.12.1.3-2 (LNG Terminal operation emissions), tbl.4.12.1.4-1 (pipeline facilities construction emissions), & tbl.4.12.1.4-2 (pipeline facilities operation emissions); Authorization Order, 170 FERC ¶ 61,202 at PP 258-59.

[753] Authorization Order, 170 FERC ¶ 61,202 at P 259. Commission staff also put the projects' GHG emissions into context by calculating their contribution to Oregon's 2020 and 2050 climate goals. Final EIS at 4-851.

number cannot inform the Commission on climate change effects caused by the project, e.g., increase of sea level rise, effect on weather patterns, or effect on ocean acidification. Without adequate support or a reasoned target, the Commission cannot ascribe significance to GHG emissions amounts.[754]

245. As for the climate models and mathematical techniques raised by NRDC and Sierra Club, these climate models are used by the USGCRP and, as explained in the Final EIS, include climate models used by the EPA, National Aeronautics and Space Administration, and the IPCC.[755] Commission staff determined that those complex national and global models could not be used to directly link the projects' incremental contribution to climate change to effects on the environment.[756] As we explained in the Final EIS, Commission staff looked at a number of simpler models and attempted to extrapolate impacts using mathematical techniques, but none allowed the Commission to link physical effects caused by the projects' GHG emissions and NRDC does not suggest any such model exists.[757]

246. In the alternative, NRDC claims the Commission has other tools at its disposal to assess the significance of GHG, including the Social Cost of Greenhouse Gases.[758] NRDC argues that the Social Cost of Greenhouse Gases contextualizes costs associated with climate change and can also be used as a proxy for understanding climate impacts and to compare alternatives.[759]

247. The Social Cost of Carbon is not a suitable method for determining whether GHG emissions that are caused by a proposed project will have a significant effect on climate change. The Commission has provided extensive discussion on why the Social Cost of Carbon is not appropriate in project-level NEPA review and cannot meaningfully inform

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[754] *See generally* Authorization Order, 170 FERC ¶ 61,202 (McNamee, Comm'r, concurring at PP 73-80) (elaborating on how it would be unreasonable for the Commission to establish its own criteria for determining significance out of whole cloth).

[755] Final EIS at 4-850.

[756] *Id.*

[757] *Id.*

[758] NRDC Rehearing Request at 64-65 (NRSC describes the Social Cost of Greenhouse Gases as comprising the Social Cost of Carbon, the Social Cost of Methane, and the Social Cost of Nitrous Oxide).

[759] *Id.*

the Commission's decisions on natural gas infrastructure projects under the NGA.[760] It is not appropriate for use in any project-level NEPA review for the following reasons:

> (1) EPA states that "no consensus exists on the appropriate [discount] rate to use for analyses spanning multiple generations"[761] and consequently, significant variation in output can result;[762]
>
> (2) the tool does not measure the actual incremental impacts of a project on the environment; and
>
> (3) there are no established criteria identifying the monetized values that are to be considered significant for NEPA reviews.[763]

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[760] *Mountain Valley*, 161 FERC ¶ 61,043 at P 296, *order on reh'g*, 163 FERC ¶ 61,197 at PP 275-297, *aff'd, Appalachian Voices v. FERC*, No. 17-1271, 2019 WL 847199 at *2 ("[The Commission] gave several reasons why it believed petitioners' preferred metric, the Social Cost of Carbon tool, is not an appropriate measure of project-level climate change impacts and their significance under NEPA or the Natural Gas Act. That is all that is required for NEPA purposes."); *see also EarthReports, Inc. v. FERC*, 828 F.3d 949, 956 (D.C. Cir. 2016); *Sierra Club v. FERC*, 672 F. App'x 38, (D.C. Cir. 2016); *350 Montana v. Bernhardt*, No. CV 19-12-M-DWM, 2020 WL 1139674, *6 (D. Mont. March 9, 2020) (upholding the agency's decision to not use the Social Cost of Carbon because it is too uncertain and indeterminate to be useful); *Citizens for a Healthy Cmty. v. U.S. Bureau of Land Mgmt.*, 377 F. Supp. 3d 1223, 1239-41 (D. Colo. 2019) (upholding the agency's decision to not use the Social Cost of Carbon); *WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41, 77-79 (D.D.C. 2019) (upholding the agency's decision to not use the Social Cost of Carbon).

[761] *See* Fact Sheet: *Social Cost of Carbon* issued by EPA in November 2013, https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html.

[762] Depending on the selected discount rate, the tool can project widely different present-day cost to avoid future climate change impacts. *See generally* Authorization Order, 170 FERC ¶ 61,202 (McNamee, Comm'r, concurring at n.147) ("The Social Cost of Carbon produces wide-ranging dollar values based upon a chose discount rate, and the assumptions made. The Interagency Working Group on Social Cost of Greenhouse Gases estimated in 2016 that the Social Cost of one ton of carbon dioxide for the year 2020 ranged from $12 to $123.").

[763] *See generally* Authorization Order, 170 FERC ¶ 61,202 (McNamee, Comm'r, concurring at P 72) ("When the Social Cost of Carbon estimates that one metric ton of

We have also repeatedly explained that while the methodology may be useful for other agencies' rulemakings or comparing regulatory alternatives using cost-benefit analyses where the same discount rate is consistently applied, it is not appropriate for estimating a specific project's impacts or informing our analysis under NEPA.[764]

248. NRDC also contends that the Commission could apply the projects' emissions to the remaining global carbon budget as outlined in the IPCC's Special Report.[765] We disagree. This approach would obscure the projects' impacts by comparing project emissions to global emissions, and, consequently would compare project emissions at too broad a scale to be useful.

249. Sierra Club argues that there are GHG emission reduction goals that the Commission could use to assess significance.[766] Sierra Club points to, the United States' adoption of a GHG emission reduction goal as part of the Paris climate accords, and states that although the Paris accords are "pending withdrawal," they are still effective.[767]

250. We do not see the utility in using the targets in the Paris climate accords, because the United States had announced its intent to withdraw from the accord.[768] But, even if the Commission were to consider those targets, without additional guidance, the Commission cannot determine the significance of the projects' emissions in relations to

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CO_2 costs $12 (the 2020 cost for a discount rate of five percent), agency decision-makers and the public have no objective basis or benchmark to determine whether the cost is significant. Bare numbers standing alone simply *cannot* ascribe significance.") (emphasis in original) (footnote omitted).

[764] *Mountain Valley*, 161 FERC ¶ 61,043 at P 296. Moreover, Executive Order 13783, Promoting Energy Independence and Economic Growth, has disbanded the Interagency Working Group on Social Cost of Greenhouse Gases and directed the withdrawal of all technical support documents and instructions regarding the methodology, stating that the documents are "no longer representative of governmental policy." Exec. Order No. 13,783, 82 Fed. Reg. 16093 (2017).

[765] NRDC Rehearing Request at 65.

[766] Sierra Club Rehearing Request at 65.

[767] *Id.*

[768] *See* Authorization Order, 170 FERC ¶ 61,202 at n.556. On November 4, 2019, President Trump began the formal process of withdrawing from the Paris Climate Accord by notifying the United Nations Secretary General of his intent to withdraw the United States from the Paris Climate Accord, which takes 12 months to take effect.

the goals. For example, there are no industry sector or regional emission targets or budgets with which to compare project emissions, or established GHG offsets to assess the projects' relationship with emissions targets.

251. Finally, NRDC, Sierra Club, and the State of Oregon, also contend that the Commission should have considered Oregon's climate reduction targets to assess significance.[769] NRDC points out that the terminal's emissions would account for 4.2% and 15.3% of Oregon's 2020 and 2050 targets, respectively—meaning that the terminal would account for almost an eighth of the total state-wide emissions permissible under Oregon law in 2050.[770] The State of Oregon points out that even if there is a lack of authority to meet the GHG emissions goals, the Commission could still use these benchmarks to assess significance.[771] Moreover, Governor Brown of Oregon recently issued an executive order to use existing authority to achieve Oregon's climate reduction goals.[772]

252. We explained in the Authorization Order that while the State of Oregon established a state policy to meet GHG emissions reduction goals, it did not create any additional regulatory authority to meet its goals.[773] Governor Brown's executive order does not change our determination that Oregon's climate goals on their own cannot be used to ascribe significance. The order directed state agencies and commissions to exercise any and all authority and discretion to help facilitate Oregon's GHG emissions reduction goals.[774] As we determined when considering the Paris climate accords,

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[769] NRDC Rehearing Request at 65-66; Sierra Club Rehearing Request at 65; State of Oregon Rehearing Request at 36.

[770] NRDC Rehearing Request at 66.

[771] State of Oregon Rehearing Request at 36.

[772] Sierra Club Rehearing Request at 65-66 (citing Office of the Governor, State of Oregon, Executive Order No. 20-04, DIRECTING STATE AGENCIES TO TAKE ACTIONS TO REDUCE AND REGULATE GREENHOUSE GAS EMISSIONS (March 10, 2020), https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf).

[773] Authorization Order 170 FERC ¶ 61,202 at P 260 (citing Or. Rev. Stat. § 468A.205 (2007)).

[774] Office of the Governor, State of Oregon, Executive Order No. 20-04, DIRECTING STATE AGENCIES TO TAKE ACTIONS TO REDUCE AND REGULATE GREENHOUSE GAS EMISSIONS (March 10, 2020), https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf.

without industry sector or regional emission targets or budgets with which to compare project emissions, or established GHG offsets to assess the projects' relationship with emissions targets, we cannot assess significance based on Oregon's climate reduction goals alone.

5. Mitigation

253. The State of Oregon and NRDC argue that the Commission could have used its authority to condition the Authorization Order with mitigation measures to address the GHGs that will be emitted by the projects.[775] NRDC suggests that the Commission require Pacific Connector and Jordan Cove to mitigate the projects' GHGs by planting trees to sequester the projects' GHG emissions, or purchase renewable energy credits equal to the projects' electricity consumption.[776]

254. We do not believe there are any additional mitigation measures the Commission could impose with respect to the GHG emissions analyzed in the Final EIS. As discussed, the Commission is unable to reach a significance determination for these emissions because of the global nature of climate change; therefore, we see no way to establish appropriate levels of potential mitigation or no way to ensure project-level mitigation measures would be effective.[777]

6. The Commission's Public Interest Determinations under Sections 3 and 7 of the Natural Gas Act

255. Finally, Sierra Club, Ms. McCaffree, and the State of Oregon contend that the Commission's conclusion that it cannot evaluate the significance or severity of GHG emissions undermines FERC's conclusion that overall environmental impacts are, with few specific exceptions, insignificant, and prevents the Commission from properly making the NGA public interest determination.[778] Sierra Club claims that the D.C. Circuit ruled in *Sabal Trail* that the Commission must consider, and therefore decide,

[775] State of Oregon Rehearing Request at 63; NRDC Rehearing Request at 71-72.

[776] *Id.* at 75.

[777] *See generally* Authorization Order, 170 FERC ¶ 61,202 (McNamee, Comm'r, Concurrence at 59-68) (stating it would be inappropriate for the Commission to require mitigation of GHG emissions when "[o]ver the last 15 years, Congress has introduced and failed to pass 70 legislative bills to reduce GHG emissions . . . .").

[778] Sierra Club Rehearing Request at 64-65; McCaffree Rehearing Request at 33; State of Oregon Rehearing Request at 35.

whether a project's contribution to climate change renders the project contrary to the public interest.[779]

256. As discussed, the Commission determined that the NGA section 3 project was not inconsistent with the public interest and the NGA section 7 project was required by the public convenience and necessity based on all information in the record, including the projects' GHG emissions.[780] These annual emissions could impact the State of Oregon's ability to meet its greenhouse gas reduction goals; however, the Commission found that the projects, if constructed and operated as described in the Final EIS with required conditions, are environmentally acceptable actions and, consequently, based on all the other factors discussed in the Authorization Order, the Jordan Cove LNG Terminal is not inconsistent with the public interest and the Pacific Connector Pipeline is required by the public convenience and necessity.[781] We affirm that decision.

Q. Water Resources and Wetlands

1. The Projects Will Not Have Significant Environmental Impacts on Water Resources or Wetlands

257. The State of Oregon and Sierra Club assert that the Commission violated NEPA because the Final EIS underestimates or ignores the LNG terminal's and the pipeline's impacts to water resources and wetlands and because the Final EIS fails to adequately include and analyze mitigation measures for these impacts.[782] Based on these flaws, they also argue that the conclusions that the projects would not significantly affect surface water resources are not supported.

258. The Final EIS explains that terminal and pipeline construction and operations would impact wetlands, groundwater, and surface water, but these impacts would not result in significant environmental impacts.[783]

259. With regard to wetlands, as discussed in the Final EIS, the terminal would impact 86.1 acres of wetlands, including 22.3 acres of wetland loss, while the pipeline would

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[779] Sierra Club Rehearing Request at 64 (citing *Sierra Club v. FERC*, 867 F.3d at 1373).

[780] *See supra* PP 64, 65.

[781] Authorization Order, 170 FERC ¶ 61,202 at P 294.

[782] State of Oregon Rehearing Request at 30-31, 50-57, 59-61, 63-70, 72-77; Sierra Club Rehearing Request at 94-106.

[783] Final EIS at 5-4.

impact 114.1 acres of wetlands and have long-term impacts on 4.9 acres of wetlands.[784] As discussed in more detail below, based on Jordan Cove and Pacific Connector's implementation of mitigation measures to reduce impacts on wetlands, the Final EIS determines that constructing and operating the project would not significantly affect wetlands.[785] Jordan Cove and Pacific Connector also developed a Compensatory Wetland Mitigation Plan to comply with Army Corps requirements, with impacts on freshwater wetland resources mitigated in-kind through the Kentuck Slough Wetland Mitigation Project (Kentuck project)[786] and impacts on estuarine wetland resources mitigated in-kind through the Eelgrass Mitigation site.[787]

260. The projects would not significantly affect groundwater resources. At the terminal, Jordan Cove would implement best management practices and other measures to address any inadvertent releases of equipment-related fluids.[788] At the pipeline, construction and operations could impact springs, seeps, and wells, but any impacts to flow and volume or from inadvertent releases of equipment-related fluids would be mitigated through measures described in its Groundwater Supply Monitoring and Mitigation, Spill Prevention, Containment, and Countermeasures Plan, and Contaminated Substances Discovery Plan.[789]

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[784] *Id.*

[785] Final EIS at 4-139.

[786] The Kentuck project includes 140 acres on the eastern shore of Coos Bay at the mouth of the Kentuck Slough. Final EIS at 2-18. Approximately 9.1 acres of the Kentuck project site would be enhanced and restored to mitigate for permanent impacts on freshwater wetlands. *Id.* at 4-134. Approximately 100.6 of the Kentuck project site would be enhanced and restored to mitigate for permanent impacts on estuarine wetlands and aquatic resources. *Id.* at 4-134 to 4-135.

[787] The Eelgrass Mitigation site is in Coos Bay near the Southwest Oregon Regional Airport. Final EIS at 2-18. Approximately 9.3 acres at the Eelgrass Mitigation site would be enhanced to mitigate for permanent impacts on aquatic resources. *Id.* at 4-134 to 4-135. Jordan Cove also proposes, in addition to the Eelgrass Mitigation site, to remove eelgrass from the access channel prior to dredging and to transplant it into the Jordan Cove embayment, a shallow, low-gradient embayment with continuous to patchy eelgrass beds located approximately 0.5 mile east of the access channel. *Id.* at 4-135.

[788] *Id.* at 5-2.

[789] *Id.* at 5-4.

261. Finally, the Final EIS determines that while the projects would impact surface waters, these impacts would not be significant. The construction of the terminal will temporarily increase turbidity and sedimentation due to initial dredging and such impacts would occur again with maintenance dredging.[790] The LNG carriers will also impact water quality due to discharges of ballast water and engine operations, but these impacts would be highly localized and minor and would not significantly affect water quality.[791] The pipeline would be constructed across or in close proximity to 337 waterbodies, 257 of which are intermittent streams and ditches, 68 are perennial waterbodies, 5 are major waterbodies, and several of which are ponds and other surface water features.[792] Pacific Connecter would cross waterbodies during low-flow periods and during in-water construction windows when possible and would also implement mitigation to reduce impacts associated with vegetation loss and sedimentation risks during construction.[793] Pacific Connector would cross major waterbodies using HDD.[794]

262. The Final EIS therefore determines, and we agree, that impacts on water resources and wetlands would not be significant. Petitioners' more detailed concerns are discussed in depth below.

a. <u>Adequacy of Information</u>

263. The State of Oregon generally contends that the Commission failed to rely on "high quality information and accurate scientific analysis" regarding impacts on water resources, as required under NEPA.[795] The State of Oregon claims that without developing empirical data and advanced models, the Commission cannot accurately identify the suite of direct and indirect biological changes and impacts that are likely to occur in association with the construction and operation of the LNG terminal and cannot

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[790] *Id.* at 5-3.

[791] *Id.*

[792] *Id.*

[793] Final EIS at 5-3.

[794] *Id.*

[795] State of Oregon Rehearing Request at 66 (quoting 40 C.F.R. §§ 1500.1(b), 1502.2 (2019)).

identify the spatial scale over which the impacts are likely to be significant or substantial.[796]

264. The Final EIS fully considers the impact that construction and operation of the Jordan Cove LNG Terminal would have on several biological and ecological resource areas, including: water resources and wetlands;[797] upland vegetation;[798] terrestrial[799] and aquatic wildlife;[800] threatened, endangered, and special-status species;[801] as well as the amount and type of land needed for construction and operation.[802] In assessing these and other impacts, Commission staff relied on a variety of studies and other reference material, a complete list of which was provided to the public.[803] Under NEPA, agencies are "entitled to wide discretion in assessing … scientific evidence"[804] and the State of Oregon does not demonstrate that Commission staff's reliance on this evidence prevented staff from considering the "full suite" of impacts, or their "spatial scale."[805]

b. Mitigation Measures

265. The State of Oregon and Sierra Club contend that the Commission's determination that the Jordan Cove LNG Terminal's impacts on water quality would not be significant is unsupported, as it appears to be based on "purported reliance" on mitigation and minimization measures, details of which Sierra Club states has not been provided to

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[796] *Id.* at 65-66.

[797] Final EIS at 4-84 to 4-94, 4-123 to 4-135.

[798] *Id.* at 4-150 to 4-159.

[799] *Id.* at 4-185 to 4-199.

[800] *Id.* at 4-235 to 4-270.

[801] *Id.* at 4-317 to 4-420.

[802] *Id.* at 4-420 to 4-434.

[803] *Id.* at app. P.

[804] *Earth Island Inst. v. U.S. Forest Serv.*, 351 F.3d at 1301.

[805] State of Oregon Rehearing Request at 66; *see also Mountain Valley*, 161 FERC ¶ 61,043 at P 237 (stating that NEPA does not require the Commission to independently collect data, and that reliance on existing literature is appropriate).

266. enable the Commission to reach such a conclusion.[806] The State of Oregon further asserts that the Commission dismisses adverse environmental impacts on water quality as being "within the purview of the U.S. Army Corps of Engineers"[807] and otherwise takes issue with Commission staff's finding that the applicants' Compensatory Wetland Mitigation Plan would satisfy state and federal regulatory requirements, as it is not yet finalized.[808]

267. Both the State of Oregon and Sierra Club cite to the conclusions of the Commission, or Commission staff, that water quality impacts would not be significant; in doing so, petitioners ignore Commission staff's detailed analysis of such impacts, as well as the relevant mitigation measures. The Final EIS discusses the potential water quality impacts from construction and operation of the projects, as well as the numerous mitigation measures that would be utilized to address them.[809] Commission staff examined how the construction and operation of the projects would potentially impact water quality, as well as the numerous mitigation measures intended to minimize such impacts, including, but not limited to: Jordan Cove's *Wetland and Waterbody Construction and Mitigation Procedures, Dredged Material Management Plan*, *Erosion and Sedimentation Control Plan*, *Spill Prevention, Containment, and Countermeasures Control and Sedimentation Plan*, as well as the implementation of construction procedures and operational controls. Commission staff's analysis addressed how, specifically, Jordan Cove would use these various mitigation measures to avoid, or lessen, water quality impacts.[810]

268. Despite the State of Oregon's assertion, neither the Final EIS nor the Authorization Order dismiss water quality impacts as being a matter solely for the Corps to consider.[811] In addition to Commission staff's own, independent analysis of water quality and wetland impacts and relevant mitigation measures, discussed immediately above, the Final EIS explains that, where unavoidable impacts to wetlands are proposed, the Corps (as well as the EPA and the Oregon Department of State Lands) require that

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[806] Sierra Club Rehearing Request at 96; State of Oregon Rehearing Request at 38-39.

[807] State of Oregon Rehearing Request at 38.

[808] *Id.* at 64-65.

[809] Final EIS at 4-83 to 4-122.

[810] *Id.*

[811] State of Oregon Rehearing Request at 38.

Jordan Cove avoid, reduce, and compensate for these impacts.[812] Jordan Cove prepared the Compensatory Wetland Mitigation Plan to address these unavoidable impacts, and is still working with the Corps, the EPA, the Oregon Department of State Lands, and other state and federal agencies to finalize the plan.[813] Although the Compensatory Wetland Mitigation Plan is noted in the Final EIS' discussion of water quality and wetland impacts, it is not a substitute for Commission staff's independent analysis of water quality and wetland impacts.[814] The State of Oregon may raise any concerns it has about the sufficiency of the Compensatory Wetland Mitigation Program—including subcomponents like the Eelgrass Mitigation plan[815] and the Kentuck Slough Wetland Mitigation project[816]—with the Corps, with its own Oregon Department of State Lands, and with the other applicable federal and state agencies.

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[812] Final EIS at 4-133 to 4-134.

[813] *Id.* at 4-134 to 4-135.

[814] *Id.* at 4-83 to 4-122.

[815] The construction of the Jordan Cove LNG Terminal and the modifications to the federal navigation channel would impact approximately two acres of eelgrass habitat. Final EIS at 4-247. Pursuant to the Compensatory Wetland Mitigation Plan, this eelgrass would be removed from the channel and replanted in the nearby Jordan Cove embayment, and a new 9-acre Eelgrass Mitigation site will be created. *Id.* at 4-247, 4-251. The State of Oregon claims that the Eelgrass Mitigation plan does not adequately consider or resolve concerns that the quality of habitat at the mitigation site will differ from the project-impacted site; that sedimentation at the mitigation site might not be conducive to the survival, growth, and propagation of the replanted eelgrass; and that five years of monitoring is too short to evaluate the long-term success given that replanted eelgrass commonly fails in the Pacific Northwest. State of Oregon Rehearing Request at 68-70. The State of Oregon also states that the plan does not adequately demonstrate whether and how alternative sites were considered and rejected. *Id*. at 69.

[816] Both Jordan Cove and Pacific Connector propose to mitigate the loss of wetlands, including estuarine areas, through the Kentuck project on a 140-acre tract on the eastern shore of Coos Bay. Final EIS at 2-18. They will deposit approximately 0.3 million cubic yards of dredged material at the Kentuck project site. *Id.* The State of Oregon argues that the applicants have not updated plans to describe where this material will be relocated to allow a grading plan to be prepared for the Kentuck project site. State of Oregon Rehearing Request at 70. The State of Oregon asserts that an update is necessary to the grading and erosion control plans for both the Eelgrass Mitigation site and the Kentuck project site, which may result in additional or different impacts to fish and wildlife. *Id.*

2. <u>The Projects' Impacts to Surface Water</u>

a. <u>State Water Quality Standards</u>

i. <u>Oregon DEQ's Denial of the Applicants' Water Quality Certification</u>

269. As discussed above, on May 6, 2019, Oregon DEQ issued a denial of Jordan Cove's and Pacific Connector's requests for CWA section 401 water quality certification. Sierra Club and the State of Oregon claim that the terminal and pipeline as authorized will violate Oregon's state water quality standards.[817] Sierra Club states that when Oregon DEQ denied the water quality certifications, Oregon DEQ indicated that the terminal and project could violate certain state standards, specifically: the terminal may violate the Biocriteria Water Quality Standard due to construction, depositing dredged material in upland areas;[818] the pipeline may violate the Dissolved Oxygen Water Quality Standard due to sediment discharge, the placement of slash and vegetation in waterbodies, and fertilizer runoff;[819] the pipeline may violate the temperature total maximum daily loads due to the loss of vegetation during stream crossings;[820] the pipeline may violate the pH Water Quality Standard because Pacific Connector did not provide site-specific information on debris flow, stream chemistry, landslide hazard assessment, proposed road use and construction, or a maintenance plan;[821] the pipeline may violate the Toxics Substances Water Quality Criteria due to construction near contaminated soils and waters; both projects may violate the standard due to stormwater runoff;[822] and both projects may violate the State of Oregon's Turbidity Water Quality Standard due to dredging of the terminal and construction of the pipeline.[823]

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[817] Sierra Club Rehearing Request at 96.

[818] *Id.* at 98-99.

[819] Sierra Club Rehearing Request at 99.

[820] *Id.* at 101.

[821] *Id.* at 100.

[822] *Id.* at 102.

[823] *Id.* at 104. The Oregon DEQ certification denial also noted that the terminal may violate Oregon's narrative criteria which are general statements designed to protect the aesthetic and health of a waterway.

270. As discussed, the Commission conditioned its authorization on Jordan Cove and Pacific Connector obtaining all necessary federal authorizations. Specifically, Environmental Condition Number 11 requires that no construction, including no ground-disturbing activities, may occur without necessary federal authorizations or waiver thereof; consequently, there is no risk of any project discharges into waters before resolution of state action under section 401 of the CWA.[824] In addition, as discussed above and in more detail below for the temperature and dissolved oxygen, the Commission fully considered the projects' impacts to water quality and determined that there would be no significant impacts.

ii. <u>Dissolved Oxygen and Temperature at the Jordan Cove LNG Terminal</u>

271. The State of Oregon argues that the Jordan Cove LNG Terminal will violate dissolved oxygen protections under the CWA. According to the state, the Coos Bay estuary is listed in Oregon's Integrated Report as a Category 5 waterbody for dissolved oxygen,[825] which means the applicable state water quality standard is not being met and that a Total Maximum Daily Load standard must be adopted.[826] Until this standard is adopted, Oregon claims that the CWA prohibits any discharges that worsen dissolved oxygen levels in the estuary.[827] The State of Oregon argues the Commission has already conceded that the project will violate the CWA because the Final EIS notes that the cumulative impacts in the estuary associated with the project and the Port of Coos Bay Channel Modification will result in an increase in salinity up to 1.5% and "some

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[824] Authorization Order, 170 FERC ¶ 61,202 at app., envtl. condition 11.

[825] The State of Oregon claims that the Coos Bay estuary is listed as impaired for dissolved oxygen and temperature on its CWA § 303(d)(1) list but offers no support for this finding. The State of Oregon's currently effective CWA § 303(d)(1) list, known as the 2012 Integrated Report on Water Quality (Integrated Report), does not list Coos Bay as impaired for dissolved oxygen or temperature. https://www.deq.state.or.us/wq/assessment/rpt2012/results.asp.

[826] State of Oregon Rehearing Request at 38-39.

[827] *Id.* at 39 (citing *Friends of Pinto Creek v. EPA*, 504 F.3d 1007 (9th Cir. 2007) (*Friends of Pinto Creek*). We note that *Friends of Pinto Creek* is inapposite. There the state had an approved CWA § 303(d)(1) list, but it had not prepared the required Total Maximum Daily Load standard. *Friends of Pinto Creek*, 504 F.3d 1011. As discussed, Coos Bay estuary is not listed as impaired for dissolved oxygen or temperature under Oregon's currently effective Integrated Report.

decrease" in dissolved oxygen.[828] According to the State of Oregon, the project will violate water quality standards and the Commission cannot rely upon unknown mitigation, which will presumably be implemented by the Army Corps, to offset known violations of water quality standards.[829]

272. The Final EIS analyzes the cumulative impacts of the Port of Coos Bay's Channel Modification and the project. The Final EIS reports the Army Corps' modeled impacts on dissolved oxygen and salinity from the Port of Coos Bay Channel Modification.[830] The Final EIS explains that tidal exchange rates are the main factor affecting salinity and dissolved oxygen levels in the bay, and that recent Army Corps modeling for the more impactful Port of Coos Bay Channel Modification showed that after channel modification changes, tidal levels and current velocities in the bay would not occur except in a very limited area.[831] The Army Corps modeling for the Port of Coos Bay Channel Modification found despite slight decreases, all dissolved oxygen levels, even during periods of lowest levels, would remain well oxygenated at over 7.7 milligrams per liter.[832] The Final EIS recognizes that the scope of dredging in the bay for the Jordan Cove LNG Terminal is less than the Port of Coos Bay Channel Modification project.[833] Thus, the Final EIS appropriately concludes that the LNG terminal's impacts on dissolved oxygen and salinity when considered with the Port of Coos Bay Channel Modification would not be substantial and that the impacts of the project on water quality would not be significant.[834]

273. Nonetheless, the State of Oregon argues that the Commission may not abdicate its responsibility under the CWA by deferring to mitigation to be required when the Army Corps' approves its channel modification because, the State of Oregon claims, the current record suggests that state water quality standards will be violated,[835] citing *American*

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[828] *Id.* at 38 (citing Final EIS at 4-836).

[829] *Id.* at 40-41 (citing *Am. Rivers v. FERC*, 895 F.3d 32, 54 (D.C. Cir. 2018)).

[830] Final EIS at 4-94.

[831] *Id.*

[832] *Id.*

[833] *Id.*

[834] *Id.*

[835] State of Oregon Rehearing Request at 40-41.

Rivers v. FERC[836] and *Save Our Cabinets v. USDA* for support.[837] Neither case is dispositive. In *American Rivers v. FERC*, the court ruled that the Commission failed to fully examine mitigation for a hydroelectric project to address data that showed that the existing dam violated the state's water quality standard for dissolved oxygen.[838] As discussed, our NEPA analysis shows that the cumulative impacts on dissolved oxygen will not significantly impair water quality. In *Save Our Cabinets v. USDA*, the court determined that the Forest Service violated the CWA by issuing a decision spanning four phases of a mining project, but the state had only approved a water quality permit for the first phase and the Forest Service had failed to support its decision when evidence in the record showed that subsequent phases would violate the state's nondegredation standard.[839] Here, the Commission's Authorization Order has no bearing on the channel modification. Moreover, although we are unable to confirm, as the State of Oregon alleges, that the Coos Bay estuary is impaired for dissolved oxygen and temperature, even if it were, the EIS shows that the Jordan Cove LNG Terminal, when considered cumulatively, will result in little more than minimal impacts on either parameter, either in scope or in magnitude.

iii. <u>Stream Temperature</u>

274. The State of Oregon and Sierra Club argue that the Final EIS errs in claiming that the pipeline's impacts on water temperature will be minor and are adequately mitigated.[840] Rather, the State of Oregon claims, the project will have a significant impact on water temperature due to the project's clearing of riparian vegetation at stream crossings, and along rights of way in proximity to streams.[841] The State of Oregon claims that modeling and monitoring of stream temperatures in certain locations shows that temperatures will exceed state temperature total maximum daily loads developed pursuant to the CWA.[842] For example, the total maximum daily load for the Upper Klamath River and Lost River Subbasins does not allow any additional warming above

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[836] 895 F.3d at 32.

[837] 254 F.Supp.3d 1241, 1254–55 (D. Mont. 2017).

[838] *Am. Rivers v. FERC*, 895 F.3d at 54.

[839] *Save Our Cabinets v. U.S. Dep't of Agric.*, 254 F. Supp. 3d at 1251.

[840] State of Oregon Rehearing Request at 56, 75-76; Sierra Club Rehearing Request at 106.

[841] State of Oregon Rehearing Request at 56.

[842] *Id.* at 56, 75-76.

0 degrees Celsius (°C) from ground disturbing activity, the total maximum daily load for the Rogue River Basin limits any cumulative increase to 0.04 °C, and the total maximum daily load for the Umpqua River Basin sets the cumulative increase at 0.1 °C.[843] The State of Oregon acknowledges that the Final EIS states that project temperature increases will be short term or that the increases can be reduced through a generalized plan to require planting of new riparian vegetation, but claims that despite discussion with Pacific Connector, Pacific Connector has not developed plans to show whether or how additional site-specific mitigation can occur to ensure compliance with applicable state limitations.[844] The State of Oregon argues that the Commission should have considered mitigation that produces in-kind canopy mitigation for trees harvested adjacent to streams.[845]

275. We do not anticipate any violations of the state's total maximum daily load standards. The Final EIS acknowledges that construction within riparian areas could affect aquatic resources by increasing erosion and runoff to nearby streams, losing future large wood input to streams, and increasing stream temperatures.[846] However, any changes in water temperature, related to the 75-to 95-foot-wide right-of-way vegetation clearing at waterbody crossings, are likely to be very small and undetectable through temperature measurements, except for possibly the very smallest perennial streams and occasional intermittent flowing streams that may have flow during a hot period. Any temperature changes that may occur would gradually be reduced or eliminated over time as most riparian vegetation, either from plantings or natural vegetation regrowth, would increase stream shading.[847]

276. The Final EIS includes BLM and Forest Service modeling to support this finding. BLM and Forest Service modeled specific streams to be crossed by the pipeline, which showed that clearings could result in an increase in temperature depending on stream size and flow.[848] Pacific Connector also assessed temperature increases due to loss of riparian vegetation using a Stream Segment Temperature Model.[849] The average modeled

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[843] *Id.* at 76.

[844] State of Oregon Rehearing Request at 57, 77.

[845] *Id.* at 75.

[846] Final EIS at 4-276, 4-299.

[847] *Id.* at 4-302.

[848] *Id.* at 4-300.

[849] *Id.* at 4-118 to 4-119.

temperature increase across a cleared right-of-way for a group of streams were slight, 0.03°F, and the maximum increase among the streams was 0.3°F.[850] This modeling did not account for proposed mitigation within the watershed that may reduce waterbody impacts and literature studies described in the Final EIS that determined that changes in temperature, especially in small streams, may recover quickly from cooler surrounding conditions downstream[851]; therefore, the model's findings can be considered conservative. Estimated stream temperature changes that would result from right-of-way clearing and permanent maintenance are expected to be minor and potential cumulative watershed temperature increases from project riparian clearing would be unlikely.[852]

277. Although these impacts are relatively minor, potential effects would be reduced by best management practices, including the *Erosion Control and Revegetation Plan* and the applicant's Plan and Procedures. For example, Pacific Connector will also limit right-of-way crossings to 75 feet and will locate temporary work areas 50 feet back from waterbody crossings.[853] Pacific Connector will also mitigate potential temperature increases on waterbodies through riparian plantings. This would include, as mitigation for the loss of riparian shade vegetation, replanting the streambanks after construction to stabilize banks and replanting the equivalent of 1:1 ratio for acres of construction or 2:1 for permanent riparian vegetation loss with the goal to restore shade along the affected or nearby stream channels in the same watershed.[854] In light of these measures, we find that no additional mitigation is necessary.

b. Cooling Water Discharges

278. The State of Oregon argues that LNG tanker cooling water discharges will result in temperature increases in and near the project and will likely result in violations of state water quality standards,[855] but does not elaborate on this point or offer any evidence that cooling water discharges will violate any specific water quality standard. The Final EIS determines that cooling water discharges would have temporary and negligible

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[850] *Id.* at 4-118, 4-300.

[851] *Id.* at 4-300 to 4-301.

[852] *Id.* at 4-301.

[853] *Id.*

[854] *Id.* at 4-120.

[855] State of Oregon Rehearing Request at 39.

impacts.[856] Jordan Cove modeled slip temperature changes resulting from the discharge of engine cooling water by an LNG carrier. The results show that the thermal effect of LNG carrier operations at the berth would have very minimal impact on water temperatures.[857]

c. Horizontal Directional Drilling for Pipeline Crossings

279. The State of Oregon argues that the Commission failed to mitigate the high risk of an inadvertent release of HDD fluid, otherwise known as a frac-out, when Pacific Connector uses HDD to cross the Coos Bay estuary, and the Coos, Rogue, and Klamath Rivers.[858] The state contends that required mitigation contained in the *Drilling Fluid Contingency Plan for Horizontal Directional Drilling Operations* is not sufficient because the only requirement is that drilling fluids released to tidal areas of the Coos Bay estuary would be contained and removed, but otherwise there is no requirement that any specific measures would be used to contain drilling fluid.[859]

280. As discussed in the Final EIS[860] and above,[861] the *Drilling Fluid Contingency Plan for Horizontal Directional Drilling Operations* contains several measures designed to prevent frac-outs and mitigate the effects of one in the event a frac-out should occur. Specifically, in the event of a frac-out in an estuarine or aquatic environment, Pacific Connector would halt HDD operations, and seal the leak, and develop a site-specific treatment plan in coordination with appropriate agencies.[862] While the particular suite of mitigation measures employed at a potential frac-out would vary in accordance with the site-specific treatment plan, the *Drilling Fluid Contingency Plan for Horizontal Directional Drilling Operations* provides for mitigation measures including the use of containment structures, monitoring downstream of the HDD to identify drilling mud accumulations, and, if possible, removal of the drilling mud.[863] Therefore, we find that

[856] *Id.* at 4-93.

[857] Final EIS at 4-94.

[858] State of Oregon Rehearing Request at 51-52.

[859] *Id.*

[860] Final EIS at 4-93.

[861] *See supra* P 186.

[862] Final EIS at 4-277.

[863] *Id.*

the potential impacts from frac-outs on estuarine and aquatic environments have been adequately addressed.

d. Impacts to Fish-Bearing Streams

281. The State of Oregon argues that the Commission has failed to take the requisite hard look at the 155 fish-bearing stream crossings associated with the pipeline,[864] Alleging that the negative effects to aquatic/stream habitats resulting from construction and operation of the pipeline will reduce the productive value of the habitats of native fish and amphibians that use these streams and waterways. According to the State of Oregon, there may be significant sedimentation risks, particularly when construction occurs on steep slopes. The State of Oregon notes that coastal sandstone soils are highly susceptible to mass-wasting when undercut, deconsolidated, de-vegetated, and generally disturbed[865] and also states that Commission should have considered mitigation that produces in-kind canopy mitigation for trees harvested adjacent to streams and other measures to mitigate the loss of large woody debris in streams.[866]

282. The Final EIS fully considers the effects on waterbodies and resident and anadromous fish from the removal of riparian vegetation due to stream crossings during construction.[867] The Final EIS takes a hard look at temperature changes to streams, as described above,[868] and also assessed slope failures and erosion along streambeds that could increase sediment, decreased large woody debris in streams, and, while not raised by petitioners, the loss of terrestrial food for aquatic organisms.[869]

283. With regard to the loss of large woody debris, Pacific Connector would replant native tree and shrub species along all fish-bearing streams.[870] Only 23% of the former riparian vegetation cleared by pipeline construction would be restricted to low-growth (herbaceous) vegetation. Approximately 77% of affected riparian vegetation would be allowed to return to pre-construction conditions, thereby reducing impacts on fish

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[864] State of Oregon Rehearing Request at 74.

[865] *Id.*

[866] *Id.* at 75.

[867] Final EIS at 4-299.

[868] *See supra* PP 274-277.

[869] Final EIS at 4-299.

[870] *Id.*

resources.[871] To reduce the impact of clearing riparian vegetation and the subsequent reduction in large woody debris to affected waterbodies, Pacific Connector has developed and would implement a *Large Woody Debris Plan* which includes a proposal to install 733 pieces of large woody debris over several fifth-field watersheds along the pipeline route where the two ESA-listed coho salmon ESUs are present.[872] Additionally, construction and operation of the pipeline would not affect the introduction of large woody debris from upstream sources.

284. The State of Oregon also raises concerns of slope failure near waterbody crossings.[873] The Final EIS acknowledges that slope failures could result in soil deposition and sedimentation of nearby waterbodies and also describes the impacts of turbidity and sedimentation on water quality and aquatic wildlife. As reported in the Final EIS, Pacific Connector considered slope stability in its proposed route and rerouted the pipeline to avoid potentially unstable areas.[874] Some segments of the pipeline route were not accessible to Pacific Connector surveyors and slopes within these segments were not subject to risk analysis. The Final EIS explains that once Pacific Connector has access to these sites, Pacific Connector will assess slope failure; if Pacific Connector determines that the risk of slope failure remains unacceptable, it may reroute the pipeline or implement additional stabilization measures.[875] We note that the Director of the Office of Energy Projects retains authority, under environmental condition 3 of the Authorization Order, to require any additional measures necessary to protect the environment.[876]

3. Wetlands and Estuary Impacts

a. Dredging Impacts

285. The State of Oregon claims that the Final EIS superficially considers the potential effects of dredging on aquatic habitat and species in the Coos Bay estuary.[877] The state

[871] *Id.* at 4-302.

[872] *Id.*

[873] State of Oregon Rehearing Request at 72.

[874] Final EIS at 4-296.

[875] *Id.*

[876] Authorization Order, 170 FERC ¶ 61,202 at app., envtl. condition 3.

[877] The State of Oregon attempts to incorporate supplemental comments on the Final EIS filed by the Oregon Department of Fish and Wildlife. Such incorporation by

provides one example where the Final EIS estimates the rate of recovery of affected benthic habitat and species based on a prior study of a group of small-bodied, rapidly-growing invertebrate species, a study group that according to the State of Oregon does not represent the large-bodied, long-lived bay clams in the estuary.[878]

286. We disagree and find that the Final EIS fully considers the impact of dredging on disturbed benthic habitat and species. In response to comments on the Draft EIS,[879] the Final EIS acknowledges that dredging would remove a variety of organisms with differing rates of recovery.[880] The Final EIS cites and summarizes findings from five studies about the recovery of various benthic communities to pre-dredging conditions[881] and concluded that recovery would likely occur on different timescales for different species: rapid initial colonization in six months after dredging, recovery for most typical benthic species within a year, and no recovery for some species, such as "longer-lived benthic resources (e.g., clams)" that could take several years to fully recover, because initial dredging will be followed by a 3- to 10-year maintenance dredging period.[882]

287. The State of Oregon also asserts that the Final EIS incorrectly illustrates the major known oyster and shrimp habitat and clamming and crabbing areas in the bay, despite the fact that Oregon Department of Fish and Wildlife provided comments on the Draft EIS noting the error.[883]

288. The Final EIS responds to the State of Oregon's comments on the Draft EIS, explaining that the map of these habitats and resources was generated from a cited

reference is improper and is dismissed. *See supra* P 15.

[878] State of Oregon Rehearing Request at 66-67.

[879] Final EIS at app. R, Response SA2-122; *id.* app. R,R-337 ("Wildlife and Aquatic Resources 5").

[880] *Id.* at 4-254 to 4-255.

[881] *Id.* at 4-255. Commission staff relied on a variety of studies and other reference material to compose the Final EIS. A complete list of which was provided to the public. *See id*. app. P.

[882] *Id.* at 4-255.

[883] State of Oregon Rehearing Request at 67.

document and considered to generally represent the habitat types present in Coos Bay.[884] The Final EIS notes that further details about site-specific categories of commercially important species would not substantially change the assessment in the Final EIS.[885] But the Final EIS does modify language and figure 4.5-2 to provide greater clarity.[886] For example, the Final EIS acknowledges, based on information provided by Oregon Department of Fish and Wildlife in 2019, that locally-known clamming areas occur west and southwest of the end of the regional airport runway and along the shoreline near the Eelgrass mitigation site.[887] Under NEPA, agencies are "entitled to wide discretion in assessing … scientific evidence"[888] and the State of Oregon does not demonstrate that Commission staff's reliance on this evidence resulted in a flawed analysis.

289. The State of Oregon claims that the Final EIS underestimates the potential loss of sediment associated with the dredging of four navigational channel enhancements and subsequent impacts on aquatic resources, especially eelgrass.[889] The State of Oregon also asserts that lost sediment may result in further impacts to and loss of eelgrass and benthic invertebrates, and may result in further degradation of the shellfish and fish habitat.[890]

290. The impacts from the potential loss of sediment due to dredging the proposed four navigational channel enhancements in Coos Bay are addressed throughout the Final EIS.[891] The Final EIS acknowledges that side slope equilibration would occur following dredging of the navigational channel over a 6- to 8-year period[892] and also acknowledges that this equilibration and subsequent potential slumping would vary depending on site-specific characteristics. Out of four dredging areas, two sites would experience slight changes in slope equilibration and the other two sites could experience slope equilibration

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[884] Final EIS at app. R, Response SA2-121. A complete list of reference material was provided to the public. *See id*. app. P.

[885] *Id*.

[886] *Id.* at 4-255 fig. 4.5-2; *id*. app. R, Response SA2-121.

[887] *Id.* at 4-245.

[888] *Earth Island Inst. v. U.S. Forest Serv.*, 351 F.3d at 1301.

[889] State of Oregon Rehearing Request at 69.

[890] *Id.*

[891] *E.g.*, Final EIS at 2-10, 2-17 to 2-18, 2-55, 4-86.

[892] *Id.* at 4-54, 4-250.

extending 300 to 700 feet upslope from the dredged areas.[893] In total, these affected areas are a small portion of Coos Bay and are considered deep-water habitat, which is a common habitat in the bay.[894] Impacts on eelgrass,[895] benthic vertebrates,[896] wildlife,[897] aquatic species and habitat,[898] and water quality,[899]which would all be affected by the project, are discussed in the Final EIS.[900] Last, the Final EIS discusses Jordan Cove's proposal to mitigate for the loss of aquatic vegetation.[901] We find that the State of Oregon's claim that sediment loss in dredged areas will be substantial and significant is unsupported.

4. Ground Water Impacts

a. Jordan Cove LNG Terminal's Ground Water Impacts

291. Sierra Club argues that although the Final EIS acknowledges the potential for groundwater reduction and contamination related to the construction and operation of the LNG terminal, it does not provide an analysis of the environmental harm that is likely to occur from these impacts: e.g., harm to species from lost wetland and lake habitat from groundwater withdrawals, long-term impacts to sensitive coastal species or Coos Bay community (including fisheries) from contamination of groundwater. Sierra Club also states that the Final EIS does not appear to provide an analysis of alternatives, including ways to reduce water use and groundwater contamination.[902]

292. Sierra Club states that the Draft EIS identified that the nearest well might drop by 0.5 feet, but the Final EIS fails to acknowledge the potential reduction in that well and

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[893] *Id.*

[894] *Id.* at 4-257.

[895] *Id.* at 4-134, 4-191, 4-251.

[896] *Id.* at 4-133, 4-238, 4-241, 4-250 to 4-256, 4-270.

[897] *Id.* at 4-196, 4-235, 4-247.

[898] *Id.* at 4-249 to 4-270.

[899] *Id.* at 4-76 to 4-79, 4-84 to 4-94, 4-123 to 4-135.

[900] *Id*. at 4-87, 4-132, 4-249, 4-252 to 4-254.

[901] *E.g., id.* at 4-133.

[902] Sierra Club Rehearing Request at 104-106.

fails to consider what that drop would do to local lakes and wetlands, including the wetlands in the proposed mitigation site close to the well. Further, Sierra Club asserts that participants in scoping asked the Commission to consider the impact of using these wells on the Oregon Dunes ecosystem, but the Final EIS fails to address the issue.[903]

293. Sierra Club states that the Final EIS fails to take a hard look at the potential impacts of the Jordan Cove LNG Terminal project on several potentially affected communities and their drinking supplies, many of which are already sensitive to contaminants of concern and many of which have already invested in expensive technology to clean and disinfect water.[904]

294. We disagree and deny rehearing on these issues. The Final EIS acknowledges that project-related groundwater withdrawals would impact surface water resources.[905] The Final EIS describes modeling completed by the applicants that estimates the maximum drawdown of wells could be up to 6 inches but would usually be less.[906] However, the impact of this drawdown would likely be temporary, as about 90% of project water use at the LNG terminal would occur during construction.[907] Following construction, naturally occurring groundwater replenishment would occur and groundwater levels are expected to return to normal levels. The Final EIS acknowledges that the withdrawal and use of groundwater may impact wetlands and surrounding vegetation.[908] These impacts would occur primarily during construction and, as described above, are expected to return to pre-disturbance conditions following construction.

b. <u>Pacific Connector Pipeline's Drinking Water Impacts</u>

295. Sierra Club objects to Pacific Connector's proposed mitigation measures in the event the Pacific Connector Pipeline impacts groundwater supplies.[909] Sierra Club

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[903] *Id.* at 106.

[904] *Id.*

[905] Final EIS at 4-77.

[906] *Id.*

[907] *Id.* at 4-77 tbl. 4.3.1.1-1.

[908] *Id.* at 4-133, 4-156.

[909] *Id.* Specifically, if a groundwater supply is affected by the project, Pacific Connector would work with the landowner to provide a temporary supply of water; if determined necessary, Pacific Connector would provide a permanent water supply to replace affected groundwater supplies (restore, repair, or replace); and mitigation

asserts that trucking in bottled water, or piping in drinking water from an alternate water source, would not fully mitigate the loss of groundwater, due to high costs, the difficulty associated with implementing this requirement, residents' decline in quality of life, and the significant reduction in land value.[910]

296. The Final EIS and Authorization Order explain that the pipeline would cross wellhead protection areas and be in proximity to groundwater-fed springs and seeps and private wells.[911] The Final EIS determines that the project would not significantly affect groundwater resources due to required mitigation, including Pacific Connector's *Groundwater Supply Monitoring and Mitigation Plan* for springs, seeps, and wells located within 200 feet of construction disturbance, *Spill Prevention, Containment, and Countermeasures Plan* and *Contaminated Substances Discovery Plan*.[912] We address concerns regarding potential impacts to landowners' wells above.[913] No additional mitigation is necessary.

297. In addition, Sierra Club alleges that the Commission failed to assess the projects' impacts on municipal water supplies.[914] The Final EIS determines that the Jordan Cove LNG Terminal would not impact any Coos Bay – North Bend Water Board wells,[915] and that neither the Jordan Cove LNG Terminal nor the Pacific Connector Pipeline would impact any EPA-designated sole-source aquifers,[916] with the nearest aquifer located approximately forty miles from either project.[917] As noted in the Final EIS and the

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measures would be coordinated with the individual landowner to meet the landowner's specific needs and would be tailored to each property. Final EIS at 4-83.

[910] *Id.*

[911] Authorization Order, 170 FERC ¶ 61,202 at P 205; EIS at 4-77 to 4-81.

[912] *Id.* P 205.

[913] *See supra* P 183.

[914] Sierra Club Rehearing Request at 106.

[915] Final EIS at 4-76, 4-80.

[916] Per the EPA, a "sole-source aquifer" supplies at least 50% of the drinking water in an area where no alternative drinking water source is available that could physically, legally, or economically supply the area.

[917] Final EIS at 4-80.

Authorization Order,[918] the Pacific Connector Pipeline will cross six wellhead protection areas.[919] However, as explained above, with the implementation of Pacific Connector's mitigation measures, impacts to groundwater resources, which would include municipal water supplies, would not be significant.[920]

R. Forest Plans

298. Sierra Club claims that the Authorization Order violates the National Forest Management Act because the Forest Service's proposed amendments essentially exempt the Pacific Connector Pipeline from numerous forest plan requirements to preserve and protect National Forests affected by the pipeline.[921] Sierra Club argues that the Forest Service failed to adhere to 2012 Forest Service requirements that the Forest Service create new plan components that meet the resource protection requirements that the Pacific Connector Pipeline project cannot meet.[922] Sierra Club also claims that the Forest Service and the Commission failed to properly analyze the proposed forest plan amendments or identify, let alone analyze, other needed amendments to forest plans related to Late-Successional Reserve land, soil, water quality, riparian areas, and other resources.[923]

299. The Pacific Connector Pipeline will cross approximately 31 miles of Forest Service lands within the Umpqua, Rogue River, and Winema National Forests.[924] The Forest Service operates the lands under forest plans known as Land and Resource Management Plans pursuant to the National Forest Management Act.[925] Contrary to Sierra Club's claims, the Commission did not propose any Land and Resource

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[918] *Id.* at 4-80 to 4-81; Authorization Order, 170 FERC ¶ 61,202 at P 205.

[919] A wellhead protection area is defined as the surface and subsurface area surrounding a water well or well field, supplying a public water system, through which contaminants are reasonably likely to move toward and reach such a water well or well field. Final EIS at 4-80.

[920] *See supra* P 294.

[921] Sierra Club Rehearing Request at 91-92.

[922] *Id.* at 92.

[923] *Id.* at 93-94.

[924] Authorization Order, 170 FERC ¶ 61,202 at P 232.

[925] *See id.*

Management Plan amendments and the Authorization Order has no impact on the Forest Service's proposed amendment process; the Land and Resource Management Plan process is exclusively within the Forest Service's jurisdiction. The Forest Service analyzed amending its Land and Resource Management Plans to allow for the project to be sited within forest lands and solicited comments on the proposed amendments during the Draft EIS comment period.[926] The Forest Service will make final decisions on the respective authorizations before it, and Pacific Connector must obtain a right-of-way grant from BLM pursuant to the Mineral Leasing Act to cross federal lands, which may include compensatory mitigation requirements recommended by the Forest Service.[927]

300. Sierra Club also suggests that, because the pipeline project allegedly violates the National Forest Management Act, the Commission should not have authorized the pipeline until these issues were resolved.[928] As discussed, the Commission appropriately conditioned its authorization in Environmental Condition 11 on Pacific Connector obtaining required federal authorizations, including any required right-of-way grant, which are dependent upon required Land and Resource Management Plans amendments, before beginning pipeline construction or any other ground disturbing activities.[929]

S. Cumulative Impacts

301. Ms. McCaffree argues that the Commission failed to adequately analyze the cumulative impacts of the projects and should have conducted a more searching cumulative impacts analysis beyond citing to tables and lists of historic and proposed actions.[930] Sierra Club asserts there was inadequate discussion and analysis of reasonable outgrowth associated with the development of a pipeline and LNG terminal at Coos Bay or the potential for colocation of other pipelines in same corridor to facilitate growth of this industrial development.[931]

302. CEQ defines cumulative impacts as "the impact on the environment which results from the incremental impact of the action when added to other past, present, and

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[926] *Id.*

[927] *Id.*

[928] Sierra Club Rehearing Request at 5.

[929] *See supra* P 75; *see also* Authorization Order, 170 FERC ¶ 61,202 at app., envtl. cond. 11.

[930] McCaffree Rehearing Request at 31-32.

[931] Sierra Club Rehearing Request at 62-63.

reasonably foreseeable future actions."[932] The "determination of the extent and effect of [cumulative impacts], and particularly identification of the geographic area within which they may occur, is a task assigned to the special competency of the appropriate agencies."[933] CEQ has explained that "it is not practical to analyze the cumulative effects of an action on the universe; the list of environmental effects must focus on those that are truly meaningful."[934] Further, a cumulative impact analysis need only include "such information as appears to be reasonably necessary under the circumstances for evaluation of the project rather than to be so all-encompassing in scope that the task of preparing it would become either fruitless or well nigh impossible."[935] An agency's analysis should be proportional to the magnitude of a proposed action; actions that will have no significant direct or indirect impacts usually only require a limited cumulative impacts analysis.[936] A meaningful cumulative impacts analysis must identify five things: "(1) the area in which the effects of the proposed project will be felt; (2) the impacts that are expected *in that area* from the proposed project; (3) other actions—past, present, and proposed, and reasonably foreseeable—that have had or expected to have impacts *in the same area*; (4) the impacts or expected impacts from these other actions; and (5) the overall impact that can be expected in the individual impacts are allowed to accumulate."[937]

303. The Authorization Order noted that the EIS considers the cumulative impacts of the proposed Jordan Cove LNG Terminal and Pacific Connector Pipeline with other

[932] 40 C.F.R. § 1508.7 (2019).

[933] *Kleppe v. Sierra Club*, 427 U.S. 390, 414 (1976).

[934] CEQ, *Considering Cumulative Effects Under the National Environmental Policy Act* at 8 (Jan. 1997), https://energy.gov/sites/prod/files/nepapub/nepa_documents/RedDont/G-CEQ-ConsidCumulEffects.pdf (1997 CEQ Guidance).

[935] *Natural Res. Def. Council, Inc. v. Callaway*, 524 F.2d 79, 88 (2d Cir. 1975).

[936] *See* CEQ, Memorandum on Guidance on Consideration of Past Actions in Cumulative Effects Analysis at 2-3 (June 24, 2005) (2005 CEQ Guidance).

[937] *TOMAC v. Norton*, 433 F.3d 852, 964 (D.C. Cir. 2006) (emphasis added) (quoting *Grand Canyon Trust v. FAA*, 290 F.3d 339, 345 (D.C. Cir. 2002) (internal quotations omitted). *See also Columbia Gas Transmission, LLC*, 149 FERC ¶ 61,255, at P 113 (2014).

projects in the same geographic and temporal scope of the projects.[938] The types of other projects evaluated in the Final EIS that could potentially contribute to cumulative impacts include: Corps permits and mitigation projects, minor federal agency projects (including road/utility improvements, water flow control, weed treatments, and miscellaneous mitigation), residential and commercial development, timber harvest and forest management activities, livestock grazing, and solar panel fields.[939] As part of the cumulative impacts analysis, Commission staff also considered non-jurisdictional utilities at the terminal site, the use of LNG carriers, ongoing maintenance dredging, modifications to the Coos Bay Federal Navigation Channel, project impact mitigation projects, and the potential removal of four dams on the Klamath River.[940]

304. As described in the Authorization Order, the Final EIS concludes that, for the majority of resources where a level of impact could be ascertained, the projects' contribution to cumulative impacts on resources affected by the projects would not be significant, and that the potential cumulative impacts of the projects and other projects considered would not be significant.[941] However, the Authorization Order found that the Jordan Cove LNG Terminal and Pacific Connector Pipeline would have significant cumulative impacts on housing availability in Coos Bay, the visual character of Coos Bay, and noise levels in Coos Bay.[942] We affirm that the analysis of cumulative impacts was consistent with the requirements of NEPA and deny Ms. McCaffree's and Sierra Club's arguments on rehearing.

<u>The Commission orders</u>:

(A) Jordan Cove Energy Project, L.P. and Pacific Connector Gas Pipeline, LP's request for rehearing is hereby granted in part and denied in part, as discussed in the body of the order.

(B) The requests for rehearing filed by the Natural Resources Defense Council; Oregon Department of Energy, Oregon Department of Environmental Quality, Oregon Department of Fish and Wildlife, and Oregon Department of Land Conservation and Development; Sierra Club; the Cow Creek Band of Umpqua Tribe of Indians; the

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[938] Authorization Order, 170 FERC ¶ 61,202 at PP 267-268; Final EIS at 4-822 to 4-852.

[939] Authorization Order, 170 FERC ¶ 61,202 at PP 267-268; Final EIS at 4-825.

[940] Authorization Order, 170 FERC ¶ 61,202 at PP 267-268; Final EIS at 4-828.

[941] Authorization Order, 170 FERC ¶ 61,202 at PP 267-268; Final EIS at 4-852.

[942] Authorization Order, 170 FERC ¶ 61,202 at PP 267-268; Final EIS at 4-852.

Klamath Tribes; Confederated Tribes of the Coos, Lower Umpqua, and Siuslaw Indians; and Citizens for Renewables, Inc., Citizens Against LNG, and Jody McCaffree are hereby dismissed or denied, as discussed in the body of this order.

(C) The requests for stay filed by Sierra Club and the Natural Resources Defense Council are dismissed as moot, as discussed in the body of this order.

(D) The requests for rehearing filed by Kenneth E. Cates, Kristine Cates, James Davenport, Archina Davenport, David McGriff, Emily McGriff, Andrew Napell, Dixie Peterson, Paul Washburn, and Carol Williams are rejected, as discussed in the body of this order.

(E) Jordan Cove Energy Project, L.P. and Pacific Connector Gas Pipeline, LP's request for clarification is hereby granted, as discussed in the body of the order, and Environmental Condition No. 34 is modified to read:

> Pacific Connector shall file a noise survey with the Secretary no later than 60 days after placing the Klamath Compressor Station in service. If a full load condition noise survey is not possible, Pacific Connector shall provide an interim survey at the maximum possible horsepower load and provide the full load survey no later than 60 days after all liquefaction trains at the LNG Terminal are fully in service. If the noise attributable to the operation of all of the equipment at the Klamath Compressor Station under interim or full horsepower load conditions exceeds an Ldn of 55 dBA at any nearby NSAs, Pacific Connector shall file a report on what changes are needed and shall install the additional noise controls to meet the level within 1 year of the in-service date that immediately preceded the noise survey showing an exceedance. Pacific Connector shall confirm compliance with the above requirement by filing a second noise survey with the Secretary no later than 60 days after it installs the additional noise controls.

By the Commission. Commissioner Glick is dissenting with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Jordan Cove Energy Project L.P.	Docket Nos. CP17-495-000
Pacific Connector Gas Pipeline, LP	CP17-494-000

(Issued May 22, 2020)

GLICK, Commissioner, *dissenting*:

1. I dissent from today's order because it violates both the Natural Gas Act[1] (NGA) and the National Environmental Policy Act[2] (NEPA). Rather than wrestling with the Project's[3] significant adverse impacts, today's order makes clear that the Commission will not allow these impacts to get in the way of its outcome-oriented desire to approve the Project.[4]

2. As an initial matter, the Commission continues to treat climate change differently than all other environmental impacts. The Commission steadfastly refuses to assess whether the impact of the Project's greenhouse gas (GHG) emissions on climate change is significant, even though it quantifies the GHG emissions caused by the Project's construction and operation.[5] That refusal to assess the significance of the Project's contribution to the harm caused by climate change is what allows the Commission to perfunctorily conclude that "the environmental impacts associated with the Project are

[1] 15 U.S.C. §§ 717b, 717f (2018).

[2] National Environmental Policy Act of 1969, 42 U.S.C. §§ 4321 *et seq.*

[3] Today's order denies rehearing and motions for stay of the Commission's order authorizing both the Jordan Cove LNG export terminal (LNG Terminal) pursuant to NGA section 3, 15 U.S.C. § 717b (2018), and the Pacific Connector interstate natural gas pipeline (Pipeline) pursuant to NGA section 7, *id.* § 717f. I will refer to these two projects collectively as the Project.

[4] *Jordan Cove Energy Project L.P.*, 171 FERC ¶ 61,136, PP 245, 253 (2020) (Rehearing Order); *Jordan Cove Energy Project L.P.*, 170 FERC ¶ 61,202, at P 262 (2020) (Certificate Order); Final Environmental Impact Statement for the Jordan Cove Project at 4-850–4-851 (EIS).

[5] Certificate Order, 170 FERC ¶ 61,202 at P 259; EIS at Tables 4.12.1.3-1, 4.12.1.3-2, 4.12.1.4-1 & 4.12.1.4-2.

"acceptable"[6] and, as a result, conclude that the Project satisfies the NGA's public interest standards.[7] Claiming that a project's environmental impacts are acceptable while at the same time refusing to assess the significance of the project's impact on the most important environmental issue of our time is not reasoned decisionmaking.

3. Moreover, the Commission's public interest analysis still does not adequately wrestle with the Project's adverse environmental impacts. The Project will significantly and adversely affect several threatened and endangered species, and historic properties, and it will limit the supply of short-term housing near the Project. It will also cause elevated noise levels during construction and impair the visual character of the local community. Although the Commission recites those adverse impacts, at no point does it explain how it considered them in making its public interest determination or why it finds that the Project satisfies the relevant public interest standards notwithstanding those substantial impacts. Simply asserting that the Project is in the public interest without any discussion why is not reasoned decisionmaking.

4. It is also important to briefly mention landowners. The underlying order approved a significant change to the route of the pipeline, taking it across new properties and affecting new landowners. Recognizing that this was a possibility early on, those landowners intervened in the proceeding. And following the underlying order, they filed a rehearing request. The Commission rejected this rehearing request for two reasons. First, as the Commission notes, the request was received at 7:54 p.m. Eastern Time (4:54 p.m. Pacific Time) on April 20, the last day to seek rehearing of that underlying order. Under the Commission's regulations, filings received after 5:00 p.m. Eastern Time are deemed filed the next day.[8] Second, the rehearing request did not contain a detailed set of arguments as is also required by our regulations. As a result, today's order leaves these landowners with no option to pursue judicial review and leaves this proceeding with no entity capable of fully representing their interests. Under those circumstances

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[6] Rehearing Order, 171 FERC ¶ 61,136 at PP 65-66; Certificate Order, 170 FERC ¶ 61,202 at P 294; EIS at ES-19. *But see* Certificate Order, 169 FERC ¶ 61,131 at PP 155, 220-223, 237, 242, 253, 256 (noting that the environmental impacts of the Project would be significant with respect to several federally listed threatened and endangered species, visual character in the vicinity of the LNG Terminal, short-term housing in Coos County, historic properties along the Pipeline route, and noise levels in Coos County).

[7] Rehearing Order, 171 FERC ¶ 61,136 at PP 65-66; Certificate Order, 170 FERC ¶ 61,202 at P 294.

[8] The Commission's business hours are "from 8:30 a.m. to 5:00 p.m.," and filings made after 5:00 p.m. will be considered filed on the next regular business day. *See* 18 C.F.R. §§ 375.101(c), 2001(a)(2) (2019).

and given the considerable issues at stake—as a result of underlying order, their property is now subject to condemnation—I would have waived the relevant regulations for good cause, rather than effectively snuffing any chance they may have to vindicate their rights on judicial review. We've heard a lot recently about how the Commission is willing to bend over backwards to accommodate landowners. Except we never actually see it.

- **The Commission's Public Interest Determinations Are Not the Product of Reasoned Decisionmaking**

5. The NGA's regulation of LNG import and export facilities "implicate[s] a tangled web of regulatory processes" split between the U.S. Department of Energy (DOE) and the Commission.[9] The NGA establishes a general presumption favoring the import and export of LNG unless there is an affirmative finding that the import or export "will not be consistent with the public interest."[10] Section 3 of the NGA provides for two independent public interest determinations: One regarding the import or export of LNG itself and one regarding the facilities used for that import or export.

6. DOE determines whether the import or export of LNG is consistent with the public interest, with transactions among free trade countries legislatively deemed to be "consistent with the public interest."[11] The Commission evaluates whether "an application for the siting, construction, expansion, or operation of an LNG terminal" is itself consistent with the public interest.[12] Pursuant to that authority, the Commission

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[9] *Sierra Club v. FERC*, 827 F.3d 36, 40 (D.C. Cir. 2016) (*Freeport*).

[10] 15 U.S.C. § 717b(a); *see EarthReports, Inc. v. FERC*, 828 F.3d 949, 953 (D.C. Cir. 2016) (citing *W. Va. Pub. Servs. Comm'n v. Dep't of Energy*, 681 F.2d 847, 856 (D.C. Cir. 1982) ("NGA [section] 3, unlike [section] 7, 'sets out a general presumption favoring such authorization.'")). Under section 7 of the NGA, the Commission approves a proposed pipeline if it is shown to be consistent with the public interest, while under section 3, the Commission approves a proposed LNG import or export facility unless it is shown to be inconsistent with the public interest. *Compare* 15 U.S.C. § 717b(a) *with id.* § 717f(a), (e).

[11] 15 U.S.C. § 717b(c). The courts have explained that, because the authority to authorize the LNG exports rests with DOE, NEPA does not require the Commission to consider the upstream or downstream GHG emissions that may be indirect effects of the export itself when determining whether the related LNG export facility satisfies section 3 of the NGA. *See Freeport*, 827 F.3d at 46-47; *see also Sierra Club v. FERC*, 867 F.3d 1357, 1373 (D.C. Cir. 2017) (*Sabal Trail*) (discussing *Freeport*). Nevertheless, NEPA requires that the Commission consider the direct GHG emissions associated with a proposed LNG export facility. *See Freeport*, 827 F.3d at 41, 46.

[12] 15 U.S.C. § 717b(e). In 1977, Congress transferred the regulatory functions of

must approve a proposed LNG facility unless the record shows that the facility would be inconsistent with the public interest.[13] In addition, section 7 of the NGA requires the Commission to determine whether the pipeline component of the Project is required by the public convenience and necessity,[14] a standard the courts have likened to the public interest standard.[15] Today's order fails to satisfy these standard in multiple respects.

- **<u>The Commission's Public Interest Determination Does Not Adequately Consider Climate Change</u>**

7. In making its public interest determination, the Commission examines a proposed facility's impact on the environment and public safety. A facility's impact on climate change is one of the environmental impacts that must be part of a public interest determination under the NGA.[16] Nevertheless, the Commission maintains that it need not consider whether the Project's contribution to climate change is significant in this order because it lacks a means to do so—or at least so it claims.[17] However, the most troubling part of the Commission's rationale is what comes next. Based on this alleged inability to assess the significance of the Project's impact on climate change, the Commission still summarily concludes that all of the Project's environmental impacts would be

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NGA section 3 to DOE. DOE, however, subsequently delegated to the Commission authority to approve or deny an application for the siting, construction, expansion, or operation of an LNG terminal, while retaining the authority to determine whether the import or export of LNG to non-free trade countries is in the public interest. *See EarthReports*, 828 F.3d at 952-53.

[13] *See Freeport*, 827 F.3d at 40-41.

[14] 15 U.S.C. § 717f (2018).

[15] *E.g.*, *Atl. Ref. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 391 (1959) (holding that the NGA requires the Commission to consider "all factors bearing on the public interest").

[16] *See Sabal Trail*, 867 F.3d at 1373 (explaining that the Commission must consider a pipeline's direct and indirect GHG emissions because the Commission may "deny a pipeline certificate on the ground that the pipeline would be too harmful to the environment"); *see also Atl. Ref. Co.*, 360 U.S. 378 (holding that the NGA requires the Commission to consider "all factors bearing on the public interest").

[17] Certificate Order, 170 FERC ¶ 61,202 at P 262; EIS at 4-4-850.

"acceptable."[18] Think about that. With that "logical hopscotch,"[19] the Commission is simultaneously stating that it cannot assess the significance of the Project's impact on climate change[20] while concluding that all environmental impacts are acceptable to the public interest.[21] That is unreasoned and an abdication of our responsibility to give climate change the "hard look" that the law demands.[22]

8. It also means that the Project's impact on climate change does not play a meaningful role in the Commission's public interest determination, no matter how often the Commission assures us that it does. Using the approach in today's order, the Commission will always conclude that a project will not have a significant environmental impact irrespective of that project's actual GHG emissions or those emissions' impact on climate change. If the Commission's conclusion will not change no matter how many GHG emissions a project causes, those emissions cannot, as a logical matter, play a meaningful role in the Commission's public interest determination. A public interest determination that systematically excludes the most important environmental consideration of our time is contrary to law, arbitrary and capricious, and not the product of reasoned decisionmaking.

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[18] Rehearing Order, 171 FERC ¶ 61,136 at PP 65-66; Certificate Order, 170 FERC ¶ 61,202 at P 294.

[19] NRDC Rehearing Request at 42.

[20] Certificate Order, 170 FERC ¶ 61,202 at P 262; EIS at 4-4-850 ("[W]e are unable to determine the significance of the Project's contribution to climate change.").

[21] Rehearing Order, 171 FERC ¶ 61,136 at PP 65-66; Certificate Order, 170 FERC ¶ 61,202 at P 294 (stating that the environmental impacts are acceptable and further concluding that the Jordan Cove LNG Terminal is not inconsistent with the public interest and that the Pacific Connector Pipeline is required by the public convenience and necessity).

[22] *See, e.g.*, *Myersville Citizens for a Rural Cmty., Inc. v. FERC*, 783 F.3d 1301, 1322 (D.C. Cir. 2015) (explaining that agencies cannot overlook a single environmental consequence if it is even "arguably significant"); *see also Michigan v. EPA*, 135 S. Ct. 2699, 2706 (2015) ("Not only must an agency's decreed result be within the scope of its lawful authority, but the process by which it reaches that result must be logical and rational." (internal quotation marks omitted)); *Motor Vehicle Mfrs. Ass'n, Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (explaining that agency action is "arbitrary and capricious if the agency has . . . entirely failed to consider an important aspect of the problem, [or] offered an explanation for its decision that runs counter to the evidence before the agency").

9. The failure to meaningfully consider the Project's GHG emissions is all-the-more indefensible given the volume of GHG emissions at issue in this proceeding. The Project will directly release over 2 million tons of GHG emissions per year.[23] The Commission recognizes that climate change is "driven by accumulation of GHG in the atmosphere through combustion of fossil fuels (coal, petroleum, and natural gas), combined with agriculture, clearing of forests, and other natural sources"[24] and that the "GHG emissions from the construction and operation of the projects will contribute incrementally to climate change."[25] In light of this undisputed relationship between anthropogenic GHG emissions and climate change, the Commission must carefully consider the Project's contribution to climate change when determining whether the Project is consistent with the public interest—a task that it entirely fails to accomplish in today's order.

- **<u>The Commission's Consideration of the Project's Other Adverse Impacts Is Also Arbitrary and Capricious</u>**

10. In addition, the Project will have a significant adverse effect on more than 20 Federally-listed threatened and endangered species—including whale, fish, and bird species[26]—as well as historic properties along the Pipeline route[27] and short-term housing in Coos County.[28] It will also cause harmful noise levels in the area[29] and impair the

[23] Certificate Order, 170 FERC ¶ 61,202 at P 259; EIS at Tables 4.12.1.3-1, 4.12.1.3-2, 4.12.1.4-1 & 4.12.1.4-2 (estimating the Project's direct and indirect emissions from construction and operation, including vessel traffic).

[24] EIS at 4-849.

[25] Certificate Order, 170 FERC ¶ 61,202 at P 262.

[26] *Id.* PP 220-223.

[27] *Id.* P 253; EIS at 4-683. Following the completion of some land surveys, the Commission states that at least 20 sites along the Pipeline route are eligible historic properties and cannot be avoided. EIS at 5-9 ("Constructing and operating the Project would have adverse effects on historic properties under Section 106 of the [National Historic Preservation Act].").

[28] Certificate Order, 170 FERC ¶ 61,202 at P 242; EIS at 4-631–4-635 (finding that the construction of the Project may have significant effects on short-term housing in Coos County, Oregon, which could include potential displacement of existing and potential residents, as well as tourists and other visitors); *see also* Certificate Order, 170 FERC ¶ 61,202 at P 279 (further concluding that these impacts would more acutely impact low-income households).

[29] EIS at 4-717–4-721. The Commission finds that pile driving associated with

visual character of the surrounding community.[30] Although the Commission discloses the adverse impacts throughout the EIS and mentions them in today's order,[31] it does not appear that they factor meaningfully, if at all, into the Commission's public interest analysis. Simply deeming those adverse impacts to be "acceptable" without any explanation of how that conclusory finding supports the Commission's public interest determination is a far cry from reasoned decisionmaking.[32]

11. Rehearing parties make this very point, arguing the Commission's public interest determinations fails to account for adverse environmental impacts.[33] The Commission's only response is to regurgitate its usual boilerplate that "balancing of adverse impacts and public benefits is an economic test, not an environmental analysis" and that it will consider environmental impacts if the Project's benefits outweigh the adverse effect on economic interests.[34] That response certainly does nothing to clarify *how* environmental impacts are considered in the Commission's public interest determination, if they are considered at all.

12. The Commission also points us to a series statements about the purported need for the Project[35] and its public benefits, assuring us that, as a result, all environmental impact

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LNG Terminal construction occurring 20 hours per day for two years would result in a significant impact on the local community.

[30] Certificate Order, 170 FERC ¶ 61,202 at P 237.

[31] *Id.* PP 155, 220-223, 237, 242, 253, 256 (noting that the environmental impacts of the Project would be significant with respect to several federal-listed threatened and endangered species, visual character in the vicinity of the LNG Terminal, short-term housing in Coos County, historic properties along the Pipeline route, and noise levels in Coos County).

[32] That is particularly important when it comes to the Commission's section 7 authorization of the Pipeline because it conveys eminent domain authority, 15 U.S.C. § 717f(h) (2018), and roughly a quarter of the private landowners have not reached easement agreements, meaning that, upon issuance of the certificate, they may be subject to condemnation proceedings.

[33] Sierra Club Rehearing Request at 22-24; NRDC Rehearing Request at 36-43; State of Oregon Rehearing Request at 29, 46; McCaffree Rehearing Request at 10.

[34] Rehearing Order, 171 FERC ¶ 61,136 at P 64; *see also* Certificate Order, 170 FERC ¶ 61,202 at P 92.

[35] Rehearing Order, 171 FERC ¶ 61,136 at P 65. *But see infra* PP 13-19.

are "acceptable."[36] But that again does not explain how the Commission considered those impacts or why the benefits rendered them "acceptable."[37] Taken seriously, the Commission's rationale, and the absence of any actual explanation for why the Project satisfies the relevant public interest standards despite the significant environmental impacts, suggests that environmental impacts cannot meaningfully factor into the Commission's application of the public interest. Indeed, if serious impacts are on more than 20 threatened and endangered species are not even worth a mention in the Commission's public interest analysis, one cannot help but doubt that they play a role in the Commission's decisionmaking process. The failure to explain how the Commission considered those adverse impacts in making its decision would seem to conflict with the Supreme Court's guidance that it must consider "all factors bearing on the public interest,"[38] not to mention basic principles of reasoned decisionmaking.

- **<u>This Record Demanded a More Thorough Review of the Need for the Pipeline</u>**

13. In addition to the above failures, the Commission finds that Pacific Connector Pipeline is needed based solely on its agreement with Jordan Cove, an affiliate of the same corporate parent, Pembina. As I have previously explained, precedent agreements between affiliates—e.g., a pipeline developer and a shipper that are part of the same larger enterprise—are not necessarily sufficient to show that a proposed project is "needed" for the purposes of a certificate of public convenience and necessity under section 7 of the NGA.[39] That is because, unlike ordinary precedent agreements, agreements between affiliates are not necessarily the product of arms-length negotiations and may reflect the best interests of their shared corporate parent, without indicating a genuine need for the pipeline. That does not, however, mean that precedent agreements between affiliates are irrelevant when evaluating the need for proposed pipeline. Instead, the absence of arms-length negotiations underscores the importance of considering all

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[36] *Id.*

[37] *Cf. Am. Tel. & Tel. Co. v. FCC*, 974 F.2d 1351, 1355 (D.C. Cir. 1992) (holding that "conclusory assertions" regarding hard issues are not the basis of reasoned decisionmaking).

[38] *See Atl. Ref. Co.*, 360 U.S. at 391 (holding that the NGA requires the Commission to consider "all factors bearing on the public interest"); *see also Sabal Trail*, 867 F.3d at 1373 (explaining that the Commission may "deny a pipeline certificate on the ground that the pipeline would be too harmful to the environment").

[39] *See generally Spire STL Pipeline LLC*, 169 FERC ¶ 61,134 (2019) (Glick, Comm'r, dissenting at P 13).

evidence that may bear on the need for the proposed pipeline, which is, after all, exactly what the Commission's 1999 Certificate Policy Statement contemplates.[40]

14. A proposed pipeline that will serve as an LNG export facility's sole source of supply can often make the need showing without too much difficulty. After all, as the Commission has previously explained, an LNG export facility cannot go forward without a source of natural gas. But where there is serious doubt about whether the export facility will actually be developed, the Commission must both take a harder look at whether putative export facility is sufficient to establish a need for the pipeline or support a finding that the project is required by the public convenience and necessity. After all, a section 7 certificate conveys the authority to exercise eminent domain, and it would be unconscionable for this Commission to permit a developer to seize private land for a project that has little chance of ever being completed.

15. This case demands that sort of hard look. The evidence suggests a number of reasons to doubt whether the Project will ever be developed. For one thing, the LNG market was on the decline when the Commission issued the certificate order and the intervening months have not provided much reason to hope that things will turn around.[41] A global downturn in the market, coupled with uncertain prospects in the months and years ahead, ought to compel the Commission to at least examine the assumption that the LNG export facility will be built and create the only conceivable need for the pipeline. That is especially so here because, unlike some of the LNG export facilities that the Commission has certificated over the last year, Jordan Cove does not have any contracts for its putative LNG output.[42] Moreover, the state of Oregon has consistently raised concerns about Project and its ability to satisfy various outstanding permitting

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[40] *See* Certification of New Interstate Nat. Gas Pipeline Facilities, 88 FERC ¶ 61,227, 61,747-48 (1999) (1999 Certificate Policy Statement).

[41] NRDC Rehearing Request at 32 (citing Irina Slay, *www.oilprice.com*, *Giant LNG Projects Fact Coronavirus Death or Delay* (Mar. 17, 2020), https://oilprice.com/Energy/Natural-Gas/Giant-LNG-Projects-Face-Coronavirus-Death-OrDelay.html (noting the glut in LNG supply and the instabilities in the LNG market given trade issues and coronavirus)).

[42] *Cf.* Venture Global LNG, *PGNiG and Venture Global LNG sign agreement for the sales and purchase of LNG from the* USA, https://venturegloballng.com/press/pgnig-and-venture-global-lng-sign-agreement-for-the-sales-and-purchase-of-lng-from-the-usa/ (last visited May 21, 2020). This is not to suggest that such contracts are a necessary perquisite to a finding of need for a section 7 facility. But, where the record otherwise suggests concerns about the likelihood a project will be developed, the absence of any contracts only heightens those concerns.

requirements, including section 401 of the Clean Water Act,[43] state air quality permits[44]—not to mention the outstanding questions regarding the Coastal Zone Management Authorization (which Oregon has already rejected)[45] and the pending requests for Forest Service authorization to cross federal lands.[46] Finally, Jordan Cove has been attempting to develop this Project for roughly 15 years at this point. While not dispositive on its own, the long and winding road that the project has taken to date ought to cause the Commission to exercise a little caution before assuming the next step will clear the way for its eventual development, meaning that the time has come to permit Jordan Cove to take private property.[47]

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[43] *See also* Oregon Entities Rehearing Request at 15-18 (discussing the history of Jordan Cove's Clean Water Act section 401 and section 404 applications).

[44] *Id.* at 33 ("In its [F]EIS, FERC asserts that operational emissions from the proposed new sources will remain below thresholds requiring a PSD Permit. . . . That conclusion is incorrect. [The Oregon Department of Environmental Quality] has not yet determined whether the operation of the proposed facilities will require a major new source review and PSD permit or a minor PSD permit, because the applicants have indicated continuing uncertainty about the exact nature of the liquefaction facilities and the Malin compressor station.").

[45] *Id.* at 25-26.

[46] Rehearing Order, 171 FERC ¶ 61,136 at P 299.

[47] These points take on added significance given the Commission's prior denial of the Project based on its failure to show it was needed. As the Natural Resources Defense Council points out in its request for rehearing, the only material change between the application that the Commission rejected in 2016 and the one it accepted in 2020 was the single affiliated precedent agreement. *See* NRDC Rehearing Request at 13-16 (citing, among others, *FCC v. Fox Television Stations, Inc.*, 566 U.S. 502 (2009) and *Organized Vill. of Kake v. U.S. Dep't of Agric.*, 795 F.3d 956, 966-70 (9th Cir. 2015) (en banc)). In denying the prior application in 2016, the Commission noted that the project developer had "failed to make any significant showing of demand," even though "submittal of precedent agreements was but one indicia of demand that an applicant could file to demonstrate the public benefits of its project." *Jordan Cove Energy Project, L.P.*, 157 FERC ¶ 61,194, at P 23 (2016). Especially in light of that prior finding of a complete absence of evidence indicating need and the 1999 Policy Statement's contemplation that the Commission would consider all relevant evidence bearing on need for a pipeline, reasoned decisionmaking requires the Commission to do more than simply point to the agreement among affiliates and call it a day.

16. On their own, none of those factors would necessarily require a hard look at the LNG facility's prospects as part of the Commission's section 7 review. But, together, they cannot be ignored. There is simply too much uncertainty in this record to justify the Commission's finding that the project is needed, that it is required by the public convenience, or that conveying the authority to exercise eminent domain is appropriate at this time. At the very least, the Commission should stay the operation of the certificate, and, with it, the authority to exercise eminent domain, pending a resolution of the numerous pending state proceedings or a showing that Jordan Cove is prepared to actually begin developing the Project.

17. Unfortunately, today's order doubles down on the conclusion that the single precedent agreement is a sufficient basis—and the sole basis—for finding that the pipeline project is needed and required by the public convenience and necessity.[48] The Commission's 1999 Certificate Policy statement, however, contemplates more holistic inquiry that weighs the extent of the need for a project against its adverse impacts. Today's order, however, makes no effort to discuss the considerable uncertainty clouding the need for the Project or how that uncertainty factors into its weighing of the adverse impacts, including the exercise of eminent domain[49] and the effects on environmental and cultural resources that lie along the pipeline's 229-mile path.[50] Especially given the Commission's increasingly frequent and fervent assurances of its concern for landowners, one would have thought that the Commission would have at least taken into account the considerable uncertainty surrounding the project before enabling the use of eminent domain for a project that may never be built. The absence of any such discussion is hard to square with that purported concern.

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[48] *See* Rehearing Order, 171 FERC ¶ 61,136 at P 35, 44. In so doing, the Commission is quick to point to D.C. Circuit cases that have upheld its reliance on precedent agreements, including a few that have done so when it comes to agreements among affiliates. But, as I have previously explained, the Court has never held that such agreements are always a sufficient condition to show the need for a proposed pipeline—the position the Commission takes in today's order. *See generally Spire STL Pipeline*, 169 FERC ¶ 61,134 (Glick, Comm'r, dissenting at PP 15-16) (discussing the D.C. Circuit's jurisprudence on precedent agreements). Instead, the court has recognized that contrary record evidence may make precedent agreements an insufficient basis on which to find a need for the new pipeline. *Id.* PP 15-16.

[49] 1999 Certificate Policy Statement, 88 FERC ¶ 61,227 at 61,749 ("The strength of the benefit showing will need to be proportional to the applicant's proposed exercise of eminent domain procedures.").

[50] *See* Rehearing Order, 171 FERC ¶ 61,136 at P 7.

- **<u>The Commission Fails to Satisfy Its Obligations under NEPA</u>**

18. The Commission's NEPA analysis of the Project's GHG emissions is similarly flawed. As an initial matter, in order to evaluate the environmental consequences of the Project under NEPA, the Commission must consider the harm caused by its GHG emissions and "evaluate the 'incremental impact' that those emissions will have on climate change or the environment more generally."[51] As noted, the operation of the Project will emit more than 2 million tons of GHG emissions per year.[52] Although quantifying the Project's GHG emissions is a necessary step toward meeting the Commission's NEPA obligations, listing the volume of emissions alone is insufficient.[53] Identifying the consequences that those emissions will have for climate change is essential if NEPA is to play the disclosure and good government roles for which it was designed. The Supreme Court has explained that NEPA's purpose is to "ensure[] that the agency, in reaching its decision, will have available, and will carefully consider, detailed information concerning significant environmental impacts" and to "guarantee[] that the relevant information will be made available to the larger audience that may also play a role in both the decisionmaking process and the implementation of that decision."[54] It is

[51] *Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1216 (9th Cir. 2008); *WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41, 51 (D.D.C. 2019) (explaining that the agency was required to "provide the information necessary for the public and agency decisionmakers to understand the degree to which [its] decisions at issue would contribute" to the "impacts of climate change in the state, the region, and across the country").

[52] Certificate Order, 170 FERC ¶ 61,202 at P 258; EIS at Tables 4.12.1.3-1, 4.12.1.3-2, 4.12.1.4-1 & 4.12.1.4-2 (estimating the Project's direct and indirect emissions from the Project's construction and operation, including vessel traffic associated with the LNG Terminal).

[53] *See Ctr. for Biological Diversity*, 538 F.3d at 1216 ("While the [environmental document] quantifies the expected amount of CO_2 emitted . . . , it does not evaluate the 'incremental impact' that these emissions will have on climate change or on the environment more generally."); *Klamath-Siskiyou Wildlands Ctr. v. Bureau of Land Mgmt.*, 387 F.3d 989, 995 (9th Cir. 2004) ("A calculation of the total number of acres to be harvested in the watershed is a necessary component . . . , but it is not a sufficient description of the actual environmental effects that can be expected from logging those acres.").

[54] *Dep't of Transp. v. Pub. Citizen*, 541 U.S. 752, 768 (2004) (citing *Robertson v. Methow Valley Citizens Coun.*, 490 U.S. 332, 349 (1989)).

hard to see how hiding the ball by refusing to assess the significance of the Project's climate impacts is consistent with either of those purposes.

19. In addition, under NEPA, a finding of significance informs the Commission's inquiry into potential ways of mitigating environmental impacts.[55] An environmental review document must "contain a detailed discussion of possible mitigation measures" to address adverse environmental impacts.[56] "Without such a discussion, neither the agency nor other interested groups and individuals can properly evaluate the severity of the adverse effects" of a project, meaning that an examination of possible mitigation measures is necessary to ensure that the agency has taken a "hard look" at the environmental consequences of the action at issue.[57]

20. The Commission responds that it need not determine whether the Project's contribution to climate change is significant because "[t]here is no universally accepted methodology" for assessing the harms caused by the Project's contribution to climate change.[58] But the lack of a single consensus methodology does not prevent the Commission from adopting *a* methodology, even if it is not universally accepted. The Commission could, for example, select one methodology to inform its reasoning while also disclosing its potential limitations or the Commission could employ multiple methodologies to identify a range of potential impacts on climate change. In refusing to assess a project's climate impacts without a perfect model for doing so, the Commission sets a standard for its climate analysis that is higher than it requires for any other environmental impact.

21. Furthermore, even without any formal tool or methodology, the Commission can consider all factors and determine, quantitatively or qualitatively, whether the Project's

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[55] 40 C.F.R. § 1502.16 (2019) (requiring an implementing agency to form a "scientific and analytic basis for the comparisons" of the environmental consequences of its action in its environmental review, which "shall include discussions of . . . [d]irect effects and their significance.").

[56] *Robertson*, 490 U.S. at 351.

[57] *Id.* at 352.

[58] EIS at 4-850 (stating that "there is no universally accepted methodology to attribute discrete, quantifiable, physical effects on the environment to Project's incremental contribution to GHGs" and "[w]ithout the ability to determine discrete resource impacts, we are unable to determine the significance of the Project's contribution to climate change."); *see also* Certificate Order, 170 FERC ¶ 61,202 at P 262 ("The Commission has also previously concluded it could not determine whether a project's contribution to climate change would be significant.").

GHG emissions will have a significant impact on climate change. After all, that is precisely what the Commission does in other aspects of its environmental review, where the Commission makes several significance determinations based on subjective assessments of the extent of the Project's impact on the environment.[59] The Commission's refusal to similarly analyze the Project's impact on climate change is arbitrary and capricious.

22. The Commission also suggests that it cannot determine the significance GHG emissions because it "has no way to . . . assess how that amount contributes to climate change" without a way to "link physical effects caused by the projects' GHG emissions." Nonsense. The Commission acknowledges that every single ton of GHG emissions, including those from the Project,[60] contributes to climate change, which causes discrete adverse effects across the globe and in the Project region.[61] That is more than enough of a basis to evaluate the effects of the Project's GHG emissions on climate change. After all, even the recent Council on Environmental Quality draft NEPA guidance on consideration of GHG emissions—hardly a radical environmental manifesto—recognizes that the quantity of GHG emissions "may be used as a proxy for assessing potential climate effects."[62] And yet, contrary to even that guidance, today's order insists that a quantity of GHG emissions cannot be used to tell us anything about the Project's effects

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[59] *See, e.g.*, EIS at 4-184, 4-619–4-620, 4-645 (concluding that there will be no significant impact on vegetation, Tribal subsistence practices, and marine vessel traffic). The Commission makes these determinations without any disclosing any "metric for assessing the significance of the environmental impact on these resources," contrary to the Commission's claim in today's order, *see* Rehearing Order, 171 FERC ¶ 61,136 at P 245.

[60] Certificate Order, 170 FERC ¶ 61,202 at P 262.

[61] EIS at 4-701, 4-706, 4-848–4-849 (finding that the Project results in 2 million tons of GHGs annually, that climate change is "driven by accumulation of GHG in the atmosphere," and that the specific climate change impacts *in the Project region* with a high or very high level of confidence include increase in stream temperatures reducing salmon habitat, more frequent winter storms, warming trends that exacerbate snowpack loss increasing the risk for insect infestation and wildfires, longer periods between rainfall leading to depletion of aquifers and strain on surface water resources, and increases in evaporation and plant water loss rates resulting in saltwater intrusion into shallow aquifers).

[62] Draft National Environmental Policy Act Guidance on Consideration of Greenhouse Gas Emissions, 84 Fed. Reg. 30,097, 30,098 (2019) ("A projection of a proposed action's direct and reasonably foreseeable indirect GHG emissions may be used as a proxy for assessing potential climate effects.").

on climate change or the significance thereof.[63] That proposition makes sense only if you do not believe that there is a direct relationship between GHG emissions and climate change.

23. In any case, as noted, the Commission does not apply this same standard when assessing the significance of the Project's other environmental impacts. For example, consider how the Commission discusses the Project's impact on upland vegetation, particularly forested land. It finds that the forested land affected by the Project supports "multiple interacting layers of organisms that include plants, animals, fungi, and bacteria"[64] and that the loss of an acre of forested land causes adverse effects on the supported organisms. In evaluating whether the Project's impact on forested land is significant, the Commission relies on acreage as the proxy for actual adverse environmental impacts, and concludes that the 2,750 acres of lost forested land would not be significant.[65] The Commission does not attempt to link those specific 2,750 acres of forested land to direct or quantifiable adverse effects for the purpose of assessing significance. Yet, this is exactly the standard the Commission suggests it must meet to assess the significance the quantity of GHG emissions on climate change. The Commission's insistence on applying a dramatically higher standard before it can assess the Project's climate change impacts is arbitrary and capricious.

24. In addition, the Commission has repeatedly justified its refusal to consider the significance of a Project's impact on climate change on the basis that it lacks "any GHG emission reduction goals established either at the federal level or by the [state]" with which to compare the Project's emissions.[66] Oregon, however, has an established "GHG

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[63] Rehearing Order, 171 FERC ¶ 61,136 at P 245 ("To assess a project's effect on climate change, the Commission can only quantify the amount of project emissions, but it has no way to then assess how that amount contributes to climate change.").

[64] EIS at 4-150.

[65] *Id.* at 4-184.

[66] *See, e.g.*, *Alaska Gasline Dev. Corp.*, 171 FERC ¶ 61,134, at P 215 (2020) (Alaska LNG Certificate Order) ("[W]e are unaware of any GHG emission reduction goals established either at the federal level or by the State of Alaska . . . . Without either the ability to determine discrete resource impacts or an established target to compare GHG emissions against, the final EIS concludes that it cannot determine the significance of the project's contribution to climate change."); Alaska LNG Project Final Environmental Impact Statement, Docket No. CP17-178-000, at 4-1222 (Mar. 6, 2020) (Alaska LNG EIS); Rio Grande LNG Final Environmental Impact Statement, Docket No. CP16-454-000, at 4-482 (Apr. 26, 2019) (asserting the Commission has "not been able to find any GHG emission reduction goals established either at the federal level or by the [state]. Without either the ability to determine discrete resource impacts or an established

emission reduction goal[]" in the form a legislative goal of reducing GHG emissions 10 percent below 1990 levels by 2020 and 75 percent below 1990 levels by 2050.[67] As NRDC noted on rehearing, the emissions from the Project would represent an eighth of the entire state-wide emissions allowable under the state's 2050 goal.[68] That is exactly the type of significance analysis that the Commission has been suggesting it could perform in order after order over the past couple of years.

25. Recognizing that, under its own standard, it might have to finally consider climate change, the Commission moves the goal posts once again, this time suggesting that Oregon's goals cannot inform a significance determination because they are aspirational and the legislature "did not create any additional regulatory authority to meet its goals."[69] More nonsense. The issue before us is whether the emissions from the Project are significant, not whether the state has the authority to enforce its goals. A comparison with state targets is relevant because it provides the context that the Commission has repeatedly claimed it needs to assess significance. The enforceability of those standards is irrelevant for the purposes of that exercise.

26. In any case, as noted, the Commission has repeatedly, including again today, suggested that these "goals" or "targets" are what it needs in order to assess the significance of a project's GHG emissions.[70] It is hard to imagine a more arbitrary and capricious action than an agency excusing itself from considering a Project's impact on climate change because there is no goal or target to compare the emissions with and then *on the same day*, when presented with such a goal, asserting that it cannot use that goal or

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target to compare GHG emissions against, we are unable to determine the significance of the Project's contribution to climate change").

[67] *See* Certificate Order, 170 FERC ¶ 61,202 at P 260; NRDC Rehearing Request at 65-66; Sierra Club Rehearing Request at 65; State of Oregon Rehearing Request at 36.

[68] NRDC Rehearing Request at 66; *see* Certificate Order, 170 FERC ¶ 61,202 at P 261 (recognizing the state's goals and acknowledging that the Project's GHG emissions would "represent 4.2 percent and 15.3 percent of Oregon's 2020 and 2050 GHG goals, respectively").

[69] Rehearing Order, 171 FERC ¶ 61,136 at P 253.

[70] *See, e.g.*, Alaska LNG Certificate Order, 171 FERC ¶ 61,134 at P 215 ("[W]e are unaware of any GHG emission reduction *goals* established either at the federal level or by the State of Alaska . . . . Without either the ability to determine discrete resource impacts or an established *target* to compare GHG emissions against, the final EIS concludes that it cannot determine the significance of the project's contribution to climate change." (emphasis added)); Alaska LNG EIS, Docket No. CP17-178-000, at 4-1222.

target because, in the Commission's judgment, the state lacks adequate to realize that goal.

27. It is clear what is going on. The Commission will say whatever it needs to in order to avoid having to evaluate whether a project's GHG emissions are significant or whether the impact of those emissions on climate change is itself significant. For the better part of the last two years, the Commission has made excuse after excuse for why it does not need to consider climate change in its decisionmaking process. Today's contradictory LNG orders are just a particularly clear example of the Commission's serial attempts to duck its responsibilities. That will continue until a court steps in to set things right.

28. In any event, even if the Commission were to find that the Project's GHG emissions are significant, that is not the end of the analysis. Instead, as noted above, the Commission could blunt those impacts through mitigation—as the Commission often does with regard to other environmental impacts. The Supreme Court has held that an environmental review must "contain a detailed discussion of possible mitigation measures" to address adverse environmental impacts.[71] As noted above, "[w]ithout such a discussion, neither the agency nor other interested groups and individuals can properly evaluate the severity of the adverse effects."[72]

29. Consistent with this obligation, the EIS discusses mitigation measures to ensure that the Project's adverse environmental impacts (other than its GHG emissions) are reduced to less-than-significant levels.[73] And throughout today's order, the Commissions uses its broad conditioning authority under section 3 and section 7 of the NGA[74] to implement these mitigation measures, which support its public interest finding.[75] For

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[71] *Robertson*, 490 U.S. at 351.

[72] *Id.* at 351-52; *see also* 40 C.F.R. § 1508.20 (2019) (defining mitigation); *id.* § 1508.25 (including in the scope of an environmental impact statement mitigation measures).

[73] *See, e.g.*, EIS at 4-656 (discussing mitigation required by the Commission to address motor vehicle traffic impacts from the Project).

[74] 15 U.S.C. § 717b(e)(3)(A); *id.* § 717f(e); Certificate Order, 170 FERC ¶ 61,202 at P 293 ("[T]he Commission has the authority to take whatever steps are necessary to ensure the protection of environmental resources . . . , including authority to impose any additional measures deemed necessary.").

[75] *See* Certificate Order, 170 FERC ¶ 61,202 at P 293 (explaining that the environmental conditions ensure that the Project's environmental impacts are consistent

example, the Commission uses this broad conditioning authority to mitigate the impact on short-term housing in Coos County caused by the influx of workers during construction of the LNG Terminal and Pipeline. The Commission concludes that the influx of workers will not only create a short-term rental shortage during the peak tourist season, but this impact would be acutely felt by low-income households.[76] To mitigate this significant impact, the Commission requires Jordan Cove to designate a Construction Housing Coordinator to address these housing concerns. Despite this use of our conditioning authority to mitigate adverse impacts, the Project's climate impacts continue to be treated differently, as the Commission refuses to identify any potential climate mitigation measures or discuss how such measures might affect the magnitude of the Project's impact on climate change.

30. Finally, the Commission's refusal to seriously consider the significance of the impact of the Project's GHG emissions is even more mystifying because NEPA "does not dictate particular decisional outcomes."[77] NEPA "'merely prohibits uninformed—rather than unwise—agency action.'"[78] The Commission could find that a project contributes significantly to climate change, but that it is nevertheless in the public interest because its benefits outweigh its adverse impacts, including on climate change. In other words, taking the matter seriously—and rigorously examining a project's impacts on climate change—does not necessarily prevent any of my colleagues from ultimately concluding that a project satisfies the relevant public interest standard.

For these reasons, I respectfully dissent.

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Richard Glick
Commissioner

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with those anticipated by the environmental analysis).

[76] *Id.* P 279.

[77] *Sierra Club v. U.S. Army Corps of Engineers*, 803 F.3d 31, 37 (D.C. Cir. 2015).

[78] *Id.* (quoting *Robertson*, 490 U.S. at 351).

Document Content(s)

Pacific Connector Gas Pipeline, LP

Resource Report No. 4

Cultural Resources

Pacific Connector Gas Pipeline Project

September 2017

Agency	Agency Comment #	Agency Comment (Original PCGP Report Text as Quoted are in " ")	Response Summary
		have some issues. Some of the issues listed in these spreadsheets overlap with the issues I noted in my April 25, 2017 email (and attachment).	
BLM	39	I did not review the unanticipated discovery plan. Seems like the best time to do this is when there is new consultation on the document related to the new MOA.	Noted, PCGP acknowledges that BLM did not review the Unanticipated Discovery Plan.
Reclamation	1	General comment regarding information that Reclamation will require: 1) Copies of all Klamath Tribes correspondence (to and from) and notes of contacts with them. 2) Maps illustrating Areas of Potential Effects and Reclamation lands. 3) Map indicating survey completion and any cultural resources identified on Reclamation lands.	PCGP to provide to Reclamation after the filing.
FERC	1	Include a description of the Project's impacts in terms of direct and indirect effects on cultural resources. Include a discussion of impacts on traditional tribal resources, including culturally significant natural resources and water quality, based on tribal input and ethnographic research. Include a justified and concise description and a map of the indirect area of potential effect (APE).	Indirect and Direct Effect impacts are provided in Section 4.2.1.1. and 4.2.1.2, respectively. Additional research and discussion with Tribes is necessary before natural resources can be addressed. Information will be provided in a forthcoming report.

Agency	Agency Comment #	Agency Comment (Original PCGP Report Text as Quoted are in " ")	Response Summary
FERC	2	Include a description of the Reconnaissance Level Survey and Intensive Level Survey for aboveground resources in the direct and indirect APE.	Information provided in Supplemental Report (Derr et al. 2017 - Section 7).
FERC	3	Include Appendix B.4 – Cultural Resources Survey and Evaluation Reports. Also include all cultural resources reports completed to date and which are being used in support of this application, even if those reports were submitted with previous applications.	Reports included.
FERC	4	Include a copy of the updated cultural resources addendum report (Derr et al. 2017) mentioned on page 2, and document that this addendum was also submitted to the Oregon State Historic Preservation Office (SHPO), interested Indian Tribes, and other appropriate consulting parties. Provide FERC with copies of the reviews of this report by the SHPO, tribes, and other appropriate consulting parties.	Derr et al. 2017 included with filing. Other requested documentation will be provided after submitted to the agencies and comments are received.
FERC	5	Document follow-up communications with appropriate federal agencies regarding their reviews of 2010, 2013, and 2015 cultural resources addendum reports (mentioned on page 5), and file copies of the comments of the agencies on those reports (Knutson et al. 2010; Bowden et al. 2013; Ragsdale et al. 2013; and Derr et al. 2015).	Agency comments are provided in Appendix 4A.
FERC	6	Document follow-up communications with the National Park Service and the California-Nevada Chapter of the Oregon-California Trails Association regarding their review of potential Project impacts on the portions Applegate Branch Trail that would be crossed by the Pacific Connector Pipeline	Agency comments are provided in Appendix 4A.

Agency	Agency Comment #	Agency Comment (Original PCGP Report Text as Quoted are in " ")	Response Summary
		route (mentioned on page 5), and file their comments.	
FERC	7	Include evidence of concurrence from the SHPO with National Register of Historic Places (NRHP) recommendations and assessment of project effects for all cultural resources identified in the APE, including Isolated Finds.	Agency comments are provided in Appendix 4A.
FERC	8	Include a revision to Table 4.1.1 that updates communications with all interested Indian Tribes, and includes the Confederated Tribes of the Siletz Reservation.	Table 4.1-1 has been updated.
FERC	9	Include complete version of Tables 4.2-1, 4.2-3, 4.2-4, 4.2-5, and 4.2-6.	Tables have been updated.
FERC	10	Regarding Table 4.2-2: explain the difference between the "Date Survey Completed" and "Date Phase II Completed" columns.	Changed "Phase II to "NRHP Evaluation" in Table.
FERC	11	Include a table indicating the schedule of future archaeological work, including additional surveys in unsurveyed portions of the direct and indirect APEs, geoarchaeological deep testing, and NRHP-eligibility testing.	Table 4.2-12 has been added, but not yet filled in (pending response/directive from JCLNG on schedule).
FERC	12	Include a revised Historic Property Management Plan that discusses all cultural resources identified to date within the APE, details efforts to evaluate and assess effects on unevaluated resources, as well as guidelines for avoidance and monitoring of recommended resources. 20170811	An updated HPMP will be provided once SHPO, Agencies, and Tribes provide comments and/or concur with Derr et al. 2015 and Derr et al. 2017.

Agency	Agency Comment #	Agency Comment (Original PCGP Report Text as Quoted are in " ")	Response Summary
FERC	13	Include a copy of a Treatment Plan for site 35DO1107, that includes measures that should be implemented to avoid, reduce, or mitigate impacts on this historic archaeological site. Document that copies of the Site 35DO1107 Treatment Plan were sent to the SHPO and the Forest Service, and file copies of the reviews of this plan by the SHPO and Forest Service.	HRA will consult with USFS and SHPO to prepare a Treatment Plan. The approved plan will be submitted to FERC at a later date.
FERC	14	Include any updates regarding communications (e.g., with the SHPO and Indian Tribes) conducted since filing of the draft version of Resource Report 4. Describe any applicable previous communications conducted in support of previous applications.	Agency and Tribal comments are provided in Appendix 4A.
FERC	15	Include the status of agreements between Pacific Connector Gas Pipeline LP (PCGP) and the Cow Creek Band of Umpqua Indians and the Klamath Tribes.	PCGP continues to meet with Cow Creek Band and Klamath Tribes to promote dialogue and agreements for the project.
FERC	16	Include a literature cited section, which provides the full reference for all literature cited in Resource Report 4.	References Cited Added as Section 4.3.
FERC	17	Include a summary of cultural resources and impacts that would occur on federally managed lands, including survey acreage calculations. Identify all cultural resources on federally managed lands, their evaluations, and concurrence from the federal land managing agencies.	HRA will provide acreage calculations for inclusion in RR4. All sites and their current NRHP status are provided in RR4 tables and in Appendix D.4.

Agency	Agency Comment #	Agency Comment (Original PCGP Report Text as Quoted are in " ")	Response Summary
FERC	18	Include a description of PCGP's review of Tribal Historic Preservation Offices databases. Provide the results of this literature review, and include a map that illustrates identified traditional, religious, and cultural, resources in relation to proposed Project facilities, and list distances in feet. Discuss direct and indirect impacts on these resources resulting from the Project, and describe measures that would be implemented to avoid, reduce, or mitigate those impacts.	Sentence added to RR4 stating that the request was made and documentation included in Appendix 4A. Information gathered from request will be submitted to FERC at a later date.
FERC	19	Include an ethnographic/traditional-use study. This study should describe potential project-related impacts on tribal traditional resources and proposed measures to avoid, reduce, or mitigate those impacts. Explain if and how PCGP would allow access and use of those resources within the Project area by tribal members. Address the following: a. Subsistence and ceremonial species of importance to Native Americans within the project area; b. Traditional and modern Native American use of the Project area, including, but not limited to, residence, hunting, gathering, religious/sacred/ceremonial uses, and myth tale sites; c. Assessment of the impacts of the project on the traditional use areas, tribal activities, and ceremonies.	Add same response as for Terminal.
FERC	20	Identify any Indian Trust Assets (fee lands and lands held in trust by U.S. government) within and near the project area. Describe potential Project impacts on these lands and proposed measures to avoid, reduce, or	Tribal land ownership is addressed in Resource Report 8, Section 8.5.1.1.

for screening soil, the need to consult tribal databases for resources that may not be in the SHPO databases, the need to look for fish weirs that could be buried 100 feet in depth, the need for more subsurface survey of high probability areas, the need for geoarchaeological deep testing in locations with significantly deep impacts, the lack of adequacy of proposed construction monitoring efforts for future construction, and the lack of acknowledgment of an alluvial deposit buried 95-125 ft below the surface of Ingram Yard dating to 5,000 to 15,000 years ago in draft resource reports.

The LNG Terminal RR 4 and attached survey/overview reports address many of these concerns by documenting a recommended project APE, discussing the cultural context of the project area (see Appendix A.4 to the LNG Terminal RR 4), and discussing potentially affected resources identified to date.

A broader ethnographic analysis of natural (plant and animal) resources as cultural resources or the more ceremonial aspects of the importance of the known and potentially unknown resources (i.e., vision quest sites, ceremonial sites, myth inspiring sites, song inspiring sites, prayer locations, and sacred places) will be undertaken in late 2017 and early 2018. This will focus on issues raised by the CTCLUSI, assess the implications of existing documentation of potential TCPs within the Project APE and include an updated review of tribal databases.

No other tribes have provided feedback or concerns regarding TCPs. PCGP sent additional letters on April 27, 2017, to interested Tribes in order to validate the initial analysis on TCPs as the Project proceeds through the FERC application process.

4.2 CULTURAL RESOURCE SURVEY

4.2.1 Area of Potential Effects

According to 36 C.F.R. § 800.16(d), the APE is defined as the geographic area or areas within which an undertaking may directly or indirectly cause alterations in the character or use of historic properties. Because the APE may be different for different kinds of effects, PCGP is considering both a direct and indirect effects APE for the Pipeline. As of August 1, 2017, approximately 90 percent (or 205.3 miles of the 229 mile pipeline corridor) of the cultural resource survey of the APE has been completed. Description of survey methods are provided in Section 4.2.3.

4.2.1.1 Direct Effects APE

The direct effects APE includes all geographic areas that will potentially experience ground disturbances from the construction, operation, and maintenance of the Pipeline. As described in Resource Report 1, PCGP proposes to utilize a 95-foot-wide temporary construction right-of-way with a 50-foot-wide permanent easement. The Pipeline will also include temporary extra work areas ("TEWAs") and uncleared storage areas ("UCSAs") located along the temporary construction right-of-way, temporary and permanent access roads, contractor and pipe storage yards, rock source and permanent disposal sites, hydrostatic discharge sites, and various aboveground facilities (compressor station, meter stations, pig launcher/receiver units, mainline block valves, and communication towers and equipment buildings). The direct effects APE includes the following: 1) a 400-foot-wide pipeline corridor centered on the Proposed Route, and 2) all areas where elements of the Pipeline extend outside the pipeline corridor. The direct effects APE measures approximately 17,037 acres.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Jordan Cove Energy Project L.P.	)	Docket No. CP17-___-000
	)	

APPLICATION OF JORDAN COVE ENERGY PROJECT L.P.
FOR AUTHORIZATION UNDER SECTION 3 OF THE NATURAL GAS ACT

Filed: September 21, 2017

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Jordan Cove Energy Project L.P.	)))	Docket No. CP17-___-000

APPLICATION FOR AUTHORIZATION UNDER SECTION 3 OF THE NATURAL GAS ACT

Pursuant to Section 3(a) of the Natural Gas Act ("NGA"), as amended,[1] and Parts 153 and 380 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") regulations,[2] Jordan Cove Energy Project L.P. ("JCEP" or "Applicant") hereby files this application ("Application") for authorization to site, construct, and operate a natural gas liquefaction and liquefied natural gas ("LNG") export facility ("LNG Terminal"), located on the bay side of the North Spit of Coos Bay, Oregon. JCEP will design the LNG Terminal to receive a maximum of 1,200,000 dekatherms per day ("Dth/d") of natural gas and produce a maximum of 7.8 million metric tons per annum ("mtpa") of LNG for export.

In order to supply the LNG Terminal with natural gas, Pacific Connector Gas Pipeline, LP ("PCGP") is concurrently filing an application pursuant to Section 7 of the NGA for authorization to construct, install, own, and operate a new, approximately 229-mile-long, 36-inch-diameter natural gas transmission pipeline from interconnections with the existing Ruby Pipeline LLC ("Ruby Pipeline") and Gas Transmission Northwest LLC ("GTN Pipeline") systems near Malin, Oregon, to the LNG Terminal ("Pipeline," and collectively with the LNG Terminal, the "Project").

[1] 15 U.S.C. § 717b(a) (2012).

[2] 18 C.F.R. Pts. 153, 380 (2017).

- the use of instrument air, utility air, and nitrogen.

The LNG carriers calling on the LNG Terminal and their transit route in Coos Bay are primarily within the jurisdiction of the U.S. Coast Guard ("USCG"). The USCG Waterway Suitability Report for this Project currently allows LNG carriers with a capacity of up to 148,000 m^3 to dock at the LNG Terminal berth.

JCEP plans to obtain limited power from the regional electric grid for the SORSC and temporary construction activities. The total power requirements for the LNG Terminal are 39.2 MW (holding mode) and 49.5 MW (loading mode). JCEP is proposing to utilize a gas turbine direct-drive process with waste heat recovery to power its liquefaction trains.[7] Electrical power will be generated via two 30 MW steam turbine generators and one spare 30 MW steam turbine generator.

B. Navigation Reliability Improvements

JCEP plans to dredge four submerged areas lying adjacent to the Channel. These minor enhancements will allow for transit of LNG vessels of similar overall dimensions to those listed in the July 1, 2008 USCG Waterway Suitability Report, but under a broader weather window. This, in turn, provides for greater navigational efficiency and flexibility, enabling JCEP to export the full capacity of the optimized design production of 7.8 mtpa from the LNG Terminal under a broader range of local meteorological and marine conditions.

C. Safety

The Project is designed to be safe, efficient, operable, and maintainable with minimal effects on the environment. All facilities will be designed, constructed, and

[7] JCEP is no longer proposing, as it did in Docket No. CP13-483, to construct a separate power generation facility.

Jordan Cove Energy Project L.P.

Resource Report No. 1

General Project Description

Jordan Cove Energy Project

September 2017

1.3.8.13 Electrical Systems

JCEP plans to obtain limited power from the regional electric grid for the SORSC and temporary construction activities as described in Section 1.9. With the exception of the SORSC, the LNG Terminal facilities will be islanded (with black-start capability) and will not have the means, infrastructure, or need to import or export power during operations.

The total power requirements for the LNG Terminal are 39.2 MW (holding mode) and 49.5 MW (loading mode). Electrical power will be via two 30 MW STGs and one spare 30 MW STG. The steam is efficiently generated by HRSGs using exhaust from the refrigerant compressor combustion turbine drivers. A black-start auxiliary boiler will be used to generate steam for power when gas turbines are not in operation. In addition, there are two standby diesel generators for the LNG facility and two for the SORSC. The facility will not be connected to the local grid, and will not import or export power. Two switchgear buses, in a main-tie-main configuration, will be connected to the STGs (minimum of one turbine to each bus). These switchgear buses will feed the plant distribution 13.8 kilovolt ("kV") switchgear, 6.9 kV switchgear and motor control center, and 480-volt switchgears and motor control center buses located throughout the plant. The plant distribution buses will contain two 6.9 kV essential power buses that power all of the essential plant loads. The LNG facility diesel generators have 100 percent redundancy and are connected to the 6.9 kV essential power buses.

1.3.8.14 Buildings

Buildings and structures required for the operation of the LNG Terminal facility include:

- Administration building;
- SORSC building;
- Fire department;
- Operations building/control room/laboratory/first aid facility;
- Main gate guard house and security building;
- Secondary entrance security gate/terminal guard building;
- Plant warehouse/receiving building;
- Maintenance building;
- Tugboat, storage, and crew building;
- Lube oil, paint and compressed gas storage;
- Water treatment building;
- Inspection station shelter;
- Fire water pump buildings;
- Fire water valve houses;
- Marine control room building;
- Electrical powerhouses;
- Equipment shelters/buildings;
- Analyzer buildings;

The siting of occupied buildings will be evaluated for overpressure, toxic release, and fire hazards. Occupied buildings will be sited in accordance with industry standards. Loads, analysis, design, and construction will be in accordance with all statutory and regulatory requirements.

1.3.8.15 Lighting System

The lighting levels will be based on API standards. Lighting around equipment and facilities where routine maintenance activities could occur on a 24-hour basis would range from 1 to 20 foot-candles, with 20 foot-candle lighting levels within the compressor enclosures.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

IN THE MATTER OF	)	
	)	
Jordan Cove Energy Project, L.P.	)	**Docket No. CP17-495-000**
	)	
Pacific Connector Gas Pipeline, L.P.	)	**Docket No. CP17-494-000**
	)	

SIERRA CLUB *et al.* COMMENT ON AND PROTEST OF APPLICATIONS

Pursuant to 18 C.F.R. 385.211, Sierra Club, Cascadia Wildlands, Center for Sustainable Economy, Citizens Against LNG, Citizens for Renewables, Hair on Fire Oregon, Oregon Shores Conservation Coalition, Oregon Wild, Oregon Women's Land Trust, Pipeline Awareness Southern Oregon, Rogue Climate, Rogue Riverkeeper, and the Western Environmental Law Center protest the applications for the Pacific Connector Gas Pipeline, CP17-494, and the Jordan Cove Energy Project, CP17-495.

Under the Natural Gas Act, 15 U.S.C. §§ 717b(e) and 717f(e), FERC must determine whether these projects are required by or consistent with the public interest, weighing "the public benefits against the adverse effects of the project[s]," including "environmental effects." *Sierra Club v. FERC*, 867 F.3d 1357, 1373 (D.C. Cir. 2017) ("*Sabal Trail*"). The applicants have once again failed to meet this standard, and these applications should be denied. Because this is the applicants' third attempt at this joint proposal, denial should be with prejudice.

see the project denied than commit to supporting it demonstrates that any support for the project is insubstantial.

2. Global Conditions Do Not Demonstrate Support for *These* Projects

Jordan Cove has no actual customer agreements. Jordan Cove's discussion of the general LNG market, Energy Information Administration forecasts, and other indirect material also fails to demonstrate support for this project.

EIA predicts that global markets will support LNG exports from the United States as a whole, but this prediction does not indicate support for Jordan Cove. Specifically, EIA does not predict that markets will support exports beyond the capacity provided by facilities FERC has already approved, the majority of which are already under construction. Jordan Cove's assertion that "U.S. LNG exports are expected to maintain their competitive advantage going forward" beyond 2020 is contradicted by the very page of the EIA report Jordan Cove cites.[12] The EIA instead states that "After 2020, U.S. exports of LNG grow at a more modest rate as U.S.-sourced LNG *becomes less competitive in global energy markets*."[13] EIA does not appear to predict U.S. exports significantly beyond the capacity of the 16.43 bcf/d of liquefaction infrastructure approved by FERC, 9.65 bcf/d of which is already under construction.[14] Thus, the cited EIA report in no way indicates that global

[12] JCEP Application at 13 (citing Energy Information Administration, Annual Energy Outlook with Projections to 2050 at 66 (Jan. 5, 2017)).

[13] Energy Information Administration, Annual Energy Outlook with Projections to 2050 at 66 (Jan. 5, 2017) (emphasis added).

[14] https://ferc.gov/industries/gas/indus-act/lng/lng-approved.pdf, attached as Exhibit 6. This table appears to not account for the full capacity of Sabine Pass,

markets would support the Jordan Cove project. Similarly, the purported "long-term fundamentals for LNG demand" asserted without citation by Jordan Cove, such as decreased use of other fossil fuels "in certain markets," provide no evidence indicating that the market will support the Jordan Cove proposal in addition to or instead of other facilities already under construction or approved. JCEP Application at 13-14.

Jordan Cove's failure to attract customers to date undermines Jordan Cove's assertion that Jordan Cove's west coast location provides meaningful unique benefits. Although potential Asian buyers presumably view decreased shipping distances, access to different producing regions, and diversification of supply as attractive benefits, the fact that no customer has entered a tolling or similar agreement demonstrates that these benefits are not attractive enough to engender market support for the Jordan Cove project.

3. Jordan Cove's Intention to Retain Some Liquefaction Capacity For Itself Does Not Demonstrate Market Support

Even in the unlikely event that Jordan Cove succeeds in negotiating tolling agreements with JERA and ITOCHU, those agreements will amount to a combined 3 mmtpa of LNG, or less than 40% of the proposed project's 7.8 mmtpa capacity. Jordan Cove states in its application that it intends to retain "a portion" of the total liquefaction capacity for itself. JCEP Application at 15. This statement of intent provides no meaningful evidence of market support for the project as a whole. This

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Louisiana, facility, and as such, these totals appear to understate national export capacity.

Pacific Connector GAS PIPELINE

Pacific Connector Gas Pipeline, LP

Plan of Development

Pacific Connector Gas Pipeline Project

January 2018

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1.2 SCHEDULE

PCGP anticipates starting right-of-way clearing (see Right-of-Way Clearing Plan – Appendix U) in the fourth quarter of the year prior to Year One prior to mainline construction, to minimize overall work space and temporary extra work area requirements. Construction for the Pipeline would commence in spring of Year One and continue through fall of Year Two with the in-service date scheduled for the last quarter of Year Two. Prior to the start of Year One or Year Two activities, road surfacing structural capacity assessments and placement of additional road surfacing, which can include brushing and limbing, will be performed as needed for the planned use (see Transportation Management Plan – Appendix Y). The construction periods in Year One and Year Two are scheduled to take advantage of the drier periods of the year and to minimize winter construction, which would reduce potential environmental impacts and construction safety risks. Restoration of construction disturbance is expected to begin in the fall of Year Two and be completed by the end of the winter season in the early part of Year Three when forest, wetland, and riparian revegetation – trees and shrubs – would be planted. Depending on site-specific conditions, it may be necessary to continue restoration and revegetation through the spring of Year Three.

During Year One, PCGP plans to horizontally directionally drill (HDD) five waterbodies (Coos Bay/two locations, Coos, Rogue and Klamath rivers) and initiate the Direct Pipe® crossing of the South Umpqua River (MP 71.30) to allow sufficient time to pursue permits for alternative crossing locations or methods in the unlikely event the proposed HDDs are unsuccessful. An alternate crossing method or an HDD at an alternate location would then be completed in Year Two during mainline construction. Additionally, PCGP anticipates starting pipeline construction in Year One for 1) the Klamath Basin area (MPs 188 to 228) to minimize agriculture impacts and to allow the crossing of most irrigation canals when they have been dewatered during the non-irrigation season (October 15 – March 15); 2) areas identified during biological surveys to have marbled murrelet (MAMU) presence or occupied stands and/or NSO activity to minimize disturbance to those federally-listed species; 3) some areas of severe slopes; and 4) construction of the second South Umpqua River crossing (MPs 95-96). The remaining pipeline mainline and aboveground facility construction is planned to begin in the spring of Year Two.

PCGP has determined that to efficiently construct the Pipeline construction will be divided into at least five construction spreads. The construction spreads will include timber clearing, construction, and restoration activities within the Right-of-Way Grant area and within specific milepost ranges along the Pipeline. The extent of each construction spread is provided in Table 1.2-1.

Table 1.2-1
PCGP Construction Spread Locations

Spread	Milepost Range [1]	Length (miles) [1]
1	0.00-51.60	52.95
2	51.60-94.67	43.41
3	94.67-132.47	37.42
4	132.47-169.50	37.07
5	169.50-228.81	58.24

[1] Equations have been inserted to prevent mileposts from changing throughout the NEPA process; Arithmetic distance between milepost values may not be an accurate indication of length.

JCEP Resource Report 5

Request 1

Provide a description of the current conditions and an analysis of the potential impacts of the LNG Project on the Southwest Oregon Regional Airport. Include the following:

a. impact and costs of LNG Terminal-related delays and interruptions to airport operations; and

b. the potential impacts of thermal plumes on the airport's operations and safety.

Response:

a. Assuming 120 vessel calls per year at the LNG Terminal and 10 minutes advance notice period with approximately three minutes of actual time during which airspace would potentially be obstructed, then the total time that air traffic could potentially be impacted, including the notice period would be 6,240 minutes/year or 104 hours/year [120 vessels x 2 (in and out transit) x 26 minutes (10 minutes advance notice + 3 minutes transit time each way)]. If the advance notice period is not included in the calculation then it is only 1440 minutes/year or 24 hours/year.

Prepared by: Gigi Cooper, Senior Planner, 503-499-0229

b. Potential impacts from thermal plumes were reviewed in July 2013, see Attachment FERC-JCEP-RR5-1. The current design layout compares as follows to the previous analysis:

	Current Design	Previous Report Basis
Number of Exhaust Stacks	5	5
Stack Height, ft	119	119
Stack Diameter, ft	10	10
Exhaust Temperature, K	390	395
Exhaust Flow, acfm	334,583	355,123
Distance to Flight Path, m	570	1,030

Factors above are lower for the proposed design and the location is still 570 meters from the flight path. No impacts are anticipated.

Pacific Connector Gas Pipeline, LP
Docket No. CP17-494-000
OEP/DPC/CB-2
Response to Staff Data Request Dated December 12, 2018

Data Request

On page 13 of its application, Pacific Connector Gas Pipeline, LP (Pacific Connector) states that approximately 81 miles of the total right-of-way required is on public land; 148 miles are privately owned, of which, 62 miles are held by timber companies. Accordingly, 86 miles of the total required right-of-way is privately held, of which Pacific Connector states that it has obtained easements from 39 percent (approximately 34 miles) of the private, non-timber landowners, leaving approximately 52 miles of right-of-way easements that must be obtained from private, non-timber landowners.

1. Provide an update of easement negotiations. Confirm the total miles of pipeline right-of-way on publicly-owned and privately-owned land. For the right-of-way required for private land, complete the following table:

Response:

Pacific Connector Gas Pipeline, LP ("PCGP") has obtained additional easements for a significant portion of the land needed for its pipeline since filing its certificate application in September 2017. PCGP's right-of-way is split between public land (a total of approximately 81 miles), private land owned by timber companies (a total of approximately 60 miles) and private land owned by other landowners (a total of approximately 87 miles).[1] At the time the application was filed, PCGP had obtained easements from 39% of the private, non-timber landowners and none of the timber landowners.

As of the date of this data response, PCGP has obtained easements from 61% of the private, non-timber landowners, representing 61% of the mileage from such landowners. Since filing its application, PCGP has obtained 50 new easements from such landowners. PCGP also has obtained survey permission from 73% of the private, non-timber landowners.

Additionally, PCGP has obtained easements from 41% of the timber company landowners, representing 52% of the mileage from the timber companies, all of which have been obtained since the application was filed. PCGP has obtained survey permission from 100% of the timber company landowners and is in negotiations for the remaining easements from these landowners.

In its certificate application, PCGP explained that it expected to obtain most of the necessary easements through negotiation. PCGP's significant progress since filing the application – easements covering an additional 50 miles of the pipeline route have been obtained since September 2017 – shows that PCGP has followed through on this commitment. PCGP continues

[1] Minor changes in the pipeline route have altered the number of miles of pipeline in these categories since the application was filed.

to negotiate with landowners for easements and still expects to obtain most of the necessary easements in this manner.

As requested, the following shows the right-of-way required for private land:

	Miles of Pipeline	**Number of Landowners**	**Number Easements Entered**	**Mileage Easements Entered**	**% of Mileage of Easements Entered**
Private Timber	60.03	27	11	31.48	52%
Private Individual Landowners	87.19	225	138	53.48	61%

Prepared by: John Stevenson, Manager, Land, (971) 940-7805

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

DRAFT
ENVIRONMENTAL IMPACT STATEMENT
FOR THE
JORDAN COVE ENERGY PROJECT

Docket Nos. CP17-494-000 and CP17-495-000

FERC/DEIS-0292D

March 2019

Cooperating Agencies:

2.1.1.5 Other Terminal Support Systems

The LNG terminal operation would require installation of several other systems within the LNG terminal site, as described below.

Vapor Handling System

The liquefaction and vessel loading processes would result in the creation of miscellaneous LNG vapors, which would be recovered and directed into a vapor handling system and recycled into the liquefaction process.

Ground Flares

The LNG terminal would have three separate flare systems for occasional pressure relief or plant protection conditions: one flare system for warm (or wet) reliefs, one for cold cryogenic (or dry) reliefs, and one for low-pressure cryogenic reliefs from the marine loading system. The warm and cold flares would both be combined within a shared multi-point ground flare, while the marine flare would be within an enclosed cylindrical ground flare. The multi-point ground flare systems would be located at the northern end of the LNG terminal site and the enclosed ground flare would be located north of the marine vessel slip. The flare systems would only be used during plant-protection situations, maintenance activities, cases of purging and gassing-up an LNG carrier, and initial commissioning/start-up.

During initial commissioning and startup flaring would occur for approximately 1 week, at 10 to 20 percent of the flare design capacity. For dryout and cooldown, flaring would occur for approximately 2 weeks at less than about 20 percent of the flare design capacity. When each subsequent liquefaction train is started, flaring may occur for approximately 2 hours, and each train would be staggered by about 1 month between startups. Flaring during other commissioning activities would occur intermittently but would consist of individual pieces of equipment being isolated with very small volumes flared compared to the flare design capacity until the system is depressurized.

Instrumentation and Process Control System

The facility would be operated through a distributed control system (DCS) that would include control panels and numerous field-mounted instruments connected to remote input/output cabinets that would interface with the central control room. In addition, independent Safety Instrumented Systems (SIS) and Fire and Gas Systems (FGS) would monitor hazardous conditions and provide emergency shutdown capability.

Electrical Systems

Electrical power to the LNG terminal would be supplied via two 30-megawatt (MW) steam turbine generators and one spare 30 MW steam turbine generator, with the steam generated by heat recovery from gas turbine operation. A black-start auxiliary boiler would be used to generate steam for power when gas turbines are not in operation. The system would also include two standby diesel generators for the LNG facility and two for the SORSC.

Lighting System

Twenty-four-hour facility lighting would be required for security and personnel safety during operation of the LNG terminal. A final lighting plan, including lighting of the LNG storage tanks,

OVERVIEW AND DESCRIPTION

Jordan Cove Energy Project L.P. ("JCEP") is seeking authorization from the Federal Energy Regulatory Commission ("FERC" or "Commission") under Section 3 of the Natural Gas Act to site, construct, and operate a natural gas liquefaction and liquefied natural gas ("LNG") export facility ("LNG Terminal"), located on the bay side of the North Spit of Coos Bay, Oregon. JCEP will design the LNG Terminal to receive a maximum of 1,171 Million Standard Cubic Feet Per Day of natural gas and produce a maximum of 7.8 million tons per annum of LNG for export. The LNG Terminal will turn natural gas into its liquid form via cooling to about -260ºF, and in doing so it will reduce in volume to approximately 1/600th of its original volume, making it easier and more efficient to transport.

In order to supply the LNG Terminal with natural gas, Pacific Connector Gas Pipeline, LP ("PCGP") is proposing to contemporaneously construct and operate a new, approximately 235-mile-long, 36-inch-diameter natural gas transmission pipeline from interconnections with the existing Ruby Pipeline LLC and Gas Transmission Northwest LLC systems near Malin, Oregon, to the LNG Terminal ("Pipeline," and collectively with the LNG Terminal, the "Project").

This Supplemental Resource Report ("Supplemental Report") includes details of Project design enhancements for the power generation system of the proposed LNG Terminal described in the FERC Application documents filed as part of Docket No. CP17-495-000. During detailed design, JCEP will implement the minor modification described in this Supplemental Report without increasing the overall environmental impacts associated with the Project. This Supplemental Report maintains the section numbers and section headings of the original Resource Reports. As a result, section numbers in this Supplemental Report may not be sequential. Text included in this Supplemental Report is intended to update the sections of the original Resource Reports that have corresponding section numbers and headings.

These design enhancements will maintain or reduce the duty of the Heat Recovery Steam Generators ("HRSGs") and Auxiliary Boiler and therefore will not result in additional environmental impacts for air quality and noise compared to those described in information filed in FERC Docket CP17-495-000 and in FERC's Draft Environmental Impact Statement for the Project", issued March 29, 2019 ("DEIS"). While the power supply is modified, the LNG Terminal layout and operations will not change, and, as a result, the reliability and safety analysis presented in the DEIS will not be affected. The import power feeder described in this Supplemental Report will be routed within the footprint of the LNG Terminal facilities displayed on Figure 2.1-2 of the DEIS; therefore, there will be no additional impacts to geological; soil and sediment; water and wetland; upland vegetation; wildlife and aquatic; threatened, endangered, and other special status species; land use; recreation and visual; socioeconomic; transportation; and cultural resources beyond those documented in the DEIS. The engineering documentation detailing these design enhancements will be submitted to FERC prior to construction of final design.

RESOURCE REPORT 1 – GENERAL PROJECT DESCRIPTION

1.3.8.13 Electrical Systems

JCEP plans to obtain power from the regional electric grid for the Southwest Oregon Regional Safety Center (SORSC) and temporary construction activities as described in Section 1.9. A portion of the electric power for operations of the LNG Terminal facilities will be generated on-site with the balance imported from the regional electric grid owned and operated by PacifiCorp ("Pacific Power"). Pacific Power distributes electric power to other industrial users within the region including the Roseburg Forest Products Company, Southport Lumber Company, LLC and DB Western. No means for exporting power to the grid are considered in the LNG Terminal design.

The total power requirements for the LNG Terminal are 39.2 MW (holding mode) and 49.5 MW (loading mode). Electric power will be via three on-site steam turbine generators ("STGs") generating up to a total maximum of 24.4 MW and imported power capacity ranging from 15 to 26 MW. The steam for the STGs is efficiently generated by HRSGs using exhaust from the refrigerant compressor combustion turbine drivers. The rated electric output of the STGs will be finalized during the detail design phase of the Project. An auxiliary boiler will be used to generate steam for power when gas turbines are not in operation.

Imported electric power to the LNG Terminal will be provided via an underground 12.47 kV connection point at the north-east corner of the South Dunes site. The 12.47 kV feeder will then be routed underground from the connection point through the South Dunes site and the Access and Utility Corridor to the Auxiliary Powerhouse Enclosure located to the north of Ingram Yard near the STGs. The approximate length of the underground cable run is 10,500 feet through the LNG Terminal property.

Two medium voltage ("MV") switchgear buses within the Auxiliary Powerhouse Enclosure will be connected to the STGs and the 12.47 kV power supply, MV switchgear breakers and capacitor banks will be provided at the switchgear to integrate the import power feeder. The MV buses will feed a plant distribution 12.47 kV switchgear, 6.9 kV switchgear and motor control center, and 480-volt switchgears and motor control center buses located throughout the plant.

Black start power supply for the STGs will be available from the grid. However, during the detail design phase of the Project, JCEP will consider installing one standby diesel generator to provide redundant black start power supply. There are two standby diesel generators for the SORSC.

RESOURCE REPORT 13 - ENGINEERING AND DESIGN MATERIAL

13.28 Electrical

13.28.1 Electrical System Design

Information on the electrical design is provided in the Electrical Basis of Design (J1-000-ELE-BOD-KBJ-50001-00) included in Appendix B.13.1, the Electrical Power Generation Study and System Description (J1-000-ELE-RPT-KBJ-50001-00) included in Appendix B.13.2, the Electrical Specifications included in Appendix F.13.3, and the electrical design information included in Appendix N.13.

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

IN THE MATTERS OF	)	
	)	
Jordan Cove Energy Project, L.P.	)	**Docket CP17-495-0000**
	)	
Pacific Connector Gas Pipeline, L.P.	)	**Docket CP17-494-0000**
	)	

The Western Environmental Law Center, Sierra Club, Greater Good Oregon, Pipeline Awareness Southern Oregon, Oregon Shores Conservation Coalition, Trout Unlimited, Center for Biological Diversity, Oregon Wild, Oregon Coast Alliance, Oregon Physicians for Social Responsibility, Umpqua Watersheds, Inc., OPAL Environmental Justice Oregon, Honor the Earth, 350 Corvallis, Columbia Riverkeeper, Friends of Living Oregon Waters (FLOW), Oregon Women's Land Trust, Earthworks, Hair on Fire Oregon, Rogue Climate, Oregon Women's Land Trust, Cascadia Wildlands, Snattlerake Hills, LLC, Waterkeeper Alliance, Great Old Broads for Wilderness, Cascade Volcanoes Chapter, Pacific Coast Federation of Fishermen's Associations, Institute for Fisheries Resources, Rogue Riverkeeper, Beyond Toxics, and affected landowners Deb Evans and Ron Schaaf submit these comments on the Draft Environmental Impact Statement (DEIS) for the Jordan Cove Energy and Pacific Connector Gas Pipeline Projects, dated March 2019.

We incorporate by reference comments on this DEIS submitted by the Institute for Policy Integrity.

These comments refer to the DEIS and other supporting documentation available in Dockets CP17-495-0000 and CP17-494-0000. Other references are made to publicly available documents, were possible. Where references may not be available on FERC's e-Dockets or otherwise publicly available, we have included these documents in Appendix A, Exhibits.

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catastrophic levels that could cause the near total loss of the facility, including any LNG ship berthed there. Such an event could present serious hazards to the public well beyond the facility boundaries." *See* Havens & Venart Comment, Jan 14, 2015.

2. Aviation Hazards.

The proposed terminal would be less 0.6 miles from the Southwest Oregon Regional Airport (SORA). DEIS 4-750. LNG carriers would pass within 0.75 mile of the end of SORA's runway number 4/22[11]. Construction and operation of the proposed project may have significant impacts on aviation, presenting both physical obstacles (including permanent structures and LNG carriers) and a hazardous thermal plume. The DEIS fails to take the required hard look at either impact.[12]

a. Obstruction Hazards

Under the Federal Aviation Act of 1958, the Federal Aviation Administration ("FAA") determines whether proposed construction will present a hazard to air navigation. *BFI Waste Sys. of N. Am., Inc. v. F.A.A.*, 293 F.3d 527, 528 (D.C. Cir. 2002) ("*BFI Waste*").

Here, the two LNG tanks, the amine regenerator, the oxidizer, and LNG carrier vessels will, by virtue of their height and location relative to the airport, constitute "obstruction[s] to air navigation." *See* 14 C.F.R. §§ 77.17(a), 77.19(b). It is likely that cranes and other construction equipment will also constitute such obstructions, but Jordan Cove has not yet submitted information on this equipment to the FAA, DEIS 4-750, and the DEIS provides no discussion of the extent to which this equipment will impact aviation.

On May 7, 2018, the FAA issued "notices of presumed hazard" for the tanks, amine regenerator, and oxidizer, and for seven LNG carrier vessel transit points. DEIS, 4-750.[13] For the amine regenerator, oxidizer, and westernmost vessel transit point, the FAA informed Jordan Cove that it could request additional study of whether the obstruction would pose an adverse impact to aviation. The other ten notices, however, explained that unless the height of the obstruction at issue was reduced, the obstruction would be deemed to have an adverse impact *per se*, because of, *e.g.*, intrusions into "traffic pattern airspace." *See* FAA, "Procedures for Handling Airspace Matters," JO 7400.2M at 6-3-8 d.1.b (Feb. 28, 2019).[14]

b. The DEIS Understates the Impact of LNG Carrier Vessels on Aviation

The DEIS provides only one short paragraph discussing the impact of LNG carriers on aviation:

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[11] FAA, Aeronautical Study No. 2018-ANM-7-OE (May 7, 2018) (providing coordinates of 43-24-55.79N, 124-16-29.14W for LNG Carrier Stack Transit Point 4); http://www.airnav.com/airport/KOTH (providing coordinates of 43-24.883747N, 124-15.635873W for end of Runway 4/22)

[12] This section addresses potential impacts of the project on aviation. The DEIS also fails to adequately address the potential impacts of aviation on the project, e.g., of an aircraft crashing into an LNG storage tank.

[13] Copies of these notices are included in the docket at Accession No. 20180510-5165, Part 8.

[14] Available at http://www.faa.gov/documentLibrary/media/Order/7400.2M_Bsc_dtd_2-28-19.pdf. Courts have described this handbook as "binding" and "controlling." *BFI Waste*, 293 F.3d at 529.

> During operation of the Jordan Cove LNG Project, LNG carriers in the Federal Navigation Channel would cross [t]he airport approach pathway. Jordan Cove has indicated that aircraft would be delayed by about 13 minutes for each passing vessel, consisting of a 10-minute advance notice period, and 3 minutes of actual time during which airspace would be potentially obstructed. LNG carrier transit times could also be adjusted to avoid conflict with air traffic, if the need arises.

DEIS, 4-625.

The DEIS does not explain how the 13 minute estimate was calculated or provide any citation in support. There is no indication that the FAA, the agency with expertise in this matter, agrees that the period of potential obstruction will only be three minutes long. Transit point 1 is more than two miles from the slip.[15] Carriers will travel between 4 and 6 knots, DEIS, 2-14, requiring roughly 20 to 30 minutes to cross this distance. Turning and mooring the carrier will require another 90 minutes, *id.*, after which time the carrier will be loaded, and the process reversed. All in all, each carrier will ordinarily be in locations where it will have a *per se* adverse impact for roughly 20 hours. *Id.* (explaining that total time spent east of Buoy K will be "about 22 hours"), *see also id.* 4-255 ("Jordan Cove estimates that about 110 to 120 LNG carriers would visit its terminal each year," and remain "at the terminal dock for a period of about 17.5 to 24.5 hours.").

Even if conflicts between aviation and carriers could be resolved by delaying flights by 13 minutes, the DEIS fails to present any discussion of the impact of such delays. The DEIS does not address how often such delays will occur, an analysis that requires, at a minimum, consideration of the amount of carrier traffic, the amount of present and foreseeable future aviation traffic,[16] and the expected timing of each. The DEIS does not address whether, how often, or how severely delaying one aircraft operation will delay other operations at the airport. Nor does the DEIS provide any explanation as to how adjusting LNG carrier transit times would reduce impacts to aviation, or the feasibility of such adjustments: with an average of more than 50 aircraft operations per day,[17] the slow speed of carriers, and the scope of the area that obstructs the airport, there may never be a good time.

We note that Jordan Cove currently expects to utilize significantly taller carriers than were previously proposed, and as such, prior analyses of the impacts of carriers on aviation (and other resources) do not address the impacts of the current proposal. According to Jordan Cove's most recent submissions to the FAA, the proposed carriers stack height will be 211' Above Mean Sea Level (AMSL),[18] 45' taller than was indicated by Jordan Cove's prior FAA submissions.[19]

c. Structures

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[15] FAA, Aeronautical Study No. 2018-ANM-4-OE (May 7, 2018) (providing coordinates of 43-23-49.37N, 124-16-56.55W).
[16] The North Bend Airport had 18,549 aircraft operations (takeoffs and landings) in 2018. https://www.gcr1.com/5010web/airport.cfm?Site=OTH&AptSecNum=2 (last visited June 12, 2019).
[17] *Id.*
[18] FAA, Aeronautical Study No. 2018-ANM-4-OE (May 7, 2018)
[19] *See also* Memo from J.C Smith, Commander, Sector Columbia River/Captain of the Port/Captain, U. S. Coast Guard to Jordan Cove Energy Project, L. P. dated 7 November 2018

According to the FAA, as currently proposed, the two LNG storage tanks will cause *per se* adverse impacts to aviation, and the amine regenerator and thermal oxidizer are obstacles that may cause adverse impacts. [20] Jordan Cove has not provided FERC or the FAA with any information about the height of cranes or other construction equipment; it is likely that this equipment would cause additional adverse impacts while onsite.

The DEIS suggests that permanent structures would not in fact impact aviation, because other existing obstacles already require aircraft to operate at altitudes and locations that provide an adequate buffer around the proposed terminal structure. DEIS 4-751 (summarizing comments of Southwest Oregon Regional Airport regarding prior proposed terminal design).[21] The DEIS does not provide detail or information sufficient to demonstrate that the structures will not in fact impact aviation. And, as the DEIS notes, the FAA has not agreed with the Airport's position, in reviewing either the prior or the current design. Finally, nothing in the DEIS or the Airport's 2015 letter addresses the impact of construction equipment on aviation.

Nonetheless, we agree with the Airport on one issue: the "option" of flipping flight patterns for Runway 04 should be avoided, because such a flip would cause adverse impacts as described in the Airport's 2015 letter. If the project cannot be reconciled with the current flight patterns, the project should be modified or rejected.

d. FERC Must Not Issue Certificates Until the FAA Has Completed Its Evaluation

The DEIS recommends that Jordan Cove "file the final determinations from the FAA prior to initial site preparation." DEIS 4-751. This is too late. FERC cannot determine whether the terminal is consistent with the public interest, and thus whether a certificate should issue, until FERC knows whether the project will present an aviation hazard and the nature and extent of the impact of the project on aviation, and FERC needs to consider the FAA's input in making this determination. If "a determination of no hazard cannot be reached," the FERC's response may need to be much more than issuance of "a modification, variance, or amendment." *Id.* Nor can FERC issue a certificate for the pipeline, and allow, *inter alia*, condemnation for the right of way to commence, prior to resolving these issues for the terminal. If the terminal cannot be reconciled with continued operation of the airport, the terminal should be denied, and the pipeline with it. This issue cannot wait to be resolved after issuance of a conditional certificate.

3. Thermal Plume

Separate from physical obstructions, the project risks impacting aviation by creation of a thermal plume. Unlike physical obstructions, the FAA does not at present regulate impacts of thermal plumes on aviation. However, "the FAA has determined that thermal exhaust plumes in the vicinity of airports may pose a unique hazard to aircraft in critical phases of flight (particularly

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[20] *See supra* note 2 and accompanying text.
[21] Although not specifically cited by the DEIS, the letter discussed at DEIS 4-750 to 4-751 can be found at Accession No. 20150803-5249.

takeoff, landing and within the pattern) and therefore are incompatible with airport operations."[22] Similarly, the National Academy of Sciences has recognized the impacts thermal plumes can have on aircraft. [23] NEPA and the Natural Gas Act require FERC to consider these impacts here.

The DEIS's dismissal of the risk of thermal plumes is nonsensical and arbitrary. DEIS 4-625 to 4-626. Thermal plumes are principally created by combustion. In the prior design, the largest source of combustion and heat was the proposed South Dunes Power Plant, where gas would be burned to generate electricity, which would then power the liquefaction equipment. As the DEIS notes, the current design does away with the South Dunes Power Plant. DEIS 4-626. However, it does not follow that "the LNG terminal would not general thermal plumes." *Id.* The current design still combusts gas; it just moved the location of that combustion from an electricity-generating powerplant to, principally, five gas combustion turbines integrated into liquefaction trains at the terminal site.[24] Combustion in these turbines will still generate significant heat, and FERC must take a hard look at the impact of the resulting thermal plume. Indeed, it may be that the thermal plume is now closer to the airport and runway ends, closer to actual flight paths, and/or at a location will prevailing wind will cause thermal plumes to be more, rather than less, of a problem.

Although the impacts of thermal plumes depends on many factors, we note that at least one facility, the Eastshore Energy project, has been rejected on the basis of the impact its thermal plume would have on aviation, even though that facility would have had a lower heat input and would have been farther from the affected airport than Jordan Cove's current proposal. *Compare* DEIS 4-656 (Jordan Cove will have five 524.1 mmbtu/hr combustion turbines, in addition to other heat sources) with Eastshore Energy Center CEC Air Quality Permit Application, Table 8.1-2[25] (proposed heat input of 1000 mmbtu/hr), National Academy of Sciences 2011 at 29 (Eastshore Energy "would consist of fourteen 70-ft-tall exhaust stacks located approximately 1 mile from the airport.").

Thus, FERC must model the size and severity of the thermal plume(s) that would be generated by the proposed terminal, and the impact on aviation. The FAA has developed, and recommends, a tool for performing this modeling: the "Exhaust-Plume-Analyzer" developed by the MITRE corporation. The prior, 2013 analysis of Jordan Cove's impacts preceded development of this tool, and was conducted using a different methodology.[26] In analyzing the effects of the current design's thermal plume, FERC must explain its choice of methodology.

4. Geotechnical and Structural Design

[22] Federal Aviation Administration, Technical Guidance and Assessment Tool for Evaluation of Thermal Exhaust Plume Impact on Airport Operations, at 2 (Jan. 21, 2015), https://www.faa.gov/airports/environmental/land_use/media/Technical-Guidance-Assessment-Tool-Thermal-Exhaust-Plume-Impact.pdf

[23] "Investigating Safety Impacts of Energy Technologies on Airports and Aviation", Transportation Research Board of the National Academies, 2011, p. 29

[24] Jordan Cove, Resource Report 9, at 5 (September 2017).

[25] Attached.

[26] Thermal Plume Study at 1-5 (July 2013).

land management practices." FERC has not demonstrated that its mitigation will be effective or is even permitted under the NWFP.

The DEIS failed to compensate for the increased Equivalent Clearcut Area (ECA) within each watershed. If the watershed has too many clearcuts, the additional ECA caused by the pipeline could cause peak flow increases, not allowed by the Aquatic Conservation Strategy of the Northwest Forest Plan.

Other ACS objectives are not being met. For instance, some mitigation proposed to meet ACS objectives repairs damage caused by the pipeline, but does not restore habitat above that. This is the case with the 6.4 miles of fencing proposed on the Winema NF to keep cattle out of pipeline right-of-way. This should not be counted as mitigation. It is simply the cost to build the pipeline.

Plants and wildlife on the Survey and Manage list of the Northwest Forest Plan have inadequate protections. Moving the pipeline around them, instead of the weak mitigations offered for destroying them, could have protected many of these areas.

V. Forest Fire Threats.

Forest fires are a significant threat to the safety of the pipeline and the ecosystems of southern Oregon. For much of its length, the pipeline goes through fire-adapted forests, where forests burn naturally and often. Threats from fire include fire started by construction of the pipeline, other human-caused fire starts, and lightening.

The pipeline's lineal early-seral habitat could act as a wick, spreading the fire further and faster than if the pipeline were not there. A buried pipeline is also in danger of explosion if a sustained fire, such as in a slash pile or a fallen tree, burned over the buried pipe. Block valves also pose a threat if a fire burns over the above-ground pipes, especially if a block valve is within a fire perimeter and cannot be reached to turn it off. Wildland fire-fighting equipment is used on ridge-tops to create a fire-break, the same places where the high-pressure pipeline is buried. Most fires would occur in Class 1 areas, where the pipes are thinner and buried higher, increasing the fire-risk further.

The DEIS fails to adequately address these fire threats.

One suggested mitigation (DEIS 2-34) is to create "Fuel Breaks". Page 4-172 even suggests "that the cleared right-of-way could serve as a fire break for large crown fires, thereby reducing the extent of a fire's spread". Fuel Breaks do not work, as fire is spread by embers flying over even wide fuel breaks. The DEIS (4-450) says: "Stand density fuel breaks would reduce the threat of losing late-successional habitat to fire." Fuel breaks would NOT reduce threats. The DEIS failed to correctly analyze these claims.

The DEIS (4-172) admits to increased fire hazard by: "Certain activities associated with construction and operation of the Pacific Connector project (such as prescribed burning of slash, mowing, welding, refueling with flammable liquids, and parking vehicles with hot mufflers or tailpipes on tall dry grass) could increase the risk of wildland fires…" Plans to park vehicles on tall dry grass is alarming. FERC should prohibit this.

The DEIS states (4-775) "In the event a fire was to occur on the surface in the vicinity of the pipeline, the presence of the pipeline would not increase fire hazards." This analysis is incomplete. It's not just the presence of the pipeline that would increase fire hazards. It is also the presence of the early-seral habitat in the right-of-way that increases fire hazards. Because these areas are sunnier and dryer, they are more fire-prone. Native and introduced brushes in the right-of-way instead of trees are also more volatile and burn hotter than in a mature forest. And because the right-of-way is linear, it has the ability to spread a hotter fire faster over the landscape. The DEIS only analyzed the risk of the pipeline to fire behavior when instead the DEIS should have included the risk of the right-of-way to fire behavior. Because the right-of-way will cause the fire to spread along the right-of-way, the damage to the forests, wildlife, and homes will increase near the right-of-way.

The DEIS also claims that "Fires on the surface are not a direct threat to underground natural gas pipelines because of the insulating effects of soil cover over the pipeline. Soil is a poor conductor of heat…" The DEIS failed to consider impacts to the buried pipe when a slash pile or fallen tree sustain a fire over the pipeline. Sustained heat could compromise the pipe. Also, the pipeline will be buried as little as 18" in many places, especially rocky areas. The FERC should present some scientific evidence that heat, especially from a sustained fire, cannot penetrate 18" in rocky soils.[367]

The DEIS claims (4-775) that "Pacific Connector would also have facilities built along the pipeline to aid in protecting the pipeline from wildfires. Along with Pacific Connector's pipeline control there are MLV sites on the pipeline to aid in isolating which portions of the pipeline have product in them." However, MLV sites (block valves) are above ground sections of the pipeline, not protected by soil. The DEIS should have considered the impacts if a MLV site, in a wooded area, were to experience a fire directly on the pipe. Also, the DEIS failed to consider the impacts if a MLV site is not accessible due to the presence of fire. MLV sites could be more of a fire danger than a fire control.

There are longer distances between block valves in Class 1 areas, which would add to the problem of reaching a MLV in time. These valves are placed in forested areas, thus, it could be impossible for personal to drive through a forest fire to reach them. Take for instance Block Valve #9, that had been proposed near MP 106 in the middle of the 2015 Stouts Creek Fire. If there had been a pipeline with gas during that fire, it would have been impossible to reach that MLV. In the newest proposal, that MLV has been moved to private industrial forest land[368], at even greater risk of a wildland fire.

The DEIS claims (4-775) that: "In past situations, local operation personnel have protected above ground mainline valves by burying the valves with sand and earth material." Is Jordan Cove claiming that they will do this to protect block valves threatened by fire? If so, there should be some assessment of where the sand or dirt will come from, how much sand is needed to burry a

[367] DEIS 4-770: "Pipelines constructed on land in Class 1 locations must be installed with a minimum depth of cover of 30 inches in normal soil and 18 inches in consolidated (solid) rock".
[368] Table 2.1.2.1-1 page 2-19.

40’ section of pipe 10’ off the ground, and how the block valve will be accessed if it means driving through the middle of a wildland fire.

The DEIS failed to analyze what would happen if there is a rupture in the pipeline. A catastrophic fire will result. The location of the pipeline is a very rural, very rugged area without prompt access to any kind of first responders, much less fully equipped crews to suppress a gas-fueled fire. As history indicates, professional fire crews from the State of Oregon, Forest Service, Bureau of Land Management, and other federal and state agencies rarely are able to suppress wildfires in this country, much less a fire fueled by natural gas. The DEIS does not analysis the likelihood that such a fire could occur, or what the environmental consequences would be. The lack of analysis is arbitrary, capricious, and not in accordance with law. 5 U.S.C. § 706(2)(A).

Another problem is the right-of-way will cause more fire suppression. It is environmentally advantageous and economical to treat many wildland fires as a controlled burn, and not suppress them in the backcountry when it doesn’t threaten homes or other infrastructures. However, the presence of a pipeline in the back-country will mean that more wildland fires will have to be suppressed, fires that otherwise would have been treated as natural, beneficial fires. The DEIS failed to consider this problem.

The pipeline would be buried as little as 18” deep in class one areas (DEIS 4-770). However, just 4 pages later, in the DEIS section called “Pipeline Standards to Minimize Fire Risk to Forest Lands”, the DEIS contradicts itself, saying the pipe would have “at least 24 inches of cover in consolidated rock”. Even if 24” is the correct answer, it is still too shallow to protect the pipe from a sustained surface fire.

This section, “Pipeline Standards to Minimize Fire Risk”, has NO proposed standards to minimize fire risk, which is a high risk in Oregon’s fire-adapted forests that burn naturally and burn often. The only standard proposed is to communicate with local fire officials, and proposed increase training, of which a substantial portion of the cost would be born by local fire officials[369].

Pipeline in-water construction activities, many of them highly fire hazardous, are planned to take place almost entirely during southern Oregon’s increasingly intense fire season, thereby posing a serious risk of sparking wildfires and resultant costs to public health and safety [ORS196.825(3)(e)] and water quality.

The Applicant plans for pipeline construction to begin in January 2021 and be completed in December 2022, with peak work during the summer of 2021. They anticipate a total of 1,500 workers across the five crews.[370] Construction of a buried pipeline requires the use of heavy equipment and explosives, activities that carry with them significant risk of starting wildfires. For example, to create a 95-foot-wide clear-cut right-of-way, trees would be felled using chain

[369] DEIS 4-775: “Pacific Connector would participate in any simulated emergency exercises and post-exercise critiques…. The majority of the training costs would be borne by Pacific Connector…” The other portion of the training costs could be significant.
[370] DSL Application APP0060697, Section 2 PCGP, Attachment A.2, Resource Report 1, General Project Description, “Construction Procedures,” PDF p. 2138.

saws and feller-bunchers; brush would be cleared, including by bull-dozing across rocky ground; 10-foot-deep trenches would be dug, using where necessary rock-saws, rock drills, and blasting; and pipe would be laid and welded. Trenches would then be backfilled to bury the pipeline, again with heavy equipment in rocky terrain.

To comply with Oregon's Fish Passage Law and Oregon Department of Fish and Wildlife (ODFW) guidelines, the company has agreed to confine pipeline construction activities in almost all water crossings to ODFW's "fisheries in-water construction windows." These windows are set so impacts to fish through damming, dredging, removal and fill, and blasting occur when key fish species are least likely to be present.[371] These windows also correspond to fire season. The construction windows for the pipeline route indicate that 90% of highly hazardous work at water crossings in Coos, Douglas, and Jackson County would occur primarily when fire danger is "high" to "extreme." Using Jackson County as an example, all but one of 77 crossings would occur between June 15 and September 15.[372] In 2017, the Oregon Department of Forestry (ODF) instituted "high danger" level in Jackson and Josephine Counties from June 30 to September 17--"extreme danger" ran for 52 days from July 24 to September 14. In 2018, "high danger" level ran from July 3 to September 30—fire danger was "extreme" for 54 days from July 20 to September 12.[373] PCGP's Construction Procedures do not discuss the above ODF compliance in terms of their overall work schedule so it is not clear when they intend on performing out-of-water construction activities.

The proponent would need to obtain permits or authorizations to operate heavy equipment from landowners, including the ODF, the U.S. Forest Service, and the BLM. For example, ODF requires a Permit to Operate Power Driven Machinery (PDM). Authorizations require the Applicant to agree to comply with prescribed practices to minimize the risk of a fire being ignited and be prepared to respond in the event of fire.[374] ODF evaluates requests for waivers of restrictions by fire danger level on the basis of conditions at the time and place of work and the willingness of the operator to agree to take precautions to make the operation fire safe.[375] PCGP can be expected to commit to comply with necessary procedures, but fire officials can expect public apprehension about all summertime pipeline construction, let alone waivers allowing work during Industrial Fire Prevention Level IV periods when work stoppage is generally enforced. In recent years, due at least to climate change caused increased temperatures and drier conditions, the risk and incidence of accidental, human-caused fires getting out of hand is increasing. More fires are becoming conflagrations. Circumstances in the wake of the two most recent destructive and deadly fires in California may suggest liability issues could be raised.
The last step of the pipeline construction process is reclamation. Among other activities, an average of 1 ton per acre of slash left by the original clearcutting would be spread over the right-

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[371] *Ibid*, PDF p. 2139; ODFW, *Oregon Guidelines for Timing of In-Water Work to Protect Fish and Wildlife Resources*, June 2008.
[372] DSL Application APP0060697, Section 2 PCGP, Table B.3-4, "Fish Utilization, EFH, Crossing Techniques/Rationales, In-Water Work Windows, and Bridges for Waterbodies," PDF pp.1525-85.
[373] Email Herb Johnson, ODF Forest Officer/Prevention Coordinator to Ron Garfas-Knowles, Ashland Fire & Rescue, January 29, 2019
[374] Oregon Department of Forestry, "Industrial Fire Precaution Levels (IFPLs) for Oregon Department of Forestry Protection west of the Cascades."
https://www.oregon.gov/ODF/Fire/Documents/2017%20IFPL%20for%20Web.pdf
[375] Email from Dave Lorenz dated 1.8.2019.

of-way, adding to already existing fuel loads. This amount exceeds the FERC's "Upland Plan;" the Applicant has indicated that they will seek a waiver.[376]

Southern Oregon communities already endure months-long summertime periods when wildfire smoke makes air quality unhealthy and makes outdoor activities unsafe. These conditions are having a heavy economic impact. The state and impacted counties are struggling to pay for the fires that are getting out of hand with just the risky circumstances of human-caused fire we now face. Concerns about this reality are among those raised by the Jackson County Commission in its January 22, 2019 comment to DSL, urging denial of the current removal-fill permit application we are considering.

W. The DEIS Does Not Clearly Identify All Affected Waterbodies and fails to fully comply with 40 CFR §1502.22 "Incomplete or unavailable Information."

The DEIS fails to clearly identify all affected waterbodies. According to the DEIS, the pipeline, associated workspace, and equipment bridges would be located across 19 HUC-5 watersheds and an additional 5 watersheds would be crossed by the proposed access roads. The pipeline would be constructed across or near 352 waterbodies, including 69 perennial streams, 270 intermittent streams, 9 perennial ponds, and 4 estuaries.[377] However, according to Resource Report 2 provided by the applicant, the pipeline would cross 400 waterbodies. [378] The DEIS does not address this discrepancy and there may be additional waterbodies that may be impacted by the proposed activities that are not identified in the analysis.

The DEIS 4-130 states**: "**Pacific Connector conducted wetland delineations of pipeline related workspaces. For areas where on-site delineation was not possible due to lack of landowner permission, Pacific Connector used USGS topographic maps, NRCS soil surveys, FWS NWI maps, and aerial photography to identify wetland type and boundaries." (i.e. desktop analysis).

DEIS 4-135 states: "Pacific Connector surveys have identified a number of springs and seeps, as noted in appendix H of this EIS. Pacific Connector has stated that it would further verify exact locations of springs and seeps during easement negotiations with land managers." and "Pre-construction surveys would be conducted to confirm the presence and locations of all groundwater supplies within and adjacent to the pipeline right-of-way." Apparently Pacific Connector has not obtained on-site delineation of all springs, seeps and groundwater supplies. This is important because the DEIS:4-135 states "Spring and seeps supplied by shallow groundwater, however, may be effected by the pipeline project, particularly if the pipeline is directly up-gradient of a spring or seep location.

Wetlands, stream crossings, seeps, springs, groundwater supplies typically require onsite evaluation to determine the feasibility of installing the pipeline by minimizing or eliminating the impact to the wetlands, stream crossings, seeps, springs and groundwater supplies. For example, onsite soil core sampling are needed to determine the feasibility of HDD or Direct Pipe that

[376] DSL Application APP0060697, Section 2, PCGP, Attachment A.2 (RR1 General Project Description), "Construction Procedures," PDF pp. 2146-47.
[377] 2019 DEIS at 4-92.
[378] Resource Report 2, 6)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Pacific Connector Gas Pipeline, L.P.
Docket No. CP17-494-000
Jordan Cove Energy Project, L.P.
Docket No CP17-495-000
PF17-4-000

THE NISKANEN CENTER,
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COMMENTS ON THE FEDERAL ENERGY REGULATORY COMMISSION'S DRAFT ENVIRONMENTAL IMPACT STATEMENT FOR THE JORDAN COVE ENERGY PROJECT

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INTRODUCTION

The Federal Energy Regulatory Commission's (FERC) Draft Environmental Impact Statement (DEIS) is an opportunity for the Commission to truly assess the potential effects and impacts of the construction of the Pacific Connector Pipeline (the "Pipeline") and the Jordan Cove LNG facility (the "LNG Facility) (together, the "Project"). Unfortunately, FERC has failed to provide a meaningful analysis of either the Project's alleged purpose and need, or of the adverse impacts of the Pipeline on landowners. This is the third time that a company has applied to FERC for the required Certificate of Public Convenience and Necessity (the "Certificate") for the Project (or variant of it) and FERC should deny the Certificate Application once again, but this time *with* prejudice. Enough is enough.

Affected Landowners:

The individual landowners on these comments are: Bill Gow; Sharon Gow; Neal C. Brown Family LLC; Wilfred E. Brown; Elizabeth A. Hyde; Barbara L. Brown; Pamela Brown Ordway; Chet N. Brown; Evans Schaaf Family LLC; Deb Evans; Ron Schaaf; Stacey McLaughlin; Craig McLaughlin; Richard Brown; Twyla Brown; Clarence Adams; Stephany Adams; Lori Lester; Will McKinley; Wendy McKinley; Frank Adams; Lorraine Spurlock; Toni Woolsey; Alisa Acosta; Gerrit Boshuizen; Cornelis Boshuizen; and John Clarke (the "Landowners"). All of these individual Landowners are intervenors in the FERC process, and own property that will be crossed by the Pipeline and thus will be taken via eminent domain under Section 717f(h) of the Natural Gas Act if FERC grants the Pipeline a Certificate. As outlined further below by each individual landowner, the Pipeline will harm the Landowners' land, surrounding environment, safety, physical and mental health, and will decimate their property values, and impede economic growth in their affected areas.

The DEIS offers little or no insight as to how the Pipeline plans to address serious issues that may completely destroy landowners' capability of remaining in their homes and on their land, including: destruction of access to potable groundwater; destruction of access to irrigation water; destruction of or adverse impacts on agriculture; destruction of or adverse impacts on timber or forest; adverse impacts on the landowners' overall health and well-being; impacts on cattle and ranchland; and impacts on landowners' income and sources of revenue from their land. The DEIS fails to sufficiently address the significant, adverse impacts on landowners and their properties.

i. Frank Adams:

Frank Adams is a Vietnam Veteran and 72-year-old landowner. Mr. Adams did 3 tours in Vietnam, from November, 1966 to March of 1969, where he was exposed to Agent Orange. He and his family have owned the land at 1731 Ireland Road, Ten Mile, Winston, OR 97496 for over 38 years. He originally purchased the land to raise his family, raise livestock, and garden with his wife and children. He is divorced, and now has frequent visits from his sons and grandchildren.

The Pipeline would cut straight through his land in an east-west direction, and it would take approximately an acre of his land. *See* attached *Exhibit* 1, Pipeline's planned route through Mr. Adams' property. It will be about 200 feet from his home with a 50-foot permanent easement. He also uses 8 acres of his affected neighbor's (Rebeca Edwards) land, to graze cattle and for fire suppression. The proposed route cuts through the middle of Ms. Edwards' land as well. The grazing of cattle on his and his neighbor's land provides from half to one full beef (approximately 600 lbs.) a year for him, his sons, and his sons' families. The cattle grazing area will be completely unusable during construction, and grass for cattle will not exist for at least 2 years during the construction period, and for some time after.

Mr. Adams has grape vines and an orchard that will be adversely impacted or destroyed by the Pipeline. His grapes, including Thompson seedless and Concord, provide at least 25 gallons of juice a year. Assuming they survive the construction of the Pipeline, the grape vines and orchard will be in continuous danger from herbicide spraying by the Pipeline, which is planned for several times a year. Mr. Adams has a well on the property that produces his water. In the 38 years that he has lived there, he has never run out of water. Any digging, blasting, or trenching activities will severely jeopardize his water supply for his home and cattle. The proposed route will also channel water away from his well source. The runoff from the Pipeline will silt up the seasonal creek, and empty into Tenmile Creek, which is a Steelhead and Coho salmon creek. It is clear that the Pipeline will negatively impact the value of his land.

Being that this is now the 3rd time this project has been proposed over a 15-year period, he has felt hostage to the impending threat of eminent domain for that length of time, and the continuous threat of a foreign company seizing his land has taken a toll on his mental and physical health. The fact that he served his country, gave this country his all, only to have the government consider giving his land to a foreign corporation, is a great source of stress and anger for him.

ii. Lorraine Spurlock:

Lorraine Spurlock is a widow who lives alone in her home, and has owned her land for 44 years, at 1127 Kirkendall Road, Camas Valley, OR 99416. Her property is 31.23 acres in total, with about 5-6 acres developed with homes (including hers) on it, and the remainder with forest, which includes old fir trees. She bought the land for its sheer beauty. She worked very hard to make her land resemble a park, which will be destroyed by the Pipeline cutting right across her property for approximately .22 miles. The Pipeline would remove a 95' swath of timber from the middle of the forested section of her property, with a permanent 50' clear cut over the Pipeline right-of-way. *See* attached *Exhibit* 2, the Pipeline's planned route through Ms. Spurlock's property. Ms. Spurlock is concerned that the reduction in timber coverage would affect the classification for tax purposes of a wood lot, as well as remove her valuable timber, which will deplete her income. It will also reduce the value of her property.

Ms. Spurlock does not have internet or access to a computer, and only was made aware of the opportunity to intervene in the FERC proceedings, as well as file comments on the DEIS, after being contacted by third parties who are representing and assisting landowners with this process.

The land will be handed down to her daughter, and she very much wants the land to remain as pristine as it currently is. The potential for the Pipeline to take her land over the years has taken a toll on Ms. Spurlock, and inflicted her with much unneeded stress.

iii. Gerrit and Cornelis Boshuizen:

Gerrit Boshuizen and his brother Cornelis have owned the land at 18191 Highway 39 in Klamath Falls, OR, 97603 since May of 1981. The land includes over 35 acres of pastureland. They bought their home and land because of their love of farming and to move out of town for a nice quiet, rural setting. Gerritt still lives on the property in his home, and Cornelis lives nearby.

The proposed Pipeline would take their land out of the business of grazing cattle for 3-5 years. *See* attached *Exhibit* 3, the Pipeline's planned route through the Boshuizens' property. They will not be able to run cattle on the land due to the Pipeline construction. They flood-irrigate their land, and the Pipeline would destroy this irrigation system, and the grass for the cattle will die. It will also destroy their hay crop. They also have to pay nearly $3,000 a year to Klamath Irrigation District for the water needed to irrigate the land and, even if they can't irrigate or use the water, they will still have to pay Klamath Irrigation District for the water in order to maintain their rights to it. During construction of the Pipeline, it will be noisy and dusty, which will ruin the Boshuizen's well-earned peace and quiet, and will significantly interfere with their quiet enjoyment of their home. The Pipeline will also be within 300 feet of their well and drinking water source, and they have no idea as of yet how the right-of-way would impact their access to potable water.

Once construction is complete, the Pipeline will block them from accessing their barn, where they process and store the hay they grow for sale. They will be unable to drive the required heavy-duty equipment in and out of the barn and over the Pipeline's right-of-way, effectively making the barn useless. This will be a huge financial hit to their family. The Pipeline will impact the irrigation and water movement of their fields, which will adversely impact the growth of their pasture. It could also impact their fence line. The Pipeline will certainly make their property less valuable.

The Pipeline has put undue stress on the Boshuizens for over 15 years. They have had to deal with several land agents and Pipeline representatives trying to bully them into signing an easement. They tried to persuade the Boshuizen that all other landowners in the area 'had already signed.' Pipeline representatives have not respected the Boshuizens' wishes for them to stay off the property, and they keep coming back despite these requests to stay off the land. A Pipeline land agent has told them several times that they would bring their supervisor by the house, but he never has. There also is the possibility of a Pipeline explosion, and the Pipeline goes right in front of their home.

iv. Toni Woolsey:

Ms. Woolsey and her family have owned the property at 213 Ragsdale Road, Trail, OR 97541 for 69 years. Her parents purchased the property and lived on it until they died. Ms. Woolsey moved onto the property 15 years ago to take care of her ailing mother, and built her dream home on the property. She took care of her mother until she passed away. Ms. Woolsey barely had time to get settled in when Pembina came knocking and told her that they wanted to take significant parts of her land to build the Pipeline. The Pipeline would be less than 135 feet from her home, and instead of a beautiful view, she will have to look at a 100 ft. scar up the side of a mountain. *See* attached *Exhibit* 4, the Pipeline's planned route through Ms. Woolsey's property. It very well may affect her only source of water, as the private well on her property is within approximately 180 yards of the proposed route, down by the Rogue River, where the Pipeline wants to do Horizontal Directional Drilling ("HDD").

The Pipeline has been hanging over her head for over 15 years, and it is never very far from her thoughts. She has spent a significant amount of time and money trying to stop the Pipeline for good, but now it is on its third round of seeking approval for the same route. The money that she has spent is nothing compared with the significant emotional toll that this ordeal has taken on her.

v. Clarence and Stephany Adams:

Clarence Adams and Stephany Adams[1] have owned their property at 2039 Ireland Rd, Winston, OR 97496 for 28 years. Mr. Adams bought the land because it was in a quiet, rural setting, and with 8.5 acres, it was enough to raise some livestock, and for privacy for him and his family. Mr. Adams and his wife Stephany raised two children on their property. Currently, their daughter and son-in-law live on the property as well.

The Pipeline will split the Adams' property in half, cutting directly through pastureland for their horses, and limiting their access to their land. *See* attached *Exhibit* 5, the Pipeline's planned route through the Adams' property. The Pipeline will climb a hill through the pastureland at 30-45% slopes, with fractured basalt lying very close to the surface. If the Pipeline is built, their land will never be restored to its original condition, mostly due to the depth of the Pipeline trench, and the Pipeline workers leveling a significant portion of their land for an approximate ¾ acre "temporary" working area to store Pipeline construction equipment for years.

The Pipeline will kill a stand of mixed hardwood and conifer trees, which along with providing firewood for the Adams and shade for the horses, also provides a privacy shield and noise barrier from the traffic on the County Road that goes past their house and leads up to a popular reservoir.

The Adams family have 3 wells on their property. One is below the proposed right-of-way, which they hoped to develop to use for irrigation. They obviously cannot do this until they know

[1] Clarence and Stephany Adams are not related to their neighbor Frank Adams.

with certainty that the Pipeline will not be built. The other is their only source of water and is currently used for household consumption, as well as irrigation for the yard, garden, and their orchard. This well will be within 400 feet of the Pipeline, and their water holding tank is within 130 feet of the Pipeline. The third is not currently in use, as it had very limited water when it was drilled. There is a real possibility that the digging and blasting for Pipeline construction will permanently and adversely affect the water that is available.

The proposed Pipeline easement would run approximately 136 feet from the Adams' home. Based on similar Pipeline construction activity close to dwellings, there is a real concern that it will cause damage to the foundation of their home. As noted above, the concrete holding tank for the house water supply is even closer to the proposed Pipeline corridor, and it would cost thousands of dollars to replace it. They also have a horse barn within 50 feet of the temporary work area, which is highly likely to be damaged. Even if it remains intact, at best, the horse barn will probably be unusable during construction.

The Pipeline will cross the seasonal creek running through the property via the 'open trench' method. The creek bed is not composed of round cobbles and gravel over a bed rock base like many other creeks in the area. Instead, their creek bed is composed of about 6 inches of very angular, fractured basalt rock on top of a clay base, which Mr. Adams has measured down to a depth of approximately 5 feet. The angular gravel is more prone to washing out then the round cobbles, so when the existing trees are removed for the 95-foot construction easement, it is a distinct possibility that the disturbed gravel will wash out; this greatly increases the chances of the erosion of the creek bed to below its current depth, which will bring the Pipeline closer and closer to the surface.

The Pipeline's maintenance of the proposed right-of-way could also have detrimental effects on the Adams, their animals, and their lifestyle. Mr. Adams has honey bee apiaries within 100 feet of the proposed right-of-way. The oldest hive has been established for over 9 years. The construction and placement of the Pipeline will surely destroy the bees' delicate environment. If the bees somehow survive the construction, the Adams will have no control or say on how vegetation will be controlled over the easement, or what herbicides they will use over the right of way that could negatively impact their bees. The herbicide may also have a negative impact on their horses, and increase the cost of feeding them. The spray could also kill the parakeets and finches that they have in a small aviary, as small birds are especially susceptible to toxins. The herbicides could also have an effect on the Adams family's health, especially when one takes long-term exposure into consideration. Further, the Adams' property – their largest investment- will obviously be devalued as a result of the Pipeline running through it, which will affect their financial stability for years to come.

The emotional cost of having this project hanging over the Adams' heads for over 15 years is incalculable. Their home and property are their refuge, and a source of great pride. The constant worry that a foreign corporation could come in and take their land has been horrible. The Pipeline will be using the lowest possible construction and safety standards, which increases the risk of a leak and possible explosion. With the Pipeline being so close to their home, the Adams face the very real possibility of being caught in a gas leak, fire, or explosion.

vi. John Clarke:

John Clarke is a Korean Conflict Marine War veteran and has owned his land at 1102 and 1363 Twin Oaks Lane, Winston, OR 97496 since 1984. Mr. Clarke is now Trustee of the John Clarke Family Trust and John Clarke Oregon Trust, which are the owners of the affected properties that he plans to pass down to his children. His land consists of 140 acres and developed structures. He bought the land for a quiet place to live. It consists of two parcels, a family home for himself, and a home for his son and daughter. His property includes mature conifer, oak, and madrone trees.

The Pipeline will lessen the value of his property, and have severely negative impacts on the quality of his land. The current proposed route of the Pipeline cuts diagonally across 140 of his timbered acres. *See* attached *Exhibit* 6, the Pipeline's planned route through Mr. Clarke's properties. The only source of water on his property is a well on the property. The Pipeline could adversely affect and permanently disrupt his family's only source of water on the property. This over 15-year battle with the Pipeline has also exacerbated Mr. Clarke's health problems.

vii. Bill and Sharon Gow:

Bill Gow and his wife Sharon Gow have owned their property for 29 years. They started with 1,365 acres in 1990, and they've incrementally added more land, which now amounts to approximately 2,400 acres. The Gows have one of the very few large, family-owned cattle ranches in the southern Oregon region. They have worked incredibly hard to create and maintain their ranch.

The Gows bought the land to develop a legacy cattle ranching business that would give their family a stable, long-term home, and a place for their children and grandchildren to be raised in the country. This ranch has always been the Gows' dream. Their whole family lives on the property: Bill and Sharon Gow; their daughter, her husband and their 2 children; their son, his wife, and their 2 children. The fact that they have a ranch to live and work together, as well as the ability to raise their families together with shared values is invaluable.

The Pipeline will interrupt and potentially destroy all that they've built. The proposed route will bisect a 3-parcel section of the ranch. *See* attached *Exhibit* 7, the Pipeline's planned route through the Gows' property. The Gows considered their ranch a refuge, which has now been under threat of foreign invasion for over 15 years. They value the quiet, remote, and rural lifestyle immensely. Having a scar across their properties from the proposed right-of-way, having to deal with continuous, inevitable problems that arise from the Pipeline's placement, and dealing with Pipeline's maintenance crews are not at all what they wanted for their ranch or for their descendants. The Pipeline defeats their dream.

On the 2017 proposed alignment, the Gows had planned to build a small venue to host weddings. However, because the planned site was 350 feet from where the Pipeline may potentially be built (and the route keeps changing), they have abandoned these plans indefinitely. Additionally, the Pipeline route would force the Gows to change the long-term timber cut plan that they've developed over the course of many years.[2]

The Pipeline will cross the Gow's property at a slope. This is a concern due to potential landslides and changes in the area's drainage with the introduction of differentials in soil compaction. Since the riparian buffers are clear-cut permanently, the agency should seriously consider whether there will be long-term introductions of sediments into the waterways as a result.

The clear cuts planned along the right-of-way will have an especially strong impact in drought season. First, clear-cuts are going to be an eyesore, especially in riparian areas on their property and around the region. Second, and more importantly, in the intense drought season the trees at the edge of the forest are suffering due to exposure to the hot sun and drier soils. By logging the right-of-way strip, the Pipeline will create more forest 'edges' that will threaten the health of the forests and riparian areas. The clear-cuts along the right of way could also have a significant impact on the water retention of soils along waterways and on the rest of the property. When the soil can't hold as much water, the Gows have to pipe it in from the springs. As discussed further below, the Gows ability to lay pipe becomes severely restricted, or at the very least much more complicated, if the Pipeline is built.

The Pipeline will also have severely negative impacts on water retention, quality, and use. There are 5-6 creeks whose headwaters start on various locations on their property, including

[2] The Gows also use the property on the 2015 proposed route for a private hunting and recreation business, where people come from all over the world to hunt deer, turkey, and elk. During construction, this business would not be able to function at all because of the noise and construction disturbance. After construction is complete, there are serious liability concerns about maintenance workers walking through the hunting grounds.

Roberts Creek, the Richardson Road Creek that feeds into to South Umpqua, and a number of others. Any adverse impact because of the Pipeline to theses headwaters, whether warming, sedimentation, turbidity, introduction of herbicides or chemicals, or geological changes to the flow structure would have dramatic impacts downstream. This significant problem also exists in the Pipeline's crossing of any creek, including the tribute to the South Umpqua, which the Pipeline is proposed to cross in the current 2017 route, very close to its intersection point with the South Umpqua River.

A major concern is the Pipeline may destroy the method by which the Gows currently irrigate drinking water to the cattle and water to the grazing areas. The Gows currently irrigate water directly across the proposed Pipeline right-of-way. This problem will be severely exacerbated because of the increasing frequency of severe drought conditions in southern Oregon. As a result, the Gows will need to move the water pipes more frequently to ensure that the cattle and their fields are watered. This could prove impossible with the Pipeline right-of-way cutting through the property.

There is a big spring located just below the ridge of the 2015 route, which provides water to an indoor horse area and 2 of the family homes on the ranch. Any impact on this source of water because of Pipeline construction on the ridge would have devastating impacts on their family's wellbeing. There is no evidence in the DEIS that the Pipeline is taking proper precautions to ensure that this spring and other waters will be protected from fissures in the bedrock from construction or other potential damage.

There are also wetlands on the Gows' property, including a large marsh, where a creek feeds from below a trout pond spreading out to an area between 0.5 and 2 acres, depending on the flow. The marsh is partially sub-irrigated, and it is a critical spot for retaining moisture into the dry months.

The hydrostatic testing proposed is also a concern, as it remains uncertain where the discharge location is in the area. The Gows have deep concerns about the water from the Klamath Basin being discharged into the South Umpqua and the adverse impact that this would have on the ecology of the region.

Over the course of 15 years, this proposed Pipeline taken up countless hours of Mr. Gow's time and resources. Mr. Gow is on the phone every day about the Pipeline, as he is not computer literate and he works extra hard to keep up with what Jordan Cove is planning.[3] The project has put significant stress on Mr. Gow's family and their relationships. Mr. Gow worked from nothing to earn and build their ranch, and the thought that the United States government will give a foreign corporation the power to take what he's built from scratch can be (understandably) all-consuming. There also is the great uncertainty of how their family will cope with the devastation to the land and their way of life if construction should ever start.

Plans for the ranch are currently on hold, as they are not sure whether or not to make any improvements on their land with the Pipeline continuing to hang over their heads.

viii. Pamela Brown Ordway, Wilfred E. Brown, Elizabeth A. Hyde, Barbara L. Brown, Chet N. Brown, and Neal C. Brown LLC:

The Brown family property has been in the family since 1937, when the six Brown siblings' father purchased it from an insurance company who had repossessed the land during the Great Depression from one of their relatives. Their father was a tank commander in WWII who earned a Bronze Star and the Purple Heart. The Brown siblings grew up in the farmhouse on the property, where their sibling Richard Brown and his wife Twyla Brown now reside. When their father passed away, Twyla Brown and her husband bought the 100 acres in the front to live and work from the farmhouse, and back 153 acres went to the other above 5 Brown siblings, or Parcel #s: R10266;

[3] It's of note that the Gows never received formal notice about the 2017 realignment going over their land. They also have never received a purchase offer.

R11298; R11338, all in Douglas County. *See* attached *Exhibit* 8, the Pipeline's planned route through the Browns' property.

Their land is made up of roughly 80 acres of farmland, 65 acres of second-growth timber, and approximately 10 acres of timber that they excluded from harvesting when they logged in 2005. The 10 acres of unharvested timber is predominately a mix of Douglas Fir and White Fir, and is well over 100 years old. They left that particular stand because it provided a visual barrier from their neighbor's logging, and it was one of the areas where the Fairy Slipper Orchid[4] thrived. The purpose of the current unharvested timber is for it to continue to grow, and it is the only stand of timber they could harvest if they needed the revenue.

The current route of the Pipeline, as well as the temporary easement Pembina states it needs for construction, will cut through the trees they excluded in the 2005 harvest. The Pipeline would severely and negatively impact their farming and logging practices. As the proposed Pipeline route cuts diagonally across their property, access to almost every part of the land is affected. If they wanted to log a portion of their timberland, they would be unable to bring in log trucks or the necessary heavy equipment over the Pipeline right-of-way. The cut area through the right-of-way would be kept free of tree and vegetation by Pembina, and the adjacent timber would thus grow inward towards the clear space, making it grow less straight, and consequently less valuable.

The portion of the Pipeline that goes through their farmland would adversely impact their farming practices as they could not bring in tractors and farm equipment over the Pipeline to harvest hay. It would limit their options for future crops, and they would not be able to grow wine grapes, fruit trees, or Christmas trees in the Pipeline easement areas. They also have the additional risk of unknown persons accessing their property via the Pipeline easement. The Browns have also

[4] The Fairy Slipper Orchid is a wildflower that they were taught as children to take special care of. While it is considered 'threatened' or 'endangered' in other states, it currently is not in Oregon.

kept their farm free from herbicides for over 10 years. Pembina's use of herbicides over their easement would obviously directly conflict with how they manage their crops.

The Browns have put their family legacy plans for the land on hold, pending a final decision on the Pipeline. For example, they would like to plant a cash crop that would allow the next generation to continue to be able to keep the land in the family. All of the best options, from planting wine grapes, to Christmas trees, to nut trees, all require a substantial financial investment (upwards of approximately $10,000 to $15,000 per acre).The Browns are 100% willing to make this investment, but with the possibility of a Canadian company coming through and ripping open a 95-foot swath through what they just planted, they can't make a commitment to this. They also want to drill a well on their portion of the land for irrigation use, but if the Pipeline were built, it would limit their options on where they can drill.

ix. Richard and Twyla Brown:

When the Brown siblings' father passed away, Richard and Twyla Brown bought the front 100 acres of farm to live and work from the farmhouse, at 2381 Upper Camas Road, Camas Valley, OR 97416.

They purchased the land to honor Mr. Brown's father's legacy, farm the land, and to pass it onto their descendants. Their grandsons currently live on the farm and are heavily involved in the day-to-day operations. They raise beef cattle, sheep, and process hay each summer. They irrigate their fields and are the only farm in the Valley that has consistently done so since 1953. Their land has also been used to grow other crops including oats, barley, and grass seed. This type of farming uses heavy equipment.

The Browns have always been good stewards of their land. For example, they worked with the Coquille watershed office early in their ownership to protect the river by fencing it off from their livestock, and to plant trees along it to preserve the river banks and provide shade and habitat for the wildlife in and around the river. The Pipeline will cut a 75-foot swath through those trees and disrupt what they've been building now for generations.

The effects of the proposed Pipeline of their land and the river running through it would be devastating. The Pipeline would restrict access to some of their fields and take away part of the land from farming. *See* attached *Exh.* 8, the Pipeline's planned route through the Browns' property.

The Pipeline would detrimentally affect the Brown's water use. For irrigation, the Browns still rely on the drainage tile in that Mr. Brown's father put in the fields. The Pipeline would cut right through their drainage tiles, destroying their ability to irrigate water, and any investment in those affected fields would be worthless. The Pipeline will also cut through grazing/pasture fields, which they also cut hay on. The Pipeline would prevent them from using those fields. The Pipeline is also cutting close to their well, their only source of potable water for their home on the land.

It is also of note that archeologists from the state of Oregon also visited the Brown's property in approximately 2010. They found numerous Native American sites on their land with relics, which is yet another reason not to permit a huge ditch to cut through their land.

Richard and Twyla are retired, and too old to sell and find another place to start all over. Their property was supposed to be their security in old age. If this Pipeline is approved, they will lose one of their central retirement incomes, and this will be an almost impossible financial blow to surmount. The Browns have wanted to plant nut trees on their land, and put money into a new irrigation system, but they realized they can't do this until it's a guarantee that the U.S. government will not permit a Canadian company to come and take their land. They can't develop anything until this is over, as anything they do could be a complete waste of their hard-earned money and resources.

x. Deb Evans, Ron Schaaf, and Evans Schaaf Family LLC:

Deb Evans and Ron Schaaf purchased their property on Parcel Number: R71040 Tract: KH-

569.000 in Klamath County on June 2, 2005. They purchased the 157-acre property to build a home, drill a well, and to enjoy being within one mile of mountains, lakes, and the wilderness. They specifically chose the property for a number of reasons, including the viewshed, the location between two beautiful stands of Winema National Forest old growth, being within hiking distance of the Mountain Lakes Wilderness, and having direct access on Clover Creek Road which has been designated a 'utility free corridor'. They also purchased it as an investment to manage and sell timber, and to have about 5 acres of organic food production. Deb and Ron have long been gardeners, hikers, and enjoy managing forest property. They wanted to invest in the timber as an asset to use in the future for other projects and productions.

Within two months of purchasing the property, there suddenly was survey flagging across the portion of the property that they had intended to build their home on. They shortly found out that the survey markers were for a proposed 36" import natural gas pipeline from Coos Bay to Malin, which would bring regasified LNG to the California market. They never would have bought their property had they known a pipeline was trying to build right through it. They have now put off their planned development of the property for over 15 years.

Clover Creek Road bisects their 157 acres on the southern part of the property leaving approximately 9 acres located on the south side of the road, and around 144 acres of timber to the north of the road. The proposed route of the Pipeline is located north of Clover Creek Road, but does not follow the road Right-of-Way. *See* attached *Exhibit* 9, the Pipeline's planned route through Deb and Ron's property. Instead, it intersects their property about 400 feet northeast of Clover Creek Road on the southern boundary of the property, and then comes up at an angle to within 75 feet of the Clover Creek Road, and finally turns back at a northwest angle and crosses off of their property 500 feet along their west property line, north of Clover Creek Road. This route results in far greater impacts to the property. They are restricted from crossing the proposed Pipeline right of way using the normal heavy logging equipment, thus making the management and harvesting of timber far more expensive and time-consuming. Additionally, access to the bulk of their property would require crossing the Pipeline's right-of way.

Five acres of their timber would be permanently taken out of production. Deb and Ron use organic growing methods, and they are opposed to the use of harmful, synthetic sprays and fertilizers. However, such harmful herbicide sprays are exactly what the company is proposing to use to maintain the right-of-way. The proposed right-of-way is within the flatter, more fertile soils of their property, where they planned to grow their own food, which they obviously will not be able to do if the Pipeline is built.

The increased risk of fire is also a concern. As a timber producer, they are seeing more drought and insect infestation with the increasingly hotter, drier summers in Oregon, and a shrinking snowpack, and with that, more and more forest fires. The construction and operation of a high-pressure 36" natural gas pipeline will introduce significant additional risks of fire and devastation of their land.

The viewshed will also be significantly affected and scarred. A part of the inherent value of the land is the surrounding viewshed and accessibility to pristine areas of Oregon. The compromising of the viewshed through construction a 95-foot swath through their property and the neighboring Winema National Forest properties (an area that is currently utility-free and protected) will have a significant impact on their property's value and very reason they purchased the property in the first place.

The fight to keep the Pipeline from being built across southern Oregon for over 15 years has taken a toll on Deb and Ron, mentally and financially. The proximity to the Pipeline and the continuous uncertainty of whether the project will ever be built has put their development plans since they bought the property on permanent hold. When the first bought the property in 2005, they were 45 and 50 years old respectively. They are now 59 and 64 years old, and physically less able to implement the development plans that they had for the property themselves. Further, the money that they saved to improve the land has been spent in part on trying to protect their asset from the ongoing risk of a taking by the Pipeline. When they first bought their property, it was never disclosed to them that a company was proposing to build a Pipeline. Over $5,000 and an attorney later, they had intervened in the first round of proceedings at FERC on this project, but with little idea as to what was happening and how to protect their property. They also had no idea that this Pipeline would continue to haunt them for over 15 years.

Deb and Ron firmly believe that no one should be forced to give or sell an easement for a project that has no public benefit or use. This is especially true when that the benefit goes to Canada, with this project uniquely utilizing primarily or solely Canadian gas, and with none of the gas benefiting U.S. consumers. They have long believed, and pointed out in earlier testimony in Round 2 (the 2012-2016 proposed project), and previously in the current Round 3, that there is a clear difference between this LNG project and every other proposal before FERC. FERC in 2016 heard and understood the landowners' arguments and denied the Section 7 and Section 3 applications. They believe the Commissioners should do the same this time.

xi. Stacey and Craig McLaughlin:

Stacey and Craig McLaughlin purchased their property at 727 Glory Lane, Myrtle Creek, Oregon in 2000. The property consists of 357 acres of farm and forest. They have merchantable timber and a developing woodland on the property. The property is also notable as an oak woodland, with old growth madrone areas. The vegetation is diverse and offers habitat for numerous species of insects and animals. There is also un-surveyed wetland on the property.

The McLaughlins bought the property to fulfill a lifelong dream of owning a ranch to grow their own organic food, and to live a sustainable and rural lifestyle. Their ultimate goal was to create a sanctuary for themselves and their family. They wanted the solitude of an isolated area, but also to be relatively close to airports for work-related travel, and to have easy access to medical care for themselves and their aging parents. Their property met all of these criteria, and included two dwelling units that met their plan to move aging family members into one of the homes for caregiving. Stacey and Craig currently live on the property, with Craig's elder cousin living in the second residence.

The Pipeline will cut diagonally across two major parcels of their land. *See* attached *Exhibit* 10, the Pipeline's planned route through the McLaughlins' property. The proposed route would essentially divide the property in half, making the second or rear parcel inaccessible for heavy equipment, including for any future residential construction or fire suppression activities.

The Pipeline construction will also adversely impact and potentially eliminate old growth madrone and oak trees, home to many species of animals. The planned route will plough through an expensive logging restoration project, wherein they planted thousands of Douglas Fir trees to rehabilitate the land and serve as a future income source. The proposed route will require the removal of much of that newly-forested land. Removal will also increase the chances of a landslide, as many of the older trees that would be removed now stabilize the land.

There are numerous water sources throughout the property, including springs, seasonal creeks, and wetlands, which are likely to be adversely impacted by the Pipeline's construction. The greatest threat is to the McLaughlin's domestic water supply. Any disruption by the construction or permanent installation of the Pipeline would significantly reduce or eradicate their water supply, which is already threatened by drought. They also are wary of the significantly increased risk of wildfires due to Pipeline-related incidents.

The McLaughlins do not use herbicides or pesticides on their land for health and safety reasons. The Pipeline's potential construction is a grave concern, as both will be used indefinitely by the company to maintain their easement as desired.

The construction of the Pipeline will destroy the very reasons why the McLaughlins purchased this property, including solitude. If Pembina gets permission from FERC to build the Pipeline, it will have 24/7 access to the McLaughlin land both during and after construction.

The proposed Pipeline has resulted in significant emotional and financial stress on the McLaughlin family. They have spent thousands of dollars both directly and in-kind, and countless hours of their time in trying to protect their home from a Canadian corporation.

xii. Alisa Acosta, as Trustee of Acosta Living Trust:

Alisa Acosta, is Trustee of the Acosta Living Trust, which is the owner of the affected property at 536 Ragsdale Road, Trail, OR 97541. The current proposed route and access road would run directly through the property, severely impacting the use and value of the property, which includes a licensed airport, a hanger building, a home with a pool, a smaller cottage and garage/utility building, a pole bar, fruit tree orchard, 80+ walnut trees, irrigation, and two pump houses. *See* attached *Ex.* 4, the Pipeline's planned route through the Acosta Living Trust's property.

The property was acquired in part for its value as a potential "fly-in" gateway to surrounding outdoor recreation for private guests, and currently serves as the base of operations for Outdoors in Oregon, LLC dba Rouge Recreation, a company that provides outdoor recreation opportunities, including concession services to the USDA Forest Service. The current proposed route will bisect and destroy the airport landing strip. The company is a significant contributor to the local economy, employing a seasonal work force of 15 people and support services from 9 local businesses. The property has served as a landing area for law enforcement and first responders, and based on its size, location, and airstrip, has public resource value as a potential staging area for emergency services, including fire suppression and search and rescue. The simple fact is that it does not make sense to bury a highly pressurized natural gas pipeline a few feet below an airport runway that is likely to be the location of take-offs and landings by a variety of private and public aircraft.

The proposed Pipeline work areas, which include an extended staging area that at some points is over a thousand feet from the proposed easement, will destroy two mature orchards. The Pipeline also seeks to appropriate the property's only current access road and provide the owner with a temporary access across land owned by neighbors to the south.

The effect of the current proposed route would be at the very least the temporary relocation of the business currently operated on the property, and the Pipeline's staging activities will be substituted for those of the owner's business. By some estimates, the period of occupation for construction activities may extend 7-10 years, and that the work area as currently defined will run the length of the property and effectively prevent any reasonable access to the airstrip, the hanger, and to the bulk of the property to the north. There will be substantial damage to, if not total destruction of, existing orchards and old growth trees. There is no public benefit to this Pipeline, and the project should be denied with prejudice.

xiii. Will and Wendy McKinley:

Will and Wendy McKinley purchased their property at 2579 Old Ferry Road from Wendy's mother in 2016. The property had been in their family since 2004. It consists of 19 acres with 600 feet of river frontage on the Rogue River. They purchased the property from Wendy's mother so that she no longer had to live with the burden of the potential Pipeline destroying her land. Her mother originally purchased the property for retirement, but once the Pipeline was announced, she no longer wanted to live there.

The Pipeline will destroy any value that the land currently has. *See* attached *Ex*. 4, the Pipeline's planned route through the McKinleys' property. The McKinleys have been using the property as a vacation rental or income property, since they have not been able to sell it since the Pipeline project was first announced in 2005. If construction starts, they will no longer be able even to rent the house on the property.

The Niskanen Center:

Niskanen is a 501(c)(3) libertarian think tank with strong interests in free markets and in protecting Americans' property rights. It is a fundamental matter of justice – and a foundational belief among libertarians – that government should forcibly take private property only as a measure of last resort, when truly for public use, and must compensate the property owners sufficient to render them indifferent to the taking.[5] The Niskanen Center sees no public use in the proposed Pipeline project, and notes that FERC failed to establish the required Purpose and Need of the project in the DEIS. The Project should be denied with prejudice.

I. THE DEIS FAILS TO ADDRESS THE PIPELINE'S SEVERELY NEGATIVE IMPACTS ON OWNERS' LAND USE AND WAY OF LIFE.

This Pipeline would have a severely negative impact on the land and on the Landowners' use of their land. The DEIS fails to analyze or capture many of these adverse impacts on landowners, and offers no discernable mitigation plan or solution. Several of these analytical voids are discussed in further detail below.

A. The DEIS Fails to Evaluate the Negative Impact on Valuation of Land.

Private landowners with a 36-inch, 1600 PSI to 1950 PSI natural gas pipeline running through their property can be sure that the potential re-sale value of their property will be drastically reduced. Just ask the McKinleys, who have been trying to sell their land since 2005. *See supra* at 21.

In the DEIS, FERC cites to four studies, all cherry-picked by the Pipeline, in support of its conclusion that "the likelihood of the pipeline resulting in a long-term decline in property values and

[5] Niskanen notes in passing that the Commission's Policy Statement appears to acknowledge that court-determined "just compensation" is insufficient to make landowners indifferent to the taking of their property: "Even though the compensation received in such a proceeding is deemed legally adequate, the dollar amount received as a result of eminent domain may not provide a satisfactory result to the landowner and this is a valid factor to consider in balancing the adverse effects of a project against the public benefits." 90 FERC ¶ 61,128, p. 19.

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

OFFICE OF FOSSIL ENERGY

JORDAN COVE ENERGY PROJECT, L.P.	)))	FE DOCKET NO. 12-32-LNG

ORDER CONDITIONALLY GRANTING LONG-TERM
MULTI-CONTRACT AUTHORIZATION TO EXPORT
LIQUEFIED NATURAL GAS BY VESSEL
FROM THE JORDAN COVE LNG TERMINAL IN COOS BAY, OREGON
TO NON-FREE TRADE AGREEMENT NATIONS

DOE/FE ORDER NO. 3413

MARCH 24, 2014

I. INTRODUCTION

On March 23, 2012, Jordan Cove Energy Project, L.P. (Jordan Cove) filed an application (Application)[1] with the Office of Fossil Energy of the Department of Energy (DOE/FE) under section 3 of the Natural Gas Act (NGA)[2] for long-term, multi-contract authorization to export as LNG both (i) domestically produced natural gas, and (ii) natural gas produced in Canada and imported into the United States. Jordan Cove seeks to export this LNG by vessel to nations with which the United States has not entered a free trade agreement (FTA) providing for national treatment for trade in natural gas (non-FTA countries).[3] Jordan Cove requests authorization to export up to the equivalent of approximately 292 billion cubic feet of natural gas per year (Bcf/yr) (0.8 Bcf per day (Bcf/d), or approximately 6 million metric tons per annum (mtpa) of liquefied natural gas (LNG), for a 25-year period commencing on the earlier of the date of first export or seven years from the date the requested authorization is granted.[4]

The proposed exports would originate from a liquefaction and export terminal to be located in Coos Bay, Oregon (Jordan Cove LNG Terminal or Terminal). Jordan Cove is requesting authorization to export the LNG on its own behalf or as an agent for other entities who hold title to LNG, after registering each such entity with DOE/FE. For the reasons discussed below, this Order conditionally authorizes Jordan Cove to export LNG in a volume equivalent to 292 Bcf/yr of natural gas, or 0.8 Bcf/d, for a 20-year term.

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[1] Application of Jordan Cove Energy Project, L.P. for Long-Term Authorization to Export LNG to Non-Free Trade Agreement Countries, FE Docket No. 12-32-LNG (Dec. 21, 2011) [hereinafter Jordan Cove App.].
[2] 15 U.S.C. § 717b. This authority is delegated to the Assistant Secretary for Fossil Energy pursuant to Redelegation Order No. 00-002.04F (July 11, 2013).
[3] Jordan Cove previously sought authorization to export LNG by vessel up to the equivalent of 438 Bcf/yr of natural gas (1.2 Bcf/d) for a 30-year term to nations with which the United States currently has, or in the future enters into, a FTA requiring national treatment for trade in natural gas and LNG (FTA countries). DOE/FE granted that authorization by order dated December 7, 2011 (Jordan Cove FTA Order). On March 18, 2014, DOE/FE also authorized Jordan Cove to import natural gas from Canada to the Jordan Cove Terminal to support this requested export authorization. *See infra* Section IV.A (procedural history of orders granted to Jordan Cove).
[4] DOE regulations require applicants to provide requested export volumes in terms of Bcf of natural gas. 10 C.F.R. § 590.202(b)(1). Accordingly, as discussed below, DOE/FE will authorize Jordan Cove's requested export in the equivalent of Bcf/yr of natural gas. *See infra* Sections X.F & XII.A.

On June 6, 2012, DOE/FE published a Notice of Jordan Cove's Application in the Federal Register.[5] The Notice of Application called on interested persons to submit protests, motions to intervene, notices of intervention, and comments by August 6, 2012. In response to the Notice of Application, DOE/FE received five timely filed motions to intervene and comment or protest respectively from the American Public Gas Association (APGA); Sierra Club; Citizens Against LNG, Inc.; Landowners United; and, jointly, Rogue Riverkeeper and the Klamath-Siskiyou Wildlands Center (collectively, KS Wild). In addition, DOE/FE received 35 timely filed and five additional late-filed comments in support of the Application; three timely filed and two late-filed comments opposing the Application (without a request to intervene);[6] and comments from an individual (Derrick Hindery) raising environmental concerns but taking no position on the merits of the Application. Additional procedural history is set forth below in Section VII.

Previously, on May 20, 2011, DOE/FE issued *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961 (*Sabine Pass*), the Department's first order conditionally granting a long-term authorization to export LNG produced in the lower-48 states to non-FTA countries.[7] In that order, DOE/FE conditionally authorized Sabine Pass to export a volume of LNG equivalent to 2.2 Bcf/d of natural gas. In August 2011, DOE/FE determined that further study of the economic impacts of LNG exports was warranted to better inform its public interest review under section 3 of the NGA.[8] By that time, DOE/FE had received two additional applications for authorization

[5] Jordan Cove Energy Project, L.P., Application to Export Domestic Liquefied Natural Gas to Non-Free Trade Agreement Nations, 77 Fed. Reg. 33,446 (Feb. 23, 2012) [hereinafter Notice of Application].
[6] Paula Jones filed both a timely comment against the Application as well as a late-filed comment against the Application. Both submissions are counted above.
[7] *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961, Opinion and Order Conditionally Granting Long-Term Authorization to Export Liquefied Natural Gas From Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations (May 20, 2011) [hereinafter *Sabine Pass*]. In August 2012, DOE/FE granted final authorization. *Sabine Pass Liquefaction, LLC*, DOE/FE Order No. 2961-A, Final Opinion and Order Granting Long-Term Authorization to Export Liquefied Natural Gas From Sabine Pass LNG Terminal to Non-Free Trade Agreement Nations (Aug. 7, 2012).
[8] DOE/FE stated in *Sabine Pass* that it "will evaluate the cumulative impact of the [Sabine Pass] authorization and any future authorizations for export authority when considering any subsequent application for such authority." DOE/FE Order No. 2961, at 33.

to export LNG to non-FTA countries—one from Freeport LNG Expansion, L.P. and FLNG Liquefaction, LLC (collectively, Freeport or FLEX)[9] and one from Lake Charles Exports, LLC (Lake Charles Exports).[10] Together, the *Sabine Pass* conditional order, the Freeport application, and the Lake Charles application proposed LNG export authorizations totaling the equivalent of up to 5.6 Bcf/d of natural gas. DOE/FE expected that more non-FTA export applications would be filed imminently. Indeed, by the end of 2011, several more applications had been filed, including a second application by Freeport[11] and an application filed by Cameron LNG, LLC.[12]

In light of these developments,[13] DOE/FE engaged the U.S. Energy Information Administration (EIA) and NERA Economic Consulting (NERA) to conduct a two-part study of the economic impacts of LNG exports.[14] First, in August 2011, DOE/FE requested that EIA assess how prescribed levels of natural gas exports above baseline cases could affect domestic energy markets. Using its National Energy Modeling System (NEMS), EIA examined the

[9] On May 17, 2013, DOE/FE granted FLEX's first non-FTA export application, conditionally authorizing it to export domestically-produced LNG in a volume equivalent to 1.4 Bcf/d of natural gas for a period of 20 years. *See Freeport LNG Expansion, L.P., et al.*, DOE/FE Order No. 3282, Order Conditionally Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Freeport LNG Terminal on Quintana Island, Texas, to Non-Free Trade Agreement Nations (May 17, 2013) [hereinafter *Freeport I*].

[10] On August 7, 2013, DOE/FE conditionally authorized Lake Charles Exports to export domestically-produced LNG in a volume equivalent to 2.0 Bcf/d of natural gas for a period of 20 years. *See Lake Charles Exports, LLC*, DOE/FE Order No. 3324, Order Conditionally Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Lake Charles Terminal to Non-Free Trade Agreement Nations (Aug. 7, 2013) [hereinafter *Lake Charles Exports*].

[11] On November 15, 2013, DOE/FE granted in part FLEX's second non-FTA export application, authorizing the export of LNG in a volume equivalent to 0.4 Bfd/d of natural gas. *See Freeport LNG Expansion, L.P., et al.*, DOE/FE Order No. 3357, Order Conditionally Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Freeport LNG Terminal on Quintana Island, Texas, to Non-Free Trade Agreement Nations (Nov. 15, 2013) [hereinafter *Freeport II*].

[12] On February 11, 2014, DOE/FE conditionally authorized Cameron to export domestically-produced LNG in a volume equivalent to 1.7 Bcf/d of natural gas for a period of 20 years. *See Cameron LNG, LLC*, DOE/FE Order No. 3391, Order Conditionally Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel From the Cameron LNG Terminal in Cameron Parish, Louisiana, to Non-Free Trade Agreement Nations (May 17, 2013) [hereinafter *Cameron*].

[13] As of the date of this Order (and excluding Jordan Cove's Application), 24 applications for long-term export of LNG to non-FTA countries, in a volume of LNG equivalent to approximately 26.59 Bcf/d of natural gas, are pending before DOE/FE. The total volume of LNG at issue in the approved and pending non-FTA applications filed with DOE/FE to date, including Jordan Cove's Application, is equivalent to approximately 35.86 Bcf/d of natural gas.

[14] *See* 2012 LNG Export Study, 77 Fed. Reg. 73,627 (Dec. 11, 2012), *available at* http://energy.gov/sites/prod/files/2013/04/f0/fr_notice_two_part_study.pdf (Federal Register Notice of Availability of the LNG Export Study).

impact of two DOE/FE-prescribed levels of assumed natural gas exports (at 6 Bcf/d and 12 Bcf/d) under numerous scenarios and cases based on projections from EIA's 2011 *Annual Energy Outlook* (AEO 2011), the most recent EIA projections available at the time.[15] The scenarios and cases examined by EIA included a variety of supply, demand, and price outlooks. EIA published its study, *Effect of Increased Natural Gas Exports on Domestic Energy Markets*, in January 2012.[16] Second, in October 2011, DOE contracted with NERA to incorporate the forthcoming EIA case study output from the NEMS model into NERA's general equilibrium model of the U.S. economy. NERA analyzed the potential macroeconomic impacts of LNG exports under a range of global natural gas supply and demand scenarios, including scenarios with unlimited LNG exports. DOE published the NERA Study, *Macroeconomic Impacts of LNG Exports from the United States*, in December 2012.[17]

On December 11, 2012, DOE/FE published a Notice of Availability (NOA) of the EIA and NERA studies (collectively, the 2012 LNG Export Study or Study).[18] DOE/FE invited public comment on the Study, and stated that its disposition of the present case and 14 other LNG export applications then pending would be informed by the Study and the comments received in response thereto.[19] The NOA required initial comments by January 24, 2013, and reply comments between January 25 and February 25, 2013.[20] DOE/FE received over 188,000 initial comments and over

[15] The Annual Energy Outlook (AEO) presents long-term projections of energy supply, demand, and prices. It is based on results from EIA's NEMS model. *See* discussion of the AEO projections at Section VIII.A *infra*.
[16] *See* LNG Export Study – Related Documents, *available at* http://energy.gov/fe/downloads/lng-export-study-related-documents (EIA Analysis (Study - Part 1)).
[17] *See id*. (NERA Economic Consulting Analysis (Study - Part 2)).
[18] 77 Fed. Reg. at 73,627.
[19] *Id*. at 73,628.
[20] *Id.* at 73,627. On January 28, 2013, DOE issued a Procedural Order accepting for filing any initial comments that had been received as of 11:59 p.m., Eastern time, on January 27, 2013.

2,700 reply comments, of which approximately 800 were unique.[21] The comments also included 11 economic studies prepared by commenters or organizations under contract to commenters.

The public comments represent a diverse range of interests and perspectives, including those of federal, state, and local political leaders; large public companies; public interest organizations; academia; industry associations; foreign interests; and thousands of U.S. citizens. While the majority of comments are short letters expressing support or opposition to the LNG Export Study or to LNG exports in general, others contained detailed statements of differing points of views. The comments were posted on the DOE/FE website and entered into the public records of the 15 LNG export proceedings identified in the NOA, including the present proceeding.[22] As discussed below, DOE/FE has carefully examined the comments and has considered them in its review of Jordan Cove's Application. Additional details about Jordan Cove, the liquefaction project, and the requested export authorization are discussed below.

II. SUMMARY OF FINDINGS AND CONCLUSIONS

Based on a review of the complete record and for the reasons set forth below, DOE/FE has concluded that the opponents of the Jordan Cove Application have not demonstrated that the requested authorization will be inconsistent with the public interest and finds that the exports proposed in this Application are likely to yield net economic benefits to the United States. DOE/FE further finds that Jordan Cove's proposed exports should be conditionally authorized at a volumetric rate not to exceed the capacity of the facilities to be used in the proposed export

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[21] Because many comments were nearly identical form letters, DOE/FE organized the initial comments into 399 docket entries, and the reply comments into 375 entries. *See* http://www.fossil.energy.gov/programs/gasregulation/authorizations/export_study/export_study_initial_comments.html (Initial Comments – LNG Export Study) & http://www.fossil.energy.gov/programs/gasregulation/authorizations/export_study/export_study_reply_comments.html (Reply Comments – LNG Export Study).

[22] *See* 77 Fed. Reg. at 73,629 & n.4.

operations and subject to satisfactory completion of environmental review and other terms and conditions discussed below.

III. PUBLIC INTEREST STANDARD

Section 3(a) of the NGA sets forth the standard for review of Jordan Cove's Application:

> [N]o person shall export any natural gas from the United States to a foreign country or import any natural gas from a foreign country without first having secured an order of the [Secretary of Energy[23]] authorizing it to do so. The [Secretary] shall issue such order upon application, unless after opportunity for hearing, [he] finds that the proposed exportation or importation will not be consistent with the public interest. The [Secretary] may by [the Secretary's] order grant such application, in whole or part, with such modification and upon such terms and conditions as the [Secretary] may find necessary or appropriate.

15 U.S.C. § 717b(a). This provision creates a rebuttable presumption that a proposed export of natural gas is in the public interest. DOE/FE must grant such an application unless opponents of the application overcome that presumption by making an affirmative showing of inconsistency with the public interest.[24]

While section 3(a) establishes a broad public interest standard and a presumption favoring export authorizations, the statute does not define "public interest" or identify criteria that must be considered. In prior decisions, however, DOE/FE has identified a range of factors that it evaluates when reviewing an application for export authorization. These factors include economic impacts, international impacts, security of natural gas supply, and environmental

[23] The Secretary's authority was established by the Department of Energy Organization Act, 42 U.S.C. § 7172, which transferred jurisdiction over imports and export authorizations from the Federal Power Commission to the Secretary of Energy.

[24] *See, e.g., Sabine Pass*, Order No. 2961, at 28; *Phillips Alaska Natural Gas Corp. & Marathon Oil Co.*, DOE/FE Order No. 1473, Order Extending Authorization to Export Liquefied Natural Gas from Alaska, at 13 (April 2, 1999), citing *Panhandle Producers & Royalty Owners Ass'n v. ERA*, 822 F.2d 1105, 1111 (D.C. Cir. 1987).

authorization ordering that Jordan Cove's authorization is contingent on both its satisfactory completion of the environmental review process and its on-going compliance with any and all preventative and mitigative measures imposed at the Jordan Cove Terminal by federal or state agencies. When the environmental review is complete, DOE/FE will reconsider its public interest determination in light of the information gathered as part of that review. This procedure will not foreclose the choice of reasonable alternatives or influence subsequent development.

C. Significance of the LNG Export Study

For the reasons discussed above, DOE/FE commissioned the LNG Export Study and invited the submission of responsive comments. DOE/FE has analyzed this material and determined that the LNG Export Study provides substantial support for conditionally granting Jordan Cove's Application. The conclusion of the LNG Export Study is that the United States will experience net economic benefits from issuance of authorizations to export domestically produced LNG. We have evaluated the initial and reply comments submitted in response to the LNG Export Study. Various commenters have criticized the data used as inputs to the LNG Export Study and numerous aspects of the models, assumptions, and design of the Study. As discussed above, however, we find that the LNG Export Study is fundamentally sound and supports the proposition that the proposed authorization will not be inconsistent with the public interest.

D. Benefits of International Trade

We have not limited our review to the contents of the LNG Export Study but have considered a wide range of other information. For example, the National Export Initiative, established by Executive Order, sets an Administration goal to "improve conditions that directly affect the private sector's ability to export" and to "enhance and coordinate Federal efforts to facilitate the creation of jobs in the United States through the promotion of exports."[159]

We have also considered the international consequences of our decision. We review applications to export LNG to non-FTA nations under section 3(a) of the NGA. The United States' commitment to free trade is one factor bearing on that review. An efficient, transparent international market for natural gas with diverse sources of supply provides both economic and strategic benefits to the United States and our allies. Indeed, increased production of domestic natural gas has significantly reduced the need for the United States to import LNG. In global trade, LNG shipments that would have been destined to U.S. markets have been redirected to Europe and Asia, improving energy security for many of our key trading partners. To the extent U.S. exports can diversify global LNG supplies, and increase the volumes of LNG available globally, it will improve energy security for many U.S. allies and trading partners. As such, authorizing U.S. exports may advance the public interest for reasons that are distinct from and additional to the economic benefits identified in the LNG Export Study.

E. Other Considerations

Our decision is not premised on an uncritical acceptance of the general conclusion of the LNG Export Study of net economic benefits from LNG exports. Both the LNG Export Study and many public comments identify significant uncertainties and even potential negative impacts from LNG exports. The economic impacts of higher natural gas prices and potential increases in gas price volatility are two of the factors that we view most seriously. Yet we also have taken into account factors that could mitigate such impacts, such as the current oversupply situation and data indicating that the natural gas industry would increase natural gas supply in response to

[159] NEI, 75 Fed. Reg. at 12,433.

increasing exports. Further, we note that it is far from certain that all or even most of the proposed LNG export projects will ever be realized because of the time, difficulty, and expense of commercializing, financing, and constructing LNG export terminals, as well as the uncertainties inherent in the global market demand for LNG. On balance, we find that the potential negative impacts of Jordan Cove's proposed exports are outweighed by the likely net economic benefits and by other non-economic or indirect benefits.

More generally, DOE/FE continues to subscribe to the principle set forth in our 1984 Policy Guidelines[160] that, under most circumstances, the market is the most efficient means of allocating natural gas supplies. However, agency intervention may be necessary to protect the public in the event there is insufficient domestic natural gas for domestic use. There may be other circumstances as well that cannot be foreseen that would require agency action.[161] Given these possibilities, DOE/FE recognizes the need to monitor market developments closely as the impact of successive authorizations of LNG exports unfolds.

F. Conclusion

We have reviewed the evidence in the record and have not found an adequate basis to conclude that Jordan Cove's export of LNG to non-FTA countries will be inconsistent with the public interest. For that reason, we are authorizing Jordan Cove's proposed exports to non-FTA countries subject to the limitations and conditions described in this Order.

[160] 49 Fed. Reg. at 6684.

[161] We understand that some commenters on the LNG Export Study, including Jayanta Sinha, President of GAIL Global, Inc., would like DOE to clarify the circumstances under which the agency would exercise its authority to revoke (in whole or in part) previously issued LNG export authorizations. We cannot precisely identify all the circumstances under which such action would be taken. We reiterate our observation in *Sabine Pass* that: "In the event of any unforeseen developments of such significant consequence as to put the public interest at risk, DOE/FE is fully authorized to take action as necessary to protect the public interest. Specifically, DOE/FE is authorized by section 3(a) of the Natural Gas Act … to make a supplemental order as necessary or appropriate to protect the public interest. Additionally, DOE is authorized by section 16 of the Natural Gas Act 'to perform any and all acts and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate' to carry out its responsibilities." *Sabine Pass*, Order No. 2961, at 33 n.45 (quoting 15 U.S.C. § 717*o*).

We have considered the cumulative impacts of past authorizations in our decision. In this case, we do not find that opponents of the Application have overcome the statutory presumption that the proposed export authorization is consistent with the public interest. By authorizing exports of LNG in a volume equivalent to 0.8 Bcf/d of natural gas (292 Bcf/yr) in this proceeding, DOE/FE will have cumulatively authorized non-FTA exports totaling 9.27 Bcf/d of natural gas, or 3.384 Tcf/yr, for the one final and six conditional export authorizations granted to date—Sabine Pass (2.2 Bcf/d), Freeport I (1.4 Bcf/d), Lake Charles Exports (2.0 Bcf/d), Dominion Cove Point (0.77 Bcf/d), Freeport II (0.4 Bcf/d), Cameron (1.7 Bcf/d), and the current authorization (0.8 Bcf/d). This total export volume is within the range of scenarios analyzed in the EIA and NERA studies. NERA found that in all such scenarios—assuming either 6 Bcf/d or 12 Bcf/d of export volumes—the United States would experience net economic benefits. As discussed above, the submissions of the intervenors do not undermine the reasonableness of the findings in the LNG Export Study. We also note that EIA's most recent projections, set forth in the AEO 2014 Early Release Overview, continue to show market conditions that will accommodate increased exports of natural gas. As explained in Section VIII.A., when compared to the AEO 2013 Reference Case, the AEO 2014 Early Release Reference Case projects marked increases in domestic natural gas production—well in excess of what is required to meet projected increases in domestic consumption.

DOE/FE will continue taking a measured approach in reviewing the other pending applications to export domestically produced LNG. Specifically, DOE/FE will continue to assess the cumulative impacts of each succeeding request for export authorization on the public interest with due regard to the effect on domestic natural gas supply and demand fundamentals. In keeping with the performance of its statutory responsibilities, DOE/FE will attach appropriate

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April 1, 2019

Larine Moore
Office of Natural Gas Regulatory Activities
U.S. Department of Energy
FE-34
P.O. Box 44375
Washington, DC 20026

Re: *Jordan Cove Energy Project, L.P.*, DOE/FE Docket Nos. 12-32-LNG, 11-127-LNG Semi-Annual Report

Dear Ms. Moore:

Pursuant to Ordering Paragraph M of DOE/FE Order No. 3413 and Ordering Paragraph I of DOE/FE Order No. 3041, Jordan Cove Energy Project L.P. ("JCEP") hereby submits its semi-annual report describing the progress of the proposed liquefaction facility.[1] On September 21, 2017, JCEP filed an application with the Federal Energy Regulatory Commission pursuant to Section 3 of the Natural Gas Act for authorization to site, construct, and operate the proposed facility.[2] JCEP continues to pursue other required federal, state, and local permits and authorizations for its facility. JCEP has also continued its negotiations with prospective customers for liquefaction services.

Please contact me if you have any questions.

Respectfully submitted,

/s/ John S. Decker
John S. Decker
Attorney for Jordan Cove Energy Project L.P.

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[1] *Jordan Cove Energy Project, L.P.*, DOE/FE Order No. 3413 (Mar. 24, 2014); *Jordan Cove Energy Project, L.P.*, DOE/FE Order No 3041 (Dec. 7, 2011).

[2] Section 3 Application of Jordan Cove Energy Project, L.P., Docket No. CP17-495-000 (filed Sept. 21, 2017).

McCULLOUGH RESEARCH

ROBERT F. McCULLOUGH, JR.
PRINCIPAL

Natural Gas Supplies for the Proposed Jordan Cove LNG Terminal

Robert McCullough
McCullough Research
July 3, 2019

Both documentary evidence and economic theory indicate that natural gas exported from the proposed LNG terminal at Coos Bay will be sourced from British Columbia and Alberta.

Jordan Cove has been an active project since 2006. For its first five years, the project then owned by Fort Chicago and Energy Projects Development was an LNG import facility. As LNG prices rose, Jordan Cove refiled with FERC as an LNG Export facility. Ownership of the project has evolved over time as Fort Chicago changed into Veresen. In 2017, Veresen was acquired by Pembina.

On February 20, 2014, Dan Althoff, the CEO of Veresen, Jordan Cove's corporate parent, was quoted in an article describing the basic structure of supplies to Jordan Cove:

> It provides a bit of diversity to exports. It's the first [U.S.] West Coast facility to be reviewed. It exports Canadian gas, which is pretty positively received in Washington. Some of the petrochemicals industry's concerns and complaints about the Gulf Coast facilities aren't shared on this project, because Jordan Cove pulls gas off existing Canadian infrastructure, from existing fields and pipelines.[1]

Following up Jordan Cove's prospects, Althoff later stated that:

> There are some synergies [between the field and the LNG terminal], because the buyers we're talking to need to find gas and we know where a

[1] How Oregon LNG facilities could be key to exporting Canadian gas to Asia, Yadullah Hussain, Financial Post, February 20, 2014.

> lot of it is," Mr. Althoff said. "We'll connect the dots and we'll support our buyers and we'll support our partners."[2]

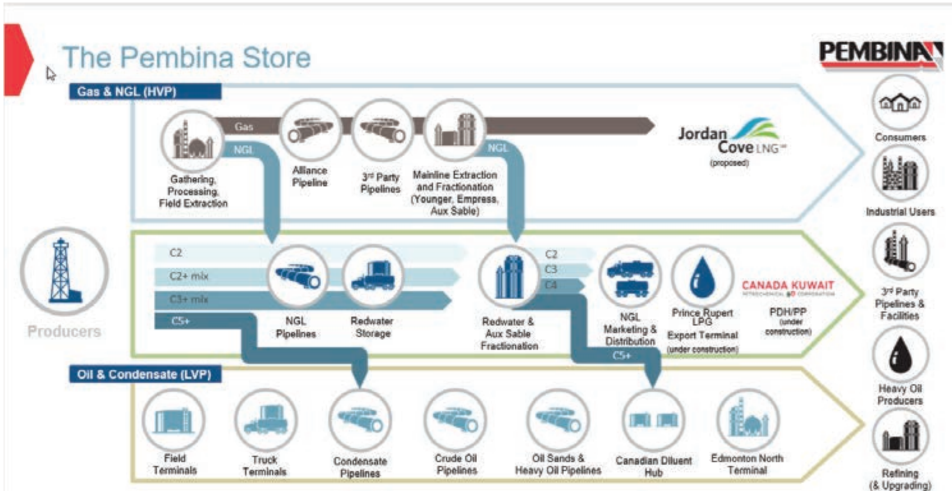
In 2017, Veresen was acquired by Pembina, also based in Alberta. Mick Dilger, Pembina's CEO made clear where Jordan Cove's gas would be coming from:

> Dilger believes Jordan Cove has a higher chance of success under Pembina than it had under Veresen because it has the money to finance it, the expertise to build both the plant and a 400-kilometre pipeline through tough terrain, and the relationships with Western Canadian producers and Asian customers to make it viable.
>
> Some day, Pembina would like to build an LNG facility on the B.C. coast, too, Dilger said, but Jordan Cove has key advantages: it is cheaper to build a pipeline to receive Western Canadian gas from existing networks than build over the Canadian Rockies; its location near larger population centres means there is labour available to build it; and shorter travel time to Asian markets versus the U.S. Gulf Coast means lower transportation costs for its LNG.[3]

Jordan Cove is planned for Coos Bay, Oregon. In order to procure natural gas, a pipeline is planned to connect to supplies at Malin, Oregon. Malin, Oregon connects to Kingsgate, Alberta and Opal, Wyoming. Overall, Coos Bay is over 909 miles from sources of supply in the east and 841 miles from Alberta.[4]

Pembina's financial presentations also indicate that Canada is the primary source of supply since Pembina does not own gathering, processing, or field extraction assets elsewhere:

[2] With Montney assets buy, Veresen eyes building first West Coast LNG facility in Oregon, Geoffrey Morgan, Financial Post, December 23, 2014.
[3] Pembina Pipeline's new purpose: Get Canada's oil and gas to the rest of the world, Claudia Cataneo, Financial Post, February 20, 2018.
[4] The Pacific Connector Gas Pipeline is 229 miles from the Malin hub. The northern terminus of the GTN pipeline is 612 miles away at Kingsgate, Alberta. The eastern terminus of the Ruby pipeline is 680 miles away.



[5]

In the diagram above, taken from a presentation this month to investors, Pembina directly aligns its Jordan Cove investments with their Canadian infrastructure. It is worth noting that the Ruby pipeline, connecting Colorado with the Malin natural gas trading hub, is not mentioned.

I. Background

On September 4, 2007, Jordan Cove LNG was proposed as an import terminal – primarily oriented to meeting domestic U.S. needs from imported natural gas.[6] The Coos Bay location and proposed interconnection to existing natural gas pipelines at Malin, Oregon was as appropriate then as it is inappropriate today. As a general rule, positioning an import terminal near potential loads is a good idea. Positioning an export terminal far from natural gas supplies is a significant disadvantage.

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[5] Pembina Pipeline Corporation Corporate Update, June 2019, page 7.

[6] Pacific Connector Gas Pipeline, LP (Docket Nos. CP07-441-000, CP07-442-000, and CP07-443-000) and Jordan Cove Energy Project, L.P. (Docket No. CP07-444-000); Notice of Application for Certificate of Public Convenience and Necessity and Section 3 Authorization, September 19, 2007.

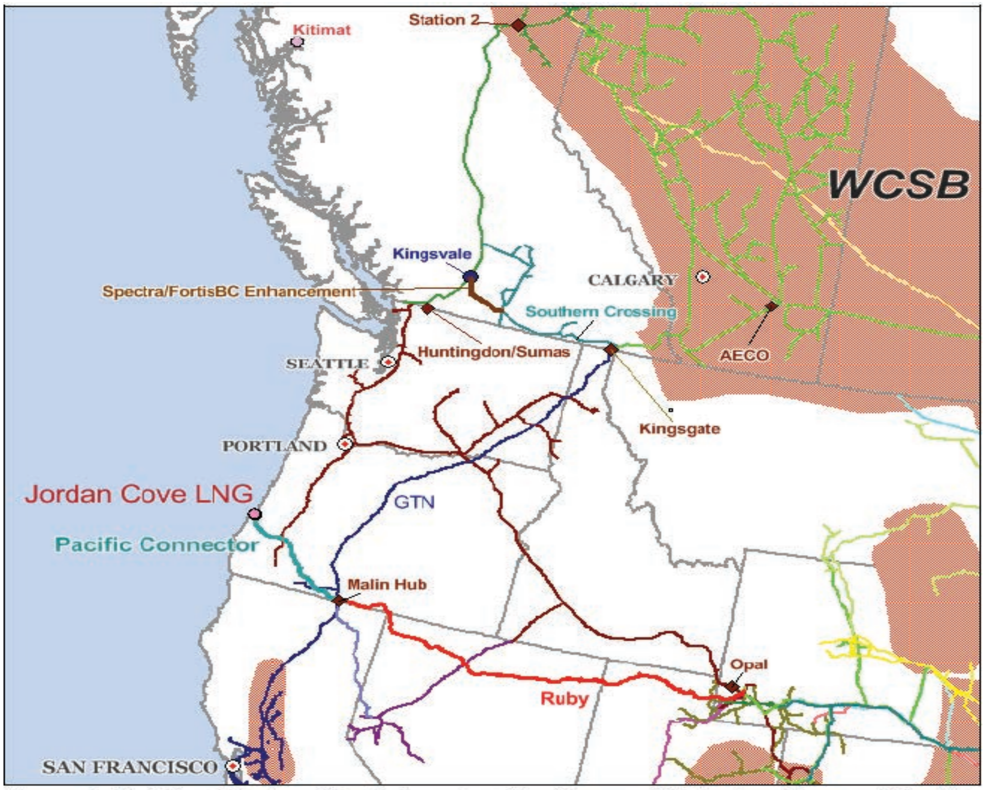

Figure 1: Existing Western North America Pipelines – with Jordan Cove and Pacific Connector [7]

Historically, California natural gas prices are significantly higher than those in Alberta and the Pacific Northwest.[8]

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[7] IN THE MATTER OF the National Energy Board Act, RSC 1985, c N-7, as amended; AND IN THE MATTER OF an application by Jordan Cove LNG L.P. for a licence pursuant to section 117 of the National Energy Board Act authorizing the export of gas, September 9, 2013, Appendix A, page 2.

[8] See, for example, Power Market Price Study and Documentation BP-18-FS-BPA-04, July 2017, page 33.

When Pacific natural gas prices were lower than those in the United States, importing LNG at Coos Bay and selling the natural gas into the lucrative California market made economic sense.

This situation did not endure for long. Over the last decade two factors changed the market dramatically:

1. On March 11, 2011, a tidal wave destroyed the nuclear plant at Fukushima Daiichi. Japanese authorities subsequently closed Japan's nuclear fleet and prices spiked dramatically.
2. Technological innovations in the U.S. and Canada revolutionized oil and natural gas production leading to an increasing surplus in North American markets.

Landed LNG prices in Japan, Korea, and China are published daily in the Platts LNG Daily. They are referred to as the JKM index. The major North American trading hub

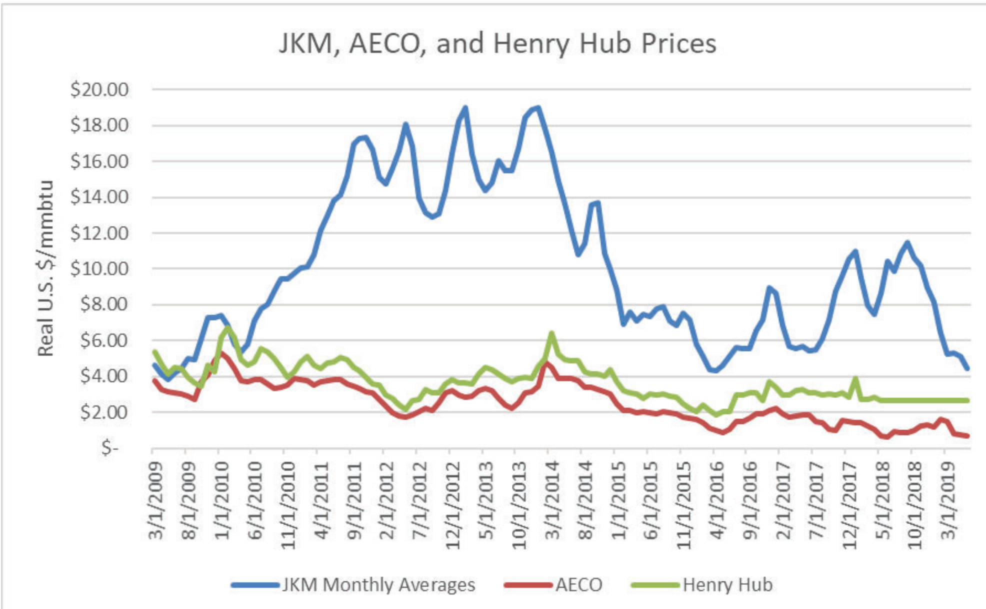
Table 1: Cash Prices at Henry Hub and Basis Differentials (nominal $/MMBtu)

	FY 2018	FY 2019
Henry	3.12	3.00
AECO	-0.89	-0.82
Kingsgate	-0.42	-0.45
Malin	-0.24	-0.24
Opal	-0.31	-0.31
PG&E	0.23	0.23
SoCal City	0.02	0.03
Ehrenberg	-0.15	-0.14
Topock	-0.15	-0.14
San Juan	-0.34	-0.32
Stanfield	-0.32	-0.32
Sumas	-0.41	-0.41

AECO prices are lower than those at Henry Hub in Louisiana – averaging a discount from Henry Hub of $.82/MMBtu.

for natural gas is Henry Hub in Louisiana. Wholesale natural gas prices in Alberta are referred to by the acronym "AECO".

Landed prices in Asia rapidly diverged from those in Alberta and the United States. The following chart shows the dramatic rise in Asian natural gas prices after the Fukushima accident (blue line) and the steady fall in North American natural gas prices in Alberta (red line) and Louisiana (green line):



The prospect of competing with Asian markets for scarce Pacific Rim LNG spelled the end of Jordan Cove's prospects as an LNG importer.

The massive differential between JKM and AECO prices spawned over twenty LNG export terminal proposals – primarily in British Columbia. Two proposals were based in Oregon – one in Astoria and one in Coos Bay.

Japan has gradually restarted its nuclear fleet and other suppliers have stepped in to supply the Pacific Rim. Not surprisingly, JKM prices are falling dramatically with prices today less than half their levels one year ago. At least five of the proposed LNG projects in

British Columbia have cancelled their plans to build LNG export terminals in the province.[9]

At today's JKM price, none of the West Coast LNG export terminals are attractive investments. Only one project, LNG Canada, has received a "Final Investment Decision" and started construction. The economics of Jordan Cove are highly problematic given its high costs and the declining Asian Prices.

On July 2, 2019, the JKM index was $4.625/MMBtu.[10] The breakeven price (the price at which the project would earn zero profits and merely recover its costs) for Jordan Cove is $4.27/MMBtu.[11] The natural gas price at the Malin hub is $1.99/MMBtu.[12] When the cost of transportation to Japan is added in, the cost of Jordan Cove LNG is $7.13/MMBtu. If today's prices would prevail into the future, Jordan Cove would lose $2.50 for every MMBtu shipped.

Scarcity of natural gas pipeline capacity from Alberta has increased the basis differential between Henry Hub and AECO.[13] To the degree that the source and transportation of an LNG export are packaged by Jordan Cove, there is an incentive to access the relatively inexpensive natural gas in Western Canada rather than natural gas from the U.S.

II. Market Hubs and the Structure of Transactions

Natural gas and electricity transactions are commonly organized by hubs – locations where buyers and sellers can make spot and forward purchases. Malin, Oregon is a market hub for both electricity and natural gas. Its development as a hub was largely based on resource and consumption differentials between the Pacific Northwest and California.

The Pacific Northwest is winter peaking, since heating loads tend to occur in cold months. California is a summer peaking region. This difference makes Malin a good location for trading between different buyers and sellers.

[9] Sightline Institute. January 2018. https://www.sightline.org/research_item/maps-british-columbia-lng-proposals/
[10] Platts LNG Daily, July 2, 2019, page 1.
[11] "The Questionable Economics of Jordan Cove LNG Terminal," McCullough Research, June 5, 2019, page 4. http://www.mresearch.com/wp-content/uploads/20190605-Jordan-Cove.pdf
[12] "Easing Heat, Stout Supplies Pressure July NatGas Bidweek Prices; Futures Remain Near Lows," NGI All News Access, July 1, 2019. https://www.naturalgasintel.com/articles/118844-easing-heat-stout-supplies-pressure-july-natgas-bidweek-prices-futures-remain-near-lows
[13] 'Basis differential' is defined as the expected price difference between two hubs.

Unlike larger national gas hubs, Malin has no forward markets traded at the major commodity exchanges. When a forward exchange is absent, long-term transactions must be made with an individual counterparty. This is generally more expensive and less likely to close since the number of counterparties may be quite limited. In language of traders, long-term transactions at the Malin natural gas hub will be over the counter.[14] Price discovery in the absence of forward markets can also be challenging in the same way that buying or selling a vintage car in a small town might be both challenging and poses the risk of paying the wrong price. Generally, such transactions tend to be more successful if you drive to a larger city with more car dealers.

In this case, it means that longer-term transactions will tend to occur at the source of the natural gas where markets are more liquid and there are more counterparties. In this case, the most liquid market for longer-term transactions is AECO in Alberta. Not only are prices generally lower in Alberta than in the Western U.S., Alberta's market is growing very rapidly with recent natural gas discoveries along the Alberta/British Columbia border.

One of the attributes of a market hub is that short term transactions take place at the going price. Regardless of the source the short-term price is the same. Malin's prices tend to reflect the higher prices found in California. As noted above, the decision to connect at Malin was a good choice when the Jordan Cove project was intended to import natural gas for sale to California. The current export proposal is at a disadvantage compared to British Columbia export terminals with a shorter path to low-priced Alberta natural gas.

Jordan Cove has frequently referred to its "tolling model," although their presentations often lack precision.[15] In tolling arrangements, the purchaser buys the gas, arranges delivery to the LNG facility, and is responsible for the shipping of the LNG; in theory, Jordan Cove would not be responsible for anything except converting the gas to LNG at their facility. In contrast, the most successful U.S. exporter, Cheniere, offers complete transactions in LNG at their dock. Purchasers do not need to handle natural gas purchasing or transportation issues in the United States.

From Jordan Cove's investor briefings and regulatory filings, it seems very likely that they will be arranging supplies and transportation in fashion similar to Cheniere.

For example, a recent presentation by Jordan Cove states:

[14] 'Over the counter' is a standard term in commodity trading that means that transactions are negotiated directly between counterparties. As a general rule, over the counter transactions are less liquid than those occurring at exchanges like the Chicago Mercantile Exchange or ICE.
[15] See, for example, the discussion of a tolling model for exporters of LNG produced in the USA: LNG Export USA 2014, Guy Dayvault, Veresen, April 30, 2014.

NATIONAL ENERGY BOARD

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

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

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

APPLICATION

SEPTEMBER 9, 2013

I. APPLICATION

1. Jordan Cove LNG L.P. (the "**Applicant**") hereby applies to the National Energy Board (the "**NEB**" or "**Board**") pursuant to section 117 of the *National Energy Board Act* (the "***NEB Act***") for a licence authorizing the export of up to 565.75 billion cubic feet ("**Bcf**") of gas per year (approximately 16,026,458 10^3m^3 per year) for a term of 25 years (the "**Licence**").

2. The terms and conditions requested by the Applicant for the Licence are as follows:

    i. **TERM:** Proposed term of the Licence is a period of 25 years commencing on the date of first export of gas under the Licence;

    ii. **EXPIRATION:** If exportation of gas has not occurred within 10 years from the date of issuance of the Licence, the Licence shall expire at that time, unless otherwise authorized by the Board. This expiration period relates to obtaining remaining regulatory approvals, completing detailed engineering, financing arrangements, a four-year construction period as well as a grace period for any unforeseen delays;

    iii. **MAXIMUM DAILY QUANTITY:** The quantity of gas that may be exported in any 24-hour period shall not exceed 1.55 Bcf (approximately 43,908 10^3m^3) subject to the daily tolerance;

    iv. **DAILY TOLERANCE:** In any 24 hour period, the quantity of gas exported may exceed the daily quantity by 20 percent;

    v. **MAXIMUM ANNUAL QUANTITY:** The quantity of gas that may be exported in any 12-month period shall not exceed 565.75 Bcf (approximately 16,026,458 $10^3m^3/y$), subject to the annual tolerance;

    vi. **ANNUAL TOLERANCE:** In any 12-month period, the quantity of gas exported may exceed the annual quantity by 15 percent;

    vii. **MAXIMUM TERM QUANTITY:** The quantity of gas that may be exported over the term of the Licence shall not exceed 15.63 Tcf;

    viii. **EXPORT POINTS:** Gas will be exported from Canada at the point at which it crosses the Canada/United States border near Kingsgate, British Columbia/Eastport, Idaho

("**Kingsgate/Eastport**") and near Huntingdon, British Columbia/Sumas, Washington ("**Huntingdon/Sumas**") (collectively, the "**Export Points**");

ix. **AGENCY:** The Licence authorizes the Applicant to export gas on its own behalf, and as an agent on behalf of the actual owners of the gas; and

x. Any further terms or relief as may be requested by the Applicant or as the Board may consider appropriate in the circumstances.

3. In light of amendments to the *NEB Act* as a result of the *Jobs, Growth and Long-Term Prosperity Act*, the Applicant relies upon the Board's interpretation of those amendments in its Decision concerning an application for a licence to export LNG made by LNG Canada Development Inc., in addition to the Board's *Interim Memorandum of Guidance Concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the National Energy Board Act*. Accordingly, the Applicant respectfully requests relief from the following information requirements, except where those requirements are addressed within this application:

   - Section 12 of the *National Energy Board Act Part VI (Oil and Gas) Regulations* (the "***Part VI Regulations***"); and

   - The Board's Filing Manual.

4. The Applicant also respectfully requests an exemption from section 4 of the *National Energy Board Export and Import Reporting Regulations* (the "***Reporting Regulations***"). The Applicant requests that its reporting requirements be set as quarterly reporting of (i) aggregate volumes of gas exported; (ii) aggregate value of export revenue at the international border; (iii) average heating value of gas exported; and (iv) aggregate export volume by country of destination.

II. APPLICATION OVERVIEW

a. Export Need

5. The quantity of gas requested for export under the Licence is necessary to support a liquefied natural gas ("**LNG**") facility (the "**LNG Facility**") to be located at the Port of Coos Bay, Oregon (the "**Project**") which has been proposed by Jordan Cove Energy Project L.P. ("**JCEP**").

6. The Project will be comprised of a natural gas liquefaction plant, associated port and infrastructure facilities and power plant as more fully described in **Appendix A – Project Description.** At full build-out, the Project will be capable of exporting 9 million tonnes ("**MMt**") of LNG per year (natural gas equivalent of approximately 502.81 Bcf/year).

Jordan Cove LNG L.P. (Jordan Cove LNG)
Application for a Licence to Export Natural Gas
pursuant to Section 117 of the *National Energy Board Act*
Filed 9 September 2013 (Application)
File OF-EI-Gas-GL-J705-2013-01 01 1.1

Jordan Cove LNG Response to NEB Information Request No. 1

1.1 Requested 15 Per Cent Annual Tolerance

Reference:

i. Application, Section I, Paragraph 2, PDF Page 3 of 11, A3K9F4

ii. Application, Appendix A, Section I, Paragraphs 3 and 4, PDF Page 1 of 8, A3K9F5

iii. Application, Appendix A, Section I, Paragraph 6, PDF Page 3 of 8, A3K9F5

Preamble: Reference i) states that Jordan Cove LNG is requesting a 15 per cent annual tolerance, that is, in any 12-month period the quantity of gas exported may exceed the annual quantity of 565.75 Bcf by up to 15 per cent.

Reference ii) indicates that Jordan Cove LNG proposes to source Western Canadian Sedimentary Basin (WSCB) natural gas using the existing natural gas pipeline networks of TransCanada PipeLines and Spectra Energy.

Reference iii) indicates that in addition to WCSB gas, Jordan Cove LNG may be supplied by the U.S. Rocky Mountain region.

Request:

a) Please explain the need for an annual tolerance for exports of natural gas via pipelines to an LNG facility that would have access to multiple supply sources.

b) Please explain why 15 per cent would be an appropriate annual tolerance amount.

Response:

a) Please explain the need for an annual tolerance for exports of natural gas via pipelines to an LNG facility that would have access to multiple supply sources.

An LNG facility may export less than its maximum annual amount in any given 12 month period as a result of (i) decreased LNG production due to technical/operational constraints; (ii) changes in cargo shipping schedules; (iii) changes in market demand including seasonal variations; and/or (iv) interruptions in pipeline deliveries or field production due to technical/operational factors. Where any of these situations occur, the annual tolerance amount allows the exporter to increase its production in any 12 month period so long as the term quantity is not exceeded.

Jordan Cove LNG interprets this IR 1.1 as related to scenario (iv) described above and a suggestion that, because the LNG facility associated with the Application will be supplied with gas resources from the WCSB as well as potentially with gas resources from the U.S. Rocky Mountain region, a situation of interruptions from one source leading to decreased LNG export volumes is unlikely to occur (*i.e.* decreased supply from one source can be compensated by increased supply from the other source). In this regard, Jordan Cove LNG confirms that the mention of the U.S. Rocky Mountain region in Reference iii) simply relates to a potential option for obtaining gas resources for the LNG facility. Like other Canadian LNG export applicants, Jordan Cove LNG seeks to preserve the flexibility to source all of its project requirements from Canada even if those requirements may vary within its requested tolerance levels from year to year.

b) *Please explain why 15 per cent would be an appropriate annual tolerance amount.*

A 15 per cent annual tolerance is required to account for variability in the operations of the LNG operations associated with Jordan Cove LNG's Application. Production of LNG at the LNG facility can be impacted positively and negatively by design optimization, variability in feedstock gas specifications, maintenance intervals, cargo scheduling and seasonal demand, among others.

In its application for an export licence, LNG Canada Development Inc. ("LNG Canada") stated that it intended to utilize the WCSB for gas supply in respect of its LNG facility, and also requested a 15 per cent annual tolerance amount. In its Letter Decision in respect of LNG Canada's application, the Board granted the 15 per cent annual tolerance, finding it to be reasonable.

Jordan Cove LNG is in the same position as LNG Canada and other applicants who have requested an LNG export licence from the NEB and who seek the ability to supply 100 per cent of their project requirements from Canada. The requested tolerance would allow Jordan Cove LNG to maximize its use of Canadian gas despite variations in plant requirements from year to year. With respect to current export licence applications before the NEB, each of Prince Rupert LNG Exports Limited, WCC LNG Ltd. ("WCC"), Pacific Northwest LNG Ltd. and Triton LNG Limited Partnership propose to utilize WCSB gas resources to supply their respective LNG facilities, and each has requested a 15 per cent annual tolerance amount. We also note that, similar to Jordan Cove LNG's mention of potential supply from the U.S. Rocky Mountain Region, WCC noted in its application that, given the integrated nature of North American gas markets and pipelines, gas supply for its LNG terminal could come from other supply basins over the life of the LNG terminal.

Accordingly, Jordan Cove LNG respectfully submits that a 15 per cent tolerance is appropriate in light of plant operations requirements and the Board's approval of a 15 per cent tolerance condition in the LNG Canada Letter Decision.

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

OFFICE OF FOSSIL ENERGY

JORDAN COVE LNG L.P.	)	FE DOCKET NO. 13-141-NG

ORDER GRANTING LONG-TERM MULTI-CONTRACT AUTHORIZATION
TO IMPORT NATURAL GAS FROM CANADA TO
THE PROPOSED JORDAN COVE LNG TERMINAL
IN THE PORT OF COOS BAY, OREGON

DOE/FE ORDER NO. 3412

MARCH 18, 2014

I. DESCRIPTION OF REQUEST

On October 21, 2013, Jordan Cove LNG L.P. (JCLNG) filed an application (Application) with the Office of Fossil Energy (FE) of the Department of Energy (DOE) under section 3(c) of the Natural Gas Act (NGA),[1] 15 U.S.C. § 717b(c), for long-term, multi-contract authorization to import natural gas from Canada in a total volume of 565.75 billion cubic feet per year (Bcf/yr), or 1.55 Bcf per day (Bcf/d), for a 25-year term. JCLNG seeks authorization to import the natural gas from Canada by pipeline, at points near Kingsgate and Huntingdon, British Columbia, to a proposed liquefied natural gas (LNG) export facility to be located at the Port of Coos Bay, Oregon, immediately north of the communities of North Bend and Coos Bay, Oregon. JCLNG's subsidiary, Jordan Cove Energy Project, L.P. (JCEP), proposes to construct, own, and operate this LNG export facility, called the Jordan Cove (or JCEP) LNG Terminal. JCLNG states that the Terminal will be capable of receiving and liquefying the imported natural gas, storing the LNG, and loading the LNG onto LNG carriers for delivery to export markets (subject to any applicable DOE/FE export authorizations) or to domestic markets in the non-contiguous United States (the Project). To support the Project, JCLNG recently obtained authorization from Canada's National Energy Board to export the same volume of natural gas from Canada to the United States that is now the subject of this import authorization, as explained below.

JCLNG seeks to import this natural gas on its own behalf and as agent for other entities that hold title to the natural gas at the time of import. JCLNG requests that this authorization commence on the earlier of the date of first import or 10 years from the date the authorization is issued (*i.e.*, March 18, 2024).

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[1] The authority to regulate the imports and exports of natural gas, including liquefied natural gas, under section 3 of the NGA (15 U.S.C. §717b) has been delegated to the Assistant Secretary for FE in Redelegation Order No. 00-002.04F issued on July 11, 2013.

II. BACKGROUND

Applicant. JCLNG states that it is a Delaware limited partnership with its principal place of business in Calgary, Alberta, Canada.[2] It is wholly owned and controlled by Veresen Inc. (Veresen), a Canadian corporation based in Calgary, Alberta, through wholly-owned subsidiaries of Veresen.

JCLNG further states that its subsidiary, JCEP, is a Delaware limited partnership. JCEP's general partner, Jordan Cove Energy Project, L.L.C., is a Delaware limited liability company. Both are owned by the two JCEP limited partners: (1) the applicant here, JCLNG, which owns 75% of each company, and (2) Energy Projects Development L.L.C., a Colorado limited liability company, which owns 25% of JCEP and 25% of Jordan Cove Energy Project, L.L.C.

Procedural History.

Canada proceedings. JCLNG states that, on September 9, 2013, it applied to Canada's National Energy Board for authorization to export the equivalent volume of gas that is subject to this Application. According to JCLNG, the authorizations sought by these two applications will afford access to Canadian natural gas supplies for the proposed Jordan Cove LNG Terminal being developed by JCEP.

On February 20, 2014, the National Energy Board granted JCLNG's request for export authorization in a letter decision.[3] Specifically, the National Energy Board issued to JCLNG a license to export natural gas at an annual volume of 16.03 billion cubic meters for a 25-year term— equivalent to the volume of 565.75 Bcf/yr of natural gas, or 1.55 Bcf/d, for a 25-year

[2] JCLNG states that its name was changed from Fort Chicago LNG II U.S.L.P. to its current name as of August 19, 2013.
[3] *See* Canada National Energy Board Letter Decision issued to Jordan Cove LNG L.P, NEB File OF-EI-Gas-GL-J705-2013-01 01 (Feb. 20, 2014), DOE/FE Docket No. 13-141-NG (stating that the export license is subject to the approval of the Governor in Council, and attaching terms and conditions to the license in App. I).

term requested for import herein. The letter decision notes that, "[t]he quantity of gas requested for export under the License is necessary to support [the Jordan Cove LNG Terminal] to be located at the Port of Coos Bay, Oregon."[4] By electronic mail dated February 21, 2014, JCLNG submitted the letter decision to DOE/FE.

Related DOE/FE proceedings. The current import authorization is sought by JCLNG. Its subsidiary, JCEP, has separately applied for two export authorizations from DOE/FE that are expected to involve some or all of the imported gas.

First, on December 7, 2011, DOE/FE issued Order No. 3041 in FE Docket No. 11-127-LNG, in which it granted JCEP's application to export LNG in a volume equivalent to 438 Bcf/yr of natural gas (1.2 Bcf/d) from the Project to nations with which the United States currently has, or in the future enters into, a free trade agreement (FTA) requiring national treatment for trade in natural gas (FTA countries).[5]

Second, on May 21, 2013, JCEP applied to DOE/FE for authority to export LNG in a volume equivalent to 292 Bcf/yr of natural gas (0.8 Bcf/d) to nations with which the United States does not have a FTA (non-FTA countries). JCEP's non-FTA application is currently pending before DOE/FE in FE Docket No. 12-32-LNG, and is subject to independent review by DOE/FE under NGA § 3(a), 15 U.S.C. § 717b(a). In that application, JCEP states that the requested volume for export to non-FTA countries is not duplicative (*i.e.*, not additive) of the volume authorized in the JCEP FTA Order.

Liquefaction Project. JCLNG seeks long-term authorization to import natural gas from Canada to the Jordan Cove LNG Terminal, which its subsidiary, JCEP, proposes to construct,

[4] *Id*. at 2.
[5] *Jordan Cove Energy Project, L.P.*, Order Granting Long-Term Multi-Contract Authorization to Export Liquefied Natural Gas by Vessel from the Jordan Cove LNG Terminal to Free Trade Agreement Nations, DOE/FE Order No. 3041 (Dec. 7, 2011) (JCEP FTA Order).

own, and operate. According to JCLNG, the Project is designed to provide a new LNG terminal on the West Coast of the United States which, in turn, will provide benefits associated with the increased export of LNG supplies. As noted above, the Project will be capable of receiving and liquefying natural gas, storing the LNG, and loading the LNG onto carriers for delivery to export markets and/or to domestic markets within the non-contiguous United States (specifically, the markets of Hawaii and Alaska, and select markets in Oregon). JCLNG states that the Project facilities will encompass natural gas receipt and conditioning equipment, liquefaction equipment, two 160,000 cubic meter full-containment LNG storage tanks, and an LNG carrier berth and cargo loading system.

Volume and Source of Natural Gas. JCLNG states that the import volume of 565.75 Bcf/yr of natural gas requested for a 25-year term mirrors the maximum annual quantity for which it requested (and was granted) a 25-year export license by Canada's National Energy Board.

According to JCLNG, the Project will have an initial capacity of six million tons per year (MMt/y) from four liquefaction trains (with each train producing 1.5 MMt/y), although the Project may be expanded to include two additional liquefaction trains. If expanded, the Project would have a total capacity of nine MMt/y among six trains. JCLNG states that production at the expanded facility would require an aggregate natural gas supply of 565.75 Bcf/yr of natural gas (1.55 Bcf/d) to allow for pipeline fuel and fuel use at the Terminal.

JCLNG further states that the Project will have access to gas supplies sourced from the U.S. Rocky Mountain region via Kinder Morgan's Ruby Pipeline, which will interconnect with the new Pacific Connector Gas Pipeline (PCGP) at the Malin Hub in Oregon, as described below. Nonetheless, JCLNG states that this Application and its twin application to Canada's

National Energy Board (now granted) are designed to create flexibility in the Project's sourcing of natural gas. Together, the two applications request the necessary export and import authorizations for the maximum volume that would be needed at the Project's maximum expanded capacity—565.75 Bcf/yr of natural gas.

Import Points and Delivery of Natural Gas. JCLNG states that the natural gas will be delivered to the Project via the PCGP, a new, approximately 230-mile long interstate natural gas pipeline connecting the Project to the interstate pipeline system grid at the Northwest United States market hub at Malin, Oregon. JCLNG states that the PCGP is being developed by Veresen and The Williams Company, with The Williams Company having responsibilities for regulatory processing, development, and construction.[6]

JCLNG proposes to import the natural gas at two points on the Canada/United States border. JCLNG states that the gas primarily is expected to cross the border near Kingsgate, British Columbia/Eastport, Idaho, after having been transported in Canada on the existing natural gas pipeline networks of both TransCanada PipeLines and Spectra. This imported gas will be transported on the existing Gas Transmission Northwest system to the Malin Hub, where there will be an interconnection with the PCGP.

Alternatively, gas may flow on the Spectra system to the Canada/United States border for export near Huntingdon, British Columbia/Sumas, Washington, where it will be transported on Williams' Northwest Pipeline for physical flow, swaps, or exchanges to the PCGP.

Business Model. JCLNG requests authorization to import gas both on its own behalf and on behalf of the owners of the gas for which JCLNG will act as agent. JCLNG states that the commercial arrangements for the Project will be based on a toll model. JCLNG envisions that

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[6] JCLNG states that PCGP's application to FERC, dated June 6, 2013, for a certificate of public convenience and necessity authorizing it to site, construct and operate an interstate pipeline to connect to the Project is presently pending before FERC in FERC Docket No. CP13-492-000.

Foreign or Domestic?

The source of the natural gas that will be processed at the proposed Jordan Cove LNG facility

Prepared for Niskanen Center

July 2, 2019

AUTHOR

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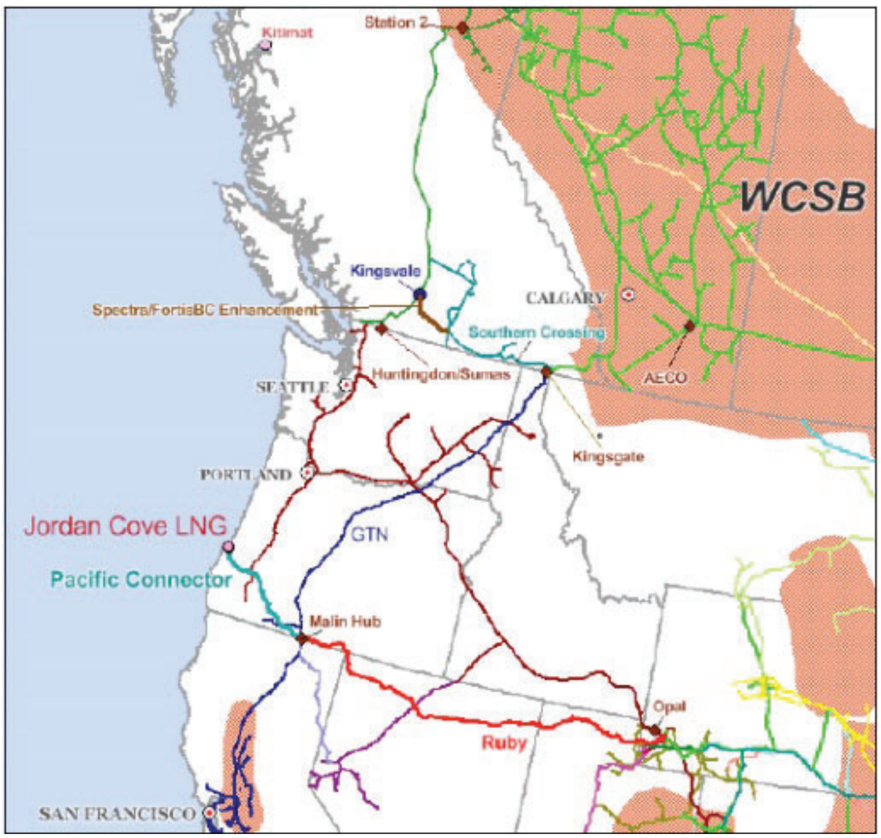
Introduction

Synapse Energy Economics, Inc. was engaged by the Niskanen Center to compare the economics of the potential sources of natural gas that would fuel the proposed Jordan Cove project, which consists of two primary components. The first is a liquefied natural gas (LNG) terminal located in the Port of Coos Bay in Coos County, Oregon, with a liquification design capacity of approximately 1 billion cubic feet per day. The second is the 36-inch diameter "Pacific Connector" gas pipeline, intended to transport natural gas from the Malin Hub to the new LNG terminal.[1] The proposed Jordan Cove project infrastructure is shown in Figure 1, along with other existing natural gas pipeline infrastructure and trading hubs in the Northwest.

Figure 1. Jordan Cove project and existing natural gas infrastructure



Source: Navigant Consulting. September 2013. Supply and Demand Market Assessment and Surplus Evaluation Report. Prepared for Jordan Cove LNG L.P.

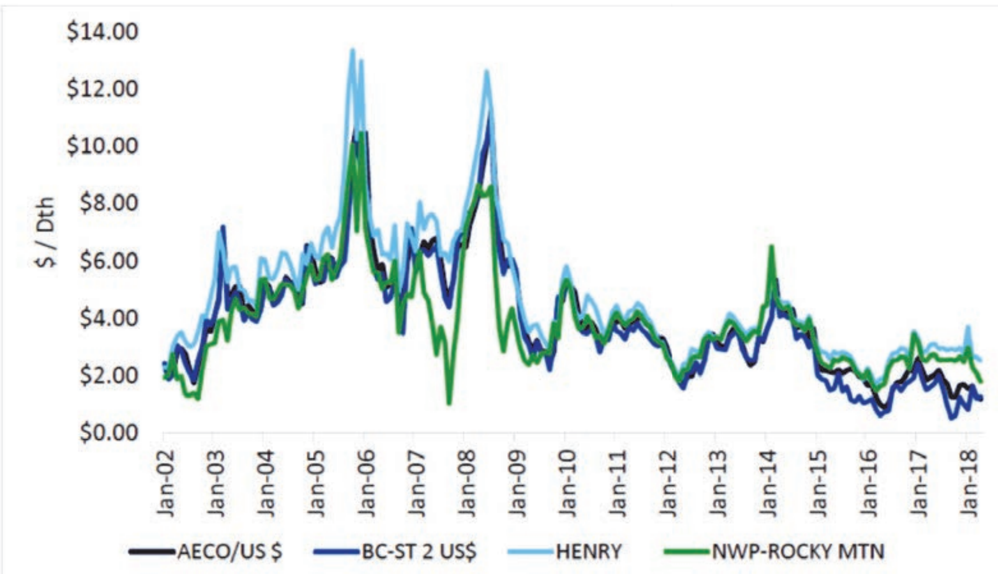
[1] Jordan Cove Project. Accessed June 24, 2019 and available at: https://www.jordancovelng.com/projectcmgh.

Natural gas from Canada would travel from the Kingsgate Hub via the Gas Transmission Northwest (GTN) pipeline while natural gas from the Rocky Mountain region would travel from the Opal Hub via the Ruby pipeline. It is highly likely that the Jordan Cove project would source most, if not all, of its natural gas designated for export from Canadian sources rather than from the Rocky Mountain region. Canadian gas supplies will continue to grow, and prices will be cheaper than natural gas sourced from the Rockies. In addition, documents supporting the applications for permission from the Canadian and U.S. governments to obtain natural gas supplies from Canada show that Jordan Cove developers intend to purchase primarily Canadian gas to supply the proposed project.

Prices for Canadian natural gas are lower than for gas from the Rocky Mountain region

Natural gas customers in the Pacific Northwest have access to gas supplies from both Canada and the Rocky Mountain region and thus can source gas from the least costly area (subject to constraints on long-haul pipelines). As shown in Figure 2, natural gas from the Rocky Mountains (NWP-ROCKY MTN) was less expensive than Canadian gas (AECO and BC-ST 2, which are shown in Figure 1) in many historical years, particularly between 2006 and 2010. That trend reversed in 2015, however, and for the past several years Canadian gas has been much less expensive for consumers in the Pacific Northwest.

Figure 2. Historical natural gas prices at select trading hubs

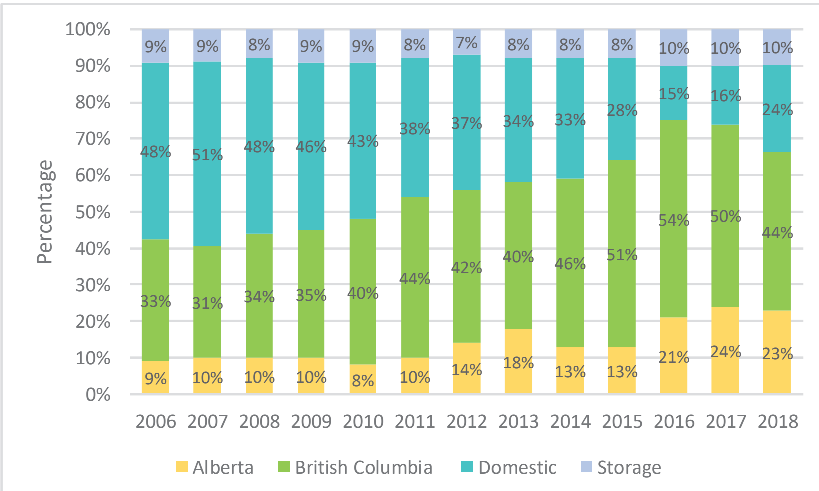


Source: Avista Corporation. 2018. Natural Gas Integrated Resource Plan. Page 96.[2]

[2] AECO refers to the AECO-C-Nova Inventory Transfer market center located in Alberta. BC-ST 2 is the Station 2 Hub located at the center of the Enbridge Westcoast Pipeline system connecting to northern British Columbia. Henry refers to Henry Hub. NWP-Rocky Mountain is the pricing point on the southern end of the NWP system in the Rocky Mountain region.

During the period in which natural gas from the Rockies was cheaper than gas from Canada, consumption of gas from that region in the Pacific Northwest peaked at 51 percent of the total in 2007. Over the last several years, however, natural gas production in British Columbia has grown. Increased supply has led to the declining prices for Canadian gas seen in Figure 2 and the increase in natural gas use from Canada seen in Figure 3. More than two-thirds of the natural gas consumed in the Pacific Northwest region came from Canada in 2018. Figure 3 shows the portions of natural gas consumed in the Pacific Northwest that came from the Rocky Mountain region and from Canada between 2006 and 2018.

Figure 3. Percentage of natural gas supply to the Pacific Northwest from Canada and the Rocky Mountain region

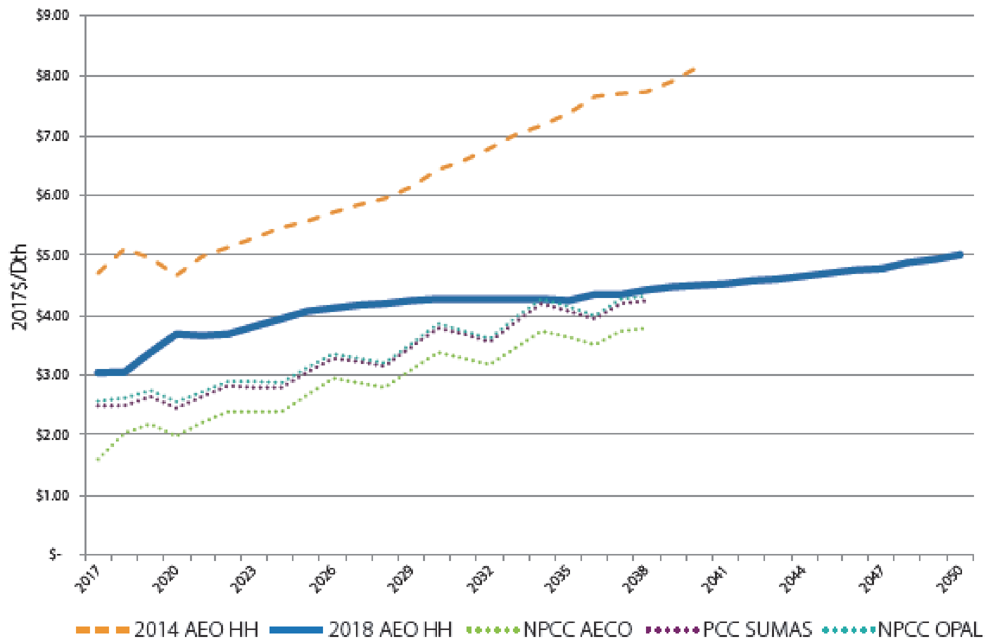


Sources: Northwest Gas Association. 2016. Pacific Northwest Gas Market Outlook. Page 6.
Northwest Gas Association. 2018. Pacific Northwest Gas Market Outlook. Page 6.

We can expect these price and supply trends to continue, as production from the Rocky Mountain region is expected to remain flat over the next decade while production from the Western Canadian Sedimentary Basin (WCSB) is expected to grow by approximately 2 billion cubic feet per day in the same time period.[3] Figure 4 shows prices at the AECO Hub in Canada trending below the Rocky Mountain Opal Hub by approximately $0.50/Dth through 2038.

[3] Northwest Gas Association. 2018. *Pacific Northwest Gas Market Outlook*. Pages 5-6.

Figure 4. Forecasted natural gas prices at select hubs



Source: Northwest Gas Association. 2018. Pacific Northwest Gas Market Outlook. Page 8.[4]

Natural gas flowing to the proposed Jordan Cove project must also include a transportation cost to ship the gas from either the Kingsgate Hub in Canada along the GTN pipeline or from the Opal Hub in the Rockies along the Ruby pipeline. Table 1 and Table 2 show the transportation charges associated with the GTN and Ruby pipelines, respectively, calculated from the rate schedules shown in the tariffs filed by the pipeline companies with the Federal Energy Regulatory Commission (FERC). Table 3 compares the price of natural gas at the Kingsgate Hub and transportation along the GTN pipeline (gas obtained from Canada) with the price of natural gas at the Opal Hub and transportation along the Ruby pipeline (gas obtained from the Rocky Mountain region).

[4] The sources of the "2014 AEO HH" and "2018 AEO HH" are the US Energy Information Administration (US EIA) 2014/2018 Annual Energy Outlook (AEO) for Henry Hub. The NPCC forecasts are from the Northwest Power and Conservation Council (NPCC) 7th Power Plan Midterm Assessment from 2017 for the AECO, Sumas, and Opal natural gas trading hubs.

Table 1. Tariff – Kingsgate to Malin along the GTN Pipeline

	Rate	Unit
Daily Mileage Rate	$0.000391	Dth-Mile
Daily Non-Mileage Rate	$0.030954	Dth
Delivery Charge	$0.000016	Dth-Mile
Fuel Charge (June 2019)	$0.015	Dth
Mileage	612.6	Miles
Total per dth per day	$0.30	

Source: Gas Transmission Northwest LLC. FERC Gas Tariff. Statement of Rates version 18.0.0. Effective January 1, 2019.

Table 2. Tariff – Opal to Malin along the Ruby Pipeline

	Rates per Dth
Monthly Reservation Rate	$34.5826
Commodity Rate	$0.0100
Electric Power Cost	$0.0450
Total per dth per day	$1.19

Source: Ruby Pipeline, LLC. FERC Gas Tariff. Service Rates Version 31.0.0, Effective March 31, 2019.

The cost to transport gas along the GTN pipeline from Canada is approximately one-quarter of the cost to transport gas along the Ruby pipeline. Table 3 compares the price of natural gas at the Kingsgate Hub and transportation along the GTN pipeline (gas obtained from Canada) with the price of natural gas at the Opal Hub and transportation along the Ruby pipeline (gas obtained from the Rocky Mountain region).

Table 3. Hub prices plus transportation costs

	2021 Hub Price $/dth	Transport Price $/dth/day
Kingsgate	$1.92	$0.30
Opal	$2.01	$1.19

Source: Hub prices are from: Bonneville Power Administration. 2019. BP-20 Rate Proceeding. Initial Proposal: Power Market Price Study and Documentation. BP-20-E-BPA-04.

When the natural gas hub price and transportation price are taken together, it becomes clear that it is much cheaper for Jordan Cove LNG to obtain natural gas from Canadian suppliers for export overseas.

Jordan Cove has stated its intent to source most, if not all, of its natural gas from Canada

The Jordan Cove LNG project applied for a license to source Canadian natural gas from the WCSB into the United States for export at the proposed LNG terminal. Developers also stated in the licensing application that the project may be supplied with natural gas from the Rocky Mountain region of the United States but noted in responses to an information request from the National Energy Board (NEB) of Canada that "the mention of the U.S. Rocky Mountain region…simply relates to a potential option for obtaining gas resources for the LNG facility. Like other Canadian LNG export applications, Jordan Cove LNG seeks to preserve the flexibility to source all of its project requirements from Canada…"[5]

In February 2014, the NEB granted Jordan Cove LNG the requested license to export Canadian natural gas. The license has a duration of 25 years and allows for annual export volumes of 1.55 billion cubic feet per day for pipeline fuel and fuel use at the terminal.[6] The U.S. Department of Energy gave its approval for the corresponding import of natural gas from Canada to the Jordan Cove LNG facility in March 2014.[7]

In the NEB's assessment of the Jordan Cove license application, it had to determine whether the natural gas proposed for export at Jordan Cove exceeded the expected surplus after considering projected Canadian demand for natural gas. Jordan Cove submitted a study by Navigant Consulting that concluded that natural gas supplies in the United States and Canada are abundant and can support both domestic market requirements and LNG export demands. In its analysis, Navigant noted that Jordan Cove applied for Canadian export authority to cover the entirety of potential LNG shipments from the project and "anticipates sourcing much, if not all, of its exports from Canadian natural gas supplies."[8]

This report has demonstrated that both Jordan Cove's stated intentions and the economics of western Canadian and domestic Rocky Mountain natural gas supplies support the conclusion that Jordan Cove intends to supply its proposed LNG export facility with Canadian gas.

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[5] Jordan Cove LNG L.P. (Jordan Cove LNG). Jordan Cove LNG Response to NEB Information Request No. 1. Application for a License to Export Natural Gas pursuant to Section 117 of the National Energy Board Act. Filed 9 September 2013 (Application). File OF-EI-Gas-GL-J705-20132-01 01 1.1.

[6] National Energy Board, Canada. February 20, 2014. *Letter Decision.* File OF-EI-Gas_GL-J705-2013-01 01.

[7] U.S. Department of Energy, Office of Fossil Energy. March 18, 2014. *DOE/FE Order No. 3412 Granting Long-Term Multi-Contract Authorization to Import Natural Gas from Canada to the Proposed Jordan Cove LNG Terminal in the Port of Coos Bay, Oregon*. FE Docket No. 13-141-NG.

[8] Navigant Consulting. September 2013. *Supply and Demand Market Assessment and Surplus Evaluation Report*. Prepared for Jordan Cove LNG L.P.

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.

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[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

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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]

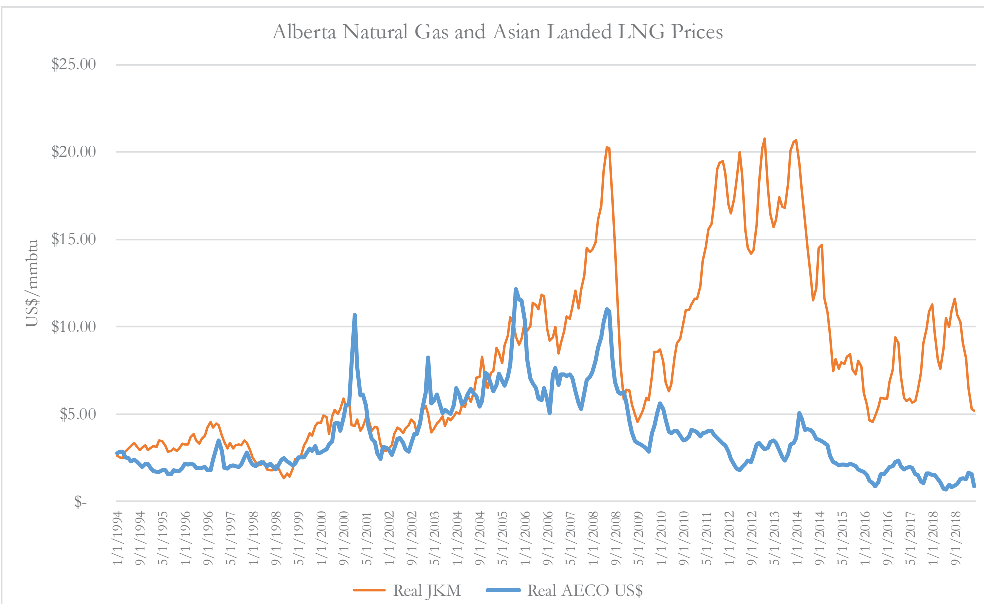

Figure 1: Natural Gas Prices in Canadian and Japanese Markets

[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.

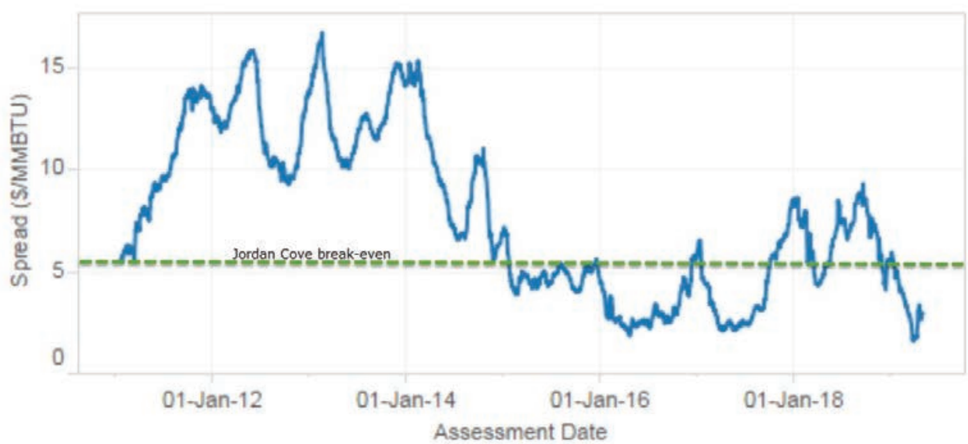

Figure 2: Recent JKM Price Changes

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.

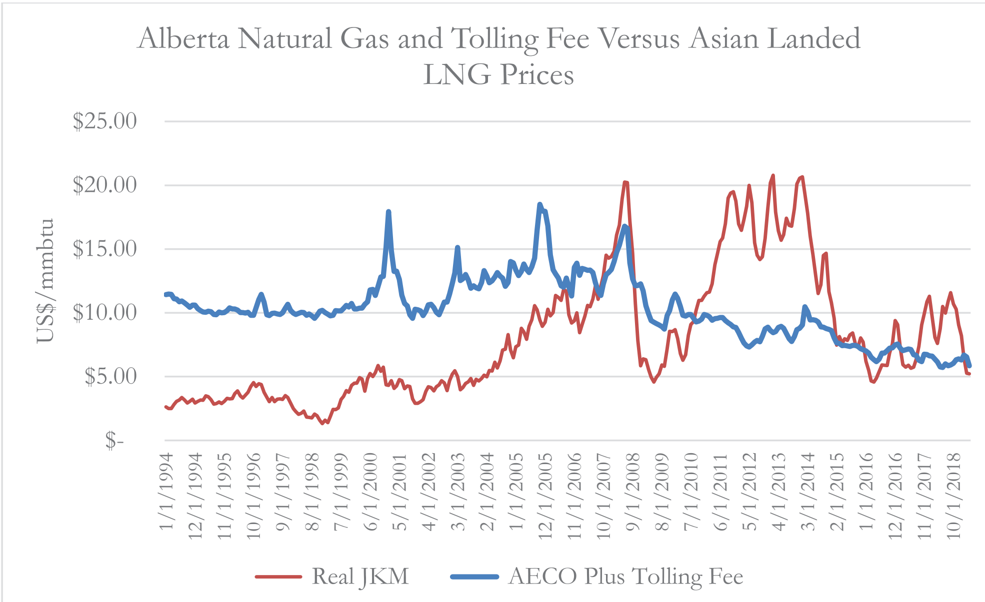

Figure 3: Delivered Cost and Asian Prices

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.

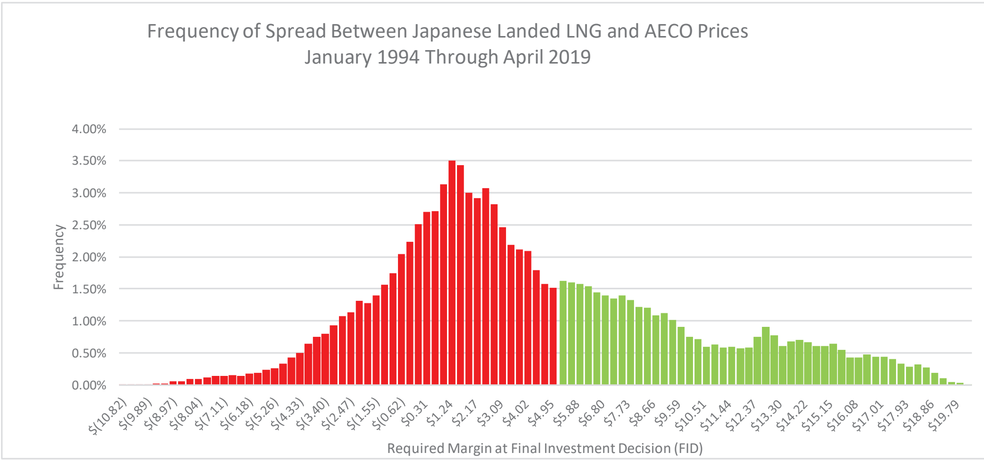

Figure 4: Monte Carlo Results

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:

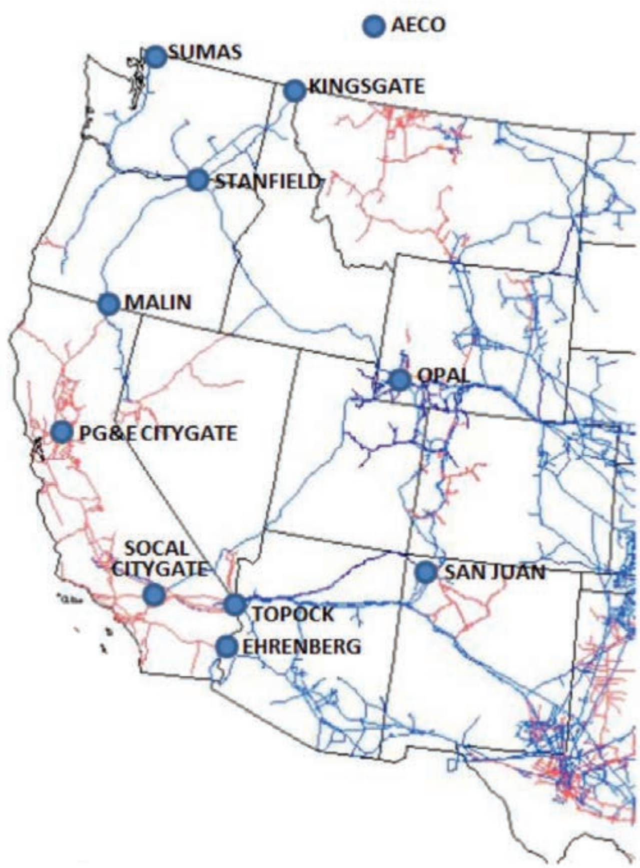

Figure 5: West Coast Natural Gas Hubs and Pipelines[9]

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

Pacific Connector Gas Pipeline

Pacific Connector Gas Pipeline, LP

Fire Prevention and Suppression Plan

Pacific Connector Gas Pipeline Project

September 2019

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List of Attachments

List of Acronyms and Abbreviations

AFMO	Assistant Fire Management Officer
ATV	All Terrain Vehicle
BLM	Bureau of Land Management
CFPA	Coos Forest Protection Association
DFPA	Douglas Forest Protection Association
FERC	Federal Energy Regulatory Commission
FMO	Fire Management Officer
IFPL	BLMM-CFPA Industrial fire Precautions Levels
NFPA	National Fire Protection Association
OR OSHA	Oregon Occupational and Health Association
ODF	Oregon Department of Forestry
OSMP	Oregon Smoke Management Plan
PCGP	Pacific Connector Gas Pipeline, LP
Plan	Fire Suppression Plan for Pacific Connector Gas Pipeline Project
Pipeline Project	Pacific Connector Gas Pipeline Project
POD	Plan of Development
R/W	Right-of-Way
SA	North Umpqua Hydroelectric Project Settlement Agreement
USDA-FS	United States Department of Agriculture-Forest Service
USDA-FS(4e) 4(e)	Conditioning Authority under the Federal Power Act

3.2 Construction

3.2.1 Forest Service Industrial Fire Precaution Levels (IFPL)

Prior to the start of each fire season, all PCGP personnel will have their fire equipment inspected by an authorized Forest Service representative prior to work on National Forest System lands (NFS lands). Inspections are available at Ranger Districts as identified by the Forest Service across all three National Forests that will be crossed by the Pipeline. PCGP shall notify the Ranger District of the need for inspection and shall be responsible for scheduling such inspections.

All PCGP personnel will be required to follow these regulations and be aware of the current Industrial Fire Precaution Level (IFPL), public use restrictions and/or fire closure level when working in forested areas. Attachment 3 details typical IFPLs. PCGP is responsible for ensuring that they operate under the current IFPLs in effect at the time work occurs.

PCGP will provide all water supply and fire tools on each active construction site as required by the current IFPL.

3.2.2 Coos Bay, Roseburg, Bureau of Land Management (BLM) and Oregon Department of Forestry (ODF) Industrial Fire Precaution Levels (IFPL) and Fire Season Requirements

The BLM has an agreement for fire prevention, suppression and investigation with the Oregon Department of Forestry (ODF). If a citation is issued for any serious violation, the Coos Bay BLM or Roseburg BLM may issue a stop work order for that specific portion of the work. Once fire season is declared, all PCGP Contractors and employees will be required to notify BLM of the location of any work to be taken place in the field. PCGP and its contractors will conform with all current IFPL notification requirements. An example of IFPL requirements is included in Attachment 3.

3.2.3 Fire Season Work Waivers

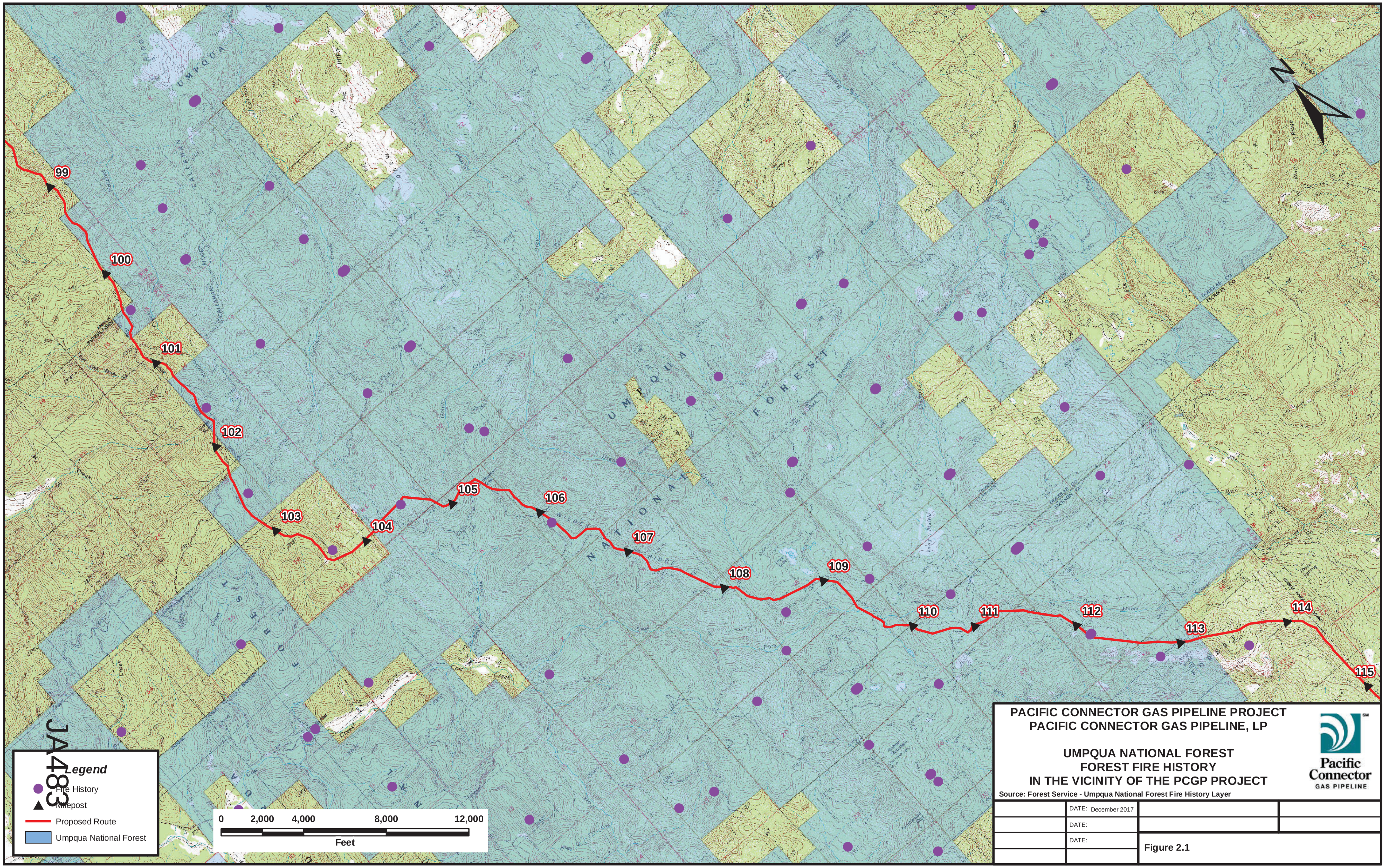
The IFPL may prohibit different types of work during different fire closure levels during fire season. PCGP will apply for waivers in advance of specific types of work identified by the IFPL at the local office of the appropriate agency as detailed below.

If the work is on BLM-managed lands, PCGP will apply for a waiver through the BLM at the district where the work would occur. If on Forest Service-managed lands, the local Fire Management Officer reviews applications and determines if a waiver is appropriate. If a waiver is authorized, additional precautions and equipment may be required. The Contractor is required to possess a copy of the waiver at the work site and adhere to all requirements of the waiver. PCGP is responsible to assure that their contractors are in compliance with waivers.

If a citation for PCGP is issued by ODF, CFPA or DFPA for activity on BLM managed lands, a future waiver request will be denied for a calendar year. Repeat warnings by the ODF, CFPA or DFPA unit can also result is denial of future waivers.

3.2.4 Prescribed Burning

For the POD, PCGP has submitted a separate Prescribed Burning Plan that contains the process for creating and submitting a burn plan, notification procedures, and how the Pipeline Project will meet the requirements as outlined in the Interagency Standards for Fire and Fire Aviation Operations as well as the Interagency Prescribed Fire Planning and Implementation



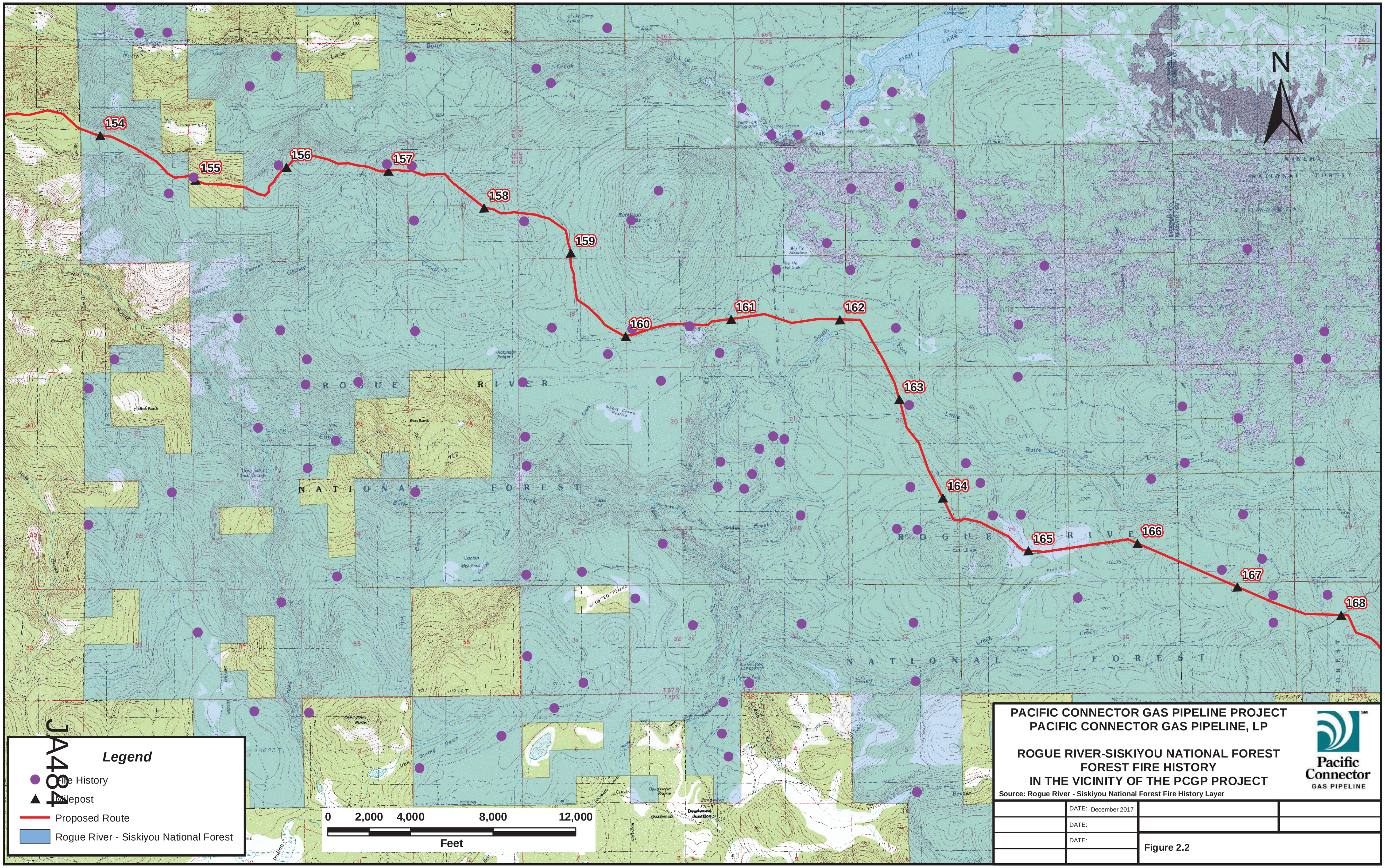
PACIFIC CONNECTOR GAS PIPELINE PROJECT
PACIFIC CONNECTOR GAS PIPELINE, LP

UMPQUA NATIONAL FOREST
FOREST FIRE HISTORY
IN THE VICINITY OF THE PCGP PROJECT

Source: Forest Service - Umpqua National Forest Fire History Layer

Pacific Connector GAS PIPELINE

	DATE: December 2017		
	DATE:		
	DATE:	Figure 2.1	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ROGUE RIVER NATIONAL FOREST
ROGUE RIVER NATIONAL FOREST
Legend
Fire History
Milepost
Proposed Route
Rogue River - Siskiyou National Forest
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Feet
PACIFIC CONNECTOR GAS PIPELINE PROJECT
PACIFIC CONNECTOR GAS PIPELINE, LP
ROGUE RIVER-SISKIYOU NATIONAL FOREST
FOREST FIRE HISTORY
IN THE VICINITY OF THE PCGP PROJECT
Source: Rogue River - Siskiyou National Forest Fire History Layer
Pacific Connector
GAS PIPELINE
DATE: December 2017
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Figure 2.2

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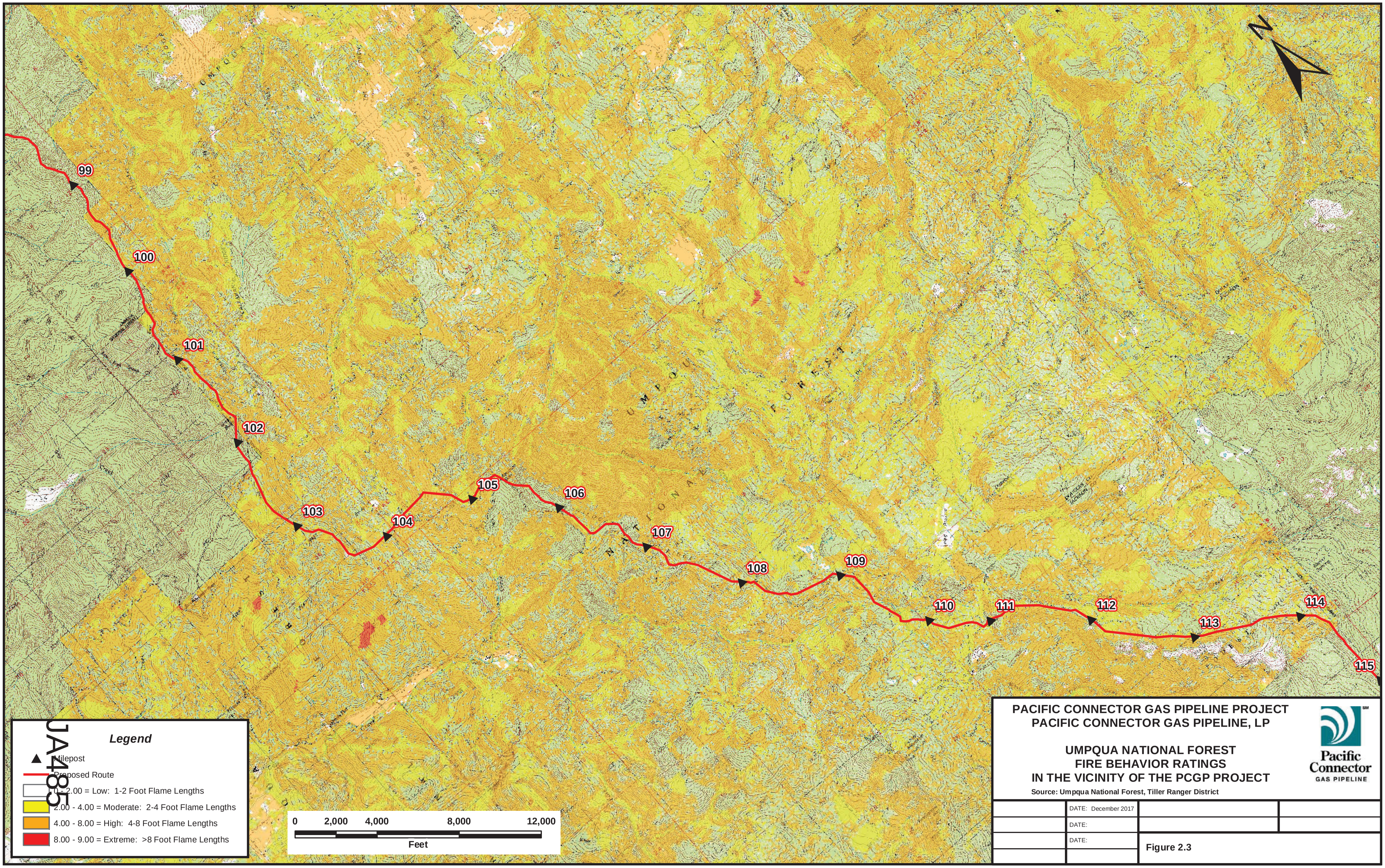


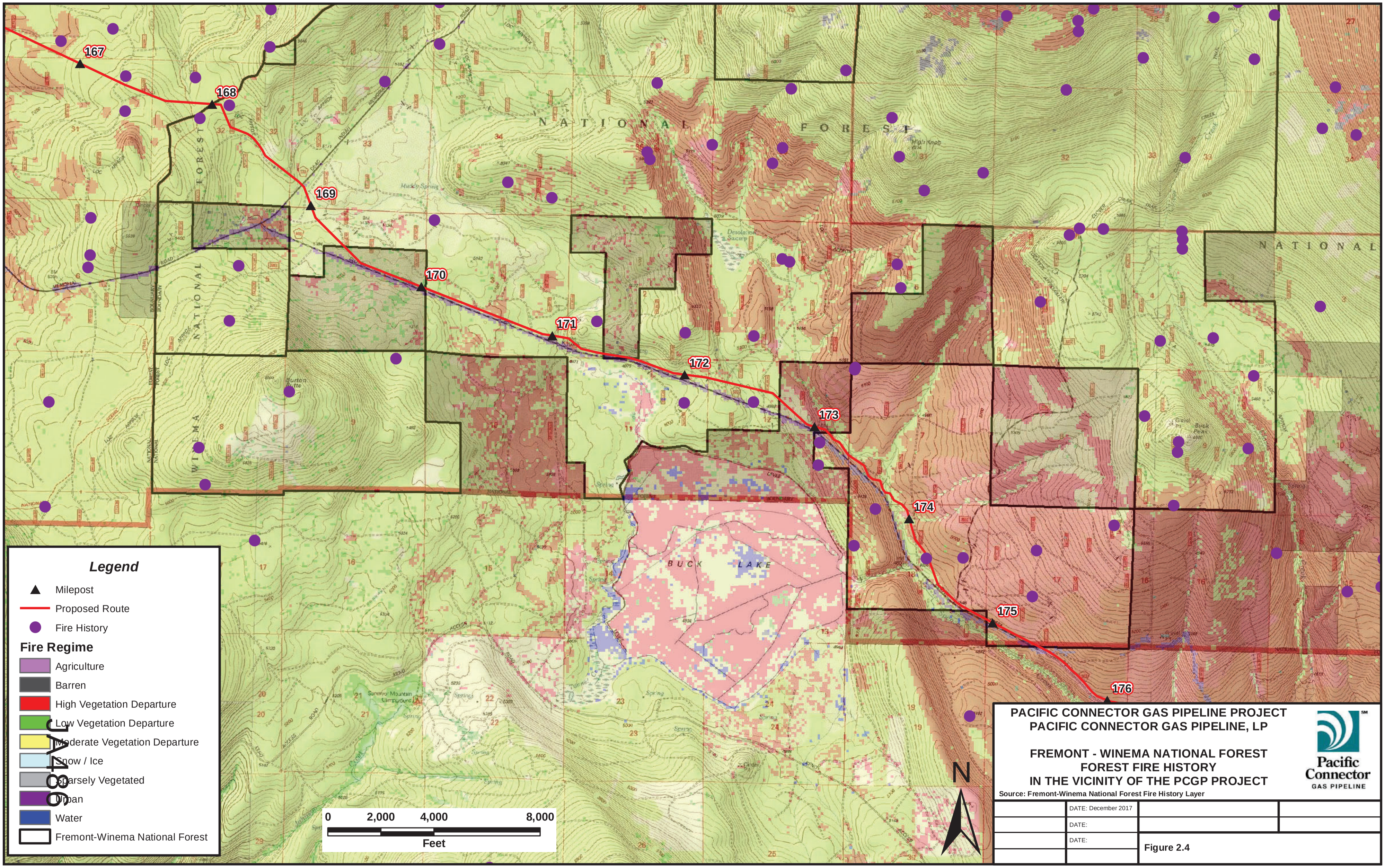
PACIFIC CONNECTOR GAS PIPELINE PROJECT
PACIFIC CONNECTOR GAS PIPELINE, LP

UMPQUA NATIONAL FOREST
FIRE BEHAVIOR RATINGS
IN THE VICINITY OF THE PCGP PROJECT

Source: Umpqua National Forest, Tiller Ranger District

Pacific Connector GAS PIPELINE

	DATE: December 2017		
	DATE:		
	DATE:	Figure 2.3	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NATIONAL FOREST
WINEMA NATIONAL FOREST
BUCK LAKE
N
0 2,000 4,000 8,000
Feet
Legend
Milepost
Proposed Route
Fire History
Fire Regime
Agriculture
Barren
High Vegetation Departure
Low Vegetation Departure
Moderate Vegetation Departure
Snow / Ice
Sparsely Vegetated
Urban
Water
Fremont-Winema National Forest
PACIFIC CONNECTOR GAS PIPELINE PROJECT
PACIFIC CONNECTOR GAS PIPELINE, LP
FREMONT - WINEMA NATIONAL FOREST
FOREST FIRE HISTORY
IN THE VICINITY OF THE PCGP PROJECT
Source: Fremont-Winema National Forest Fire History Layer
Pacific Connector
GAS PIPELINE
DATE: December 2017
DATE:
DATE:
Figure 2.4

JA486


PACIFIC CONNECTOR GAS PIPELINE PROJECT
PACIFIC CONNECTOR GAS PIPELINE, LP
COOS BAY BLM DISTRICT
FOREST FIRE HISTORY
IN THE VICINITY OF THE PCGP PROJECT
Source: Forest Service - Umpqua National Forest Fire History Layer
DATE: December 2017
DATE:
DATE:
Figure 2.5
Pacific Connector
GAS PIPELINE
Legend
Fire History
Milepost
Proposed Route
BLM Resource District Boundary
BLM District Boundary
Surface Jurisdiction
Bureau of Indian Affairs
BLM
Private or Other Lands
0
2.5
5
Miles
N
10R
15BR
20BR
25
30
35
40
45
50
T24S, R12W
T25S, R11W
T25S, R12W
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T28S, R14W
T28S, R15W
T29S, R8W
T29S, R9W
T29S, R10W
T29S, R11W
T29S, R12W
T29S, R13W
T29S, R14W
T30S, R9W
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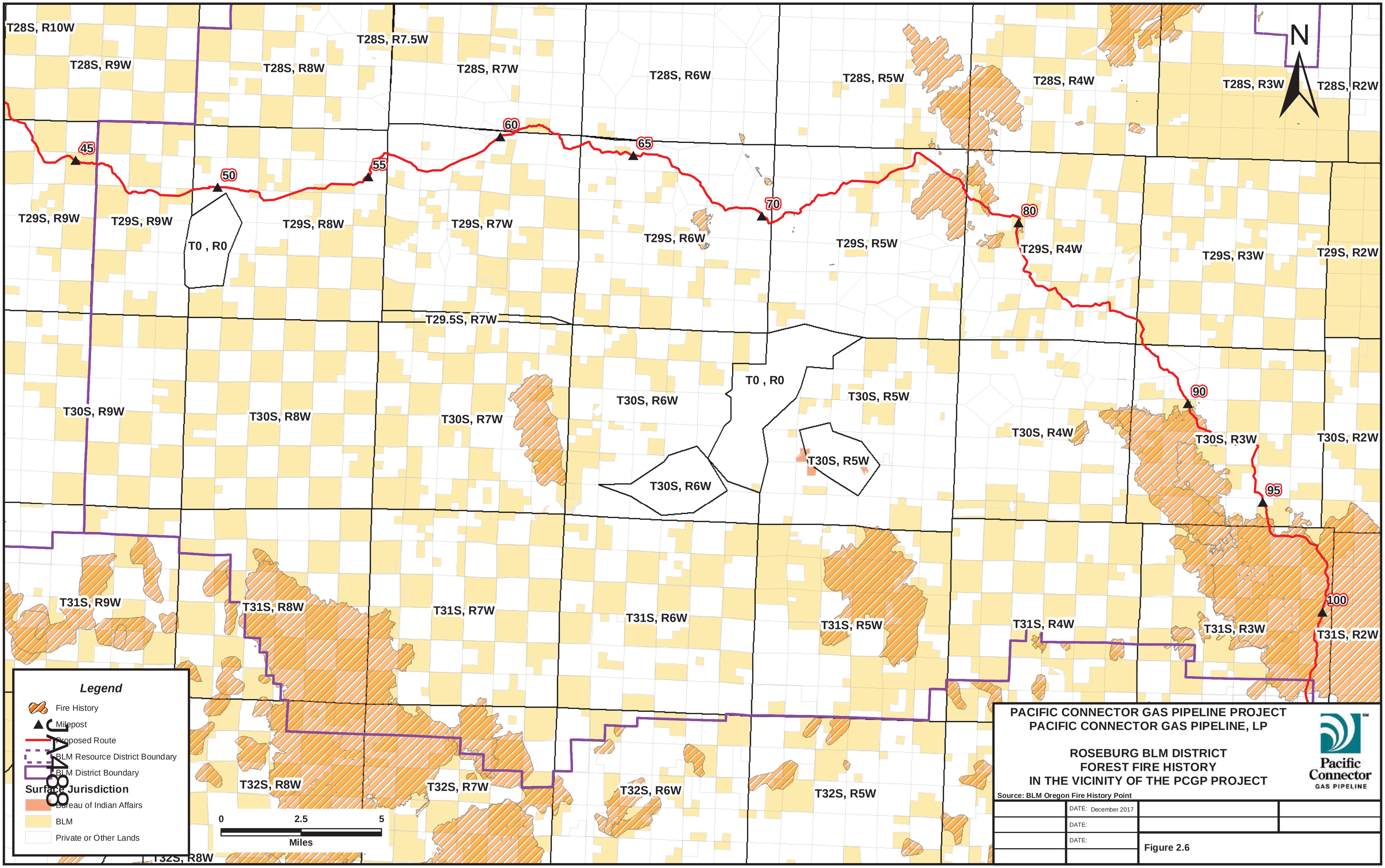
T0 , R0

JA487



PACIFIC CONNECTOR GAS PIPELINE PROJECT
PACIFIC CONNECTOR GAS PIPELINE, LP

ROSEBURG BLM DISTRICT
FOREST FIRE HISTORY
IN THE VICINITY OF THE PCGP PROJECT

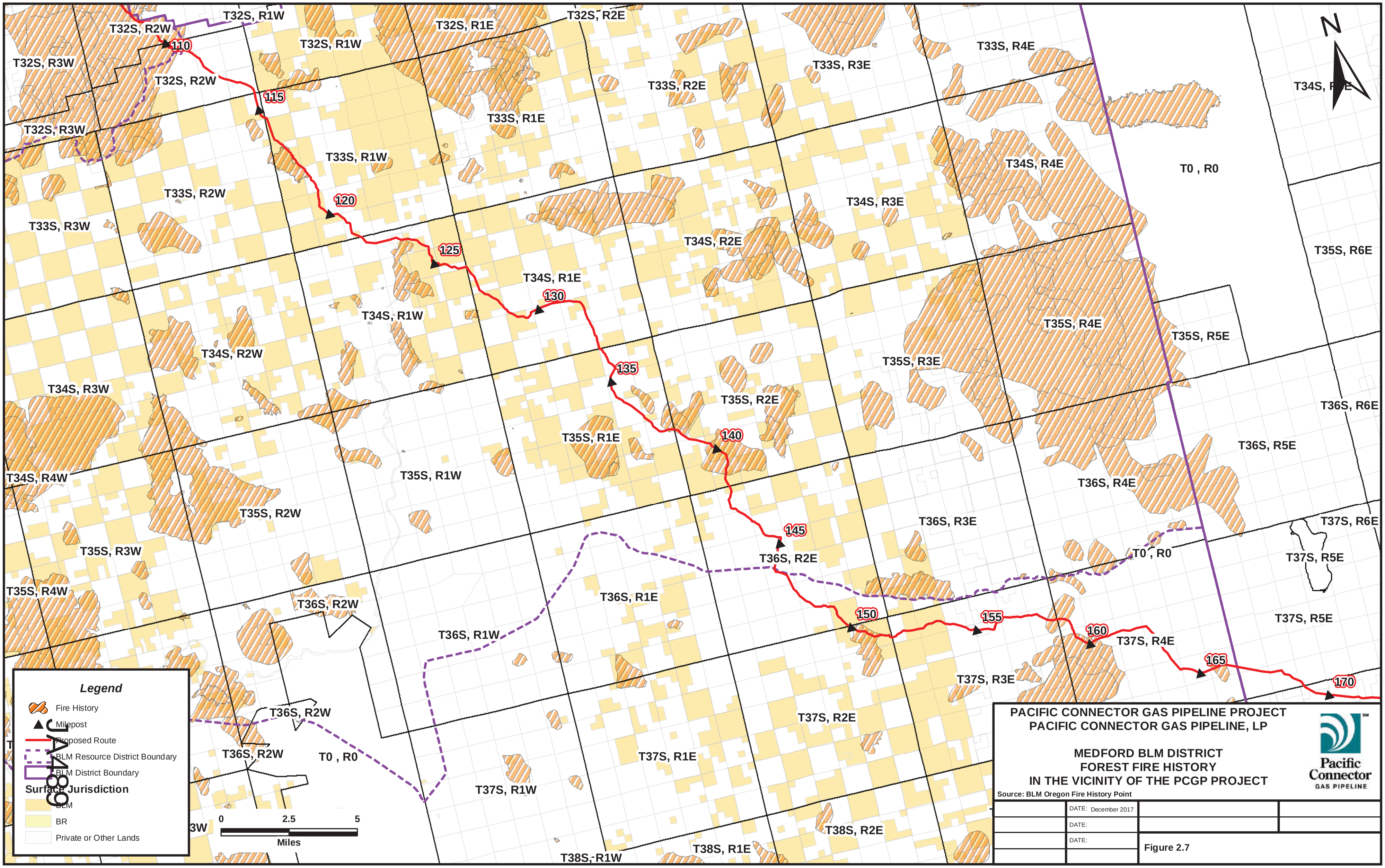
Source: BLM Oregon Fire History Point

Pacific Connector GAS PIPELINE

DATE: December 2017
DATE:
DATE:

Figure 2.6

JA488


N
Legend
Fire History
Milepost
Proposed Route
BLM Resource District Boundary
BLM District Boundary
Surface Jurisdiction
BLM
BR
Private or Other Lands
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2.5
5
Miles
110
115
120
125
130
135
140
145
150
155
160
165
170
T32S, R3W
T32S, R2W
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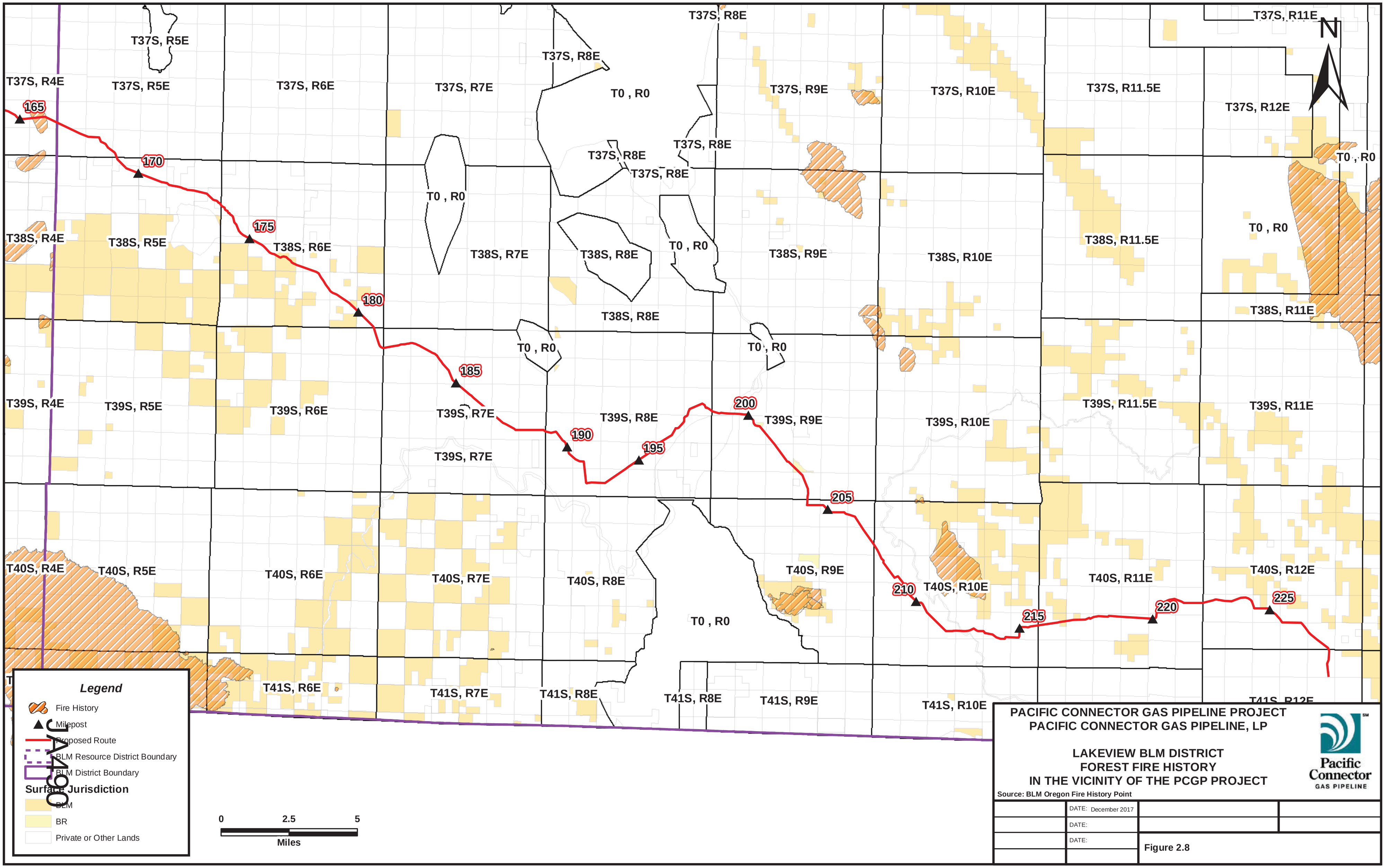
T38S, R2E
T0 , R0
PACIFIC CONNECTOR GAS PIPELINE PROJECT
PACIFIC CONNECTOR GAS PIPELINE, LP
MEDFORD BLM DISTRICT
FOREST FIRE HISTORY
IN THE VICINITY OF THE PCGP PROJECT
Source: BLM Oregon Fire History Point
DATE: December 2017
DATE:
DATE:
Figure 2.7
Pacific Connector
GAS PIPELINE

JA489



PACIFIC CONNECTOR GAS PIPELINE PROJECT
PACIFIC CONNECTOR GAS PIPELINE, LP

LAKEVIEW BLM DISTRICT
FOREST FIRE HISTORY
IN THE VICINITY OF THE PCGP PROJECT

Source: BLM Oregon Fire History Point

	DATE: December 2017		
	DATE:		
	DATE:	Figure 2.8	

JA490

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

FINAL
ENVIRONMENTAL IMPACT STATEMENT
FOR THE
JORDAN COVE ENERGY PROJECT

Docket Nos. CP17-494-000 and CP17-495-000

FERC/FEIS-0292F

November 2019

Cooperating Agencies:

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ENERGY PROJECTS

In Reply Refer To:
OEP/DG2E/Gas Branch 3
Jordan Cove Energy Project L.P.
Docket No. CP17-495-000
Pacific Connector Gas Pipeline, LP
Docket No. CP17-494-000
FERC/EIS-0292F

TO THE INTERESTED PARTIES:

The staff of the Federal Energy Regulatory Commission (FERC or Commission), with the participation of the cooperating agencies listed below, has prepared a final environmental impact statement (EIS) for the Jordan Cove Liquefied Natural Gas Project proposed by Jordan Cove Energy Project L.P. (Jordan Cove) and the Pacific Connector Gas Pipeline Project proposed by Pacific Connector Gas Pipeline, LP (Pacific Connector) (collectively referred to as the Jordan Cove Energy Project or Project). Under Section 3 of the Natural Gas Act (NGA), Jordan Cove requests authorization to construct and operate a liquified natural gas (LNG) terminal in Coos Bay, Oregon, capable of liquefying up to 1.04 billion cubic feet of natural gas per day for export to overseas markets. Pacific Connector seeks a Certificate of Public Convenience and Necessity under Section 7 of the NGA to construct and operate a natural gas transmission pipeline providing about 1.2 billion cubic feet per day of natural gas from the Malin hub to the Jordan Cove terminal, crossing portions of Klamath, Jackson, Douglas, and Coos Counties, Oregon.

The final EIS assesses the potential environmental effects of the construction and operation of the Project in accordance with the requirements of the National Environmental Policy Act (NEPA). As described in the final EIS, the FERC staff concludes that approval of the Project would result in a number of significant environmental impacts; however, the majority of impacts would be less than significant because of the impact avoidance, minimization, and mitigation measures proposed by Jordan Cove and Pacific Connector and those recommended by staff in the EIS.

The United States (U.S.) Department of the Interior Bureau of Land Management, (BLM), Bureau of Reclamation (Reclamation), and Fish and Wildlife Service; U.S. Department of Agriculture Forest Service (Forest Service); U.S. Department of Energy; U.S. Army Corps of Engineers; U.S. Environmental Protection Agency; U.S. Department of Commerce National Oceanic and Atmospheric Administration National Marine Fisheries Service; U.S. Department of Homeland Security Coast Guard; the Coquille

Indian Tribe; and the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration participated as cooperating agencies in preparation of this EIS. Cooperating agencies have jurisdiction by law or special expertise with respect to resources potentially affected by the proposal and participate in the NEPA analysis. The cooperating agencies provided input into the analyses, conclusions, and recommendations presented in the EIS. Following issuance of the final EIS, the cooperating agencies will issue subsequent decisions, determinations, permits, or authorizations for the Project in accordance with each individual agency's regulatory requirements.

The BLM, with the concurrence of the Forest Service and Reclamation, would adopt and use the EIS to consider issuing a Right-of-Way Grant for the portion of the Project on federal lands. Other cooperating agencies would use this EIS in their regulatory process, and to satisfy compliance with NEPA and other related federal environmental laws (e.g., the National Historic Preservation Act).

The BLM and the Forest Service would also use this EIS to evaluate proposed amendments to their District or National Forest land management plans that would make provision for the Pacific Connector pipeline. In order to consider the Pacific Connector right-of-way grant, the BLM must amend the affected Resource Management Plans (RMPs). The BLM therefore proposes to amend the RMPs to re-allocate all lands within the proposed temporary use area and right-of-way to a District-Designated Reserve, with management direction to manage the lands for the purposes of the Pacific Connector right-of-way. Approximately 885 acres would be re-allocated. District-Designated Reserve allocations establish specific management for a specific use or to protect specific values and resources. In accordance with Code of Federal Regulations (CFR) part 36 § 219—Planning, the Forest Service is considering amendments of Land and Resource Management Plans (LRMP) for the Umpqua, Rogue River, and Winema National Forests. Proposed amendments of LRMPs include reallocation of matrix lands to Late Successional Reserves and site-specific exemptions from 15 standards to allow construction of the Pacific Connector pipeline. Exemptions from standards include requirements to protect known sites of Survey and Manage species, changes in visual quality objectives at specific locations, limitations on detrimental soil conditions, removal of effective shade at perennial stream crossings and the construction of utility corridors in riparian areas.

The Commission mailed a copy of the Notice of Availability of the final EIS to federal, state, and local government representatives and agencies; elected officials; environmental and public interest groups; Indian Tribes; potentially affected landowners and other interested individuals and groups; and newspapers and libraries in the Project area. The final EIS is available in hard copy at libraries in the area of the Project and in electronic format. It may be viewed and downloaded from the FERC's website (www.ferc.gov), on the Environmental Documents page (https://www.ferc.gov/industries/gas/enviro/eis.asp). In addition, the final EIS may be accessed by using the eLibrary link on the FERC's website. Click on the eLibrary link (https://www.ferc.gov/docs-filing/elibrary.asp), click on General Search, and enter the docket number in the "Docket Number" field, excluding the last three digits (i.e., CP17-494 or CP17-495). Be sure you have selected an appropriate date range. For assistance, please contact FERC Online Support at FercOnlineSupport@ferc.gov or toll free at (866) 208-3676, or for TTY, contact (202) 502-8659.

Questions?

Additional information about the Project is available from the Commission's Office of External Affairs, at **(866) 208-FERC**, or on the FERC website (www.ferc.gov) using the eLibrary link. The eLibrary link also provides access to the texts of all formal documents issued by the Commission, such as orders, notices, and rulemakings.

In addition, the Commission offers a free service called eSubscription that allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries, and direct links to the documents. Go to www.ferc.gov/docs-filing/esubscription.asp.

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APPENDICES

EXECUTIVE SUMMARY

The staff of the Federal Energy Regulatory Commission (FERC or Commission) has prepared this final environmental impact statement (EIS) to assess the impacts of constructing and operating the Jordan Cove Liquefied Natural Gas (LNG) Project proposed by Jordan Cove Energy Project L.P. (Jordan Cove) and the Pacific Connector Gas Pipeline Project proposed by Pacific Connector Gas Pipeline, LP (Pacific Connector). The purpose and need of the Jordan Cove LNG Project is to export natural gas supplies derived from existing natural gas transmission systems to overseas markets. The purpose and need of the Pacific Connector Gas Pipeline Project is to connect the existing natural gas transmission systems of Gas Transmission Northwest, LLC and Ruby Pipeline, LLC with the proposed LNG export terminal. Collectively, Jordan Cove and Pacific Connector are referred to as the Applicant or Applicants, and the projects are referred to collectively as the Jordan Cove Energy Project or simply the Project.

The purpose of this EIS is to inform FERC decision-makers, the public, and other permitting agencies about the potential adverse and beneficial environmental impacts of the proposed Project and as appropriate recommend measures that would avoid, reduce, and mitigate adverse impacts to the extent practicable. We[1] prepared this analysis based on information provided by the Applicants; our independent review of this information; in consultation with federal cooperating agencies (see below); and in consideration of comments provided by state and local agencies, Indian Tribes, non-governmental organizations, and individual members of the public. This EIS was prepared in accordance with the requirements of the National Environmental Policy Act of 1969 (NEPA) and the Commission's implementing regulations under Title 18 of the Code of Federal Regulations, Part 380 (18 CFR 380).

The FERC is the federal agency responsible for authorizing onshore LNG facilities, and is responsible for regulating the siting and construction of natural gas transmission pipelines. the FERC is the lead federal agency responsible for the preparation of this EIS. The United States (U.S.) Department of the Interior Bureau of Land Management (BLM), Bureau of Reclamation, and Fish and Wildlife Service; U.S. Department of Agriculture Forest Service (Forest Service); U.S. Department of Energy; U.S. Army Corps of Engineers (COE); U.S. Environmental Protection Agency (EPA); U.S. Department of Commerce National Oceanic and Atmospheric Administration National Marine Fisheries Service; U.S. Department of Homeland Security Coast Guard (Coast Guard); the Coquille Indian Tribe; and the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration are cooperating agencies for the development of this EIS consistent with 40 CFR 1501.6(b). A cooperating agency has jurisdiction by law or has special expertise with respect to the environment potentially affected by the Project. The cooperating agencies provided input into the analyses, conclusions, and recommendations presented in the EIS. Following issuance of this final EIS, the cooperating agencies will issue subsequent decisions, determinations, permits or authorizations for the Project in accordance with each individual agency's regulatory requirements.

[1] "We," "us," and "our" refer to the environmental and engineering staff of the FERC's Office of Energy Projects.

PROPOSED ACTION

On September 21, 2017, the Applicants, in Docket Nos. CP17-494-000 and CP17-495-000, filed applications with the Commission pursuant to Sections 3 and 7 of the Natural Gas Act (NGA) seeking an Authorization and a Certificate of Public Convenience and Necessity to construct and operate an LNG export terminal and a natural gas transmission pipeline. The LNG terminal would be located in Coos County, Oregon on the North Spit of Coos Bay and would be capable of liquefying up to 1.04 billion cubic feet of natural gas per day for export. The 200-acre LNG terminal site would include:

- an access channel from the existing Coos Bay Federal Navigation Channel to the LNG terminal;
- modifications to the existing Federal Navigation Channel;
- a marine slip containing two berths (one Production Loading Berth and one Emergency Lay Berth), a dock for tug and escort boats, and a material offloading facility;
- LNG loading platform and transfer line;
- two full-containment LNG storage tanks and associated equipment;
- five natural gas liquefaction trains;
- a pipeline gas conditioning facility;
- a temporary workforce housing facility;
- the non-jurisdictional Southwest Oregon Regional Security Center and Fire Department building; and
- other security and control facilities, administrative buildings, and other support structures.

As proposed, the LNG terminal would be called upon by about 120 LNG carriers per year.

The pipeline would originate at interconnections with existing pipeline systems in Klamath County, Oregon, and would span parts of Klamath, Jackson, Douglas, and Coos Counties, Oregon, before connecting with the LNG terminal. The approximately 229-mile-long, 36-inch-diameter pipeline would be capable of transporting up to 1.2 billion cubic feet of natural gas per day. Operating the pipeline would require the use of one compressor station and other associated facilities including mainline block valves, pig[2] launchers and receivers, communication systems, and meter stations.

PUBLIC INVOLVEMENT

The Applicants began participating in the Commission's Pre-filing Process in early 2017 (Docket No. PF17-4-000). The FERC's Pre-filing Process encourages the early involvement of interested stakeholders and responsible regulatory agencies to identify and resolve environmental issues before an application is filed with the FERC. During the Pre-filing Process, the Applicants held Open Houses in Coos Bay and along the pipeline route in March of 2017 to provide the public with information about the Project and to solicit its concerns about the Project.

In June 2017, the FERC issued a *Notice of Intent to Prepare an Environmental Impact Statement for the Planned Jordan Cove LNG Terminal and Pacific Connector Pipeline Projects, Request for*

[2] A pig is a remotely operated pipe inspection and cleaning tool.

Comments on Environmental Issues, and Notice of Public Scoping Sessions (NOI). The NOI was sent to affected landowners; federal, state, and local government agencies; elected officials; environmental and public interest groups; interested Indian tribes; and local libraries and newspapers. The NOI also began a 30-day scoping period. During the scoping period, the FERC along with the BLM and Forest Service, held joint public scoping sessions in Coos Bay and along the pipeline route to receive comments about the Project. Each session was attended by at least 150 people, and some sessions were attended by substantially more. During scoping, we also met with several federally recognized Indian Tribes in person and via teleconference to discuss their respective concerns about the Project.

On March 29, 2019, the Commission issued a Notice of Availability (NOA) of the draft EIS. The NOA established a 90-day period to receive comments on the draft EIS, ending on July 5, 2019. The 90-day comment period was established to meet public review requirements of the BLM for the proposed amendments to BLM and Forest Service Land Management Plans. A formal notice was also published by the EPA in the *Federal Register* on April 5, 2019, indicating that the draft EIS was available.

The NOA announced the time, date, and location of four public comment sessions in Oregon to take comments on the draft EIS. Locations and dates of the public sessions included Coos Bay on June 24, 2019; Myrtle Creek on June 25, 2019; Medford on June 26, 2019; and Klamath Falls on June 27, 2019. Transcripts of the sessions were placed in the public record for these proceedings.[3] A summary of the comments received from the public sessions, as well as written comments on the draft EIS submitted by the public and agencies, is provided in the EIS and appendix R of this EIS which also includes our response to these comments. Most comments received during scoping and on the draft EIS concern land use, purpose and need, safety and security, potential geological hazards (tsunamis and mountainous terrain), wildlife, water quality, and the FERC's approach to the NEPA process. Comments from Indian Tribes expressed concern about meaningful consultation, cultural resources, environmental resources including fish (salmon) and vegetation, impacts on traditional use(s) of the land, environmental justice, cumulative impacts, and documentation of concerns in the EIS. Additionally, many comments raised concerns that are outside the scope of this EIS. Examples include comments regarding the public benefit or need to export LNG; comments on the State's permitting process; history of the Project (i.e., the multiple past applications); horizontal hydraulic drilling through shale formations during exploration for natural gas (often referred to as "fracking"); greenhouse gas emissions resulting from the combustion of exported gas; the concept of a "programmatic" EIS to cover LNG export terminals throughout the United States; the structure and format of FERC public meetings; the availability of hard copies of the draft EIS; the differences between "FERC Recommendations" versus "FERC Conditions"; and administrative information technology system operations at the FERC. These issues are not addressed in this EIS.[4] However, all other comments received were considered and addressed as appropriate in our analysis.

[3] Copies of the transcripts of the public sessions to take comments on the draft EIS were placed into the dockets through the FERC's eLibrary system. See Accession Nos. 20190624-4003, 20190625-4001, 20190626-4005, and 20190627-4004.
[4] As appropriate, these issues would be addressed in any Order the Commission may issue.

PROJECT IMPACTS

Constructing and operating the Project would impact geological resources, soils and sediments, water resources, wetlands, vegetation, wildlife, aquatic resources, threatened and endangered species, and other species of concern, land use, recreation, visual resources, socioeconomics, transportation, cultural resources, air quality, and noise. Our analysis also evaluates cumulative impacts on these resources.

Constructing and operating the LNG terminal would permanently impact about 200 acres of land. Coos Bay would temporarily experience increased turbidity and sedimentation due to the construction of the marine facilities. Wildlife in the vicinity of the LNG terminal, especially those species who are sensitive to noise and light would experience increased rates of stress, injury, and mortality and would likely avoid and relocate from the Project area. Areas adjacent to the Coos Bay Federal Navigation Channel would be modified. The Coast Guard has determined that the Federal Navigation Channel is suitable to support the LNG carriers that would call on the terminal. LNG carriers would cause delays for other marine traffic in the waterway. Vehicle traffic and associated commute times near the LNG terminal site would also increase. Permanent and temporary structures at the LNG terminal as well as LNG carrier operations in the Federal Navigation Channel would exceed Federal Aviation Administration obstruction standards and could significantly impact Southwest Oregon Regional Airport operations. Constructing the LNG terminal would also have a temporary significant impact on the short-term housing market in Coos County. The LNG terminal would also permanently and significantly impact the visual character of Coos Bay, and pile driving at the terminal would result in a significant noise impact on the surrounding area. The LNG terminal design accounts for possible tsunamis and includes safeguards and protections to ensure facility integrity and public safety.

Constructing the pipeline would require the temporary use of more than 4,900 acres of land. Operating the pipeline would permanently impact about 1,400 acres of land; however, many land uses including livestock grazing would not be permanently affected. The pipeline would be located across steep terrain through the Cascade Mountains, but Pacific Connector has planned minimization and mitigation measures accordingly for potential landslides and erosion. The pipeline would also cross over 300 waterbodies including the Coos, Rogue, and Klamath Rivers. These larger rivers would be crossed using horizontal directional drills to avoid and reduce impacts. The pipeline would also impact over 2,000 acres of forest including over 750 acres of late stage old-growth forest that provides habitat for the marbled murrelet, the northern spotted owl, and other federally-listed threatened and endangered species. Several federally-listed threatened the and endangered species are likely to be adversely affected by the Project. Recreation areas crossed by the pipeline would be temporarily disturbed and users of these areas would likely find construction to be an annoyance and an inconvenience. Vehicle traffic on area roads would increase as well as demand for local services and business, but these increases would be temporary. Following construction, the primary impact of the Project would be the visible nature of the permanent pipeline easement. The visual impact of the easement would be similar to that of other utilities and roadways in the region.

ALTERNATIVES CONSIDERED

As required by the NEPA and in consultation with the cooperating agencies, and considering public comments, we identified and considered reasonable alternatives to the Project to determine if the implementation of an alternative would be preferable to the proposed action. An alternative is considered reasonable if it meets the stated purpose of the Project and is technically and economically feasible and practical. A preferable alternative would offer a significant environmental advantage over the proposed action.

In our alternatives analysis we considered the no action alternative, system alternatives, LNG terminal site alternatives, and pipeline route alternatives and variations. Our analysis considers and the EIS evaluates alternatives developed by staff, developed by the Applicants, or suggested by stakeholders that were able to meet the Project's purpose and were feasible or practical.

Under the No Action alternative, the environmental impacts associated with constructing and operating the Project would not occur. However, exports of LNG from one or more other LNG export facilities may occur if developers elect to apply for export authorization based on these same market considerations. Thus, although the environmental impacts associated with constructing and operating the Project would not occur under the No Action Alternative, impacts could occur at other location(s) in the region as a result of another LNG export project seeking to meet the demand identified by Jordan Cove.

The systems alternatives we considered include existing and proposed LNG terminals in Alaska, Canada, and Mexico; an LNG project currently under construction in Tacoma, Washington; an existing Northwest Pipeline natural gas transmission pipeline system in Oregon; and a non-jurisdictional intrastate pipeline in Coos County. Existing and proposed LNG terminals in Alaska, Canada, and Mexico are too far removed (700 to 3,000 miles) from the interconnections in Klamath County to offer a significant environmental advantage over the proposed action. The Tacoma LNG Project is designed to serve local customers and provide marine vessel fuel and would not meet the Project's stated purpose for export. The Northwest Pipeline system and the Coos County Pipeline have insufficient capacities to meet the design requirements of the proposed pipeline. Modifications to these systems to create such capacity would result in equal or greater environmental impacts and would not offer a significant environmental advantage over the proposed action.

The LNG terminal site alternatives we considered include a site in Humboldt Bay, California; sites in Oregon and Washington; another site in Coos Bay; and an inland site east of Coos Bay. The impacts of constructing an LNG terminal and pipeline to Humboldt Bay would be comparable to that of the proposed Project. Alternative sites in Oregon and Washington would result in greater impacts on the environment. Therefore, alternative LNG terminal sites in California, Oregon, and Washington would not offer a significant environmental advantage over the proposed action. The Coos Bay site alternative would also not offer a significant environmental advantage over the proposed action. The inland site alternative would be located at least 5 miles east of Coos Bay and would require the construction of an LNG cryogenic pipeline to the proposed marine loading facilities. Our analysis indicates that the relocation of the terminal site would reduce, but not eliminate impacts on wetlands; it would also still result in impacts on Coos Bay, and would likely increase overall impacts on the environment due to the need for an LNG cryogenic pipeline. Therefore, an inland alternative would not offer a significant environmental advantage over the proposed action.

Pipeline route alternatives considered include three major route alternatives and nine pipeline route variations. Based on our analysis as described in the EIS, we conclude that one route variation would be preferable to the corresponding proposed action. We are recommending that Pacific Connector incorporate the Blue Ridge Variation into its proposed route for the Project. We have determined that this variation would offer a significant environmental advantage over the proposed action.

The Survey and Manage Species Variation, East Fork Cow Creek Variation, and the Pacific Crest Trail Variation were recommended in the draft EIS, and Pacific Connector has since adopted these variations into the proposed action between the draft and final EIS. The final EIS includes these route modifications in the project description and impact assessment.

CONCLUSIONS

We conclude that constructing and operating the Project would result in temporary, long-term, and permanent impacts on the environment. Many of these impacts would not be significant or would be reduced to less than significant levels with the implementation of proposed and/or recommended impact avoidance, minimization, and mitigation measures. However, some of these impacts would be adverse and significant. Specifically, we conclude that constructing the Project would temporarily but significantly impact short-term housing in Coos County and that constructing and operating the Project would permanently and significantly impact the visual character of Coos Bay. In addition, noise impacts from pile driving at the LNG facility would temporarily, but significantly impact the Coos Bay area. The Project could also have a significant impact on the operations of the Southwest Oregon Regional Airport. Furthermore, constructing and operating the Project is likely to adversely affect 15 federally-listed threatened and endangered species including the marbled murrelet, northern spotted owl, and coho salmon. Additionally, the Project is likely to adversely affect three species proposed for listing. Our conclusions are based wholly or in part on the following factors:

- the Project would be constructed in compliance with all applicable federal laws, regulations, permits, and authorizations;
- the Applicants would implement all best management practices, the measures described in their Erosion Control and Revegetation Plan, Wetland and Waterbody Construction and Mitigation Procedures and Upland Erosion Control, Revegetation, and Maintenance Plans, and other impact avoidance, minimization, and mitigation measures;
- the Applicants' *Compensatory Wetland Mitigation Plan* would satisfy the COE's regulatory requirements to mitigate unavoidable impacts on wetlands and waters of the U.S.;
- the BLM and Forest Service's plan amendments would provide for the crossing of federal lands;
- compliance with the Endangered Species Act would be complete prior to construction;
- a Memorandum of Agreement would be developed with the goal of resolving adverse effects under Section 106 of the National Historic Preservation Act, and compliance with the National Historic Preservation Act would be complete prior to construction;
- the LNG terminal was designed consistent with maximum tsunami run-up elevations and considered tsunami wave heights and inundation elevations;
- the LNG terminal would include protections and safeguards that ensure facility integrity and public safety;

- the Coast Guard issued a Letter of Recommendation indicating the Coos Bay Federal Navigation Channel would be considered suitable for the LNG marine traffic associated with the Project; and
- FERC's environmental and LNG engineering construction inspection programs would ensure compliance with the Applicants' commitments, and the conditions of any FERC Authorization and Certificate.

In addition, we recommend that the Project-specific impact avoidance, minimization, and mitigation measures that we have developed (included in this EIS as recommendations) be attached as conditions to any Authorization and Certificate of Public Convenience and Necessity issued by the Commission for the Project.

1.0 INTRODUCTION

The vertical line in the margin identifies text that is new or modified in the final EIS and differs materially from corresponding text in the draft EIS. Changes were made to address comments from cooperating agencies and other stakeholders on the draft EIS; incorporate modifications to the Project after publication of the draft EIS; update information included in the draft EIS; and incorporate information filed by Jordan Cove Energy Project, L.P. and Pacific Connector Gas Pipeline, LP in response to our recommendations in the draft EIS. As a result of these changes, some of the recommendations identified in the draft EIS are no longer applicable to the Project and do not appear in the final EIS, while some recommendations identified in the draft EIS have been substantively modified in the final EIS, and some new recommendations have been added in the final EIS.

1.1 PROJECT SUMMARY

The staff of the Federal Energy Regulatory Commission (FERC or Commission) prepared this final Environmental Impact Statement (EIS) to describe our assessment of the potential environmental impacts that may occur from constructing and operating the Jordan Cove Liquefied Natural Gas (LNG) Project and Pacific Connector Gas Pipeline Project.

On September 21, 2017 Jordan Cove Energy Project L.P. (Jordan Cove) and Pacific Connector Gas Pipeline, LP (Pacific Connector)[1] filed applications with the FERC pursuant to Sections 3 and 7 of the Natural Gas Act (NGA) to construct and operate an LNG terminal and associated pipeline facilities. A Notice of Application for the Jordan Cove and Pacific Connector Projects[2] was issued by the FERC on October 5, 2017.

In FERC Docket No. CP17-495-000, Jordan Cove seeks an NGA Section 3 Authorization (Authorization) to construct and operate an LNG export terminal in Coos County, Oregon. The terminal would be capable of receiving, processing, and liquefying natural gas[3] into LNG, then storing and loading the LNG onto LNG carriers. The Jordan Cove facilities could receive a

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[1] Collectively, Jordan Cove and Pacific Connector are referred to in this EIS as the "Applicant" or the "Applicants".
[2] Individually, the Jordan Cove proposal may be referred to in this EIS as the Jordan Cove LNG Project, LNG Project, or the Jordan Cove facilities; the Pacific Connector proposal may be referenced similarly, as the Pacific Connector Pipeline Project, Pacific Connector pipeline, or Pipeline Project. Both proposals combined are referred to as the Project.
[3] Natural gas is a fossil fuel, consisting primarily of methane, that is used for a variety of purposes, including electrical generation, home heating and cooking, fuel for motor vehicles, and other industrial/commercial applications. Natural gas is obtained from underground wells and transported from places of production to consumers mainly by way of pipelines. LNG is natural gas that has been cooled to about -260 degrees Fahrenheit (°F). As a liquid, LNG is about 600 times more dense than natural gas in a vapor state and can be stored and transported much more efficiently than the equivalent amount of gas. There are specially designed vessels (referred to as LNG carriers) that can transport LNG overseas from points of origin to customers. Exported LNG can be vaporized at receipt terminals, returned to natural gas, and then transported by pipelines to end-users.

maximum of 1.2 billion cubic feet per day (Bcf/d) of natural gas from the Pacific Connector pipeline and produce a maximum of 7.8 million metric tons per annum of LNG.

In FERC Docket No. CP17-494-000, Pacific Connector seeks a Certificate of Public Convenience and Necessity (Certificate), under NGA Section 7, to construct and operate an approximately 229-mile-long, 36-inch-diameter natural gas transmission pipeline, crossing through Klamath, Jackson, Douglas, and Coos Counties, Oregon.[4] The pipeline would transport about 1.2 Bcf/d of natural gas from interconnections with the existing Ruby Pipeline LLC (Ruby) and Gas Transmission Northwest LLC (GTN) systems[5] near Malin, Oregon to the Jordan Cove terminal.

As specified by the NGA and the Energy Policy Act of 2005 (EPAct), the FERC is responsible for authorizing onshore LNG terminals and natural gas transmission facilities. EPAct also establishes the FERC as the lead federal agency responsible for coordinating applicable federal authorizations and complying with the requirements of the National Environmental Policy Act (NEPA). The FERC's regulations for implementing the elements of the NEPA are at Title 18 Code of Federal Regulations (CFR) Part 380.

Consistent with federal regulations, applicable guidance, and other agreements,[6] the United States (U.S.) Department of the Interior Bureau of Land Management (BLM) Oregon State Office; U.S. Department of Agriculture Forest Service (Forest Service) Pacific Northwest Region; Bureau of Reclamation (Reclamation) Klamath Basin Area Office; U.S. Department of Energy (DOE); U.S. Army Corps of Engineers (COE) Portland District; U.S. Environmental Protection Agency (EPA) Region 10; U.S. Department of the Interior Fish and Wildlife Service (FWS) Oregon Fish and Wildlife Office; U.S. Department of Commerce National Oceanic and Atmospheric Administration's (NOAA) National Marine Fisheries Service (NMFS); U.S. Department of Homeland Security Coast Guard (Coast Guard) Portland (Sector Columbia River); the Coquille Indian Tribe[7]; and the Pipeline and Hazardous Materials Safety Administration (PHMSA) within

[4] Pacific Connector also requested a blanket certificate to allow for future construction, operation, and abandonment activities under Subpart F of Title 18 Code of Federal Regulations (CFR) Part 157 of the Commission's regulations and requested a blanket certificate to provide open-access transportation services under its tariff in accordance with Subpart G of Part 284.

[5] GTN is owned by TransCanada, while Ruby is owned by Pembina.

[6] May 2002 "*Interagency Agreement on Early Coordination of Required Environmental and Historic Preservation Reviews Conducted in Conjunction With the Issuance of Authorizations to Construct and Operate Interstate Natural Gas Pipelines Certificated by the Federal Energy Regulatory Commission*", signed by the FERC, Advisory Council on Historic Preservation, CEQ, EPA, Department of the Army, Department of Agriculture, Department of Commerce, DOE, Department of the Interior, and USDOT. February 2004 "*Interagency Agreement Among the Federal Energy Regulatory Commission, United States Coast Guard, and Research and Special Programs Administration for the Safety and Security Review of Waterfront Import/Export Liquefied Natural Gas Facilities*." June 2005 "*Memorandum of Understanding Between the United States Army Corps of Engineers and the Federal Energy Regulatory Commission Supplementing the Interagency Agreement on Early Coordination of Required Environmental and Historic Preservation Reviews Conducted in Conjunction with the Issuance of Authorizations to Construct and Operate Interstate Natural Gas Pipelines Certificated by the Federal Energy Regulatory Commission*," executed 30 June 2005.

[7] The Project would be located across ancestral territory of the Coquille Indian Tribe (Coquille Tribe). Due to their continued presence in the area, their modern and historic interest throughout their five-county fee-to-trust / service area, their concern for the land, and their special expertise regarding the natural environment, the Coquille Tribe are participating as a cooperating agency. The Coquille Tribe manages over 10,000 acres of land, primarily as sustainable forest; and provides education assistance, health care, elder services, and housing assistance to its members. The Coquille Tribe provided a unique and invaluable perspective to the development of this EIS.

the U.S. Department of Transportation (USDOT) are cooperating agencies in the development of this EIS. Cooperating agencies have jurisdiction by law or special expertise with respect to any environmental impacts involved in a proposal. The responsibilities of cooperating agencies are summarized in 40 CFR 1501.6, the Council of Environmental Quality (CEQ) regulations for implementing the NEPA.

1.1.1 Previous Proposals

Beginning in 2006, Jordan Cove and Pacific Connector sought to import LNG into a terminal at Coos Bay, Oregon, and transport natural gas through a sendout pipeline to interconnections with existing pipeline systems at the Malin hub.[8] The import terminal and associated sendout pipeline applications were authorized by the Commission with conditions; however, due to changes in the natural gas industry, the facilities were never constructed, and the Commission withdrew its previous approval for the Project.[9] Although the facilities required for the import of LNG are different than those required to export LNG, the original terminal location and footprint and the pipeline route are similar to the current Project proposed in Docket Nos. CP17-494-000 and CP17-495-000.

In 2012, Jordan Cove and Pacific Connector sought to export LNG from a terminal at Coos Bay, Oregon, with an associated feeder pipeline proposed to transport natural gas from existing pipeline systems near Malin.[10] In response to those applications, the Commission issued an Order Denying Applications for Certificate and Section 3 Authorization on March 11, 2016 for Docket Nos. CP13-483-000 and CP13-492-000, and upheld its decision in its Order Denying Rehearing issued December 9, 2016. However, because the denial was without prejudice, Jordan Cove and Pacific Connector were able to file new applications in Docket Nos. CP17-494-000 and CP17-495-000.

1.1.2 Proposed Action

The facilities addressed in this EIS and described further in section 2 are the proposed LNG and pipeline facilities identified by Jordan Cove and Pacific Connector in their respective applications, and are summarized as follows:

<u>LNG Project Facilities</u>:

- an access channel from the existing Coos Bay Federal Navigation Channel to the LNG terminal;
- modifications to the marine waterway, including four dredge locations located adjacent to the Federal Navigation Channel;
- a terminal marine slip containing two berths (one Production Loading Berth and one Emergency Lay Berth), and a dock for tug and escort boats, and a material offloading facility (MOF);
- LNG loading platform and transfer line;
- LNG storage system, consisting of two full-containment storage tanks;

[8] The originally proposed Pacific Connector sendout pipeline (in Docket No. CP07-441-000) would have connected with the existing GTN, Pacific Gas and Electric Company, and Tuscarora pipelines near Malin, Oregon. The original Jordan Cove LNG import project was authorized by the Commission in an "Order Granting Authorizations Under Section 3 and Issuing Certificates" issued on December 17, 2009 in Docket No. CP07-444-000.
[9] On April 16, 2012, the Commission issued an "Order Granting Rehearing in Part, Dismissing Request for Stay, and Vacating Certificate and Section 3 Authorizations" in Docket Nos. CP07-441-000 and CP07-444-000.
[10] Like the current Project, the first LNG export and feeder pipeline proposal had the Pacific Connector pipeline connecting with the existing GTN and Ruby pipelines near Malin, Oregon.

- five natural gas liquefaction trains;
- a pipeline gas conditioning facility;
- Southwest Oregon Regional Security Center (SORSC); and Fire Department building; and
- other security and control facilities, administrative buildings, meteorological station, and other support structures associated with the terminal.

Pipeline Project Facilities:

- a 229-mile-long, 36-inch-diameter welded steel underground pipeline, extending between interconnections near Malin in Klamath County and the Jordan Cove LNG terminal in Coos County, Oregon;
- the Klamath Compressor Station, at the eastern end of the pipeline; and
- other associated facilities (e.g., meters stations, mainline block valves, pig launchers, and communication systems).

The general location of LNG terminal and pipeline facilities are depicted in figure 1.1-1 and section 2.

The primary differences between the previously proposed LNG terminal facilities (in Docket No. CP13-483-000) from the currently proposed Project are as follows:

- The South Dunes Power Plant has been eliminated from the current proposal.
- The locations of the workforce housing facility, the SORSC, and the Project related Fire Department have been relocated.
- New staging areas have been added at Oregon International Port of Coos Bay (Port) Laydown and Boxcar Hill sites.
- The Al Pierce Company (APCO) sites (APCO 1 and 2) would be used for some Project related dredge disposal.
- The number of LNG carriers that would visit the terminal has increased to 110 to 120 vessels per year.
- The proposal now includes the excavation of four submerged areas (removing about 700,000 cubic yards of material) lying adjacent to the existing federally-authorized Federal Navigation Channel, and dredge slurry pipelines in Coos Bay; and
- The habitat mitigation areas at West Jordan Cove and West Bridge locations have been eliminated.

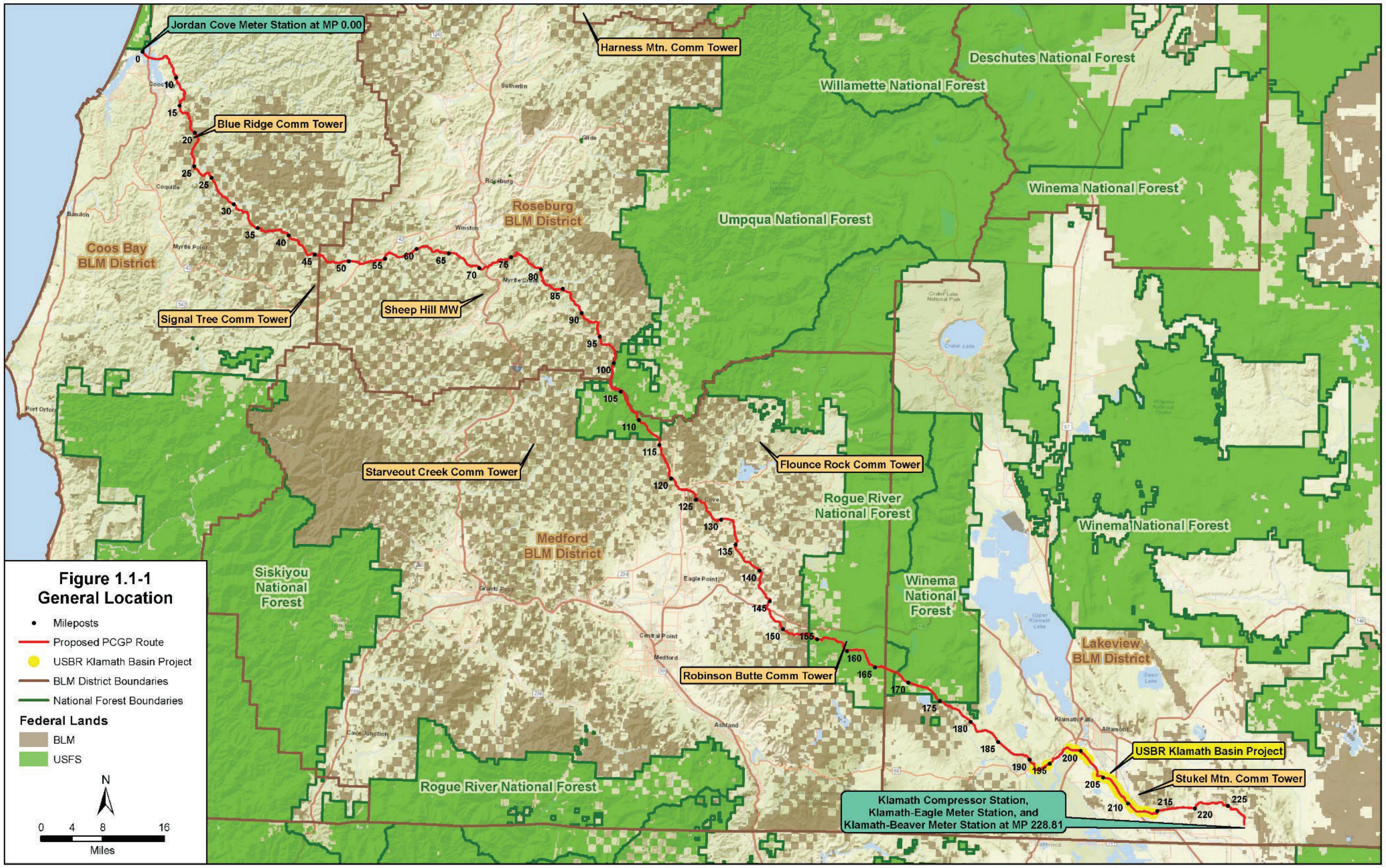
Figure 1.1-1
General Location
Mileposts
Proposed PCGP Route
USBR Klamath Basin Project
BLM District Boundaries
National Forest Boundaries
Federal Lands
BLM
USFS
N
0 4 8 16
Miles
Jordan Cove Meter Station at MP 0.00
Blue Ridge Comm Tower
Signal Tree Comm Tower
Sheep Hill MW
Harness Mtn. Comm Tower
Starveout Creek Comm Tower
Flounce Rock Comm Tower
Robinson Butte Comm Tower
USBR Klamath Basin Project
Stukel Mtn. Comm Tower
Klamath Compressor Station,
Klamath-Eagle Meter Station, and
Klamath-Beaver Meter Station at MP 228.81
Coos Bay
BLM District
Roseburg
BLM District
Medford
BLM District
Lakeview
BLM District
Deschutes National Forest
Willamette National Forest
Winema National Forest
Umpqua National Forest
Rogue River
National Forest
Winema
National
Forest
Siskiyou
National
Forest
Rogue River National Forest

JA511

The primary differences between the previously proposed pipeline Project (Docket No. CP13-492-000) from the currently proposed Project are as follows:

- Multiple horizontal directional drill (HDD) crossings have been newly proposed, including an approximately 5,200-foot-long HDD crossing under Coos Bay from about mileposts (MP) 0.12[11] to 1.11.
- Multiple route modifications have been made based on detailed civil survey, project design enhancements, and landowner or land-management agency input.
- Increased compression at the Klamath Compressor Station from 41,000 horsepower (hp) to 93,300 hp.
- Elimination of the Clark's Branch Meter Station.

1.2 APPLICANTS' PURPOSE AND NEED

The FERC does not plan, design, build, or operate natural gas transmission infrastructure. As an independent regulatory commission, the FERC reviews proposals to construct and operate such facilities. Accordingly, the project proponent is the source for identifying the purpose for developing, constructing, and operating a project.

In its application, Jordan Cove states the purpose of its Project is to export natural gas supplies derived from existing natural gas transmission systems (linked to the Rocky Mountain region and Western Canada) to overseas markets, particularly Asia.[12] According to Jordan Cove, the Project is a market-driven response to increasing natural gas supplies in the U.S. Rocky Mountain and Western Canada production areas, and the growth of international demand, particularly in Asia.

In its application, Pacific Connector states that the purpose of its Project is to connect the existing natural gas transmission systems of GTN and Ruby with the proposed Jordan Cove LNG terminal.

1.3 FEDERAL AGENCY ROLES AND RESPONSIBILITIES

The NEPA requires all federal agencies to consider the environmental consequences of federal actions or undertakings. The Commission's environmental staff, in partnership with the aforementioned cooperating agencies, has prepared this EIS to comply with the requirements of the NEPA. This EIS discloses and assesses the potential environmental effects that are likely to result from the construction and operation of the Project. In addition to complying with the NEPA, our purposes for preparing this EIS include:

- identify and assess potential impacts on the human environment that would result from the implementation of the proposed action;
- identify and assess reasonable alternatives to the proposed action that would avoid or reduce adverse impacts on the human environment;

[11] Notice that the MPs for the Pacific Connector pipeline in Docket No. CP17-494-000 are reversed from the actual direction of natural gas. Although the natural gas would flow east (from Malin) to west (to Coos Bay) in the current Project, the MPs are numbered from west (0.0. at the Jordan Cove Meter Station) to east (MP 228.8 at the Klamath Compressor Station).

[12] Note that the Commission will consider as part of its decision whether or not to authorize natural gas facilities, all factors bearing on the public interest, including the project's purpose and need. Additional information regarding the Commission's process and considerations in regard to the project's purpose and need are provided in section 1.3.1.

As the lead federal agency for the Project, the FERC has taken on the lead role for consultation under these statutes for itself and in collaboration with the cooperating agencies. The BLM will make its determinations in accordance with the FLPMA, NFMA, and Mineral Leasing Act (MLA), as it relates to the Pacific Connector's Right-of-Way Grant application to cross federal lands, with concurrence necessary from the Forest Service and Reclamation (see section 1.3). Some federal permits or approvals, such as Section 401 of the CWA, the CAA, and the CZMA, have been delegated to state agencies, as discussed below.

In accordance with Section 313(d) of the EPAct, the FERC is required to keep a complete consolidated record of all actions or decisions made by agencies undertaking federal authorizations. On October 19, 2006, in Order No. 687, the FERC issued implementing regulations regarding the maintenance of a consolidated record.

Table 1.5.1-1 lists the major federal, state, and local permits, approvals, and consultations identified for the Project.

TABLE 1.5.1-1

Major Permits, Approvals, and Consultations for the Jordan Cove and Pacific Connector Project

Agency	Authority/Regulation/ Permit	Agency Action	Initiation of Consultations and Permit Status
FEDERAL			
Federal Energy Regulatory Commission (FERC)	Sections 3 and 7 of the National Gas Act (NGA)	Order Granting Section 3 Authorization and Issuing Certificate of Public Convenience and Necessity.	Jordan Cove and Pacific Connector filed applications with the FERC on September 21, 2017.
	Section 311 of the EPAct		In September 2017, Pacific Connector filed an application with the FERC under Section 7 of the NGA. The FERC's decision is pending.
USDA Forest Service (Forest Service)	Mineral Leasing Act (MLA)	Concur with Right-of-Way (ROW) Grant.	Pending. The Forest Service letter on concurrence of the ROW grant is pending until after preparation of a Record of Decision (ROD).
	36 CFR 219 Subpart B 36 CFR 218 Subpart A and B	Amend Land and Resource Management Plans (LRMP).	Pending. The Forest Service proposed decision(s) on plan level amendments of LRMPs are subject to Administrative Review Regulations at 36 CFR 219 Subpart B. Decisions by the Forest Service to approve project-specific plan amendments are subject to the Administrative Review Process of 36 CFR 218 Subpart A and B. A final decision will follow consideration and resolution of any administrative reviews.

TABLE 1.5.1-1 (continued)

Major Permits, Approvals, and Consultations for the Jordan Cove and Pacific Connector Project

Agency	Authority/Regulation/ Permit	Agency Action	Initiation of Consultations and Permit Status
Bureau of Land Management (BLM)	Section 28 of MLA	Issue ROW Grant for crossing federal lands.	Pending. The BLM decision on the ROW Grant will follow BLM and Forest Service decisions on LRMP amendments and receipt of Letters of Concurrence from the Forest Service and Reclamation.
	Federal Land Policy and Management Act of 1976, as amended, Section 202	Resource Management Plan (RMP) Amendments.	Pending. BLM's proposed decision(s) on amendments of RMPs are subject to Protest following completion of the final EIS. A final decision will follow consideration and resolution of any Protests.
	Federal Land Policy and Management Act of 1976, as amended, Section 501	Issue a ROW Grant for the proposed wastewater line near the Jordan Cove LNG facility.	Anticipated. An application for ROW related to the wastewater line has not been submitted by the Applicant to the BLM.
Bureau of Reclamation	MLA	Concur with issuance of the ROW Grant	Pending.
U.S. Department of Energy (DOE)	Section 3 of the NGA	Long-Term authority to export LNG to Free Trade Agreement (FTA) Nations	FTA authorization granted December 7, 2011 (DOE/FE Order No. 3041). DOE authorized amendment to FTA authorization on July 20, 2018 (DOE/FE Order No. 3041-A).
	Section 3 of the NGA	Long-Term conditional authority to export LNG to Non-FTA Nations.	Conditional non-FTA authorization issued on March 24, 2014; subject to satisfactory completion of the NEPA review and related conditions. DOE is currently reviewing the amendment request with respect to the non-FTA application.
U.S. Army Corps of Engineers (COE)	Section 10 and 408 of the Rivers and Harbors Act (RHA)	Process permit applications for structures or work in or affecting navigable waters of the United States. Approval of requests to alter COE civil works projects.	Pending. The Applicants requested COE initiate the project's review per the RHA and have submitted both regulatory and Section 408 applications to the COE. The Applicants are continuing to work with the COE to provide supplemental information regarding the RHA review.
	Section 404 of the Clean Water Act (CWA)	Process permit application for the discharge of dredged or fill material into waters of the United States.	Pending. The Applicants requested the COE initiate the Project's review per the CWA and have submitted a regulatory application to the COE. The Applicants are continuing to work with the COE to provide supplemental information regarding the CWA review.
U.S. Environmental Protection Agency (EPA)	Section 404 of the CWA	Co-administers CWA 404 program with the COE. EPA retains veto authority for wetland permits issued by the COE.	Pending.

TABLE 1.5.1-1 (continued)

Major Permits, Approvals, and Consultations for the Jordan Cove and Pacific Connector Project

Agency	Authority/Regulation/ Permit	Agency Action	Initiation of Consultations and Permit Status
	Section 309 of the CAA	Reviews and evaluates EIS for adequacy in meeting the procedural and public disclosure requirements of the NEPA.	Pending.
U.S. Fish and Wildlife Service (FWS)	Section 7 of the ESA	Provide a BO if the Project is likely to adversely affect federally listed threatened or endangered aquatic species or their habitat.	Pending. The FERC has prepared a biological assessment (BA) that was submitted to the FWS and NMFS. The FWS has notified the FERC that formal consultation under section 7 of the ESA has been formally initiated for the Project based on the BA.
	Fish and Wildlife Coordination Act of 1934 (FWCA)	Provide comments to prevent loss of and damage to wildlife resources.	Pending. FWS generally addresses FWCA issues via comments on the FERC NEPA and COE 404 permit processes.
	MBTA Executive Order 13186	Consultation regarding compliance with the MBTA.	Pending. The Applicants are currently consulting with the FWS regarding the projects requirements under the MBTA.
	Eagle Act	Coordination regarding compliance with the Eagle Act	Pending. The Applicants will consult with the FWS regarding the project's requirements under the Eagle Act. Jordan Cove and Pacific Connector would apply for an Eagle Act permit if needed.
National Marine Fisheries Service (NMFS)	Section 7 of the ESA	Provide a BO if the Project is likely to adversely affect federally listed threatened or endangered aquatic species or their habitat.	Pending. The FERC has prepared a BA that was submitted to the NMFS. The NMFS has notified the FERC that formal consultation under section 7 of the ESA has been formally initiated for the Project based on the BA.
	MMPA	Authorize, upon request, take of marine mammals incidental to otherwise lawful activities, subject to mitigation monitoring and reporting requirements.	Pending. The Applicants have filed an Incidental Take Authorization with the NMFS. The NMFS review is pending.
	MSA	Provide conservation recommendations if the Project would adversely impact EFH.	EFH was addressed in the FERC BA.
U.S. Coast Guard	Ports and Waterway Safety Act	Captain of the Port (COTP) issues a Letter of Recommendation (LOR) recommending the suitability of the waterway for LNG marine traffic.	Jordan Cove submitted LOI on January 9, 2017. Coast Guard issued LOR on May 10, 2018.
		Review Emergency Manual.	Pending. Must be completed prior to receiving first LNG carrier.
		Review Operations Manual.	Pending. Must be completed prior to receiving first LNG carrier.
		Establish safety and security zones for LNG vessels in transit and while docked.	Pending.

TABLE 1.5.1-1 (continued)

Major Permits, Approvals, and Consultations for the Jordan Cove and Pacific Connector Project

Agency	Authority/Regulation/ Permit	Agency Action	Initiation of Consultations and Permit Status
	Maritime Transportation Security Act	Review and Approve Facility Security Plan.	Pending. Must be completed 60 days prior to receiving first LNG carrier at the facility
	Navigation and Vessel Inspection Circular – Guidance related to Waterfront LNG Facilities	Develop LNG Vessel Transit Management Plan.	Pending. Must be completed prior to receiving first LNG carrier.
		Validate WSA and produce LOR and LOR Analysis.	Issued LOR and LOR Analysis on May 10, 2018.
U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (USDOT PHMSA)	Natural Gas Pipeline Safety Act	Administer national regulatory program to ensure the safe transportation of natural gas and issue LOD on the project's compliance with the siting requirements of 49 CFR 193.	Applicants met with PHMSA in November 2017 to review their technical design package. The USDOT PHMSA submitted the LOD to the FERC on September 11, 2019, which found that the proposed siting of the Project complies with the Federal Pipeline Safety Standards set forth in 49 CFR 193.
U.S. Department of Defense (DOD)	Section 311(f) of the EPAct and Section 3 of the NGA Memorandum of Understanding (MOU) between the FERC and DOD	Consult with the Secretary of Defense to determine whether an LNG facility would affect the training or activities of an active military installation.	In November 2012, the DOD indicated that the previously proposed project would have minimal impacts on military operations in the area. In December 2017, the DOD indicated that because it had previously reviewed the last proposal, it has "no issues" concerning the current Project.
DOE, Bonneville Power Administration (BPA)	Land Use Agreement for electric transmission line crossings	Permit review.	Pending.
USDOT, Federal Aviation Administration (FAA)	18 CFR Subchapter E Federal Aviation Regulations (FAR) Part 77 IAW FAA Order 7400.2G, 6-1-6	Aeronautical Study of Objects Affecting Navigable Airspace. Feasibility Study for Hazard Determination.	Pending. The FAA has issued a Notice of Presumed Hazard. Jordan Cove is currently consulting with the FAA to address potential impacts on airport operations.
Advisory Council on Historic Preservation (ACHP)	Section 106 of the NHPA	Opportunity to comment on the undertaking.	Pending.
Federal Communication Commission	License for fixed microwave stations and service	Review proposals for new or additions to existing communication towers.	Pending.
U.S. Department of Agriculture (USDA), Natural Resources Conservation Service (NRCS)	Farmland Protection Policy Act	Determine if the Project would result in the permanent conversion of prime farmland.	Pending.
STATE – OREGON			
Oregon Department of Geology and Mineral Industries (DOGAMI) – Mineral Land Regulation and Reclamation (MLRR)	Building Code Section 1802.1 Oregon Revised Statute (ORS) 455.446	Required to consult with DOGAMI for assistance in determining the impact of tsunamis on the proposed development, and for assistance in developing mitigation.	Pending.

TABLE 1.5.1-1 (continued)

Major Permits, Approvals, and Consultations for the Jordan Cove and Pacific Connector Project

Agency	Authority/Regulation/ Permit	Agency Action	Initiation of Consultations and Permit Status
Oregon Department of Agriculture (ODA)	Oregon Endangered Species Act Oregon Senate Bill 533 and ORS 564	Consult on Oregon listed plant species, and ODA would review botanical survey reports covering non-federal public lands prior to ground-disturbing activities where state listed botanical species are likely to occur.	Pending.
Oregon Department of Consumer and Business Services – Building Code Division	ORS 455.446	Site-specific exemption approval under the state building code,	Pending.
Oregon Department of Energy (ODE)	State Authorities under Section 311 of the EPAct	Furnish an advisory report on state safety and security issues to the FERC regarding the Jordan Cove LNG terminal proposal and conduct operational safety inspections if the facility is approved and built. ODE requires all applicants to enter into an MOU to meet state established minimum standards for LNG safety, security, and emergency preparedness.	Pending.
Oregon Department of Environmental Quality (ODEQ)	Water Quality Certification Section 401 of the CWA	Issue a license or permit to achieve compliance with state water quality standards.	Applicant submitted their CWA Section 401 application package to the ODEQ on April 6, 2018. On September 25, 2018, the Applicant requested that the 401 application be withdrawn and resubmitted to allow ODEQ additional time to consider the request. On May 5, 2019, the ODEQ denied the application without prejudice.
	Section 402 of CWA	Issue National Pollutant Discharge Elimination System (NPDES) permits for discharge of stormwater.	NPDES permit for storm water (e.g., effluent discharge to the ocean outfall) issued in July 2015 and expires in June 2020.
	Ballast Water Management	Review liabilities and offences connected to shipping and navigation.	Pending.
	CAA – Title V	Issue Title V Air Quality Operating permit. Issue Enforce Greenhouse Gas (GHG) Reporting Requirements.	Permit application to be filed by Pacific Connector one year after beginning operations of the Klamath Compressor Station.
	Air Contaminant Discharge Permit CAA	Review air quality analyses to ensure compliance with all applicable Ambient Air Quality Standards.	Pending.
	Hazardous Waste Activity ORS 466 Oregon Administrative Rule (OAR) 340-102	Review plans for storage and management of hazardous waste	Pending.
	Oregon's Water Quality Pollution Control Facility (WPCF) Permit	A permit required for wastewater discharges to land during construction.	Pending

TABLE 1.5.1-1 (continued)

Major Permits, Approvals, and Consultations for the Jordan Cove and Pacific Connector Project

Agency	Authority/Regulation/ Permit	Agency Action	Initiation of Consultations and Permit Status
Oregon Department of Fish and Wildlife (ODFW)	FWCA and the Oregon Endangered Species Act under ORS 496, 506, and 509 OAR 635	Consult on sensitive species and habitats that may be affected by the Project and, in general, regarding conservation of fish and wildlife resources (including state listed species).	Pending.
	Fish and Wildlife OAR 345-22 & 60	Consult on and approve fish and wildlife mitigation plan.	Pending.
	Oregon Fish Passage Law ORS 509.-585 OAR 635-412-5 to 40	Review stream crossing plans for consistency with Oregon Fish Passage Law and screening criteria.	Pending.
	In-Water Blasting ORS 509-140, et al. OAR 635-425 to 50	Consider issuance of in-water blasting permits.	Pending.
Oregon Department of Forestry (ODF)	Easement on State lands Oregon Forest Practices Act OAR 629 ORS 477 ORS 527	Management of State Forest lands for Greatest Permanent Value, develops Forest Management Plans, stewardship under State's Land Management Classification System, monitors harvests of timber on private lands, and protects non-federal public and private lands from wildfires.	Pending.
Oregon Department of Land Conservation and Development (ODLCD)	CZMA 15 CFR Part 930 ORS 196.435	Determine consistency with CZMA program policies.	Pending. A joint CZMA Certifications and Necessary Data and Information application was submitted to ODLCD on April 12, 2019. The ODLCD consistency review is scheduled to be finalized on February 17, 2020.
Oregon Department of Transportation (ODOT)	Section 303(c) DOT Act 49 CFR 303 OAR 734-030(4) OAR 734-051-4020	Review and approve traffic management plans	Pending. A draft traffic impact analysis was provided to ODOT, Coos County, and City of North Bend on December 4, 2017 by the Applicant. ODOT and North Bend provided comments on December 21, 2017. The Applicant continue to work with ODOT.
	State Highway ROW ORS 374-305 OAR 734- 55	Permits to be issued from each ODOT District Office to allow construction within State Highway ROW and use of State Highways for Project access, and where utilities would cross over, under, or run parallel to ODOT ROWs.	Pending. Applications for ODOT Approach and Utility Permits to be submitted with enough advance notice (which could be up to 12 months or more depending on individual District requirements) prior to construction activities to ensure adequate time to review the specific proposals.
Oregon Department of State Lands (ODSL)	Submerged and Submersible Land Easement OAR 141-122	Grant submerged land easements.	Pending.
	Lease and Registrations OAR 141-082	Issue wharf registrations	Pending.

TABLE 1.5.1-1 (continued)

Major Permits, Approvals, and Consultations for the Jordan Cove and Pacific Connector Project

Agency	**Authority/Regulation/ Permit**	**Agency Action**	**Initiation of Consultations and Permit Status**
	Sand and Gravel Lease/License OAR 141-014	Issue licenses or leases for removal of state-owned materials.	Pending.
	Joint Removal-Fill Law ORS 196-795-990 OAR 141-85	Approve removal or fill of material in waters of the state.	Pending.
	Special Use Permits OSAR 141-125	Allow work within state-owned lands	Pending.
	Compensatory Wetland Mitigation Rules OAR 141-85-121	Review and approve wetland mitigation plans.	Pending.
Oregon Water Resources Department (OWRD)	New Water Rights ORS 537 OAR 690-310	Issue permits to appropriate surface water and groundwater.	Pending.
	Temporary Water Use ORS 537 OAR 690-340	Issue limited licenses for temporary use of surface waters.	Pending.
Oregon Public Utilities Commission (OPUC)	OAR 860-031	Authorize intrastate electric transmission lines. Inspect the natural gas facilities for safety.	Pending Pacific Connector's submittal of appropriate applications to OPUC.
State Historic Preservation Office (SHPO)	Section 106 of the NHPA 36 CFR 800 ORS 338-920	Review cultural resources reports and comments on recommendations for National Register of Historic Places eligibility and project effects. Issue permits for excavation of archaeological sites on non-federal lands.	Pending. SHPO wrote a letter to the FERC on June 21, 2017 offering to assist FERC with the development of the definition of the area of potential effect (APE) for the projects. (FERC directs Applicant to work with SHPO in developing the appropriate APE and for determining eligibility for listing on the National Register of Historic Places [NRHP].) SHPO sent subsequent letters on January 18 and September 24, 2018, commenting on reports submitted by the Applicant. SHPO sent another letter on July 19, 2019 to the FERC indicating their office has determined the Traditional Cultural Property (TCP) *Q'alya ta Kukwis shichdii me* eligible for listing on the NRHP.

TABLE 1.5.1-1 (continued)

Major Permits, Approvals, and Consultations for the Jordan Cove and Pacific Connector Project

Agency	Authority/Regulation/ Permit	Agency Action	Initiation of Consultations and Permit Status
LOCAL – COUNTIES and CITIES			
Various County Permits	Coos County Zoning and Land Development Ordinance, Coos County Comprehensive Plan, and Coos Bay Estuary Management Plan (CBEMP) Douglas County Comprehensive Plan and Douglas County Land Use and Development Ordinance Jackson County Comprehensive Plan and Jackson County Land Development Ordinance Jackson County Comprehensive Plan and Jackson County Land Development Ordinance Klamath County Land Development Code Various Road Crossing; Grading; and Solid Waste Disposal North Bend Comprehensive Plan North Bend City Code	Issue Conditional Use Permits. Zoning Changes and Verifications. Issue Land Use Compatibility Statement under Statewide Planning Goals.	Pending.

1.5.1.1 Endangered Species Act

Section 7 of the ESA, as amended, states that "Federal agencies shall, in consultation with and with the assistance of the Secretary, utilize their authorities in furtherance of the purposes of this Act by carrying out programs for the conservation of endangered species and threatened species listed pursuant to Section 4 of this Act," and any project authorized, funded, or conducted by a federal agency should not "jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of habitat of such species which is determined...to be critical". The lead federal agency, or the Applicant as a non-federal party, is required to consult with the FWS and the NMFS to determine whether any federally listed or proposed endangered or threatened species or their designated critical habitat occur in the vicinity of the Project. If, upon review of existing data, or data provided by the Applicant, one (or both) of the Services find that any federally listed species or critical habitats may be affected by the Project, the FERC is required to prepare a biological assessment (BA) to identify the nature and extent of adverse effects, and to recommend measures that would avoid, reduce, or mitigate effects on habitats and/or species. The FERC's request for consultation with the BA begins the consultation process. The consultation process concludes with the issuance of a biological

2.0 DESCRIPTION OF THE PROPOSED ACTION

As described herein, Jordan Cove proposes to construct and operate an LNG production, storage, and export facility in Coos County, Oregon. Pacific Connector proposes to construct and operate a natural gas transmission pipeline and associated facilities in Coos, Douglas, Jackson, and Klamath Counties, Oregon. The proposed action also includes amendments to BLM and Forest Service LMPs. In addition to the proposed action and amendments, this section also describes impact mitigation projects.

2.1 PROJECT OPERATIONAL COMPONENTS

2.1.1 Jordan Cove LNG Project

The Jordan Cove LNG export terminal would be located on the bay side of the North Spit of Coos Bay, Oregon. The general location of the terminal and associated temporary construction work areas including marine facilities and mitigation sites is shown on figure 2.1-1. The primary components of the LNG terminal include five liquefaction trains[23], two full-containment LNG storage tanks, vessel loading facilities, a vessel slip, and a marine access channel. The terminal site would also include a connection to the Pacific Connector pipeline and a gas conditioning facility. Jordan Cove is proposing five mitigation sites (i.e., the Kentuck Slough Wetland Mitigation project [Kentuck project]; the Eelgrass Mitigation site; and the Lagoon, Panhandle, and North Bank upland wildlife habitat mitigation sites). As shown on figure 2.1-2, portions of the terminal site are referred to as Ingram Yard which would contain the main terminal facilities; South Dunes, which would contain the SORSC, administration building, and temporary workforce housing and laydown areas; and an access and utility corridor between the Ingram Yard and South Dunes. Components that make up the proposed LNG terminal are described below, and the location of specific components are shown on figure 2.1-3.

The proposed LNG terminal site is within a potential tsunami inundation zone, and Jordan Cove has incorporated measures into the proposed facility design to account for potential tsunami inundation. Measures include elevating some site components and protecting some site components with berms or wall. Details are discussed as appropriate within this EIS.

2.1.1.1 Gas Conditioning

Natural gas would require conditioning prior to liquefaction to remove components that could freeze out and clog the liquefaction equipment or would otherwise be incompatible with the liquefaction process such as mercury, hydrogen sulfide, carbon dioxide (CO_2), water, and heavy hydrocarbons that would freeze during the liquefaction process. Heavy hydrocarbons removed would be blended into the fuel gas stream, so no on-site storage or disposal would be required.

[23] A liquefaction train consists of all components of the liquefaction process arranged in a linear relationship.

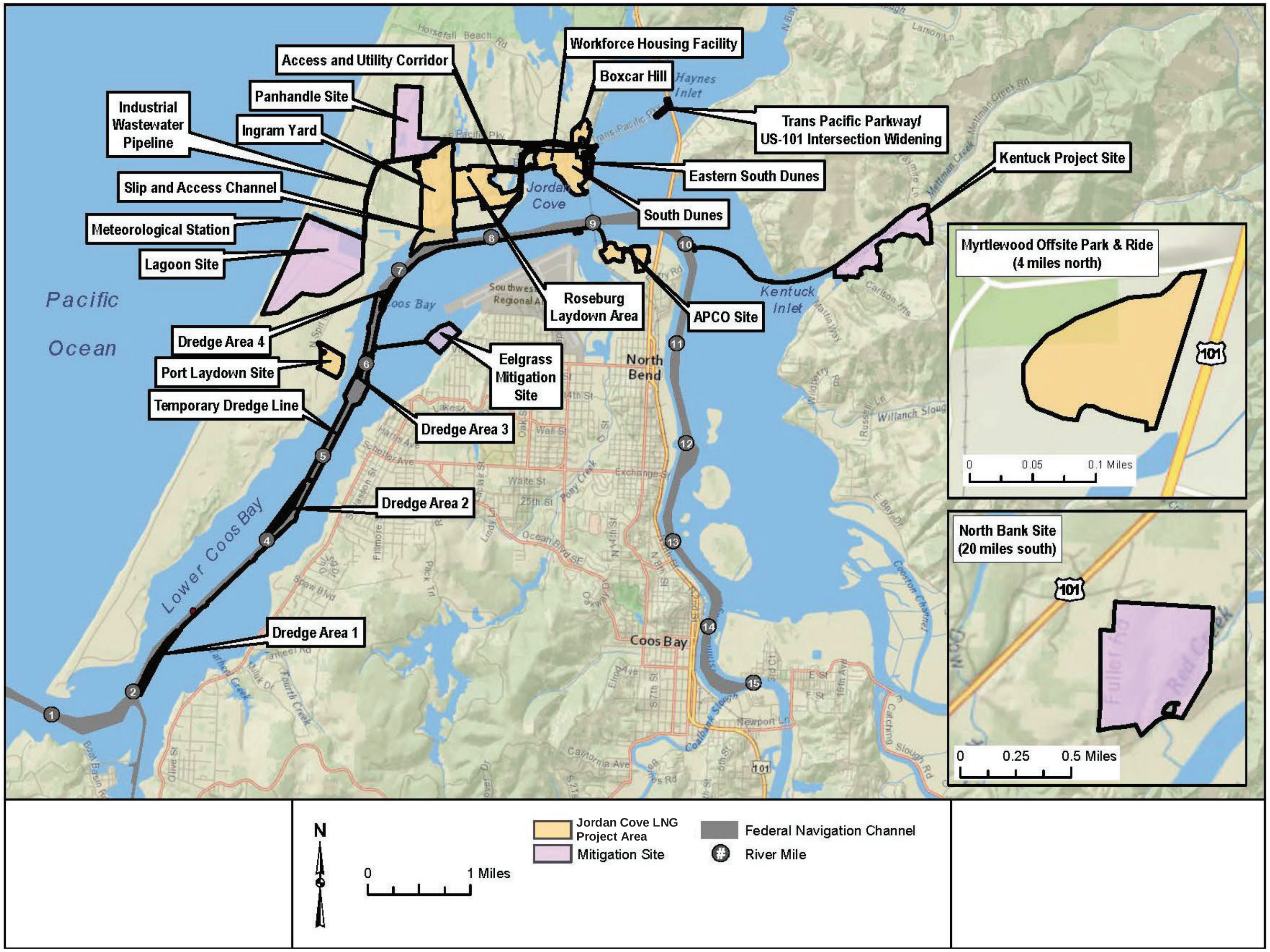

Figure 2.1-1
Jordan Cove LNG Project General Location

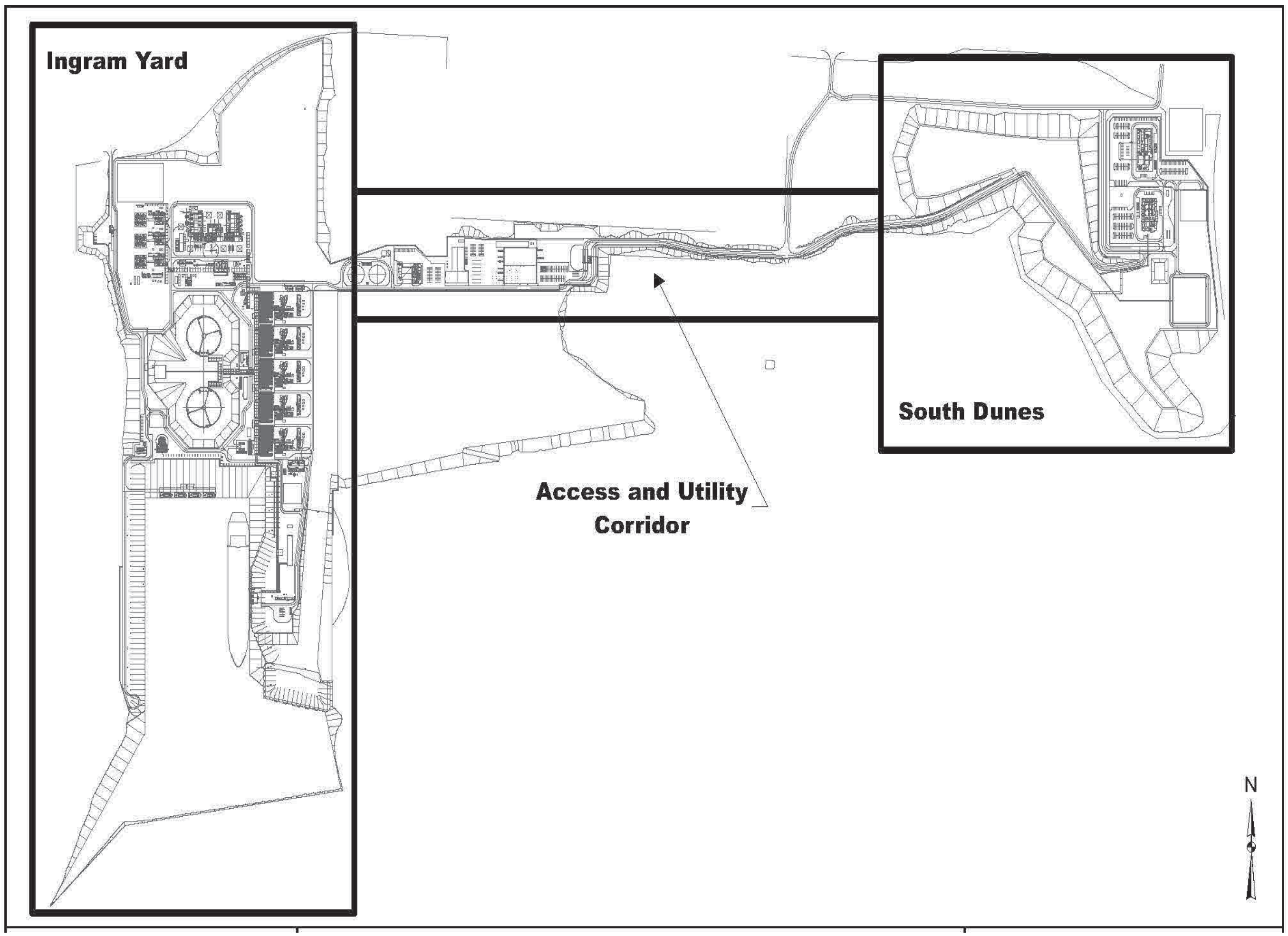

Figure 2.1-2
LNG Terminal Facilities

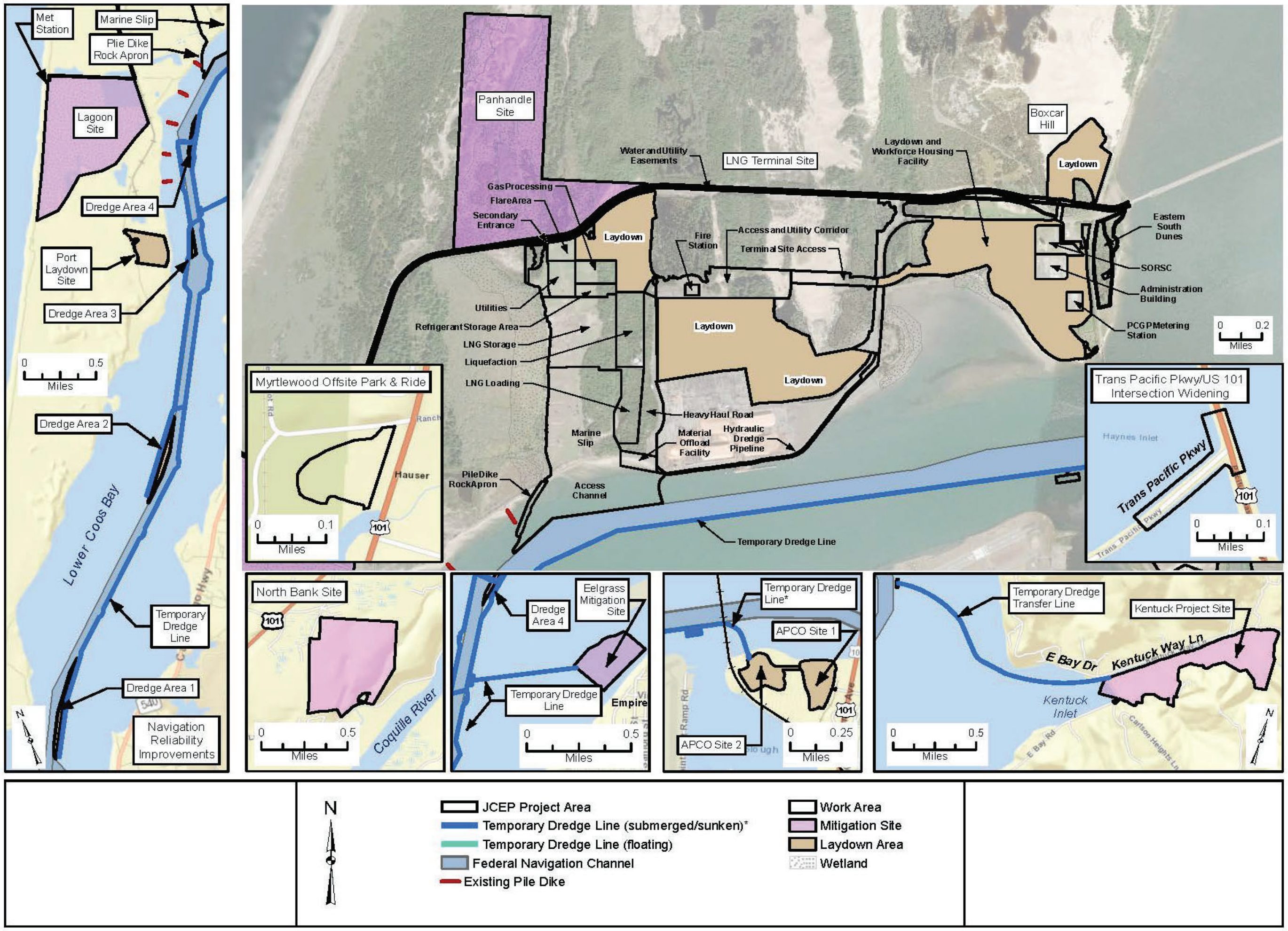

Figure 2.1-3
Jordan Cove LNG Project Detail

Electrical Systems

Operating the LNG terminal would require approximately 39.2 megawatts (MW) (holding mode) and 49.5 MW (loading mode) of electricity. Electrical power would be generated by three on-site steam turbine generators capable of generating a total maximum of 24.4 MW; and brought to the site from a connection with the local power grid (15 to 26 MW). Also, an auxiliary boiler would be used to generate steam to power the generators when gas turbines are not in operation.

Imported electric power would be provided to the LNG terminal via an underground 12.47-kilovolt connection point at the northeast corner of the South Dunes site. The 12.47-kilovolt feeder would be routed underground from the connection point through the South Dunes site and along the access and utility corridor. The approximate length of the underground cable would be 10,500 feet, located entirely within the LNG terminal property.

The "black start power supply"[25] for the steam turbine generators would be provided through the grid (as described above); however, Jordan Cove has indicated that they may consider installing one standby diesel generator to provide redundant black start power supply as well. There would be two standby diesel generators for the SORSC.

Lighting System

Twenty-four-hour facility lighting would be required for security and personnel safety during operation of the LNG terminal. A final lighting plan, including lighting of the LNG storage tanks, would be developed during detailed LNG terminal design; however, Jordan Cove states that only lighting required for operation and maintenance, safety, security, and meeting FAA requirements would be used on the LNG storage tanks.

Water Systems

Jordan Cove would design and construct a stormwater management system to gather runoff from impervious surfaces within the terminal and direct the flow to designated areas for disposal. Stormwater collected in areas that are potentially contaminated with oil or grease would be pumped or would flow to oily water collection sumps before discharging to the industrial wastewater pipeline (IWWP). No untreated stormwater would be allowed to enter federal or state waters.

Sanitary waste would either be directed to a holding tank and disposed of by a sanitary waste contractor as necessary or would be treated by a packaged treatment system and directed to an existing IWWP.

During construction of the Jordan Cove LNG Project, an existing IWWP would be abandoned, replaced, and relocated. The new replacement pipeline would consist of 16-inch-diameter slip joint polyvinyl chloride (PVC). It would run for about two miles from the South Dunes portion of the site along the shoulder of the Trans-Pacific Parkway within an easement owned by the Port to connect with the existing outfall pipe west of the Weyerhaeuser lagoon on the North Spit (see figure 2.1-5).

[25] A black start is the process of restoring electric power station without relying on the external electric power transmission network.

Dredging for the Marine Waterway Modifications

Approximately 590,000 cy of material would be excavated/dredged to complete the marine waterway modifications. Storage of the dredge material would be distributed between the APCO 1 and APCO 2 upland disposal sites (see figure 2.1-1), or placed entirely at APCO Site 2 if shown to be feasible.

Operational Maintenance Dredging

Jordan Cove proposes to conduct maintenance dredging about every 3 years with about 115,000 cy of material removed per dredging interval for the first 10 years of operation, and after that maintenance dredging could be done about every 5 years with up to 160,000 cy of materials removed during each dredging event.[30] For the marine waterway modification projects within the channel, maintenance dredging would also be conducted about every 3 years with about 27,900 cy of materials removed during each dredging event. Jordan Cove proposes to distribute maintenance dredge material between the upland APCO Sites 1 and 2 (see figure 2.1-3). Jordan Cove may be required to acquire a new permit from the COE if future dredge materials could not be distributed at the upland APCO Sites 1 and 2, due to unforeseen future conditions.

2.1.1.9 Applicant Proposed Mitigation Areas

This section describes mitigation actions proposed by Jordan Cove and Pacific Connector to address established mitigation policies and programs at the federal and state level. Jordan Cove and Pacific Connector have identified several areas that would be affected by the measures they have proposed to mitigate Project-related impacts. These mitigation measures are addressed in subsequent analyses, as appropriate.

Jordan Cove developed two wetland/aquatic vegetation mitigation sites per the requirements of section 401 and 404 of the CWA.

- Jordan Cove and Pacific Connector propose to mitigate the loss of wetlands (including estuarine areas) through the Kentuck project (i.e., wetland impacts include permanent and temporary impacts and loss of aquatic resource types, functions and values; see section 4.3). The Kentuck project includes about 140 acres on the eastern shore of Coos Bay at the mouth of Kentuck Slough (see figures 2.1-1 and 2.1-3). Formerly, this property was the Kentuck Golf Course, but it is currently owned by Jordan Cove. On August 30, 2016, the Coos County Board of County Commissioners granted Jordan Cove's request for a conditional use permit to allow for mitigation and restoration within this property.
- Jordan Cove proposes to mitigate for the loss of aquatic vegetation via an eelgrass restoration program in Coos Bay, near the Southwest Oregon Regional Airport in North Bend, including establishing new eelgrass beds (see figures 2.1-1 and 2.1-3). Additional information about wetland impacts and mitigation is presented in section 4.3.3.

Jordan Cove developed three upland mitigation sites per recommendations from the ODFW in response to the mitigation policy set forth in OAR 635-415-0000 through 0025. The proposed

[30] Proposed maintenance dredge frequency and volume is based on a sedimentation study conducted by Jordan Cove and summarized in Jordan Cove's *Dredged Material Management Plan* filed as Appendix N.7 in Resource Report 7 as part of its September 2017 application to FERC.

of-way or existing Pacific Power right-of-way or fenced facilities. Water would be provided from water wells located on property owned by Pacific Connector, immediately adjacent to the compressor station. Telecommunications would be provided by Cal-Ore, which would require a short tie-in from the existing service available immediately adjacent to the compressor station.

For the Jordan Cove Meter Station, Pacific Power would supply electricity through a connection to an existing powerline located adjacent to the Trans Pacific Lane southwest of Ingram Yard. Telecommunications would be supplied from three existing networks, ORCA Communications, LS Networks, and Frontier Communications, through extensions of fiber optic and cable that would be installed to the SORSC proposed by Jordan Cove.

Pacific Connector has located its automated MLV facilities near available electrical power facilities such that only short tie-ins would be required. If it were to become necessary, in lieu of purchased power, thermal power generation equipment would be installed to provide electricity for the minimal power requirement at these sites.

2.3 LAND REQUIREMENTS

2.3.1 Jordan Cove LNG Terminal Facilities

The LNG Project would require the use of about 1,355 acres of land. When complete, the Jordan Cove LNG terminal would occupy about 203 acres. Jordan Cove owns about 295 acres at the terminal site and would acquire the use of the remaining area (e.g., via easements or lease). Table 2.3.1-1 lists the land requirements for the Jordan Cove LNG terminal facilities.

TABLE 2.3.1-1

Land Requirements for the Jordan Cove LNG Project a/

Facilities	Acres Required During Construction b/	Acres Required During Operation b/
Jurisdictional Facilities		
Total for Jurisdictional Facilities	202.6	197.1
Non-Jurisdictional Facilities		
Southwest Oregon Regional Safety Center	5.4	5.4
Fire Department	0.8	0.8
Total for Non-Jurisdictional Facilities	**6.2**	**6.2**
Temporary Construction Areas		
Total for Temporary Construction Areas	**368.1**	**0**
Mitigation Sites		
Eelgrass Mitigation Area and Dredge Line	33.4	0
Kentuck Project and Dredge Line	135.6	0
Panhandle Site	132.6	0
Lagoon Site	320.3	0
North Bank Site	156.1	0
Total for Mitigation Sites	**778.0**	**0.0**
GRAND TOTAL	**1,355.1**	**203.3**

a/ This table lists the acres of land that would be encompassed by Project components or mitigation areas, but may not directly relate to areas that would experience direct effects (e.g., the entire footprint of each of the mitigation areas may not experience direct effects such as clearing, but are included in this table to disclose the scope of the projects footprint). See section 4 for the acres of land and resources that would be affected by the Project.
b/ Columns may not sum correctly due to rounding.

2.3.2 Pacific Connector Pipeline and Associated Aboveground Facilities

Constructing and operating the Pacific Connector pipeline would require the use of about 4,937 acres and 1,404 acres of land, respectively. Table 2.3.2-1 lists the land requirements for the Pacific Connector Pipeline Project.

TABLE 2.3.2-1

Land Requirements for the Pacific Connector Pipeline Project a/

Project Component	Land Required During Construction (acres) b/	Land Required During Operation (acres) b/
Pipeline ROW	2,585.5	1,375.8 c/
Temporary Extra Work Areas	925.8	0
Uncleared Storage Areas	671.2	0
Rock Source & Disposal Sites d/	41.2 d/	0
Contractor and Pipe Storage Yards	661.3	0
Access Roads (PARs, TARs, & Road Improvements)	28.8 e/	2.6
Aboveground Facilities	23.0 f/	25.4 g/
Totals	**4,936.8**	**1,403.8**

a/ This table lists the acres of land that would be encompassed by Project components or designations (e.g., permanent easements), but may not directly relate to areas that would experience direct effects (e.g., the entire permanent easement would not be cleared during operation). See section 4 for the acres of land and resources that would be affected by the Project.
b/ Columns may not sum correctly due to rounding.
c/ 50-foot-wide permanent pipeline easement (on federal lands, 30-year maintenance corridor).
d/ Includes rock source and disposal sites that would remain disturbed following construction but would not be used during operation of the Project and therefore are not included in the operational total.
e/ Road improvements would remain following construction, but these roads would not be used for operation of the Project and therefore are not included in the operational total.
f/ Construction impacts associated with the aboveground facilities are included in the construction land requirement for the pipeline ROW and TEWAs except the potential off-ROW communication tower sites (1.6 acres) and the Klamath Compressor station (21.4 acres), which are included here..
g/ Includes Klamath Compressor Station, Jordan Cove Meter Station, and permanent mainline block valve acreages.

For private and non-federal lands crossed by the pipeline, Pacific Connector would need to negotiate a mutually agreed upon easement for its pipeline with the affected landowners. The agreement between Pacific Connector and the landowner would specify compensation for the easement, compensation for damage to property and loss of use during construction, and loss of renewable and nonrenewable or other resources. The agreement would also specify uses of the permanent right-of-way after construction. If the company is unable to reach an agreement with a landowner, and if the Project is authorized by the FERC, the Certificate would convey the right of eminent domain under section 7h of the NGA. In these situations, Pacific Connector could initiate condemnation proceedings, and the value of the easement and the amounts for compensatory damages would be determined by a local, state, or district court.

2.3.2.1 Pipeline

Construction Right-of-Way

As illustrated in figure 2.3-1, Pacific Connector would generally construct the pipeline using a 95-foot-wide right-of-way. Pacific Connector would also use, as necessary, temporary extra work areas (TEWAs) to accommodate construction across waterbodies, roads, steep terrain, dense forest, and other areas of concern.[37] Where feasible (i.e., where topographic conditions allow) through forested and scrub-shrub wetlands as well as stream crossings, the construction right-of-way would be narrowed to 75 feet in width to reduce impacts on these resources and be consistent with the FERC's *Procedures* (Section VI.A.3). See additional discussion in section 4.3 of this EIS.

[37] About 42 acres of the TEWAs would be existing quarries, rock sources, or rock disposal areas that would be permanent storage areas for excess rock, and these areas would remain as exposed rock sites following construction.

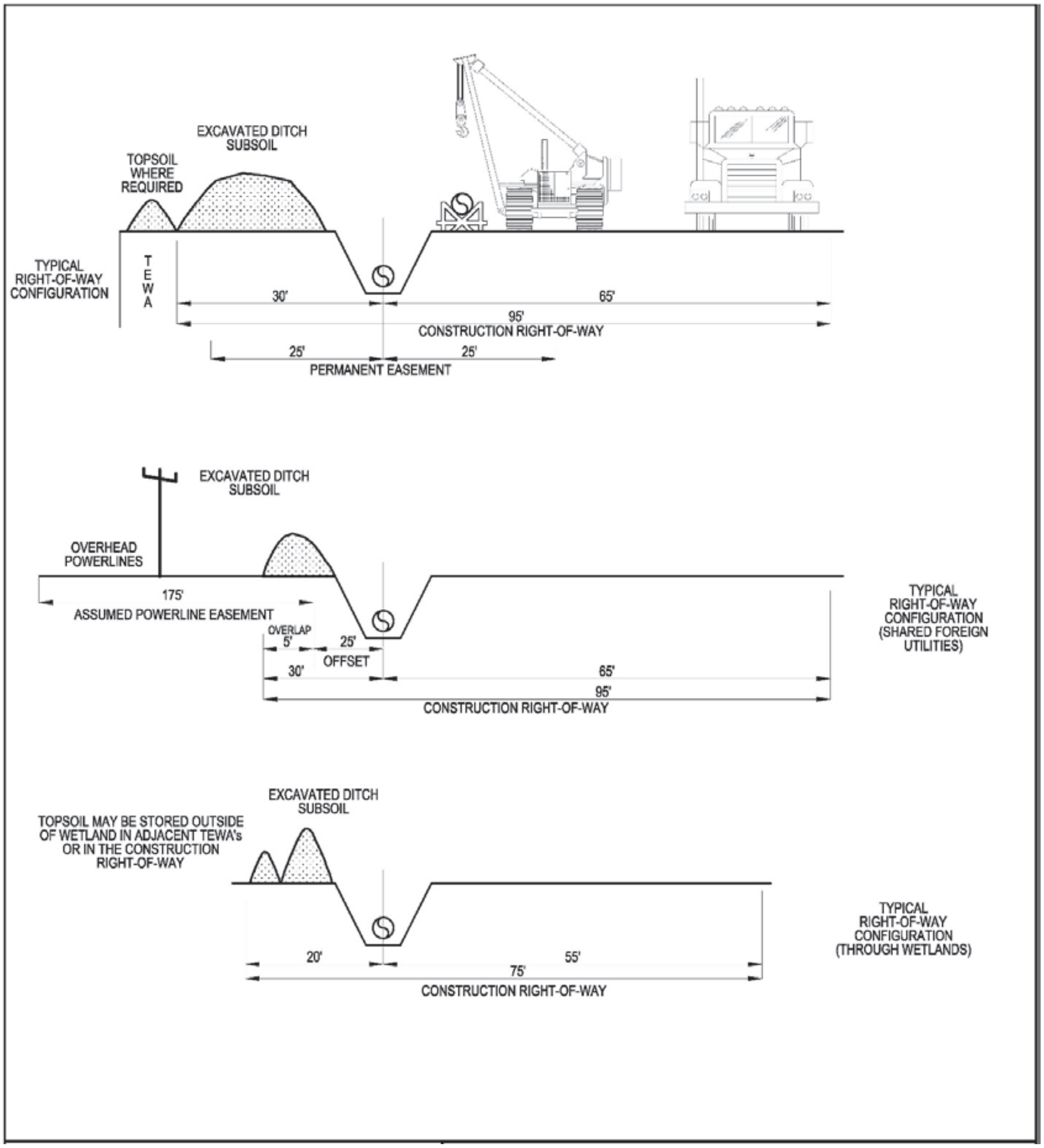

Figure 2.3-1. Typical Pipeline Right-of-Way Cross Sections

Pacific Connector would also use approximately 676 acres of uncleared storage areas (UCSA). UCSAs would not be cleared of trees during construction. UCSAs would be used to store forest slash, stumps, and dead and downed log materials that would be removed from the construction work area before construction and then scattered back across the right-of-way after construction.

In some locations, the UCSAs may be used to store spoil or to temporarily park equipment between the mature trees. However, storage and temporary parking of equipment/vehicles would not occur immediately adjacent to any trees so as to reduce tree damage. In extremely steep and side sloping topography, the UCSAs may be required as a contingency location to contain rock which rolls beyond the construction limits. Along extremely steep and narrow ridgeline areas, logs, slash, and dead and downed material may be used as cribbing to contain materials disturbed or excavated during right-of-way grading and trenching activities. During restoration, some of the materials that are pulled out of the cribbing may roll beyond the construction limits. Where feasible, Pacific Connector would retrieve materials that have rolled downhill using cables and chokers attached to standard on-site restoration equipment (i.e., bulldozers and trackhoes) to winch the material back to the right-of-way. There may be some cases where retrieval of the lost cribbing material may cause more harm to resources than allowing it to remain where it settled. On federal lands, Pacific Connector would protect trees within the UCSAs in accordance with the procedures outlined in its *Leave Tree Protection Plan* (Appendix P of its POD [appendix F.10 of this EIS]). After construction, the UCSAs would be restored to their pre-construction condition and use.

Operational Pipeline Right-of-Way

Pacific Connector would retain a 50-foot-wide permanent easement for the long-term operation and maintenance of the pipeline on non-federal lands. On federal lands, an operational right-of-way may be issued for a specific period of use, with potential for extension. After construction, workspace outside of the maintenance easement would be restored to its original condition and use to the extent possible (although mature forest would take many years to be re-established). The restoration and revegetation of the temporary construction right-of-way would be done in accordance with Pacific Connector's *Erosion Control and Revegetation Plan* (ECRP). On NFS and BLM lands where Riparian Reserves[38] would be affected, up to a 100-foot riparian strip or to the edge of the existing riparian vegetation would be replanted adjacent to stream crossings.

Access Roads

Pacific Connector would primarily use existing roads to access pipeline workspaces. Existing roads that would be used for construction access are listed in table D-2 in appendix D of this EIS. Pacific Connector has identified 10 locations where it would be necessary to construct new temporary access roads (TARs). Pacific Connector has also identified 27 existing roads that would need to be modified to handle construction traffic. The roads would be stabilized using gravel and appropriate BMPs, as outlined in the ECRP, to reduce potential surface water runoff and to avoid potential sedimentation impacts. Following construction, new TARs would be removed, and the affected areas restored to pre-construction conditions.

[38] As a key element of the Aquatic Conservation Strategy, Riparian Reserves provide an area along all streams, wetlands, ponds, lakes, and unstable and potentially unstable areas where riparian-dependent resources receive primary emphasis.

3.0 ALTERNATIVES

As required by the NEPA, Commission policy, and in cooperation with the COE, BLM, Forest Service, Reclamation, and the other NEPA cooperating agencies, we identified and evaluated reasonable and practical alternatives to the facilities (and locations) proposed by Jordan Cove and Pacific Connector as described in section 2.1 of this document. Specifically, and consistent with the Purpose and Need of the Project as described in section 1.2, we evaluated the No Action Alternative, System Alternatives, LNG Terminal Site Alternatives, and Pipeline Alternatives (including Federal Lands Alternatives and Compressor Station Alternatives). To satisfy its responsibilities per the CWA Section 404(b)1(1) Guidelines, the COE will also evaluate whether the alternatives identified by the Applicants and/or cooperating agencies would be practicable.[56]

Our evaluation of alternatives is based on Project-specific information provided by the Applicants, affected landowners, and other concerned parties; publicly available information; our consultations with federal and state resource agencies; federally recognized tribes; and our expertise and experience regarding the siting, construction, and operation of LNG export facilities and interstate natural gas transmission facilities and their potential impact on the environment. In evaluating alternatives, we considered and addressed, as appropriate, the comments provided to the Commission regarding possible alternatives.

As described in section 1.4, the Commission received thousands of letters and comments expressing concern about the Project during scoping and in response to the draft EIS. Many of these letters requested that we evaluate alternatives to the Project or expressed concern about our alternatives analyses. In response to these comments, we required the Applicants to provide additional environmental information, requested they assess the feasibility and practicability of alternatives as proposed by the commenters (including other federal agency alternatives requests); conducted site visits and field investigations; met with affected landowners and local representatives and officials; and consulted with federal and state regulatory agencies and tribes. All comments received concerning alternatives were considered, and many, but not all, of these alternatives are included in this analysis. Not included in this analysis is an assessment of renewable energy resources as an alternative to the Project. Renewable energy resources include, but are not limited to, wind, solar, and hydroelectric power. These resources are alternatives to electrical power production. Because the Project's purpose is to transport natural gas across southern Oregon and convert it to LNG for export to overseas markets, not generate electricity, the development and use of renewable energy resources would not meet the purpose of the Project, and therefore is not a reasonable or practicable alternative to the proposed action and is not considered further in this analysis. Additionally, several comments on the draft EIS suggested that measures proposed as mitigation for the impacts of the previous iteration of this Project should be considered as a potential alternative. In preparation of the draft EIS, we determined that mitigation for a previous iteration of this project was inappropriate as an alternative, and as stated previously, where we

[56] When making a decision on whether to issue a permit for the Project, the COE must consider whether the proposed Project represents the least environmentally damaging practicable alternative pursuant to the CWA section 404(b)(1) guidelines. The term "practicable" means available and capable of being done after taking into consideration cost, existing technology, and logistics in light of the overall purpose of the Project. The COE may only permit discharges of dredged or fill material into waters of the U.S. that represent the least damaging practicable alternative, so long as the alternatives do not have other significant adverse environmental consequences.

consider additional mitigation necessary, we are including recommendations to the Commission that if adopted would avoid, reduce, or mitigate environmental impacts.

The purpose of this analysis is to satisfy NEPA requirements that agencies take a "hard-look" at a project's impacts, inform the public of these impacts, and determine whether the adoption and implementation of an alternative(s) would be preferable to the proposed action. As described below, we consider numerous reasonable and practicable alternatives to the proposed action. In consultation with the NEPA cooperating agencies, using our collective professional judgment, and through environmental comparison, each alternative is considered until it is clear that the alternative would not satisfy one or more of the evaluation criteria (see below). Furthermore, it is important to note that the Commission's role under the NGA is to review applications filed with it, not to develop a general plan for energy infrastructure. Thus, comments suggesting that the Commission require Applicants to pursue alternatives that are substantially different than their proposals will be considered, but may not result in a reasonable alternative that would be addressed in our alternatives analysis.

In response to the draft EIS, a number of route variations recommended by staff were adopted by Pacific Connector and incorporated into the proposed action described in section 2 of this EIS. The changes to the proposed action have been considered in the preceding environmental analysis. Additionally, in response to concerns raised by the BLM regarding recent biological surveys, an additional pipeline route variation has been included in the following analysis. We also received in response to the draft EIS numerous comments concerning the need for site-specific construction alternatives for each waterbody crossed by the pipeline, and dredging method alternatives for the proposed dredging within Coos Bay, and similar site-specific resource alternatives. The proposed action including all waterbody crossings and the proposed dredging methods for the marine facilities in Coos Bay have been reviewed and assessed in this EIS. As our review concludes that the proposed crossing methods provide adequate protection of the affected resources, we are not including an alternatives analysis for each crossing. Staff considered alternatives, and as appropriate, discusses them herein.

Evaluation Process

The purpose of this evaluation is to determine whether an alternative would be preferable to the proposed action. To determine if an alternative would be preferable to a proposed action, we generally evaluate an alternative using three criteria:

1. does the alternative meet the stated purpose of the project;
2. is it technically and economically feasible and practical; and
3. does it offer a significant environmental advantage over a proposed action.

The alternatives were reviewed against the evaluation criteria in the sequence presented above. If the alternative would not meet the Project's purpose, or is not feasible or practical, we did not compare environmental information to determine if the third evaluation criterion was satisfied.

The first consideration for including an alternative in our analysis is whether or not it could satisfy the stated purpose of the Project. As described previously, the purpose and need of the Jordan Cove Project is to export natural gas supplies derived from existing interstate natural gas transmission systems to overseas markets; and the purpose and need of the Pacific Connector Project is to connect the existing interstate natural gas transmission systems of GTN and Ruby with the proposed Jordan Cove LNG terminal. Alternatives that do not achieve these purposes cannot be considered as feasible or reasonable alternatives to the Project. Furthermore, the Commission cannot simply ignore a project's purpose and substitute a purpose it or a commenter deems more suitable.

The only location where the GTN and Ruby pipeline systems interconnect is near Malin, Oregon. Malin is a major natural gas trading hub providing access to multiple supply basins in the United States and Canada. GTN and Ruby have a combined natural gas transportation capacity of 3.8 Bcf/d at Malin providing access to diverse and abundant supplies to support Jordan Cove's export operations. Therefore, in the alternatives analyses below, all pipeline alternatives originate near Malin, Oregon. All of the alternatives considered here, except the No Action Alternative, are able to meet the Project purpose stated in section 1.2 of this EIS.

Not all conceivable alternatives are technically and economically feasible and practical. Technically feasible alternatives, with exceptions, would generally involve the use of common LNG facility and pipeline construction methods. Economically practical alternatives would result in an action that generally maintains the price competitive nature of the proposed action. An alternative that would involve the use of a new, unique, or experimental construction method(s) may be technically feasible, but not economically practical. Generally, we do not consider the cost of an alternative as a critical factor unless the added cost to design, permit, and construct the alternative would render the Project economically impractical.

To determine if an alternative is practicable and would provide a significant environmental advantage over the proposed action, we compare the impacts of the alternative and the proposed action (e.g., number of wetlands/waterbodies affected by the alternative and number of wetlands/waterbodies affected by the proposed action). To ensure consistent environmental comparisons and to normalize the comparison of resources, we generally use "desktop" sources of information (e.g., publicly available data, aerial imagery) and assume the same construction and operation right-of-way widths and general workspace requirements. We evaluate data collected in the field if surveys were completed for both the proposed action and the corresponding alternative. Our environmental comparison uses common factors such as (but not limited to) total amount, length/distance, and acres affected of a resource. Furthermore, this analysis considers impacts on both the natural and human environments. The natural environment is generally characterized by vegetation, waterbodies, wildlife, and other biological resources; while the human environment includes land use, existing infrastructure, and community (socioeconomic) characteristics. Where appropriate and available, we also use site-specific information. In comparing the impact between resources, we also consider the magnitude of the impact anticipated on each resource. As applicable, we assess impacts on resources that are not common to the alternative and the proposed action (e.g., an alternative affects old growth forest whereas the proposed action affects agricultural lands). Our determinations attempt to balance the overall impacts (and other relevant considerations) of the alternative(s) and the proposed action. Recognizing the often-competing interests driving alternatives and the differing nature of impacts resulting from an alternative (i.e., impacts on the natural environment versus impacts on the human environment), we also consider other factors that are relevant to a particular alternative or discount or eliminate factors that are not relevant or may have less weight or significance. Ultimately, an alternative that is environmentally comparable or results in minor advantages in terms of environmental impact would not compel us to shift the impacts from the current set of landowners to a new set of landowners.

The factors considered for an aboveground facility alternative are different than those considered for a pipeline route alternative because an aboveground facility is a fixed location rather than a linear facility which is routed between two points. In evaluating aboveground facility locations, we consider the amount of available land, current land use, adjacent land use, location accessibility, engineering requirements, stakeholder comments, and impacts on the natural and human environments.

In its comments on the draft EIS, the Applicant suggested that a number of alternatives assessed and not recommended by staff were erroneously analyzed and should have been found to not be technically and economically feasible and practical. We considered these comments and as appropriate have modified our discussions.

3.1 NO ACTION ALTERNATIVE

The NEPA requires federal agencies to consider and evaluate a No Action Alternative. Additionally, a No Action Alternative serves as a baseline against which the impacts of the proposed action are compared and contrasted. Under the No Action Alternative, the proposed action would not occur, the permits and authorizations listed in section 1.5 would not be required, and as a result, the environment would not be affected.

Under the No Action Alternative, the RMPs of the Coos Bay, Roseburg, Medford, and Klamath Falls Resource Area of the Lakeview District and the LRMPs of the Rogue River, Umpqua, and Winema National Forests would not be amended to make provision for the Project. Furthermore, the Forest Service would not consent to the BLM to grant an easement because construction of the Project would not be consistent with the National Forest LRMPs. The BLM would not issue a Right-of-Way Grant for the Project because the Project would not be a conforming use of federal land. Under the No Action Alternative, there would be no need for Reclamation to concur with BLM with respect to issuance of a Right-of-Way Grant. Also, several consultations and permits would not be completed or issued under the No Action Alternative because there would be no impact on the environment. Furthermore, under the No Action Alternative specific to the COE's role in the Project review, construction of the Project would result in a modified project design or location that eliminates work that would require a Department of the Army review (i.e., avoidance of aquatic resource impacts).

In Order No. 3041-A issued July 20, 2018, the DOE amended its previous authorization to export LNG from the Jordan Cove LNG Project to countries with which the U.S. has an FTA (DOE 2018). By law, under Section 3(c) of the NGA, applications to export natural gas countries with which the U.S. has FTAs that require national treatment for trade in natural gas are deemed to be consistent with the public interest. The DOE also issued a conditional authorization to the Jordan Cove Project to export to non-Free Trade Agreement countries in Order No. 3413 on March 24, 2014. For the non-Free Trade Agreement conditional authorization, granted under Section 3(a) of the NGA, the DOE determined that exports from the Jordan Cove Project were not inconsistent with the public interest, provided the Project successfully completes the environmental review. In its application to FERC, Jordan Cove states the purpose of its Project is to export natural gas supplies derived from existing interstate natural gas transmission systems (linked to the Rocky Mountain region and Western Canada) to overseas markets, particularly Asia. According to Jordan Cove, the Project is a market-driven response to increasing natural gas supplies in the U.S. Rocky Mountain and Western Canada markets, and the growth of international demand, particularly in Asia.

Given that the Project is market-driven, it is reasonable to expect that in the absence of a change in market demand, if the Jordan Cove LNG Project is not constructed (the No Action Alternative), exports of LNG from one or more other LNG export facilities may occur. Thus, although the environmental impacts associated with constructing and operating the Project would not occur under the No Action Alternative, impacts could occur at other location(s) in the region as a result of another LNG export project seeking to meet the demand identified by Jordan Cove.

As stated in the introduction to this section, the No Action Alternative would not meet the Project's purpose and need. Therefore, we conclude that the No Action Alternative does not meet the Project purpose (criterion 1) and an alternative project to meet the market demand has not been proposed but would require a similar footprint. Although the resources that would be affected by an alternative project are not defined, we conclude that it would not likely provide a significant environmental advantage over the proposed action (criterion 3). Therefore, we do not consider the No Action Alternative further. However, the other NEPA cooperating agencies, consistent with their review and regulatory responsibilities, may choose to select this alternative.

3.2 SYSTEM ALTERNATIVES

System alternatives would make use of existing or other proposed LNG facilities and pipelines to meet the purpose of the Project. Implementing a system alternative would make it unnecessary to construct all or part of the Project, although some modifications or additions to existing LNG facilities or pipeline transmission systems/facilities, or other proposed LNG or pipeline transmission systems/facilities might be necessary. The pipeline portion of a system alternative would involve the use of all or portions of other natural gas transmission systems to transport natural gas from near Malin, Oregon, to the proposed terminal near Coos Bay, Oregon. Existing natural gas pipelines in southern and central Oregon include the jurisdictional interstate transportation systems operated by Northwest, GTN, and Ruby, and the non-jurisdictional intrastate Coos County Pipeline (figure 3.2-1).

As of the issuance of this EIS, there are no existing LNG export (or import) terminal facilities located on the west coast of the contiguous United States (Washington, Oregon, and California). Additionally, we are not aware of any proposed LNG export (or import) terminals on the west coast of the contiguous United States. Existing and proposed East Coast and Gulf Coast LNG export facilities are located 2,000 – 3,000 miles from Oregon, and would not be reasonable alternatives. According to USDOT PHMSA, there are four LNG storage facilities (peak-shaving plants) in Oregon and Washington connected to natural gas pipeline systems. These facilities are not designed to export LNG, are insufficient to meet the purpose of the Project, and would require significant modifications to meet the Project's purpose. Additionally, an LNG storage facility is being built in Tacoma, Washington (i.e. the Tacoma LNG) that would provide fuel for marine vessels and natural gas service for local residential and commercial customers. However, this facility which is located on a 30-acre site in a highly industrialized area is physically constrained with insufficient land available for the expansion necessary to meet the Project's purpose. Therefore, we conclude that there are no reasonable LNG system alternatives located on the west coast of the contiguous United States.

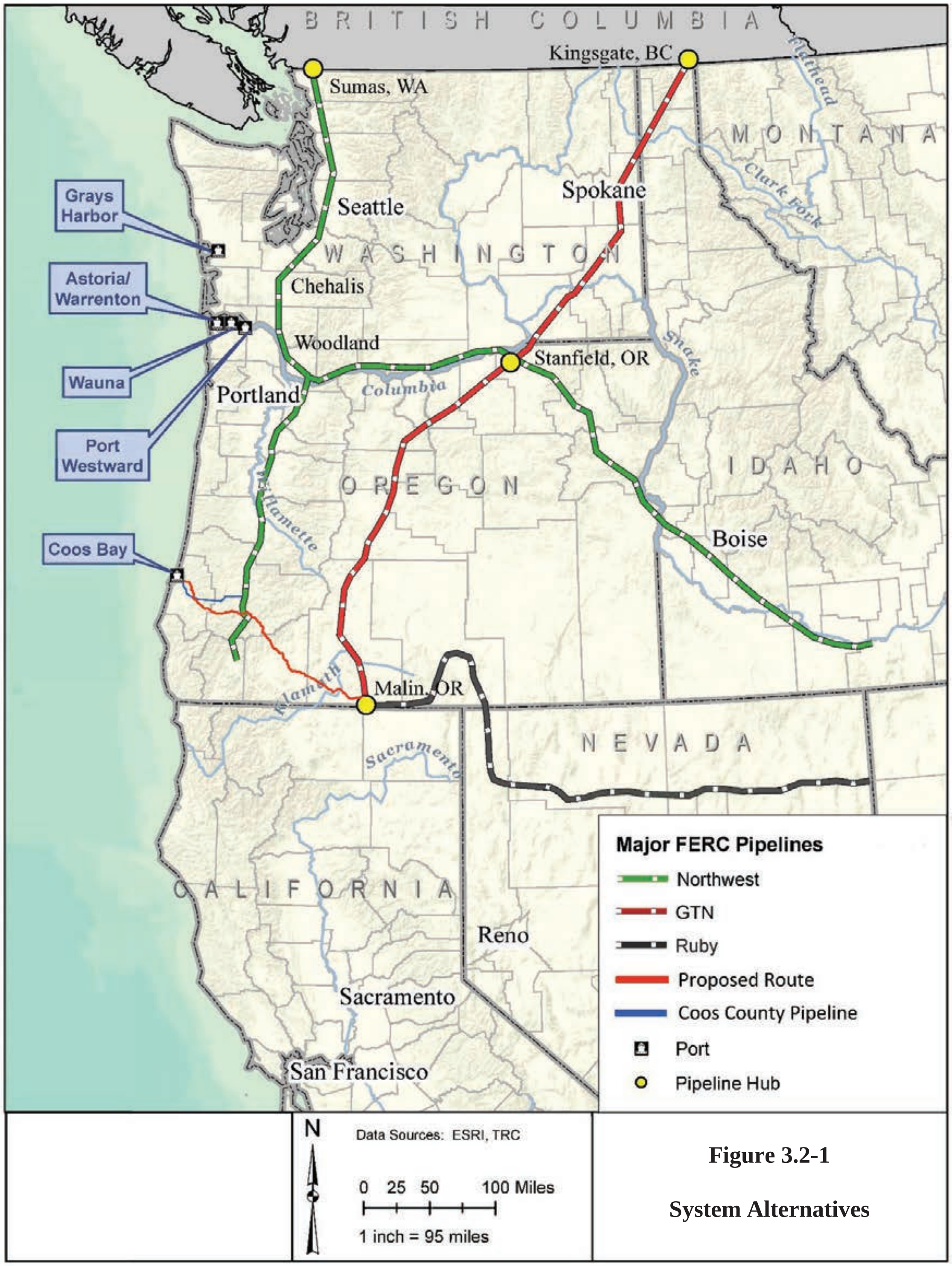

Figure 3.2-1

System Alternatives

We received several comments suggesting this analysis consider existing and proposed LNG export facilities located in Alaska, Canada, and Mexico. In Alaska, there is an idle LNG export facility on the Kenai Peninsula; however, there is a proposal with the Commission in Docket No. CP19-118-000 to bring this facility back online to allow for the import of LNG. The Commission is also currently reviewing an application (FERC Docket No. CP17-178-000) to construct and operate a new LNG export facility in Nikiski, Alaska. These facilities are not connected to the "lower-48" natural gas transmission pipeline network and although constructing a pipeline from the existing GTN and Ruby pipelines systems near Malin, Oregon to the existing or proposed facility in Alaska (a distance of close to 3,000 miles) is technically feasible, it is not economically practical. Furthermore, constructing a pipeline to Alaska from Malin would result in significantly more environmental impacts than the proposed Project as this pipeline would be an order of magnitude longer than the currently proposed pipeline. Based on the length of the Pacific Connector Pipeline and the total footprint, including all extra workspace, the pipeline would affect about 21.6 acres per mile of length. Therefore, adding 2,700 miles would affect as much as 58,320 acres of land. Consequently, we conclude that an LNG system alternative making use of the existing or proposed Alaska LNG facilities would not provide a significant environmental advantage and do not consider it further in this analysis.

According to Natural Resources Canada (2018), 13 LNG export facilities have been proposed in British Columbia, Canada (see table 3.2-1). The final specifications and permitting/ construction statuses of these facilities are unknown. Assuming these facilities have been designed to accommodate a pre-determined need/level of service, it may be possible that with modifications, one or more of these facilities would be able to provide an equivalent level of service to that which would be provided by the Project. However, we are unable to determine what modifications would be necessary and what the impacts of those modifications would be. Furthermore, although constructing a pipeline from the existing GTN and Ruby pipelines systems to western Canada (a distance ranging from 700 to 1,400 miles) is technically feasible, it would increase the Project footprint by between about 10,100 and 25,300 acres. Therefore, we conclude that an LNG system alternative making use of a proposed western Canada LNG facility would not provide a significant environmental advantage and do not consider it further in this analysis.

TABLE 3.2-1

Proposed Canadian LNG Projects

Project	Terminal Location	Output (Max Bcf/d)
Cedar LNG Project	Near Kitimat, B.C.	0.8
LNG Canada Project	Port Edward, Prince Rupert Island, B.C.	3.5
WesPac LNG Marine Terminal	Tilbury Island, B.C.	0.6
Kitimat LNG Project	Kitimat, B.C.	1.3
New Times Energy Ltd.	Prince Rupert area, B.C.	1.6
Orca LNG Project	Prince Rupert area, B.C.	3.2
Steelhead LNG Project	Sarita Bay, Vancouver Island, B.C.	4.3
Woodfibre LNG Project	Near Squamish, B.C.	0.3
Stewart Energy Project	Stewart, B.C.	4.0
Discovery LNG Project	Campbell River, Vancouver Island, B.C.	2.6
Kitsault Energy Project	Kitsault, B.C.	2.7
Triton LNG Project	Floating facility – TBD near Kitimat or Prince Rupert, B.C.	0.3
Watson Island LNG	Watson Island, near Prince Rupert, B.C.	Unknown

There are no existing LNG export facilities on the west coast of Mexico. However, there are two import facilities—the Costa Azul LNG Project in Baja California, and the Manzanillo LNG Project in Colima. The owner of the Costa Azul Project (Sempra Energy) is proposing to convert this project into an LNG export terminal. We are not aware of any other proposed LNG facilities in

Mexico; however, we acknowledge that additional proposals may exist. Similar to the proposed Canadian LNG facilities, the final specifications and permitting/construction status of the Costa Azul LNG Project is unknown. Assuming this facility has also been designed to accommodate a pre-determined need/level of service, it may be possible that with modifications, it would be able to provide an equivalent level of service to that which would be provided by the Project. However, we are unable to determine what modifications would be necessary and what the impacts of those modifications would be. Although constructing a pipeline from the existing GTN and Ruby pipelines systems to Baja California (a distance of about 900 miles) is technically feasible, it would increase the Project footprint by about 14,500 acres. Therefore, we conclude that an LNG system alternative making use of the Costa Azul LNG facility would not provide a significant environmental advantage and do not consider it further in this analysis.

The Northwest Pipeline is an approximately 3,900-mile-long bi-directional interstate natural gas transmission system. This system crosses the states of Washington, Oregon, Idaho, Wyoming, Utah, and Colorado. This transmission system provides access to British Columbia, Alberta, Rocky Mountain, and San Juan Basin natural gas supplies. We received comments on the draft EIS stating that the Northwest Pipeline system should be assessed as a potential system alternative, with some comments suggesting the system has available existing capacity or could be expanded to provide the needed capacity. Commenters noted that the Northwest Pipeline is generally sited parallel to the coast (see figure 3.2-1) and could be connected to an LNG facility on the coast with less new pipeline construction required than the proposed Project. As stated above, to meet the Applicant's stated Project purpose, the pipeline needs to originate near Malin, Oregon. The distance from Malin to the closest point of the Northwest Pipeline is approximately 250 miles. Assuming some excess capacity is available in the Northwest Pipeline, a pipeline loop would still need to be constructed in order to provide the total proposed capacity. Co-locating this pipeline loop with the existing Northwest Pipeline would require the construction of at least an additional 125 miles of pipeline. Lastly, the modified Northwest Pipeline would then need to be connected to the coast and new LNG terminal facilities. Depending on the location of these terminal facilities, at least 50 miles of additional pipeline would need to be constructed. Constructing 425 miles of new pipeline to connect to Malin may be technically feasible and economically practical, but would not result in a significant environmental advantage when compared to the proposed action; therefore, use of the existing Northwest Pipeline is not evaluated further.

In Oregon, two lateral pipelines connect to the Northwest mainline system. The Camas to Eugene and the Eugene to Grants Pass Lateral are generally parallel to I-5, running north to south through western Oregon. The laterals begin in the north as dual 20-inch-diameter pipelines, and consist of a single a 10-inch-diamter pipeline at the southern end. The only portion of the Northwest Pipeline system that could potentially serve as a system alternative to move gas from near Malin to the LNG terminal in Coos Bay would be a portion of the north-south Eugene to Grants Pass Lateral. Such an alternative would require modifying roughly the eastern one-half of the proposed pipeline to connect to the southern end of the Grants Pass Lateral, then constructing about 70 miles of "looping" pipeline north along the Grants Pass Lateral to near Sutherlin, Oregon, and then constructing about 50 miles of new pipeline west to Coos Bay. Such an alternative would result in roughly the same length of pipeline as proposed; however, may affect more forested area, and could result in similar or greater environmental impacts. Therefore, the implementation of a system alternative involving the use of the Northwest Pipeline Grants Pass Lateral would not provide a significant environmental advantage over the proposed action.

The GTN interstate natural gas transmission system includes about 600 miles of 36- and 42-inch pipeline beginning at Kingsgate, British Columbia, traversing through northern Idaho, southeastern Washington, and central Oregon, and terminating near Malin. Natural gas for the GTN pipeline originates primarily from western Canadian supplies; although it can receive Rocky Mountain gas through interconnections with Northwest near Spokane and Palouse, Washington and Stanfield, Oregon. The Ruby interstate natural gas transmission system includes about 680 miles of 42-inch-diameter pipeline beginning near Opal, Wyoming, and extending west through Montana and Idaho to Malin. Neither GTN nor Ruby would be suitable as system alternatives and neither would be able to meet the purpose of the Project because both systems terminate near Malin and would require a connection to a west coast LNG facility similar to the proposed pipeline route from Malin to Coos Bay. Therefore, systems alternatives involving these systems would not provide a significant environmental advantage over the proposed action.

The Coos County Pipeline is a non-jurisdictional 12-inch-diameter local distribution company (LDC)[57] pipeline that extends about 60 miles from the Northwest Grants Pass lateral, near Roseburg, to Coos Bay. The Coos County Pipeline has a MAOP of 1,000 psig and was designed to bring gas to the communities around Coos Bay. The terminus of the Coos County Pipeline is approximately 7.7 miles south of the proposed Jordan Cove LNG terminal. Northwest Natural built a pipeline lateral from the terminus of the Coos County pipeline across Coos Bay to the North Spit, as part of its LDC system. The diameter and available capacity of the Coos County Pipeline are too small to meet the purpose of the Project. The Coos County Pipeline does not connect to the GTN and Ruby Pipeline systems. Expanding the Coos County Pipeline as needed to provide the required natural gas capacity from the GTN and Ruby Pipeline systems would result in similar impacts as that of the proposed action. For these reasons, the Coos County Pipeline as an existing system cannot meet the Project purpose and expanding it to meet the purpose would not provide a significant environmental advantage.

3.3 LNG TERMINAL SITE ALTERNATIVES

We received numerous comments stating that LNG site alternatives in California, Washington, Canada, and Mexico be considered. Commenters suggested that sites in these states and countries could be more suitable for an LNG terminal. We do not evaluate in this EIS alternative projects or LNG terminal sites located in Canada or Mexico. Below we address the potential for an LNG terminal to be sited in California, and then we address potential alternative sites in Oregon and Washington.

As stated previously, the Commission's staff evaluates a proposal and reasonable alternatives. While we may ask the project proponent to evaluate alternative technologies or facility layouts to reduce impacts, we do not completely redesign proposals. Additionally, some alternative technologies and/or facility designs represent such a large departure from the Applicant's proposal that they could significantly affect the feasibility and economic practicality of the proposal. Consequently, we are not evaluating offshore site alternatives that would require specialized LNG carriers. We do however, to ensure a comprehensive review of alternatives, evaluate the concept of an inland (non-waterfront) alternative (see section 3.3.4) and a shoreside berth alternative (see section 3.3.5).

[57] LDCs (local distribution company) are intrastate systems that are regulated by the state, and do not come under the jurisdiction of the FERC.

3.3.1 LNG Terminal Site Alternatives in California

California has 11 public ports. The closest deepwater port to Coos Bay in California is the Port of Humboldt Bay. The Port of Humboldt Bay is located approximately 185 miles south of Coos Bay and 225 miles north of San Francisco (the next closest deepwater port is in San Francisco bay). The Samoa Peninsula lies between the Pacific Ocean and Humboldt Bay and hosts several active and former marine facilities, berths, docks, and terminals. According to the 2018 Humboldt Bay Maritime Industrial Use Market Study, 948 acres of land have been designated for Coastal-Dependent Industry (CDI) on the Samoa Peninsula including the approximately 344-acre Eureka Municipal Airport site which has waterfront access and is the largest single property on the peninsula. It is unknown whether a combination of other CDI properties equaling approximately 200 acres is available. The channel system leading into and within Humboldt Bay varies in length, width, and depth. The Bar and Entrance Channel is approximately 8,500 feet long, 500 to 1,600 feet wide, and is authorized to a depth of 48 feet mean low level water (MLLW). The North Bay Channel which serves the Samoa Peninsula is 18,500 feet long, 400 feet wide, and is authorized to a depth of 38 feet MLLW. The distance by air from Malin, Oregon to Humboldt Bay is about 170 miles (the distance from Malin, Oregon to Coos Bay by air is also about 170 miles). We estimate the pipeline distance between these two points would be at least 200 miles, which is comparable to the proposed pipeline.

An LNG terminal in Humboldt Bay would impact the environment in a manner similar to that of the proposed Project, including; permanent conversion of land use, dredging, turbidity, loss of wetlands, visual impacts, air quality and noise. Concerns at this location such as marine traffic restrictions, socioeconomic impacts, tsunamis, and public safety would also be the same as the proposed Project. A natural gas transmission pipeline from Malin, Oregon to Humboldt Bay, California would traverse Klamath County, Oregon as well as Siskiyou and Humboldt Counties, California. The environment crossed by a pipeline from Malin to Humboldt Bay would be similar to that of the proposed route, including; mountainous terrain, several large rivers, three national forests, and BLM-managed lands. This pipeline route would also cross the ranges of over 20 federally-listed threatened and endangered species including NSO, MAMU, and salmon. Concerns with this pipeline route such as rural property values, socioeconomic impacts, and public safety would also be the same as the proposed Project.

Based on the similarity of impacts of an LNG terminal in Humboldt Bay and the associated natural gas transmission pipeline from Malin, Oregon to Humboldt Bay, we conclude this alternative would not result in a significant environmental advantage when compared to the proposed action.

3.3.2 LNG Terminal Site Alternatives in Oregon and Washington (LNG Terminal Site Characteristics)

As provided in Jordan Cove's application and identified in table 3.3.2-1, we are evaluating four terminal site alternatives. We determined that a reasonable LNG terminal site alternative should include the following site characteristics.

1. **Available Land** – a parcel or combination of parcels available[58] for development and large enough to accommodate the proposed LNG terminal facilities and associated safety

[58] Section 3 of the NGA does not grant the authority of eminent domain. In some cases, a site may be of adequate size for an LNG terminal, but the owner is unwilling to sell or lease the property.

exclusion zone, about 200 acres to accommodate the facilities and associated workspace proposed by Jordan Cove.

2. **Deep Channel Access** – a channel with depth of at least 36 feet MLLW in order to accommodate the draft of anticipated LNG carriers.
3. **Waterfront Access** – a site that can safely accommodate the mooring of an LNG carrier and the facilities required to transfer LNG from the terminal to the carrier.
4. **Comparable Pipeline** – a site that could be reached by a comparable natural gas transmission pipeline from the intersection of the GTN and Ruby pipeline systems.

For the purposes of our alternatives analysis of sites, we do not further evaluate sites that do not or could not satisfy these LNG site requirements. For example, sites that are of insufficient size or are unavailable for purchase or lease are not carried forward into this analysis.

Locations having the four necessary characteristics were identified in Astoria, Wauna, and Port Westward, Oregon, and Grays Harbor, Washington (figure 3.2-1). An environmental comparison and discussion of these LNG terminal site alternatives is provided below.

Each alternative site would require construction of new natural gas pipelines, and in some cases modifications and upgrades to existing transmission pipelines to access western Canadian and U.S. Rocky Mountain natural gas sources from the intersections of the GTN pipeline and Ruby pipeline near Malin, to meet the stated Project purpose. An estimate of the pipeline length required for each alternative is included in table 3.3.2-1. In each of these alternatives, the associated natural gas supply pipeline would need to cross the Cascade Mountains.

TABLE 3.3.2-1

LNG Terminal Port Alternatives Comparison

	Alternative Port				
Feature	**Proposed (Coos Bay)**	**Astoria, OR**	**Wauna, OR**	**Port Westward, OR**	**Grays Harbor, WA**
Available Site Size (acres)	412	519	321	336	272
Supply pipeline length (miles)	229	399	375	332	379
Pipeline construction footprint (acres) a/	4,946	8,618	8,100	7,170	8,186
Freshwater wetland impacts (acres) b/	83	143	49	51	61
Estuarine/open water impacts (acres) b/	35	130	35	60	42
Number of listed species with potential habitat	21 c/	10	15	16	9
Existing residences within 1 mile (number)	116	975	5	828	1,637

a/ Estimated using the average area per mile that would be affected by the proposed pipeline, including all extra temporary work space (21.6 acres/mile).
b/ Assuming all mapped resources within the site would be affected.
c/ This includes the LNG terminal site and LNG carrier transit in the waterway. There are only seven federally listed species that may occur at the LNG terminal site itself.

As shown in table 3.3.2-1, environmental features and potential impacts from use of the alternative sites would vary when compared to the proposed site. Three sites (Astoria, Port Westward, and Grays Harbor) would have a significantly greater number of residences located within 1 mile, while one site (Wauna) would have significantly fewer. Three sites (Wauna, Port Westward, and Grays Harbor) would have less impact on freshwater wetlands than the proposed site, while one site (Astoria) would have more. One site (Astoria) is estimated to require significantly more impact on estuarine and open water habitats than the proposed site. All four alternative sites would require at least 100 more miles of supply pipeline than the proposed site, ranging from an estimated 103 miles (Port Westward) to 170 miles (Astoria) of additional pipeline required, which would require an estimated 2,224 to 3,672 additional acres of disturbance for pipeline construction. When evaluating these potential impacts, we have not identified an alternative site that would result in a significant environmental advantage over the proposed site. Therefore, we conclude that none of the regional alternative sites would result in a significant environmental advantage over the proposed site in Coos Bay.

3.3.3 Coos Bay Terminal Alternatives

We evaluated one alternative site for the LNG terminal facilities within Coos Bay. The alternative site is located west of the swinging railroad bridge and on the western side of the Coos Bay Navigation Channel. The swinging railroad bridge is an impediment to vessel traffic and the eastern side of the channel does not contain any sufficiently sized parcels due to the presence of the North Bend and Coos Bay communities. Sites along the west side of the North Spit are not suitable because navigational accessibility is limited by exposure to the open ocean.

The Jordan Point alternative site is located about 1 mile east of the proposed LNG terminal site at about river mile 8.5 of the Coos Bay Federal Navigation Channel (figure 3.3-1). The Jordan Point site would be approximately the same size as the proposed site, and Jordan Cove indicates the site would be available for development of an LNG facility. The alternative site overlaps part of the South Dunes portion of the proposed site. A comparison of major environmental factors between the Jordan Point site and the proposed site are listed in table 3.3.3-1.

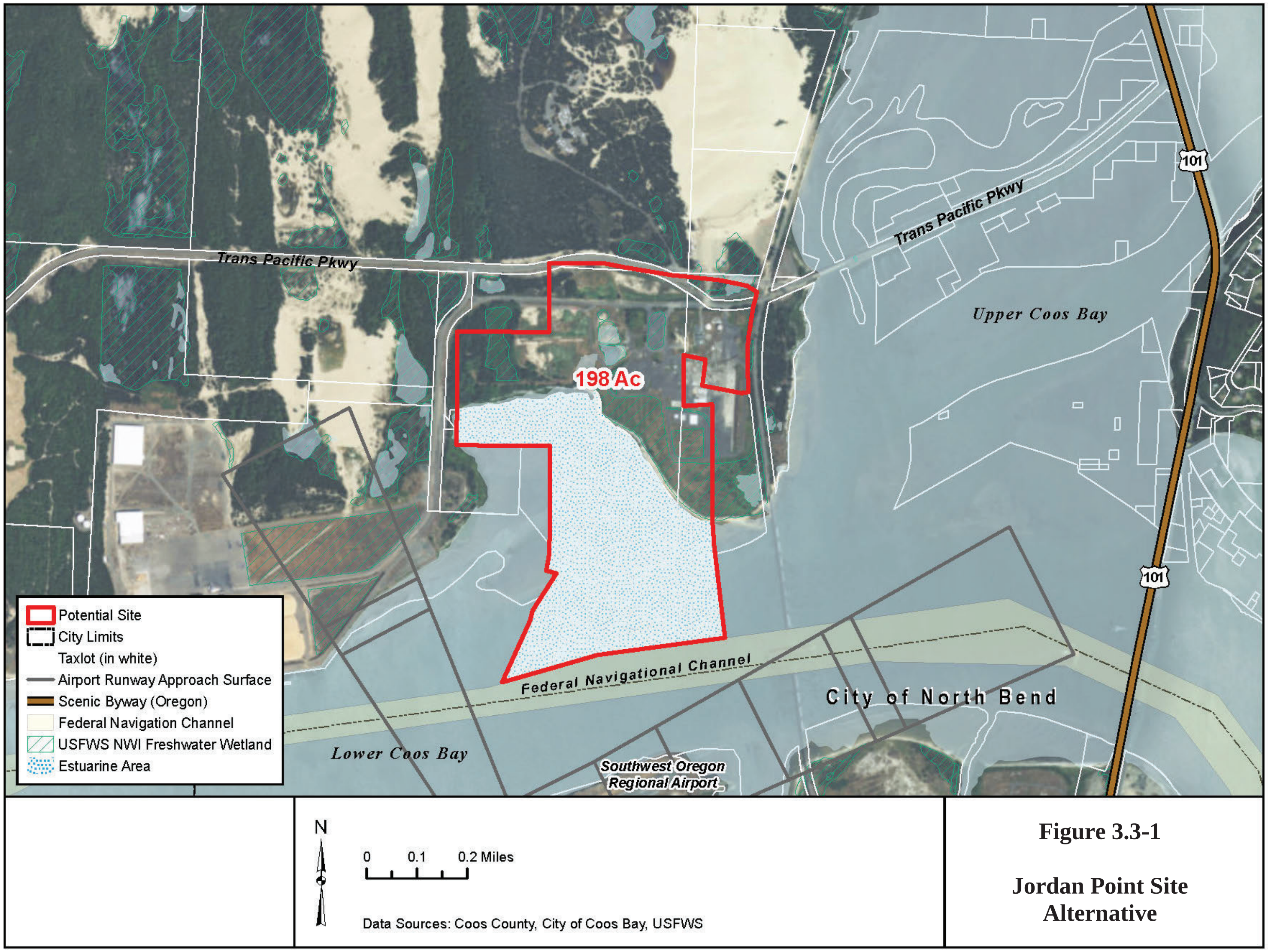

Figure 3.3-1

Jordan Point Site Alternative

TABLE 3.3.3-1

Comparison of Proposed and Jordan Point Alternative LNG Sites

Environmental Factor	Proposed Site	Jordan Point Site
Estuarine Area (acres) a/	32	101
Wetland Area (acres) b/	2	22
Threatened and Endangered Species (number) c/	9	9
Approximate Site Size (acres)	199	198
Land Availability	Y	Y
Federal Land Affected (acres) d/	0	0
Within Airport Runway Approach Zone	No	No
Adequate Area for Safety Exclusion Zone	Y	Y
Existing Residences within 1 Mile (number) d/	116	128

a/ Based on approximate boundary of shoreline to the edge of the Federal Navigation Channel or waterward extent of the potential site boundary.
b/ Based on NWI wetland GIS data within potential site boundary, See Figures 10.3-9 to 10.3-11 in Jordan Cove Resource Report 10.
c/ Based on FWS 2017a and NMFS 2015.
d/ Based on GIS tax lots.

The number of residences within 1 mile would be slightly more for the Jordan Point site (128) than for the proposed site (116), and LNG carriers would have to travel about 1 mile farther along the Federal Navigation Channel to reach the site. Based on NWI mapping, the Jordan Point site would also include more wetlands (approximately 22 acres) compared to the proposed site (approximately 2 acres). The primary disadvantage of the alternative site is its farther distance from the Federal Navigation Channel, which would require a greater area of dredging within the estuarine area between the site and channel (approximately 101 acres) compared to the proposed site (32 acres). For the reasons described above, the Jordan Point site would not provide a significant environmental advantage over the proposed site.

3.3.4 Inland (Non-Waterfront) Alternative

We received comments from the COE requesting that we evaluate an inland LNG terminal site, in order to reduce impacts on wetlands and Coos Bay. An inland alternative site would locate the liquefaction and LNG storage facilities at an upland location outside of Coos Bay and would be connected to the proposed marine loading facilities by an LNG cryogenic pipeline or LNG trucking system. At the proposed site, approximately 86.1 acres of wetlands would be affected by construction and approximately 22.3 acres of wetlands would be permanently altered (see table 4.3.3.1-1). An inland site would not completely eliminate impacts on wetlands as numerous operational and safety facilities would still be required along the shoreline to support the marine loading and LNG carrier berth facilities. Operational and safety facilities would include spill containment systems and utilities such as compressed air, nitrogen, potable water, utility water, fire water, and electrical equipment. An inland site would also require the use of a marine berth and turning basin; therefore, dredging in Coos Bay would still be necessary. As a result, impacts on Coos Bay would not be substantially reduced by an inland terminal site.

Due to the presence of the Oregon Dunes National Recreation Area immediately north of the proposed site, the cities of North Bend and Coos Bay, immediately south, and the Pacific Ocean to the west, any inland site alternative would need to be located at least five miles east of the proposed site. Furthermore, due to the steep topography east of Coos Bay, the distance from the marine loading facilities to a suitable parcel of land for the terminal facilities would likely be greater than five miles and likely require a larger site with more ground disturbance (50 acres or more) to accommodate the significant earthwork (spoil storage, leveling, and slope considerations) that would be required to create an appropriate site. The marine loading facilities would remain at the proposed site because LNG carriers are prevented from travelling farther east by the rail and Highway 101 bridges across Coos Bay.

An LNG cryogenic pipeline, which would be subject to expansion and contraction due to temperature fluctuations, could be located aboveground or underground within a tunnel system. Regardless of the pipeline placement, the USDOT's siting requirements and regulations would apply. In order to ensure pipeline integrity and public safety, the USDOT may require the operating company to obtain legal control of activities up to 400 feet on each side of the pipeline, resulting in an additional 450 acres of land encumbered by the permanent easement. The subsequent amount of affected land when compared to the amount of land typically affected by a natural gas pipeline would be significantly greater. In addition, the USDOT siting requirements for LNG cryogenic pipelines require security features (fencing and exclusion zones) and spill containment systems. At a minimum, an LNG cryogenic pipeline system would need to accommodate the LNG ship loading pipe, an LNG recirculating and cooldown pipe, and the ship vapor return pipe as well as access points for inspection and maintenance work. The cryogenic pipelines would also require insulation along the entire length to maintain (low) operating temperatures. These facilities would require a larger permanent operational easement and would likely require a larger construction right of way, both of which would increase impacts on the environment. Unlike an interstate natural gas pipeline regulated under Section 7 of the NGA that provides for the use of eminent domain, temporary and permanent easements required for an LNG cryogenic pipeline regulated under Section 3 of the NGA must be obtained without the use of eminent domain which could result in a longer pipeline route further increasing impacts on the environment. An LNG cryogenic pipeline would also require pump stations to ensure LNG flows and pressures are maintained. These pump stations would need additional provisions for electrical power, security, firewater, control room, etc. and would require the permanent use of additional lands and impacts on the environment. A cryogenic pipeline transporting LNG from an inland terminal site to the marine loading facilities is technically feasible, but would require numerous design and siting changes, resulting in additional environmental impacts, and could affect the economic competitiveness of the Project.

An inland LNG terminal alternative could impact a larger footprint than the proposed site and would affect other resources. Because the proposed site has been previously disturbed, the impacts of an inland LNG terminal could be greater than the impacts at the proposed site. Furthermore, constructing a LNG cryogenic pipeline would require several additional systems and measures to be designed and implemented to ensure safety and integrity. Ultimately, when considering the footprint of the inland terminal, the marine loading facilities, power infrastructure for the pumps, and the difficulties and costs associated with a redesigned pipeline, we conclude that while perhaps feasible, an inland site would not be practical.

A trucking system transporting LNG from an inland terminal site to the marine facilities at the proposed output volumes would require thousands of truck trips per day. This amount of traffic on area roads would be a significant impact and would greatly increase public safety concerns. In addition, exhaust emissions from the trucks would impact local air quality. Therefore, we conclude that an inland terminal with a trucking system would not provide a significant environmental advantage over the proposed LNG terminal.

3.3.5 Shoreside Berth Alternative

At the request of the COE we assessed an LNG terminal layout at the proposed site that includes a shoreside dock and berth (parallel to the shoreline). As shown on figure 2.1-7, the navigation channel at RM 7.5 is not wide enough to accommodate a docked LNG carrier within the existing channel; therefore, a new berth would be required. Under this alternative a single, new in-water berth could be dredged to the north of the existing channel, generally parallel to the shoreline, and long enough to accommodate an LNG carrier approximately 1,000 feet in length. Docking and LNG loading structures would then need to be constructed from the land-based LNG facilities into the bay to connect to the new berth, estimated to be about 400 to 500 feet. In addition, such a shoreside berth alternative would also require dredging of a turning basin to allow turning of the LNG carriers before entering the berth. Assuming a turning basin would be roughly centered on the existing navigation channel and would be about 1,500 feet in diameter, and the berth would be dredged parallel to the shoreline at the north edge of the turning basin, we estimate that this alternative would require dredging a minimum of about 30 acres outside of the existing navigation channel. In addition, approximately 5 acres of dredging would also be required to create an access channel between the berth and MOF, although it is possible this could be at a reduced depth than required for the LNG carrier berth and turning basin. In total approximately 35 acres of dredging within Coos Bay, outside of the existing navigation channel, would be required for this alternative. As shown in table 4.5.1.1-2, approximately 37 acres of water-based or intertidal habitat would be affected by the proposed Project. Therefore, a shoreside berth alternative would require essentially the same amount of in-water dredging than the proposed configuration. The shoreside berth alternative would, however, eliminate about 42 acres of upland excavation that would be required for construction of the berth as proposed, and the creation of new deep subtidal habitat within the berth area as proposed.

Further, the proposed Project includes an emergency lay berth; therefore, this facility would need to be included in the alternative. Assuming a second berth could utilize the same turning basin, construction of a second emergency berth in a shoreside configuration would add an estimated 15 acres of dredging, bringing the total area of dredging to about 50 acres. However, the current Jordan Cove site is not large enough to allow for two berths placed end-to-end parallel to the shoreline, therefore, agreements with adjacent landowners would likely be required to allow for placement of an emergency berth, either east or west of the proposed site.

As described above, the shoreside berth alternative could eliminate the need for about 42 acres of upland excavation required for construction of the proposed berth and the creation of new deep subtidal habitat within this new berth area. However, a shoreside berth alternative would require about the same area of in-water dredging and associated impacts on aquatic and benthic resources as proposed for a single berth (35 vs. 37 acres), and more area of estimated in-water dredging and associated impacts on aquatic and benthic resources as proposed (50 vs. 37 acres) to include an emergency lay berth. While it is possible that a similar shoreside berth alternative could be located at a different site within Coos Bay, the amount of dredging required would be the same as estimated for the proposed site.

One disadvantage of a shoreside berth alternative would be a reduced level of safety and reliability related to placing the LNG carrier berth along an outside bend in the channel. The shoreside berth alternative would place docked LNG carriers in the direct path of other vessel traffic navigating north (up river) at the RM 7.5 curve, and therefore in danger of allision from a vessel that fails to navigate the turn. This danger could be avoided by shutting down up-river traffic for the entire time that an LNG carrier is at berth (approximately 18 hours). The proposed slip would place LNG carriers at dock to be in a protected berth generally perpendicular to the navigation channel and would allow for other vessel traffic to continue within the navigation channel while an LNG carrier is at berth.

Because in-water dredging and the associated impacts on aquatic and benthic resources would be similar or greater than the proposed berth and access channel, we conclude the shoreside berth alternative does not offer a significant environmental advantage over the proposed action. Therefore, a shoreside berth alternative is not considered further in this EIS.

3.3.6 Refrigeration Compressor Power Supply Alternatives

In response to comments on the draft EIS, we compared the potential emissions from the proposed natural gas-fired direct drive combustion turbines that would supply the refrigeration compressors to the estimated emissions that would result from using electric refrigeration compressors operated exclusively with grid-supplied electric power, and also to the potential emissions from using an on-site power plant to provide power for electric compressors.

The previously proposed LNG export terminal as described in the 2015 final EIS (FERC 2015), included a purpose-built power plant (the South Dunes Power Plant) to provide power for electric refrigeration compressors. As described in the 2015 final EIS, the previous design included four electric refrigeration compressors each rated at 65,000 hp, with a maximum electric power demand of 310 MW for the entire terminal. The South Dunes Power Plant was planned to have a nominal power output of 420 MW. Table 3.3.6-1 presents estimated emissions for the South Dunes Power Plant from the 2015 final EIS, with a comparison to the potential emissions from the currently proposed Project combustion turbines, and to the estimated indirect, off-site emissions that would be produced by using existing power plants in the regional grid to supply the power required for electric compressors. Although the South Dunes Power Plant was to have a nominal capacity of 420 MW, for the purpose of this analysis we have estimated off-site regional grid emissions on the assumption that electric refrigeration compressors would require no more than 310 MW of power. Also, for the purpose of this analysis we did not attempt to re-design the previously proposed on-site South Dunes Power Plant although we recognize that it was to have larger power output than the off-site alternative evaluated here. Indirect emissions were estimated using the Avoided Emissions and Generation Tool (AVERT), which looks at emissions using historical patterns of actual generation in one selected year. Currently, AVERT has data for 2007-2018, and we used the 2018 dataset.

AVERT's dispatch model is able to determine incremental demand increases (or decreases) for specific generation facilities based upon historic patterns of usage for specific changes in power demand in the region. The model generates an output which determines annual decreases or increases in NOx, SO_2, particulate matter with an aerodynamic diameter less than 2.5 micrometers ($PM_{2.5}$), and GHGs. The model also allows emission increases by specific generation plant and county.

TABLE 3.3.6-1

Potential Emissions from Proposed Natural Gas-Drive, On-Site Electric Generation, and Grid-Supplied Electric Power Compressor Options

	Annual Emissions (tpy)			
Pollutant	**Gas Turbine Driven Refrigeration Compressors (Proposed)**	**420 MW Purpose-Built Power Plant to Drive Electric Compressors (from 2015 design) a/**	**AVERT Generated Indirect Emissions from 310 MW of Off-Site Generation to Drive Electric Compressors b/**	**Net Change for Proposed Option over Next-Best Option**
NO_x	82.22	154.1	1,700	-72
VOC	32.82	74.8	N/A	-42
CO	98.55	132.3	N/A	-34
SO_2	35.19	46.1	1,320	-11
PM_{10}	112.37	180.4	N/A	-68
$PM_{2.5}$	112.37	180.4	107	-68
CO_2e	1,292,894	1,695,525	2,250,000	+402,982

CO = carbon dioxide; CO_2e = carbon dioxide equivalent; NO_x = oxides of nitrogen; PM_{10} = particulate matter with a diameter of less than 10 microns; $PM_{2.5}$ = particulate matter with a diameter of less than 2.5 microns; SO_2 = sulfur dioxide; tpy = tons per year; VOC = volatile organic compound

a/ Purpose-built power plant based on potential emissions for the South Dunes Power Plant included in the 2015 final EIS, which employed selective catalytic reduction for control of NO_x, an oxidation catalyst for control of CO and VOC, and natural gas as the only fuel for control of SO_2, PM_{10}, $PM_{2.5}$, and CO_2e.

b/ Indirect emissions would be produced by existing power generation facilities distributed across the regional grid service area. Emissions estimated based on the AVERT 2018 model for the Northwest Power Pool subregion. https://www.epa.gov/statelocalenergy/avoided-emissions-and-generation-tool-avert

As shown in table 3.3.6-1, the currently proposed Project design using direct-drive refrigeration compressors powered by gas-fired combustion turbines would produce less emissions than would be produced by either alternative method for powering electric compressors, for all pollutants except GHG. Using the AVERT metric, it is estimated that the regional grid power needed to operate electric compressors would result in significantly higher emissions of NO_x and SO_2, slightly lower emissions of $PM_{2.5}$, and significantly greater emissions of CO_2. Therefore, we conclude that electric power supply alternatives using electric refrigeration compressors powered either exclusively with grid-supplied electric power or from electric power from an on-site power plant would not provide a significant environmental advantage over the proposed design.

3.4 PIPELINE ROUTE ALTERNATIVES AND VARIATIONS

We evaluated numerous pipeline route alternatives and variations to determine whether their implementation would be preferable to the proposed corresponding action. Major route alternatives are generally greater than 50 miles in length and can deviate from the proposed route by a significant distance. Route variations are generally less than 50 miles in length and deviate from the proposed route to a lesser degree than a major route alternative.

Route alternatives and variations were identified based on public comments received during the scoping and draft EIS comment periods, information provided by Pacific Connector, agency consultations, and our independent review of the Project. Also, as required by Subsection 28 (p) of the Mineral Leasing Act, the agencies considered opportunities for co-location with existing rights-of-way where the proposed pipeline would cross federally managed lands. In addition to alternatives and variations evaluated in this EIS, during the course of refining the proposed route, Pacific Connector incorporated a number of minor route modifications to address agency concerns and landowner requests, constructability issues or constraints, to avoid cultural resources or geological hazards, or reduce impacts on special status, threatened, or endangered species. These include minor modifications recommended by the BLM between MPs 119.5 and 119.8, at MP

126.0, and at MP 131.5, and between MPs 183.9 and 187, and recommended by the Forest Service between MPs 154.7 and 155.1, MPs 157.1 and 158.7, and MPs 171.2 and 173.0.

3.4.1 Major Route Alternatives

Elements we considered during our analysis of potential alternatives included pipeline length, use of or co-location with existing rights-of-way, forest land, agricultural land, waterbody and wetland crossings, residences, known cultural resources, habitat for federally listed threatened or endangered species, and geological hazards and slope stability.

3.4.1.1 All Highway Alternative

We evaluated the All Highway Alternative as a potential alternative that would follow existing highways as much as possible in order to co-locate rights-of-way and reduce the creation of new corridors through resource areas. This alternative would follow Highway 50 west from Malin to Highway 39, northwest to Klamath Falls, then along Highway 140 west to Medford, then along I-5 north to Winston, then west along Highway 42, and then north along Highway 101 to Coos Bay. This route would be approximately 281 miles long, or about 52 miles longer than the proposed route, resulting in approximately 600 acres of additional construction right-of-way disturbance.

The potential advantage of the All Highway Alternative is that the pipeline would be co-located with the existing highway right-of-way, co-locating new disturbance and associated impacts with existing disturbance. However, as explained below, the pipeline would be placed adjacent to, but not within, highway rights-of-way, and therefore the alternative would still require acquisition of new right-of-way. The Federal Highway Administration (FHWA) historically prohibited the installation of new utility facilities within the rights-of-way of access-controlled freeways except in some extraordinary cases. This prohibition was consistent with the American Association of State Highway Transportation Officials (AASHTO) policies for longitudinal accommodation. However, with a 1988 amendment to the FHWA regulations, the FHWA's policy changed to allow each state to decide whether to permit new utility facilities within these rights-of-way, or continue to adhere to the stricter AASHTO policies (FHWA 2014). Oregon defines its policy for accommodating utilities in highway rights-of-way in OAR 734-055-0080. In general, Oregon does not allow utilities to occupy interstate rights-of-way with the exception of perpendicular crossings (Caswell 2008).

In addition to the further disturbance that would result from the longer length of the alternative, there are disadvantages related to its location parallel to highways. The pipeline route paralleling the highway rights-of-way has constraints such as highway cuts and fills; elevated roadway sections, bridges, overpasses and underpasses; clover leaf and other interchanges; as well as commercial, industrial, and residential developments located immediately adjacent to the rights-of-way and interchanges. To be technically feasible, the pipeline would need to divert from the highway right-of-way to avoid cuts and fills, overpasses and other highway infrastructure, and existing developments, which would reduce the area of co-location and increase the pipeline length and associated environmental impacts. For these reasons, we have determined that implementation of the All Highway Alternative would not result in a significant environmental advantage and is not preferable to the proposed route.

3.4.1.2 Federal Lands Route Alternative

We considered a conceptual Federal Lands Alternative that would place the pipeline entirely on federal lands as a potential alternative to avoid or significantly reduce impacts on private property. Given the patchwork nature of federal land holdings in the Project area in southern Oregon, with federal blocks scattered between private tracts, we were unable to identify a route between Malin and Coos Bay that would be entirely on federal lands and not cross private lands. Therefore, a route that would be entirely on federal land and would avoid private property is not feasible and is not considered further in this EIS.

3.4.1.3 Federal Lands Avoidance Route Alternative

We attempted to identify a pipeline route alternative that would avoid crossing federally managed lands. However, given the extensive Forest Service lands and the checkerboard nature of BLM-managed lands in southwest Oregon (see figure 1.1-1), we were unable to identify a route between Malin and Coos Bay that would avoid crossing federally managed lands. We also attempted to identify a pipeline route that would avoid crossing federally managed lands by heading in any direction from Malin and eventually reaching Coos Bay, regardless of length. Again, due to the extensive and connected Forest Service lands to the north, east, south, and southwest of Malin, we were unable to identify a route that could reach Coos Bay without crossing federally managed lands. Therefore, a federal lands avoidance route alternative is not feasible and is not considered further in this EIS.

3.4.2 Pipeline Variations

3.4.2.1 Coos Bay Estuary Variations

We received a number of comments during the scoping and draft EIS comment periods concerning the impact of the pipeline crossing of the Coos Bay estuary, including comments from the Confederated Tribes of Coos, Lower Umpqua, and Siuslaw Indians (CTCLUSI). Pacific Connector proposes to cross the Coos Bay estuary using HDD in two segments between MPs 0.3–1.0 and MPs 1.5–3.0. We evaluated several pipeline variations in this area that would modify the crossing location and method to determine if any alternatives might reduce effects on the estuary, including a North Route Variation, a Modified North Route Variation, and a Haynes Inlet East Avoidance Variation (see figure 3.4-1).

The North Route Variation and the East Avoidance Variation would begin at the pipeline terminus and cross north of Haynes Inlet to the north of Sherwood, and both include HDDs to avoid impacts on the Mangan and Wetle Natural Resource Conservation Service Wetland Reserve Program (WRP) easements on the west and east side of Haynes Inlet (see figure 3.4-1). The Modified North Route Variation would have the same route as the North Route Variation until a point north of Sherwood where it includes an HDD (approximately 5,200 feet in length) that extends from ridgeline to ridgeline on either side of the inlet.

A comparison of major environmental and land use features crossed by each of these variations compared to the corresponding segment of the proposed route is included in table 3.4.2.1-1. The potential advantage of the variations is avoidance of pipeline-related disturbance on the North Point area of North Bend, and avoidance of the Federal Navigation Channel that would be crossed twice, by HDD, at MP 0.66 and MP 1.6 of the proposed route. However, activities proposed by Jordan Cove, which would still occur with use of any of these variations, would affect both the North Point area and the Federal Navigation Channel, essentially negating any advantage of avoiding these areas with the pipeline. The North Point would still be used for construction laydown yards and dredge spoil disposal (within APCO sites 1 and 2, see sections 2.1.1.8 and 2.1.1.10) and the Federal Navigation Channel would still be affected by dredging for the access channel and the marine waterway modifications (see section 2.4.1.5).

The primary disadvantages of the Coos Bay Estuary variations are greater pipeline length and greater associated construction disturbance. Other disadvantages include greater number of waterbody crossings, more forest clearing, and greater number of private land parcels affected.

For the reasons described above, we have determined that implementation of these alternatives would not result in a significant environmental advantage and are not preferable to the proposed route.

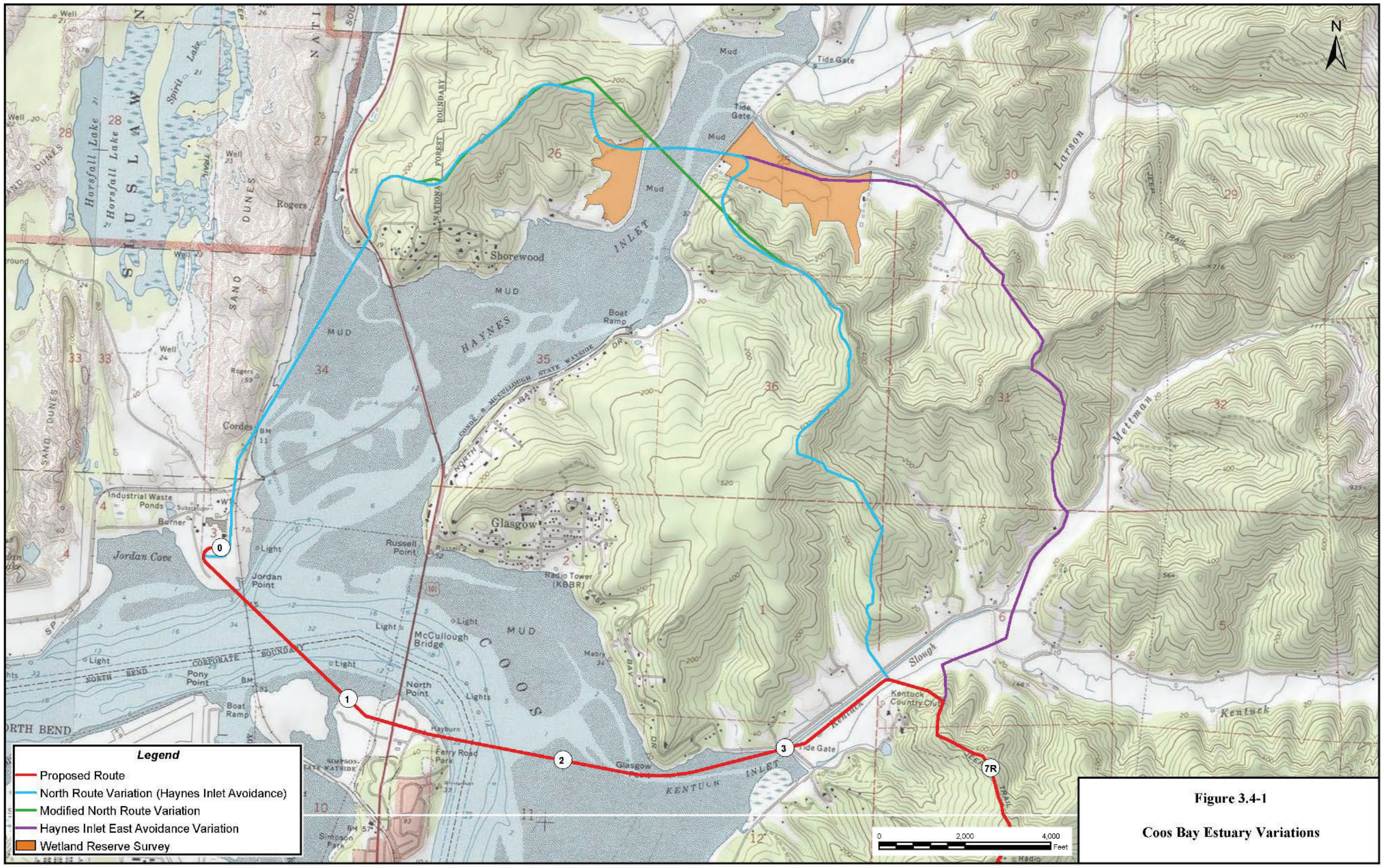

Figure 3.4-1

Coos Bay Estuary Variations

TABLE 3.4.2.1-1

Comparison of Coos Bay Estuary Variations with Proposed Route

Impact/Issue		**Proposed Route**	**North Route Alternative**	**Modified North Route Alternative**	**Haynes Inlet East Avoidance Alternative**
Variation length (miles) a/		3.43 (2.20 HDD)	7.15 (1.65 HDD)	6.55 (2.54 HDD)	7.55 (1.65 HDD)
Construction ROW (acres) b/		9.3	65.5	52.4	67.9
Temporary extra work areas (TEWA) (acres)		54.9	60.9	49.3	64 c/
Total acres of construction disturbance		64.2	126.4	101.7	131.9
Operational easement (acres) d/		9.8	36.3	30.0	45.8
Land ownership (miles)	Private	0.2	5.5	5.1	5.3
	State	3.3	1.7	1.4	2.3
	Federal	0.0	0.0	0.0	0.0
Number of residences within 50 feet of the construction ROW		0	0	0	1 (HDD)
Number of waterbodies crossed e/		3	7	6	16
Length of wetland crossings (feet) e/		3,168	3,711	950	12,936
Agricultural land affected (miles)		0.5	0.5	0.2	2.2
Forest lands affected (miles) f/		0.0	3.5	3.8	2.8
Miles of ROW parallel or adjacent to existing rights-of-way (percent of route length)		0.2	1.9	1.9	2.5
COE 408 facilities g/		2	0	0	0
NRCS WRP Easements h/		0.0	0.4	0.0	0.9
Miles of critical habitat for federal T&E species and EFH species		0 (2.2 avoided by HDD)	0 (1.3 avoided by HDD)	0 (1.2 avoided by HDD)	0 (1.3 avoided by HDD)

General: All values are rounded (acres to nearest whole acre, miles to nearest tenth of a mile, feet to nearest whole foot).

a/ Variation lengths are measured from the point where they deviate from and then return to the proposed route. Lengths cannot be accurately calculated by comparing mileposts due to shifts in the alignment.

b/ The construction right-of-way (ROW) for the proposed route and alternatives is 9 feet wide in upland areas and, where HDDs are proposed, the ROW width has been removed.

c/ TEWAs for the Haynes Inlet East Avoidance Variation are estimated.

d/ The assumed permanent easement width is 50 feet.

e/ NWI coverages and photo interpretation were used for the Proposed Route and the Haynes Inlet East Avoidance Variation.

f/ Includes all forestland types: Evergreen forest, Mixed conifer, Regenerating forests and clear-cuts. The routes do not cross late successional nor old-growth forests.

g/ The proposed route would traverse under the Coos Bay Federal Navigation (shipping) Channel twice at MPs 0.66 and 1.6 by HDD. The alignment of the Haynes Inlet East Avoidance Variation was realigned to avoid crossing dikes associated with the Larson Inlet Flood Damage Reduction (FDR) Project located along Larson Slough. According to the National Levee Database (http://geoplatform.usace.army.mil/home), the Larson Inlet FDR Project is a federally authorized and constructed and a non-federally operated and maintained, agricultural flood-protection project.

h/ The Mangan WRP would be crossed by both North and East Avoidance Variation on the west side of Haynes Inlet for approximately 1,150 feet. The Wetle WRP would be crossed on the east side of Haynes Inlet by the North Route Variation for approximately 1,130 feet and by the East Avoidance Variation for approximately 3,450 feet.

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3.4.2.2 Blue Ridge Variation

Based on comments received during scoping and concerns expressed by the BLM regarding steep topography, late-successional old-growth (LSOG), and potential impacts on threatened and endangered terrestrial species, we evaluated an alternative between MPs 11 and 25 referred to as the Blue Ridge Variation. The 15.2-mile-long Blue Ridge Variation, which is depicted in figure 3.4-2, would deviate from the proposed route near MP 11 just south of the Coos River, continuing southwest across Catching Slough, turning south/southeast, generally co-locating with an existing utility right-of-way before rejoining the proposed route near MP 25. Table 3.4.2.2-1 compares the variation to the corresponding segment of the proposed route. Additional details regarding the assessment of this variation can be found in appendix F.9. In response to the draft EIS, we received numerous comments on the Blue Ridge Variation analysis. We also received additional information from the Applicants. These comments and this information are incorporated as appropriate into the following revised analysis.

The Blue Ridge Variation is longer and would affect about 174.5 acres compared to 161.8 acres for the proposed route. The Blue Ridge Variation more than doubles the number of private parcels (from 21 to 47) and miles of private lands crossed (from 6.5 to 13.8).

When compared to the corresponding segment of the proposed route, the Blue Ridge Variation would reduce clearing of LSOG forest (late-successional forest stands greater than 80 years old) from 32 acres to 9 acres, or from 1.7 miles to 0.6 miles. Additional analysis, specific to BLM lands, was conducted by the BLM utilizing the agency's Forest Operations Inventory (FOI) in response to comments received on the draft EIS. This analysis determined that 18 acres of the 32 acres of LSOG habitat that would be removed by the proposed route was complex LSOG. Similar data was not available to assess the complexity of the 9 acres of LSOG occurring on private lands.

Late-successional forest stands have a well-defined, multi-tiered canopy, which creates microhabitats for many species (Bingham and Sawyer, Jr. 1991; Spies and Franklin 1996), including the federally listed NSO and MAMU. The Blue Ridge Variation would substantially reduce the acres of occupied and presumed occupied (suitable habitat) MAMU stands removed from 25 acres to 3 acres and reduce the acres of NSO nesting, roosting and foraging habitat removed from 36.3 acres to 9 acres. The Blue Ridge Variation would remove 29 acres less of ODFW-designated Category 1 Habitat (see definition and discussion in section 4.5.1.1).

The Blue Ridge Variation increases the number of perennial waterbodies crossed from 3 to 31; increasing the number of known and assumed anadromous fish-bearing streams crossed from 4 to 18 (includes intermittent anadromous fish-bearing waterbodies). The acres of wetlands crossed under this variation also increases from 13.4 acres to 32.4 acres, of which, 1.2 acres would be permanently converted. The Blue Ridge Variation would also increase construction in landslide prone areas from two areas, totaling 1,088 feet, to five areas, totaling 7,137 feet.

As indicated in the comparison table, the above discussion, and the analysis contained in appendix F.9, the primary trade-offs between the proposed route and the variation are between terrestrial resources (e.g., LSOG forest and MAMU stands/habitat) and aquatic resources (e.g., waterbody crossings and anadromous fish habitat), as well as public and private lands. With respect to terrestrial and aquatic resources, the measures that would be implemented to avoid or reduce these impacts differs considerably. Constructing and operating the pipeline along the proposed route would result in a permanent[59] loss of LSOG forest and would adversely affect MAMU (see sections 4.4, 4.6, and appendix F.9 for discussions regarding these resources). The Applicants have very minimal options available for avoidance and minimization measures to address these permanent effects to upland resources (i.e., complex LSOG habitat, MAMU and NSO nesting habitat), and have not proposed mitigation for these long-term effects. The MAMU timing constraints required by BLM's RMP would require construction to occur over several years on BLM lands for the proposed route resulting in a number of direct and indirect effects on both the human and natural environment (e.g., noise, water quality, traffic). In contrast, these constraints are not expected to cause construction delays along the Blue Ridge Variation due to the small amount of BLM lands that provide MAMU habitat along the variation.

As illustrated in table 3.4.2.2-1, some of the impacts on aquatic resources, waterbodies, and anadromous fish would be temporary to short-term with the implementation of Jordan Cove's and Pacific Connector's proposed impact minimization and waterbody restoration measures (e.g., Jordan Cove's *Plan*, *Procedures*, and ECRP), as well as our recommendations (see sections 4.3 and 4.5 for discussions regarding these resources). For waterbody crossings on federal lands the Applicants have adopted construction and restoration procedures and also proposed compensatory mitigation to avoid, reduce, and compensate for the effects to waterbodies and anadromous fish as part of the federal Right-of-Way Grant application (see appendices F.10 and F.12). However, some permanent unmitigated effects on waterbodies and anadromous fish would occur in the form of the permanent loss of mature riparian areas associated with affected waterbodies.

Our experience from reviewing stream crossings by FERC-regulated pipelines constructed in numerous habitats across the U.S. has confirmed that the short duration of the crossing and the prompt restoration of the stream bed and stabilization of the stream banks results in very few impacts on waterbodies that extend in time beyond the construction and initial restoration of the right-of-way. This is in part due to implementation of best management practices such as dry crossing methods, timing and duration, and restoration methods that are required by the FERC's *Plan* and *Procedures*, which are methods that the Applicants have incorporated into their proposal. By comparison, the removal of LSOG habitat is a permanent impact for the operational right-of-way and, even in temporary work areas, recovery of the habitat would take at least 80 years.

We acknowledge that the variation would increase the number of private parcels crossed. Numerous public comments in the Commission's administrative record express concerns about how these lands would be affected. However, we note that although many additional private parcels are affected by the variation, only one residence is located within 50 feet of the construction right-of-way. This EIS addresses numerous measures to be employed during and following construction that would reduce impacts and facilitate restoration of the right-of-way.

We also acknowledge the concerns expressed by the NMFS and the COE regarding the increased impacts on waterbodies, threatened and endangered aquatic species, and adjacent riparian vegetation; and the BLM, FWS, and Tribes regarding the impacts on LSOG forest, threatened and endangered terrestrial species, and other upland managed resources. As stated previously, there are considerable trade-offs between the proposed route and the variation.

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[59] The removal of LSOG habitat would result in a long-term (80+ year) timeframe for conifers to mature to a point where they could provide functional LSOG habitat.

In the alternatives methodology described at the beginning of this section, we state that an alternative would be preferable if it meets the stated purpose of the Project; is technically and economically feasible and practical; and if implemented would result in a significant environmental advantage when compared to the proposed action. We also state that when making an alternatives determination we attempt to balance the overall impacts (and other relevant considerations) of the alternative and the proposed action. Therefore, recognizing the trade-offs between the proposed route and the variation; the differences between terrestrial and aquatic resource impacts in regard to temporal effects, as well as the scope of avoidance, minimization, and mitigation for these effects; and the magnitude of the effects, we have determined that the Blue Ridge Variation would result in a significant environmental advantage when compared to the corresponding segment of the proposed route. Our conclusion is based primarily on the variation's ability to reduce long-term permanent impacts on LSOG habitat affected by the proposed route. Both the sensitivity and value of this habitat and the duration of the impact contribute to this finding. Therefore, **we recommend that:**

- **<u>Prior to construction</u>, Pacific Connector should file with the Secretary, for review and written approval by the Director of OEP, revised alignment sheets that incorporate the Blue Ridge Variation into its proposed route between MP 11 and MP 25.**

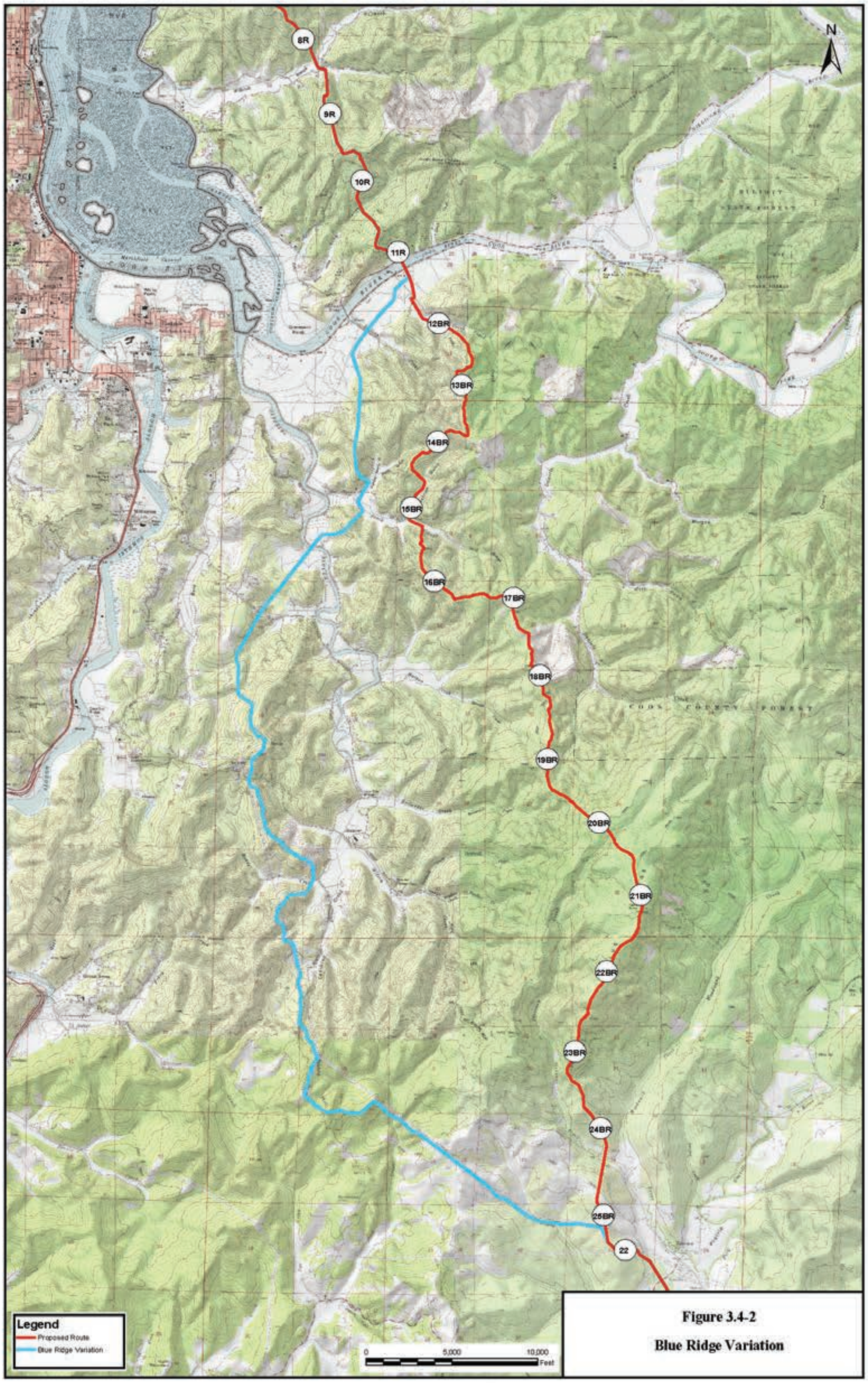

Figure 3.4-2

Blue Ridge Variation

TABLE 3.4.2.2-1

Comparison of Blue Ridge Variation with the Proposed Route

Alternatives Analysis		Proposed Route	Blue Ridge Variation
General			
Length (miles) a/		14.0	15.2
Construction right-of-way (acres)		161.8	174.5
Temporary extra work areas (TEWA) (acres)		37.5	57.0
Uncleared storage areas (acres)		44.7	1.5
Temporary access roads (TARs) Permanent access roads (PARs)		1 (TAR 12.08/0.2 ac) 1 (PAR 22.16 BR/0.1 ac)	1 (TAR 13.8/0.2 ac) 1 (PAR 15.6/0.3 ac)
Land Use			
Permanent easement (acres) b/		85.2	92.3
Land ownership (miles)	Private	6.5	13.8
	BLM	7.5	1.4
	State	0.0	<0.1
Number of landowner parcels crossed	Private	21	47*
	BLM	12	4
	State	2	2
BLM Coos Bay Wagon Road Lands crossed (miles) c/		7.5	1.4
BLM Public Domain Lands crossed (miles) c/		0.0	<1.0 miles
Number of residences within 50 feet of the construction right-of-way (ROW)		0	1
Waterbodies and Wetlands			
Number of waterbodies crossed	Field survey data	3 perennial 7 intermittent d/ e/ (5.7 unsurveyed)	30 perennial 29 intermittent 1 estuarine (4.6 unsurveyed)
Length of wetland crossings (miles)		0.8	1.8
Permanent conversion of wetlands (acres)		0.0	1.2
Vegetation			
Designated Riparian Reserves on BLM-managed lands Impacted (acres)		12.3	9.1
Agricultural pastures affected (acres construction right-of-way)		8.6	11.1
Coniferous forest (acres construction ROW) f/	LSOG	22.8	8.8
	Mid-seral	59.7	37.5
	C – R	78.5	129.0
LSRs crossed (miles/acres)		5.5 miles / 97.3 acres	0.44 mile / 5.16 acres
Direct LSOG Effects, all ownerships (miles/acres)		1.7 miles/32 acres	0.6 miles/9 acres
Direct LSOG Effects on BLM Lands (acres) m/		49.0	0.2
Direct Complex LSOG Effects on BLM lands (acres) m/		18.0	0.0
Biological Resources			
Northern Spotted Owl (NSO) home range (1.5-mile radii)		1 / 1.23 miles	1 / 0.75 mile
High NSO NRF and NRF habitat removed on all lands (acres) g/		22.8	8.8
Direct Effects on NSO Nesting Habitat on BLM Lands (acres)		16.4	0.0
Indirect Effects on NSO Nesting Habitat on BLM Lands (acres)		60	0.0
Direct Effects on NSO NRF Habitat on BLM Lands (acres)		1.4	0.0
Indirect Effects on NSO NRF Habitat on BLM Lands (acres)		11.4	0.0
Number of marbled murrelet (MAMU) stands (all lands) crossed by ROW		3 occupied stands; 14 presumed occupied stands h/	3 presumed occupied stands
MAMU Suitable Habitat removed on all lands (acres) i/		25 (5.8 acres occupied; 19.1 acres presumed)	3.0
MAMU Suitable Habitat Modified on all ownerships (Indirect Effect)		9	0
Occupied/Potential MAMU stands on BLM Lands		3/1	0/0
Direct Effects on MAMU Nesting Habitat on BLM Lands (acres)		10.4	0.0
Indirect Effects on MAMU Nesting Habitat on BLM Lands (acres)		34.3	0.0
Construction Effects on ODFW Irreplaceable Essential Habitat – BLM Lands (acres)		27	<1
Construction Effects on ODFW Irreplaceable Essential Habitat – Other Lands (acres)		5	3
Operational Effects on ODFW Irreplaceable Essential Habitat – BLM Lands (acres)		5	<1
Operational Effects on ODFW Irreplaceable Essential Habitat – Other Lands (acres)		1	1
Number of anadromous fish-bearing streams crossed j/	Known	4	9
	Assumed	0	9

TABLE 3.4.2.2-1 (continued)

Comparison of Blue Ridge Variation with the Proposed Route

Alternatives Analysis		Proposed Route	Blue Ridge Variation
Fisheries critical habitat	Coho k/	4	7
(streams crossed)	Green Sturgeon l/	0	0
Number of anadromous fish species (BLM)		0	0
Number of resident fish species (BLM)		1	0
Number of EFH fish species (BLM)		0	0
Number of ESA fish species (BLM)		0	0
Number of anadromous fish species (other)		5	15
Number of resident fish species (other)		5	19
Number of EFH fish species (other)		5	9
Number of ESA fish species(other)		5	9
Geotechnical			
Landslide prone areas m/		2 landslide areas (totaling 1,088 feet)	5 landslide areas (totaling 7,137 feet)
Cultural Resources			
Number of known cultural resources sites		1 n/ o/	0
Number of newly identified cultural resources		1 n/	0 p/
Other			
Right-of-way adjacent to existing rights-of-way (miles and percent of route length) q/		8.3 (59 percent)	7.1 (47 percent)

General: All values are rounded (acres to nearest whole acre, miles to nearest tenth of a mile, feet to nearest whole foot).
* Does not include county parcels associated with existing county roads.

a/ Route Alternative lengths are measured from the point where they deviate from and then return to the proposed route. Lengths cannot be accurately calculated by comparing mileposts due to shifts in the alignment.
b/ Acres of permanent easement calculated based on a 50-foot-wide permanent easement.
c/ See further explanation of these land categories in section 4.7.3.3.
d/ Includes waterbodies not crossed by the centerline but within the right-of-way.
e/ Field surveys on BLM lands and desktop analysis on private lands.
f/ Evergreen Forest: LSOG (late successional/old-growth forest) = 80+ years; Mid-seral = 40 to 80 years; C-R (Clear-cut/regenerating forest) = 0 to 40 years.
g/ Acreage is based on 2019 updated NSO habitat coverage for the pipeline project (nesting, roosting, and foraging habitat: NRF, High NRF).
h/ “Presumed occupied stands” have not been surveyed following the species-specific survey protocol (Mack et al. 2003). “Occupied stands” are confirmed occupied based on the species-specific survey protocol.
i/ Acreage is based on 2019 updated MAMU habitat coverage for the pipeline.
j/ ODF (2017). Each crossing would include clearing of some riparian vegetation.
k/ NMFS (2008a).
l/ NMFS (2009).
m/ Defined in appendix F.9 of this EIS.
n/ Surveys are incomplete on approximately 6.0 miles (43 percent) of the route on private lands.
o/ The historic Barker-Morris Families Cemetery, dating to 1872, is located on private land in Township 27 S, Range 12 W, Section 14. The historic cemetery is situated at MP 24.3 of the proposed route. The cemetery is shown on the McKinley 7.5-minute quadrangle approximately 24 meters east of the construction right-of-way. However, cultural surveys have not been conducted on this privately-owned parcel, and the exact location of the cemetery has not been verified. The cemetery is listed in the Oregon Burial Site Guide but has not been recorded as an archaeological site with the Oregon State Historic Preservation Office.
p/ Surveys have not been conducted along the entire route of the variation.
q/ The Blue Ridge Variation is adjacent to a BPA Powerline corridor, whereas the proposed route is adjacent to logging roads.

3.4.2.3 Weaver Ridge Variations

At the request of the BLM, we evaluated several route variations between MPs 42.7 and 49.8 to determine if impacts on MAMU and NSO critical habitat could be reduced. As illustrated in figure 3.4-3, we evaluated the Deep Creek Variation, Weaver Ridge Variation 1, Weaver Ridge Variation 2, Weaver Ridge Variation 2a, Weaver Ridge Variation 3, Weaver Ridge Variation 3a, and Weaver Ridge Variation 4.

The Weaver Ridge Variation 1 would deviate from the proposed route around MP 46.0 crossing the logging spur road north of a reservoir and head almost due east on the north side of a tributary of Wildcat Creek over ridges, reconnecting with the proposed route at about MP 49.8. This alternative would be slightly shorter than the proposed route. However, the Weaver Ridge Variation 1 would cross more miles of critical habitat for MAMU and NSO, and would cross two MAMU occupied stands (compared to one along the proposed route) and five NSO home ranges (compared to four along the proposed route).

The Weaver Ridge Variation 2 would start at the same location as Variation 1 but deviate from Variation 1 east of the proposed route at about MP 46, crossing a logging spur road, pass the Signal Tree Quarry, then follow Signal Tree Road for about 3 miles. It would head south over ridges, then join Variation 3 along Wildcat Creek. Weaver Ridge Variation 2a would deviate from Variation 2 just across the Coos County line along Signal Tree Road, cutting diagonally along Wildcat Creek to rejoin Variation 2 Route across the Douglas County line.

The Weaver Ridge Variation 3 would deviate from the proposed route at about MP 42.6. It would follow ridges for about 3.5 miles, crossing Signal Tree Road and Upper Rock Creek. The variation would then turn east and follow ridges for almost 4 miles, crossing Wildcat Creek before rejoining the proposed route at about MP 48.5. Weaver Ridge Variation 3a would deviate from Variation 3 and follow Wildcat Creek for 1.5 miles to join the proposed route at about MP 49.0.

A comparison of the environmental features of the Weaver Ridge Variations and the corresponding segment of proposed route are shown in table 3.4.2.3-1. Weaver Ridge Variations 2, 2a, 3, and 3a are all longer than the corresponding segment of proposed route and would cross more miles of MAMU and NSO critical habitat. Variations 3 and 3a would cross six NSO home ranges, while Variations 2 and 2a would cross five NSO home ranges (compared to four for the corresponding segment of proposed route). Compared to the proposed route, these variations would require clearing more LSOG and affect more acres of LSR on lands managed by the BLM. As a result, none of these variations within this area would ultimately reduce impacts on MAMU and NSO critical habitat. Therefore, we have determined that implementation of Weaver Ridge Variations 2, 2a, 3, and 3a would not result in a significant environmental advantage and are not preferable to the proposed route.

Weaver Ridge Variation 1 would be shorter than the corresponding segment of proposed route and would cross less waterbodies than the proposed route; however, it would have greater impacts on forested habitats, cultural resources, as well as MAMU and NSO critical habitat. Therefore, we have determined that implementation of Weaver Ridge Variation 1 would not result in a significant environmental advantage and is not preferable to the proposed route.

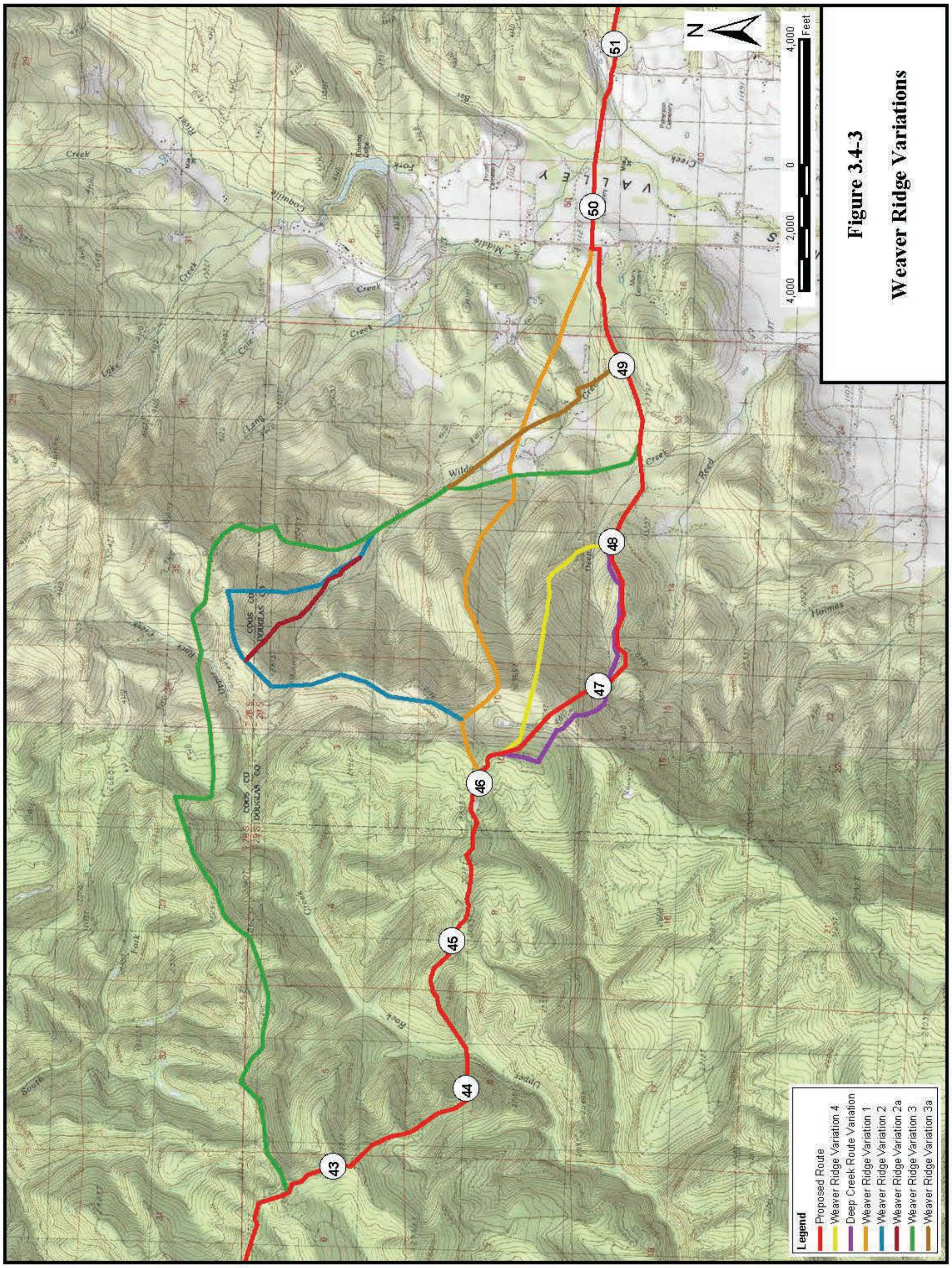

Figure 3.4-3

Weaver Ridge Variations

TABLE 3.4.2.3-1

Comparison of Weaver Ridge Variations with the Proposed Route

Alternatives Analysis		Proposed Route	Deep Creek Variation	Weaver Ridge Variations: 4	1	2	2a	3	3a
General									
Total length (miles) a/		7.3	7.4	7.2	7.0	9.3	9.0	8.6	8.2
Construction ROW (acres) b/, c/		84	85	82	80	107	103	99	94
Operational easement (acres) d/		44	45	43	42	56	54	53	50
Number of Parcels Affected	BLM	4	4	4	3	5	4	4	4
	Private	12	12	11	11	15	14	12	13
	State	0	0	0	0	0	0	0	0
Land ownership (miles)	BLM	2.7	2.8	3.3	2.5	3.4	2.8	3.6	3.2
	Private	4.6	4.6	3.9	4.5	6.0	6.2	5.0	5.0
	State	0	0	0	0	0	0	0	0
Waterbodies and Wetlands									
Number of waterbodies crossed e/		5	5	5	2	7	7	11	11
Total wetland crossing length (feet) f/		0	0	0	0	0	0	0	0
Land Use									
Land Allocations (miles)	Matrix	2.1	2.1	2.1	1.1	1.4	1.4	0.7	0.4
	LSR	0.6	0.7	1.2	1.4	1.9	1.4	2.9	2.9
	Riparian Reserves	0.5	0.7	0.5	<0.1	0.5	0.3	0.6	0.5
Evergreen forest, Mixed conifer (late successional/old-growth) (miles)		0.4	0.7	0.4	1.8	2.2	1.7	1.2	1.7
Regenerating/mid-seral forest (miles)		3.7	5.4	3.9	3.4	4.5	4.5	6.3	5.2
Total forest lands affected (miles)		6.0	7.1	5.9	6.3	8.5	8.1	8.0	7.4
Other land use types (miles)		1.3	0.3	1.3	0.7	0.8	0.8	0.7	0.8
Right-of-way parallel or adjacent to existing rights-of-way (miles)		3.2	3.8	3.6	2.4	3.6	3.2	2.7	2.3
Number of previously identified cultural resources along the route f/		0	0	0	1	0	0	0	0
Newly identified cultural resources along the route (number) f/		0	0	0	0	0	0	0	0
Endangered Species									
MAMU critical habitat crossed (miles)		0.6	0.7	1.2	1.4	2.0	1.4	2.9	2.9
Number of MAMU occupied stands crossed		1	1	2	2	1	1	0	0
MAMU occupied stands crossed (miles)		<0.1	<0.1	0.4	1.0	<0.1	<0.1	0	0
NSO critical habitat crossed (miles)		0.9	1.0	1.0	1.1	1.7	1.3	2.5	2.5
Number of NSO home ranges crossed		4	4	4	5	5	5	6	6
NSO home ranges crossed (miles)		5.9	6.0	5.8	6.0	8.1	7.8	7.3	7.0
Number of NSO 500-acre core areas crossed		1	1	0	1	2	2	2	2
NSO core areas crossed (miles)		0.6	0.6	0	1.1	1.4	1.0	1.9	1.9

TABLE 3.4.2.3-1 (continued)

Comparison of Weaver Ridge Variations with the Proposed Route

Alternatives Analysis	Proposed Route	Deep Creek Variation	Weaver Ridge Variations					
			4	1	2	2a	3	3a
Number of 30-acre nest patches crossed	0	0	0	1	1	0	0	0
NSO 30-acre nest patches crossed (miles)	0	0	0	0.1	0.4	0	0	0

General: All values are rounded (acres to nearest whole acre, miles to nearest tenth of a mile, feet to nearest whole foot).
a/ Variation lengths are measured from the point where they deviate from and then return to the proposed route. Lengths cannot be accurately calculated by comparing mileposts due to shifts in the alignment.
b/ Assumes a 95-foot-wide construction right-of-way (ROW) for all variations.
c/ TEWAs for all route variations have not been designed and are not included in the total acres of disturbance.
d/ The assumed operational easement is 50 feet; however, Pacific Connector would only maintain vegetation within 15 feet of the pipeline centerline for a total of 30 feet during operation.
e/ Waterbodies from PNW Hydrography Framework Clearinghouse.
f/ NWI CONUS data.

Weaver Ridge Variation 4 would deviate from the proposed route at about MP 46.3 and head southeast over ridges on the north side of Deep Creek, crossing the logging spur road south of the reservoir and reconnecting with the proposed route at about MP 48.0. The Deep Creek Variation would deviate from the proposed route at about MP 46.3 and follow a ridge north of Holmes Creek Spur Road and an unnamed four-wheel-drive road back to the proposed route at about MP 47.0 and cross to the north side of the proposed route and parallel that route for about 1 mile before reconnecting with the proposed route near MP 48.0. The Deep Creek Variation would be about 0.1 mile longer than the corresponding segment of proposed route. Based on a geotechnical review, a high risk of landslides and surface erosion were identified where the Deep Creek Variation would cross the eastern flank of Weaver Ridge above a first order stream. Similarly, where Weaver Ridge Variation 4 would cross Weaver Ridge, it would traverse an extremely steep, narrow rock outcrop that would require blasting. These areas would be avoided by the proposed route where it would ascend Weaver Ridge westward from a forest plantation near MP 46.5 up the slope to the north avoiding the rock outcrop. For these reasons, we have determined that implementation of the Deep Creek Variation and Weaver Ridge Variation 4 would not result in a significant environmental advantage and are not preferable to the proposed route.

3.4.2.4 Camas Valley Northern Variation

Pacific Connector had initially identified a potential variation through the Camas Valley between MPs 50 and 53 to reduce impacts on MAMU habitat (i.e., the Camas Valley Northern Variation), and we evaluated this variation to see if it would be environmentally preferable to the proposed route. This variation is illustrated on figure 3.4-4 and compared in table 3.4.2.4-1.

The Camas Valley Northern Variation would deviate from the proposed route at about MP 50.2 and head northeast across the Camas Valley then turn southeast over forested hills before rejoining the proposed route near MP 53.0. This variation would cross habitat and one occupied stand for MAMU and habitat for NSO on BLM-managed lands. For this reason, the BLM found it unacceptable. We agree and have determined that implementation of the Camas Valley Northern Variation would not result in a significant environmental advantage and is not preferable to the proposed route.

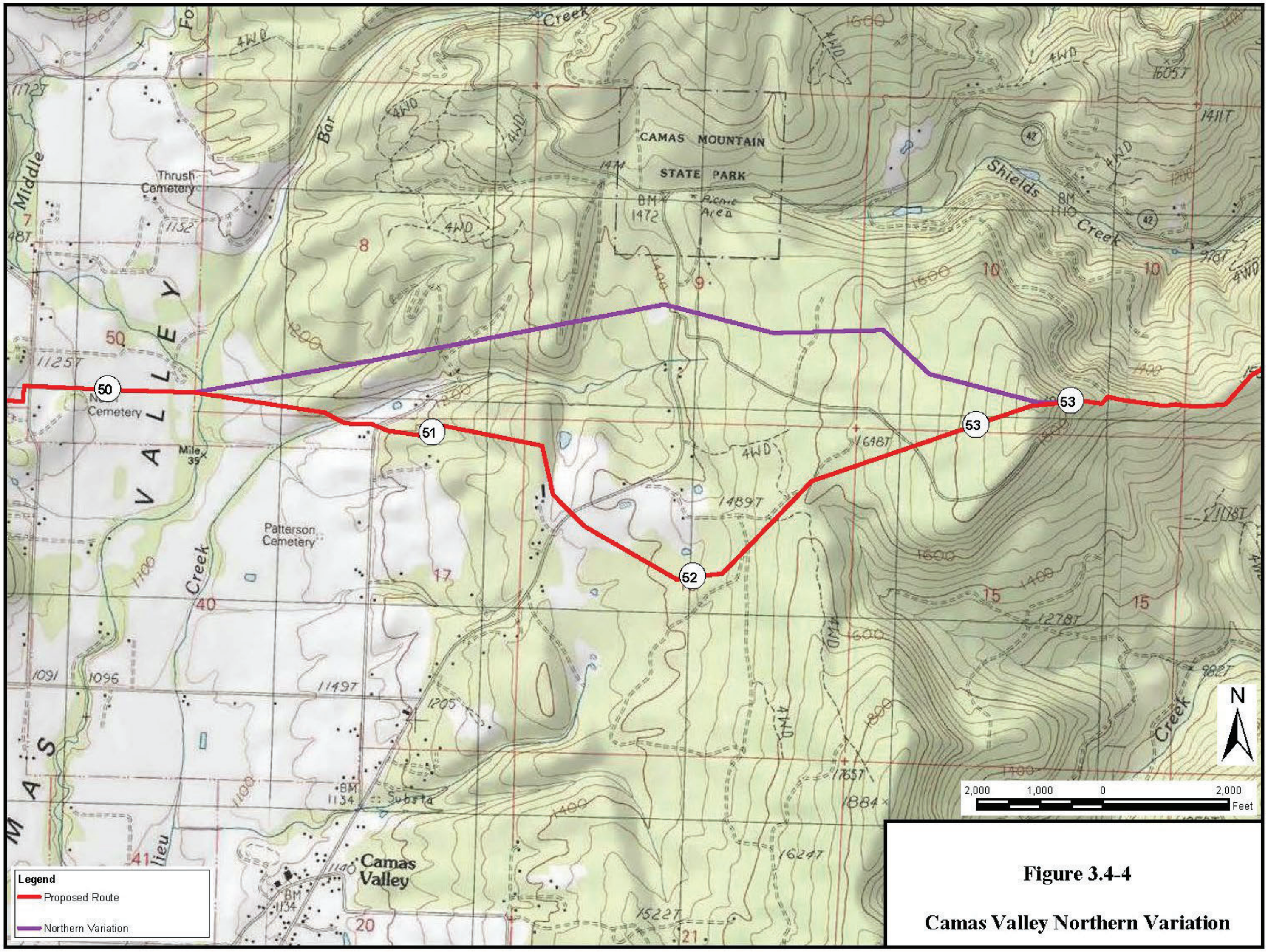

Figure 3.4-4

Camas Valley Northern Variation

TABLE 3.4.2.4-1

Comparison of Camas Valley Northern Variation with the Proposed Route

Alternatives Analysis		Proposed Route		Camas Valley Northern Variation
General				
Length (miles) a/		2.9		2.7
Construction ROW (acres)		33		31
Permanent easement (acres) b/		17		16
Land Use				
Land Ownership (miles)	Private	2.3		2.0
	State	0		0
	Federal (BLM/NFS lands)	0.6		0.8
Number of landowner parcels crossed		15		8
Number of residences within 50 feet of construction ROW		0 c/		0
Right-of-way parallel or adjacent to existing rights-of-way (miles)		0.1		0.1
LSR - Federal land use designation (acres)		5 d/		0
Riparian Reserves - federal land use designation (acres)		1		3
Waterbodies and Wetlands				
Number of waterbodies crossed e/		4		11
Length of wetland crossings (feet) f/		0		0
Vegetation				
Agricultural lands affected (acres)		8		2
Total forest clearing (acres)		28		39
Clearcut/ Regenerating (0 to 40 years) (acres) g/		14		22
Mid-Seral Forest (40 to 80 years) (acres)		8		10
Late-Successional Forest (80 to 175 years) (acres)		6		2
Old-Growth Forest (175 years +) (number)		0		4
Biological Resources				
MAMU suitable habitat crossed (feet) h/		5		18
MAMU stands		No known stands	Occupied	Alignment crosses 1,043 feet of Occupied Stand R3027
		No known stands	Presumed	Alignment crosses 350 feet of potential MAMU Stand B12 not likely to be occupied based on 2-year survey protocol.
MAMU critical habitat (acres)		5 Pacific Connector made a minor adjusted to the Southern Route Variation to avoid crossing approximately 175 feet of the old-growth forest within this Critical Habitat Unit.)		0
NSO suitable habitat crossed (acres) i/		20		33
NSO nest patch/cores		No known nest patch/cores		None
NSO critical habitat crossed (feet)		0		0
Area affected by habitat category (acres) j/			Category	
		2	1	5
		13	2	5
		17	3	15
		16	4	18
		2	5	2
		3	6	2

TABLE 3.4.2.4-1 (continued)

Comparison of Camas Valley Northern Variation with the Proposed Route

Alternatives Analysis	Proposed Route	Camas Valley Northern Variation
Kincaid's lupine	Approximately 1.1 miles of habitat may be suitable for Kincaid's lupine.	Approximately 2.2 miles of potential habitat crossed; 0.8 mile surveyed of which 0.3 mile was considered suitable.
ESA fish species present/habitat k/	1 stream crossing known, 3 stream crossings unknown. 1 stream crossing - Oregon Coast ESU Coho, assumed.	1 stream crossing known, 3 stream crossings unknown. 1 stream crossing - Oregon Coast ESU Coho, assumed.
StreamNet – anadromous fish distribution l/	None	None
Geotechnical		
Steep or difficult terrain (miles) m/	0.0	0.0
Highly erosive soils (miles) n/	0.2	0.2
Cultural Resources		
Number of previously recorded cultural resources	2 sites	3 - Isolated finds; 2- sites
Number of newly identified cultural resources o/	1- isolated find	N/A

General: All values are rounded (acres to nearest whole acre, miles to nearest tenth of a mile, feet to nearest whole foot).
a/ Variation length is measured from the point where it deviates from and then returns to the proposed route. Length cannot be accurately calculated by comparing mileposts due to shifts in the alignment.
b/ Assumes 50-foot-wide operational easement.
c/ There are 2 outbuildings (barns/sheds) in the vicinity of the proposed route that are within 50 feet of the construction right-of-way (ROW) (MP 51.4 and MP 51.9). Neither of these structures is suspected of being residences; however, during the ROW acquisition phase, Pacific Connector would attempt to locate the construction ROW at least 50 feet from any residences, where feasible.
d/ Approximately 5 acres of LSR would be affected, with 3 acres occurring within clear- cut/regenerating forests (0 to 40 years) and 2 acres occurring within mid-seral forest (40 to 80 years).
e/ Waterbodies from PNW Hydrography Framework Clearinghouse.
f/ NWI CONUS data.
g/ Forest Age Classes: Includes recent clearcut forests and areas of inroad construction where forest clearing would be reduced.
h/ Huff et al. (2006).
i/ Forest Service (2005a).
j/ Based on surveys completed by Pacific Connector.
k/ FWS, NMFS, and StreamNet (http://www.streamnet.org).
l/ ODFW (2000, 2006a); StreamNet.
m/ Based on Soil Mapping Units that have slopes of 50-75 percent and have a water erosion rating of high or severe (NRCS 2004).
n/ Based on Soil Mapping Units that have a water erosion rating of high or severe (NRCS 2004).
o/ Variation has not been completely surveyed.

3.4.2.5 Umpqua National Forest Variations

In consultation with the Forest Service and to evaluate potential options to reduce impacts on forested lands, we evaluated three route variations within the Umpqua National Forest between MPs 104.8 and 111.5. The proposed route and variations are shown on figure 3.4-5.

Variation 1 would generally follow along Wildcat Ridge close to the proposed route between MPs 105 and 109, where it would then turn east and then southeast, crossing near Long Prairie, then south before rejoining the proposed route near MP 111.2. Environmental features crossed or affected by Variation 1, and a comparison to the corresponding segment of proposed route, are included in table 3.4.2.5-1.

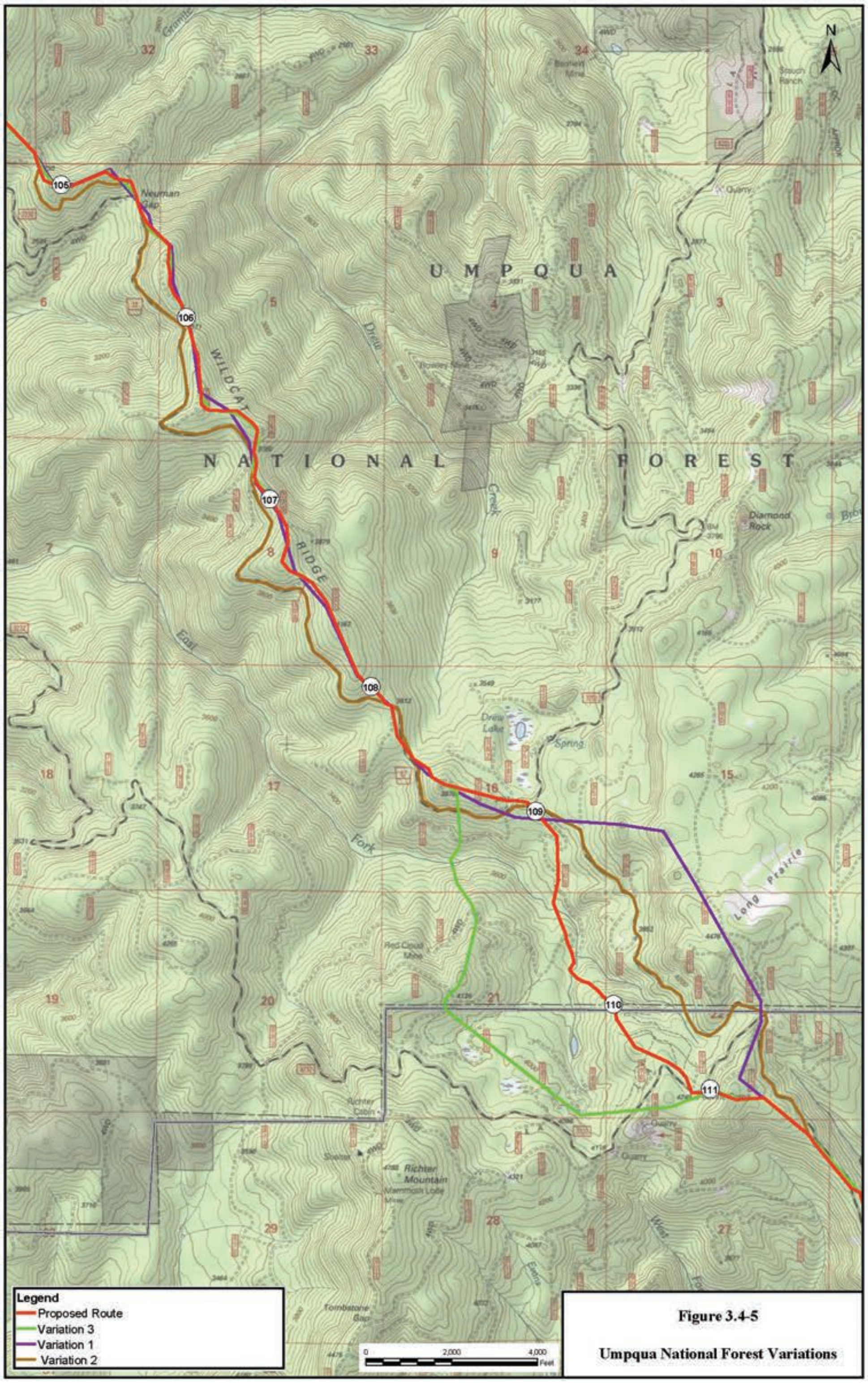

Figure 3.4-5

Umpqua National Forest Variations

TABLE 3.4.2.5-1

Comparison of Umpqua National Forest Variations with the Proposed Route

Impact/Issue	Proposed Route	Variation 3	Variation 1	Variation 2
General				
Total length (miles) a/	6.4	6.7	6.4	7.5
Construction ROW (acres) b/	73	77	73	86
Total construction disturbance (acres)	110	117	110 c/	129 c/
Operational easement (acres) d/	45	41	45	45
Land Ownership (miles)				
Forest Service	6.4	6.7	6.4	7.5
Geotechnical				
Steep or difficult terrain crossed (miles) e/	0.2	0.4	0.1	7.5 (side hill along existing road)
Waterbodies and Wetlands				
Number of waterbodies crossed f/	5	6	1	13
Wetlands crossed (feet) f/	150	120	0	30
Waterbody and wetland disturbance during construction (acres)	0.2	0.3	0	0
Land Use				
Land allocations crossed (miles):				
Matrix	2.9	3.3	3.1	3.3
LSR	3.5	3.4	3.3	4.2
Riparian Reserves	0.5	0.2	0.0	0.3
Evergreen Forest, Mixed conifer (miles)	4.2	3.9	3.4	5.6 h/
Regeneration Forest (miles)	1.8	2.3	2.7	1.8 h/
Clearcuts (miles)	0.0	0.0	0.1	0.0 h/
Total forest lands crossed (miles)	6.0	6.2	5.9	7.4 h/
Other land use types	0.4	0.5	0.4	0.1 h/
Parallel or adjacent to existing rights-of-way (miles)	5.6	5.1	5.4	7.3
Cultural Resources				
Number of previously identified cultural resources along route	0	1 – site 2 – isolated finds	3	0
Number of newly identified cultural resources along route	3 – site 1–isolated find	Information not available	1	Information not available
Critical Habitat g/				
Federally listed critical habitat for NSO affected (acres)	52	33	34	40 (95-foot ROW only)
Federally listed critical habitat for NSO crossed (miles)	6.4	6.7	6.3	7.5
Number of NSO core areas crossed (0.5-mile buffer of nest site)	3	4	3	3

General: All values are rounded (acres to nearest whole acre, miles to nearest tenth of a mile, feet to nearest whole foot).
a/ Variation lengths are measured from the point where they deviate from and then return to the proposed route. Lengths cannot be accurately calculated by comparing mileposts due to shifts in the alignment.
b/ Assumed construction right-of-way (ROW) 95 feet wide.
c/ TEWAs for the variation have not been designed but are estimated assuming they would be comparable to the proposed route.
d/ The assumed operational easement is 50 feet.
e/ Based on slopes that are greater than 50 percent (based on 10-meter digital elevation model).
f/ Waterbodies identified using USGS National Hydrography Dataset, and wetlands identified using FWS National Wetland Inventory mapping.
g/ Includes acres of impact associated with the construction ROW and TEWAs. This analysis used the final revised critical habitat designation (2008).
h/ Variation 2 follows existing Forest Service Road 3200 which is assumed would require extensive side-cuts, therefore, miles crossed considered habitat adjacent to the road.

Most environmental impacts from Variation 1 would be similar to those from the proposed route. The primary environmental advantage would be fewer waterbodies crossed (1 compared to 7), and less NSO critical habitat affected (34 compared to 52 acres) than the corresponding segment of proposed route. The primary disadvantage of the variation is that it has the potential to impact an important traditional cultural property as identified by the Forest Service and Cow Creek Tribe.

Based on this concern, we have determined that implementation of Variation 1 would not result in a significant environmental advantage and is not preferable to the proposed route.

Variation 2 would follow a route suggested by the Forest Service that would follow existing Forest Service Road 3200 between about MPs 104.8 and 111.5 of the proposed route. The rationale for this variation is to utilize the existing cleared road corridor to reduce forest fragmentation and reduce impacts on LSRs. Variation 2 would be about 1.1 miles longer and result in about 19 additional acres of construction disturbance and would follow 7.3 miles of existing roadway (97 percent) compared to 5.6 miles (88 percent) along the proposed route. Environmental features crossed or affected by Variation 2, and a comparison to the corresponding segment of proposed route, are included in table 3.4.2.5-1.

Most environmental impacts from Variation 2 would be similar to those of the proposed route. The primary environmental advantage would be its location along an existing roadway which would reduce creation of a new linear forest clearing. The primary disadvantages of Variation 2 would be that more perennial waterbodies would be crossed (13 compared to 7) and that the route would be located adjacent to steep sideslopes along the existing narrow Forest Road 3200. A high risk of landslide occurrence from pipeline installation has been identified along Forest Service Road 3200 headwall swales and constructed fill slopes that would be required to create a working surface for pipeline installation. Steep side slopes along Forest Road 3200 would require significant excavations to construct a 95-foot-wide construction corridor. Pacific Connector estimates the cut slope required to create the work space would be between 100 to 135 feet in height and extend at least 50 feet upslope of the existing cut slope along the road. The required extra cut and fill construction impact area would negate any advantage from following the existing roadway. For these reasons, we have determined that implementation of Variation 2 would not result in a significant environmental advantage and is not preferable to the proposed route.

Variation 3 would begin at MP 108.5 where it would turn south from the proposed route, and then turn southeast and then east, rejoining the proposed route at MP 111.1. Environmental features crossed or affected by Variation 3, and a comparison to the corresponding segment of proposed route, are included in table 3.4.2.5-1.

The Forest Service has stated that Variation 3 would cross an area planned for expansion of the Peavine rock quarry and therefore considers the variation an incompatible use, and identified concerns with potential slope instability and aquatic impacts at the crossing location of the East Fork Cow Creek. The Peavine quarry is the largest and most extensively developed quarry within the upper reaches of the watershed and is of strategic importance to the Umpqua National Forest. For these reasons, we have determined that implementation of Variation 3 would not result in a significant environmental advantage and is not preferable to the proposed route.

3.4.2.6 Rogue River National Forest Variations

To evaluate potential alternatives that may reduce impacts on LSR and Riparian Reserves, we consulted with the Forest Service and evaluated two route variations within the Rogue River National Forest in the vicinity of Robinson Butte and Cox Butte between about MPs 155.1 and 168.9. Table 3.4.2.6-1 provides a comparison of Variation 1 and Variation 2, and the corresponding segment of proposed route. These variations and the proposed route are shown on figure 3.4-6.

TABLE 3.4.2.6-1

Comparison of Rogue River National Forest Variations with the Proposed Route

Impact/Issue		Proposed Route	Variation 1	Variation 2
General				
Total Length (miles) a/		13.8	12.9	15.7
Construction ROW (acres) b/		159	148	180
Total construction disturbance (acres)		209	194 c/	236 d/
operational easement (acres) e/		84	78	95
Land ownership crossed (miles)	Forest Service	12.5	11.5	14.3
	Private	0.5	0.5	0.6
	State	0.0	0.0	0.0
Waterbodies and Wetlands				
Number of waterbodies crossed f/		6	2	14
Land Use				
Land allocations crossed (miles)	Matrix	0.0	0.0	0.0
	LSR	12.5	11.5	14.3
	Riparian Reserves	0.4	1.5	1.1
Evergreen Forest, Mixed Conifer crossed (miles)		6.1	6.8	6.0
Regeneration Forest crossed (miles)		5.6	5.9	5.4
Clearcuts crossed (miles)		0.3	0.1	0.0
Total Forest lands crossed (miles)		12.0	12.8	11.4
Right-of-way parallel or adjacent to existing rights-of-way (miles)		4.4	1.6	14.0
Visual Resources				
Visual Impacts along existing Forest roads		Moderate where parallel to existing roads (4.4 miles)	Minimal except at existing road crossings	Existing road corridors expected to be significantly altered from 95-foot-wide construction footprint along 13.6 miles of Forest roads.
Cultural Resources				
Number of previously identified cultural resources along route		1	1	0 g/
Habitat for Federally Listed Species				
Federally listed critical habitat for the NSO (acres) h/		159	148	180
Number of NSO activity centers crossed		2 - ½ mile buffer of site	2 - ½ mile buffer of site	2 - ½ mile buffer of site

General: All values are rounded (acres to nearest whole acre, miles to nearest tenth of a mile, feet to nearest whole foot).

a/ Route Alternative are measured from the point where they deviate from and then return to the proposed route. Lengths cannot be accurately calculated by comparing mileposts due to shifts in the alignment.

b/ The construction right-of-way (ROW) for the preferred route and original proposed alignment is 95 feet.

c/ Pacific Connector estimates that the Variation 1 would likely require more TEWAs compared to the compromise route because of side slope construction between approximately MPs 149 and 152.9 and because of the increased number of stream crossings along the Variation 1. However, because they have not been designed, we have estimated the area of TEWAs based on a comparable length of the proposed route.

d/ TEWAs have not been designed for this route; however, we have estimated the area based on a comparable length of the proposed route.

e/ The assumed operational easement for all routes is 50 feet. However, Pacific Connector would only maintain vegetation within 15 feet of the pipeline centerline for a total of 30 feet in the long term.

f/ Waterbodies from PNW Hydrography Framework Clearinghouse.

g/ Surveys are incomplete or in progress on the proposed route.

h/ Includes acres of impact associated with the construction ROW.

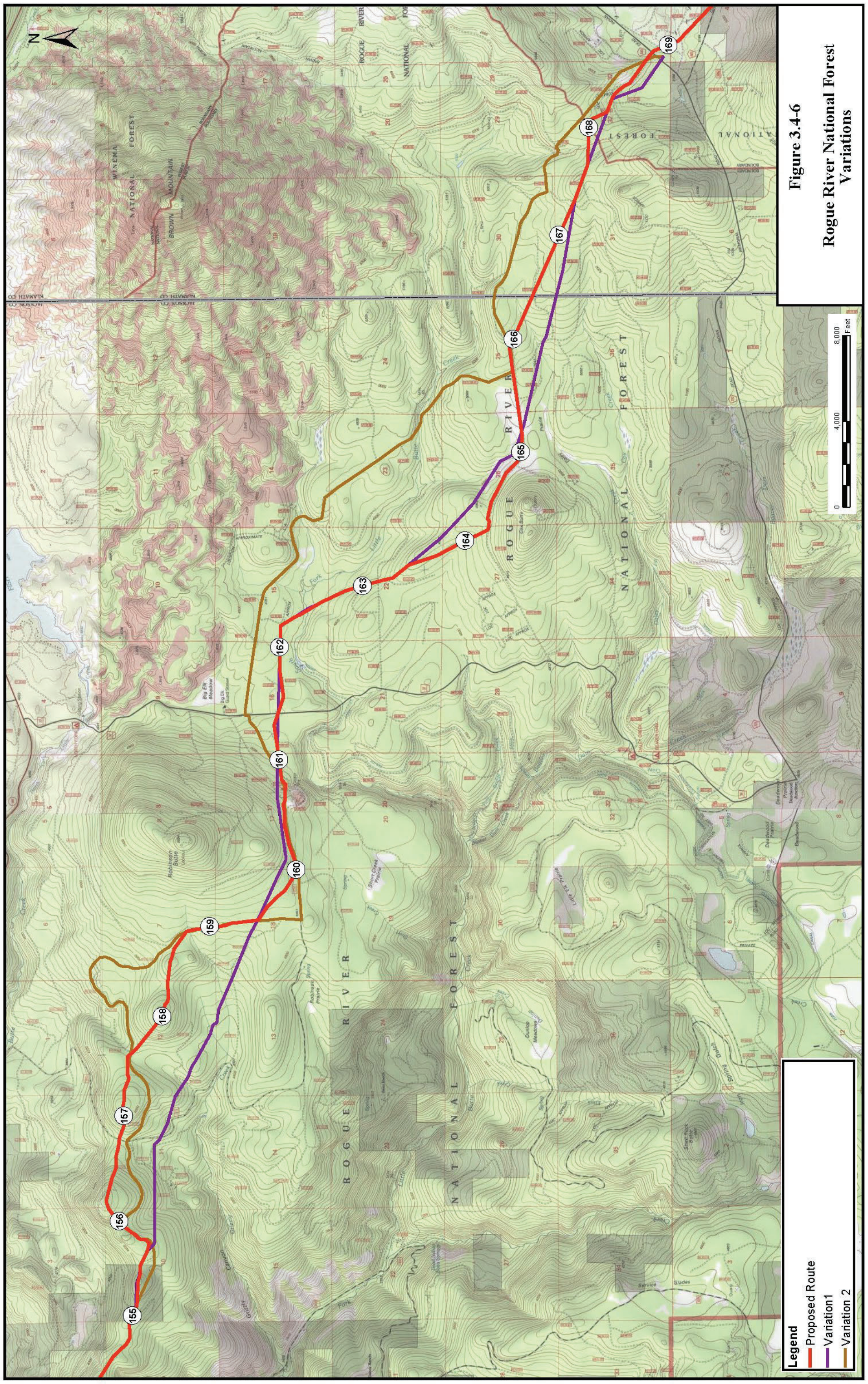

Figure 3.4-6
Rogue River National Forest Variations

Variation 1 would deviate from the proposed route at about MP 155 and remain south of it on the south side of Robinson Butte near MP 159. From that point, Variation 1 would closely follow the proposed route but would be straighter and cross through older forests, which provide NSO habitat. Variation 1 would cross Big Elk Road, cross northeast of Cox Butte, and would cross Daley Prairie, then cross into Klamath County and rejoin the proposed route near MP 169. Variation 1 would be about a mile shorter than the corresponding segment of proposed route. The variation would be adjacent to existing rights-of-way for 1.6 miles (12 percent) compared to 4.4 miles (32 percent) for the corresponding segment of the proposed route.

The primary advantage of Variation 1 is it would require less construction disturbance (194 compared to 209 acres), cross fewer waterbodies (2 compared to 6), cross less LSR (11.5 compared to 12.5 miles), and affect less critical habitat for NSO (148 compared to 159 acres) than the corresponding segment of the proposed route.

The primary disadvantages of Variation 1 are that it would affect more forest (12.8 compared to 12.0 acres), more Riparian Reserves (1.5 compared to 0.4 acres), and less length adjacent to existing rights-of-way (12 percent compared to 32 percent) than the corresponding segment of proposed route. As described above, the variation would have some environmental advantages and some environmental disadvantages over the corresponding segment of proposed route. Overall, we do not believe that the advantages overcome the disadvantages, and for this reason we have determined that implementation of the Rogue River National Forest Variation 1 would not result in a significant environmental advantage and is not preferable to the proposed route.

The rationale for evaluating Variation 2 was to evaluate the potential for reducing forest vegetation clearing by utilizing the existing cleared roadways as part of the construction corridor, thereby reducing some of the forest fragmentation and habitat loss in LSR 227. Also, this variation would cross the PCT along an existing road, reducing potential impacts on trail users by eliminating a separate crossing. Variation 2 would deviate from the proposed route at about MP 155, north of Grizzly Canyon, and head east along Forest Service Roads 410 and 300, around the south side of Robinson Butte along Forest Service Road 3730, south of Big Elk Guard Station along Forest Service Road 3705, across the South Fork Little Butte Creek, turn east along Forest Service Road 3720, entering Klamath County, to Forest Service Road 700, cross the PCT several miles south of Brown Mountain, then head southeast cross-county into the Winema National Forest, across Dead Indian Memorial Highway, and would rejoin the proposed route along Clover Creek Road north of Burton Butte just east of MP 169.

Variation 2 would be about 3 miles longer than the proposed route and would require widening the existing roads, which are generally between 20 and 30 feet wide. This would require cutting mature forest in portions of the right-of-way. Based on input from the engineering review conducted by Pacific Connector, the pipeline would not be constructible along portions of some roads due to the steep terrain and side slope and the tight radius turns. For this reason, we have determined that implementation of the Rogue River National Forest Variation 2 is not technically feasible and do not consider it further.

3.4.2.7 Forest Service Survey and Manage Species Variations

During the development of the proposed route, Pacific Connector and the Forest Service identified seven locations where the pipeline could impact Survey and Manage species that occupy habitat on NFS lands managed by the Rogue River and Winema National Forests. The Forest Service developed seven minor route deviations at these locations which were accepted by Pacific Connector and are incorporated into the proposed route, and that would ensure the pipeline in these locations would not have a negative effect on the viability and persistence of these Survey and Manage species. These deviations were incorporated into the proposed action analyzed in this EIS. Additional documentation of the development of the seven minor deviations is included in FERC 2015, and appendix F.5 provides additional information on the species, location, and minor route deviations. The minor deviations would avoid impacts on the following Survey and Manage species and are briefly summarized below.

- *Gymnomyces abietis*
- *Sedecula pulvinate*
- *Albatrellus ellisii*
- *Boletus pulcherrimus*
- *Cortinarius olympianus*
- *Gomphus kauffmanii*
- *Albatrellus dispansus*
- *Hygrophorus caeruleus*
- *Choiromyces alveolatus*
- *Arcangeliella crassa*

<u>Rogue River National Forest, MPs 154.7–154.9</u>: To avoid Survey and Manage fungus species *Gymnomyces abietis* identified during surveys. This deviation shifted the alignment 180 feet to the south to ensure an adequate buffer for this species.

<u>Rogue River National Forest, MPs 158.1–158.2</u>: To avoid Survey and Manage fungus species *Sedecula pulvinata* identified during surveys. This deviation shifted the alignment 130 feet to the south to ensure an adequate buffer for this species.

<u>Rogue River National Forest, MPs 162.5–162.8</u>: To avoid a cluster of Survey and Manage species, including *Albatrellus ellisii*, *Boletus pulcherrimus*, *Cortinarius olympianus*, *Gomphus kauffmanii*, and *Albatrellus dispansus*, a Forest Service strategic species, identified during surveys. This deviation creates a protective buffer between right-of-way clearing and these species.

<u>Rogue River National Forest, MPs 164.2–164.3</u>: To avoid a Survey and Manage fungus species *Hygrophorus caeruleus*, identified during surveys. This deviation shifted the alignment and construction right-of-way to the south side of Forest Service Road 37200000 to avoid this species.

<u>Winema National Forest, MPs 168.6–169.1</u>: To avoid Survey and Manage fungus species *Hygrophorus caeruleus* identified during surveys. This deviation shifted the alignment approximately 500 feet to the north at the crossing of Dead Indian Memorial Road to ensure an adequate buffer for this species.

<u>Winema National Forest, MPs 171.9–173.0</u>: To avoid Survey and Manage fungus species *Choiromyces alveolatus* identified during surveys. This deviation shifted the alignment 125 feet to the north to ensure an adequate buffer for this species.

<u>Winema National Forest, MPs 173.2–173.3</u>: To avoid Survey and Manage fungus species *Arcangeliella crassa*, identified during surveys. This deviation shifted the alignment to the north so that the construction right-of-way would avoid this species by 125 feet or more.

In addition to the minor deviations described above, in the draft EIS we evaluated a route variation between MPs 111.5 and 111.6 that would avoid impacts on *Sarcodon fuscoindicus*, a Survey and Manage fungi species identified during surveys conducted within the Umpqua National Forest, and in the draft EIS we recommended that Pacific Connector incorporate the variation into the proposed route. After issuance of the draft EIS, Pacific Connector incorporated this variation into the proposed route and this final EIS has been revised as appropriate. Below is a summary of this route change and how it accomplishes the objective of avoiding impact on *Sarcodon fuscoindicus.*

The previously proposed pipeline location as evaluated in the draft EIS would affect a portion of one site where two observations of this species have been documented on NFS lands. This Survey and Manage site is located in the Trail Creek watershed on the ridge just east of the South Fork Cow Creek watershed between MPs 111.5 and 111.6. The location of this site is shown in appendix F.5 (section 2.27, figure SAFU-5).

The previously proposed pipeline location would disturb vegetation and soils within approximately 1.2 acres (30 percent) of the site where this species was identified, which would consist of construction right-of-way (0.8 acres) and UCSA (0.4 acres). The area within the site is mostly forested and the construction and operational right-of-way could modify microclimate conditions around the recorded observations. The removal of forests and host trees and disturbance to soil could also negatively affect *S. fuscoindicus* in adjacent areas by removing its habitat, disturbing soil or duff around trees or roots of trees, and affecting its mycorrhizal association with the trees, potentially affecting site persistence even if the entire site is not disturbed. In addition, modification of shading, moisture, and habitat conditions within 100 feet of the species could make habitat within the site no longer suitable for the species. Restored portions of the right-of-way and workspace would be dominated by early seral vegetation for approximately 30 years, which would result in long-term changes to habitat conditions. A 30-foot-wide corridor centered on the pipeline would be maintained in low-growing vegetation for pipeline maintenance and would not provide habitat for the species during the life of the Project. Material storage within UCSAs could damage individuals and would disturb understory habitat within the site, which could modify microhabitats near individuals that are not removed or damaged, potential making the habitat no longer suitable for the species. Based on this analysis, the Forest Service concluded that *S. fuscoindicus* is not likely to persist at this location if the pipeline was constructed along the previously proposed location. This site is the only site on NFS lands in the local area, and the nearest sites on NFS lands are approximately 45 miles to the northeast and 75 miles to the southwest.

The route modification shifts the construction right-of-way between MPs 111.5 and 111.6 at least 25 feet to the northeast and eliminates the UCSA on the southwest side of the construction right-of-way. As a result, at least one of the two known occurrences of this species within the site would be at least 100 feet from any Project-related disturbance and protected (see figure 3.4-7). The proposed route now includes a no-disturbance buffer for *Sarcodon fuscoindicus* at this location which is necessary to protect these sites and to comply with the 2001 Survey and Manage ROD to maintain the persistence of the affected species within the range of the NSO (see also section 4.6.4.3 of this EIS).

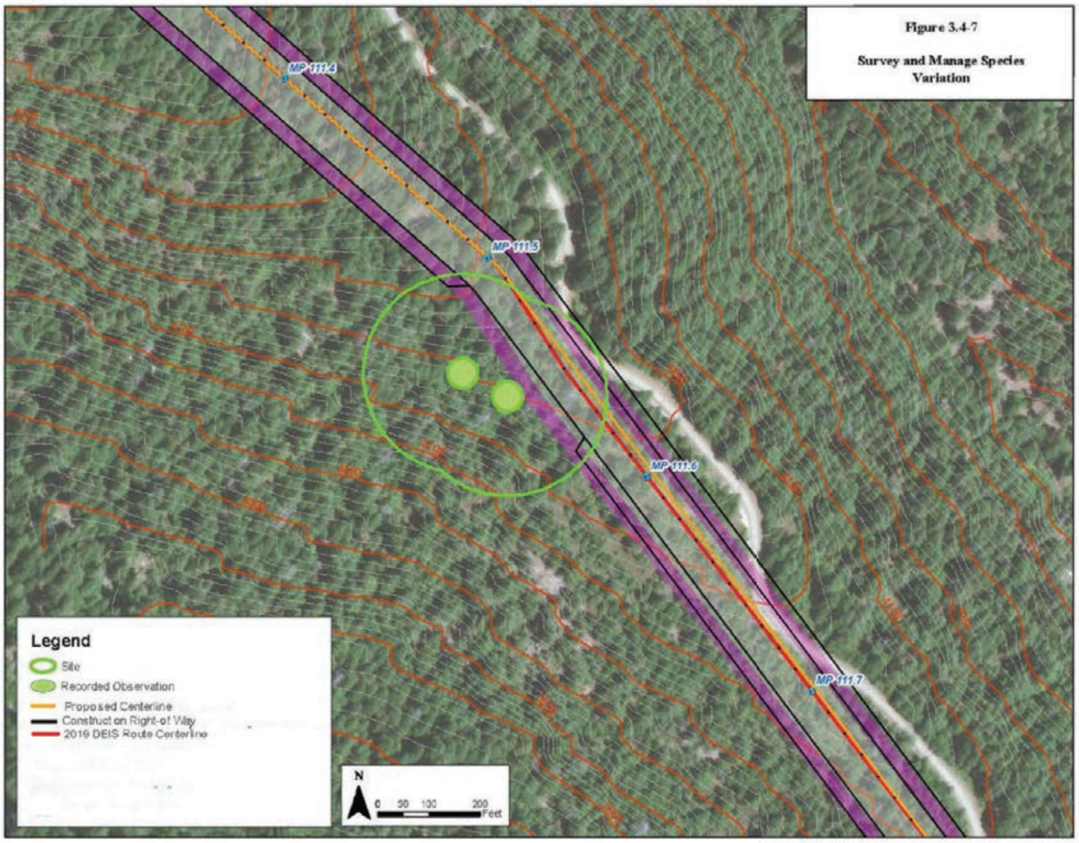

Figure 3.4-7

Survey and Manage Species Variation

3.4.2.8 Revised East Fork Cow Creek Variation

In the draft EIS we evaluated the East Fork Cow Creek Variation and based on that evaluation and consultation with the Forest Service recommended that Pacific Connector incorporate the variation into its proposed route. Since issuance of the draft EIS Pacific Connector incorporated this variation into the proposed route and this final EIS has been revised as appropriate. Below we evaluate the Revised East Fork Cow Creek Variation, which is the previously proposed route as evaluated in the draft EIS, and compare it to the current proposed route in this location.

The variation would be between MPs 109.7 and 109.8 of the proposed route and includes an alternative crossing of East Fork Cow Creek and a crossing of a tributary just upstream of the FS Road 3200-500 crossing of East Fork Cow Creek that would result in a parallel pipeline alignment between the upper reaches of the perennial streams in close proximity to these crossings. The Revised East Fork Cow Creek Variation would proceed southeasterly crossing a tributary of the East Fork Cow Creek and then continue in a southeasterly direction where it would cross the East Fork Cow Creek before climbing the ridgeline before rejoining the proposed route at MP 109.9 (see figure 3.4-8). This variation would parallel about 0.23 miles of the East Fork Cow Creek and its tributaries, and therefore would be inconsistent with the Umpqua National Forest LRMP with respect to water and riparian areas.[60] Use of this variation would require an amendment to the LRMP.

As indicated in table 3.4.2.8-1, the variation is 0.01 mile shorter and would impact 1.3 acres less NFS land, it would require more clearing of LSOG habitat (0.73 acres) and slightly more clearing of Riparian Reserve (0.06 acres) than the corresponding segment of proposed route. This variation would have a direct impact on eight Survey and Manage species compared to four Survey and Manage species by the corresponding segment of the proposed route, and the variation would also indirectly impact four other Survey and Manage species. The variation traverses a narrow ridgeline that supports old-growth forest/high nesting-roosting-foraging (NRF) habitat within Riparian Reserves.[61] The potential for long-term restoration and monitoring of Riparian Reserve and associated geomorphic and water quality conditions affected during construction would be decreased due to the steeper slopes and incised nature of the channels crossed by this variation.

The proposed route in this location would avoid a parallel alignment with perennial streams, whereas the Revised East Fork Cow Creek Variation would be parallel to perennial streams for about 535 feet. For the reasons described above, the Revised East Fork Cow Creek Variation would not result in a significant environmental advantage and is not preferable to the proposed route.

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[60] Standard & Guideline 1 (UNF LRMP IV-33). Maintain all effective shading vegetation on perennial streams. Prescriptions C2-II (LRMP IV-173 par.1, 1st sentence) and C2-IV (LRMP IV-177 last par. last sentence) Utility/transportation corridors, roads or transmission lines may cross but must not parallel streams and lake shores within the riparian unit.

[61] There are overlapping Riparian Reserves associated with channels on either side of this ridge.

TABLE 3.4.2.8-1

Revised East Fork Cow Creek Variation

Alternatives Analysis	Proposed Route	Revised East Fork Cow Creek Variation
General		
Length (miles)	0.42	0.42
Construction right-of-way (acres)	4.6	4.8
Number of temporary extra work areas (TEWAs)	9	7
Acres of TEWAs	1.0	0.91
Number of Uncleared Storage Areas (acres) a/	2 (1.34)	0 (0.0)
Permanent Easement (acres) All NFS lands b/	2.55	2.55
Land Use		
Miles of right-of-way parallel or adjacent to existing rights-of-way (percent of alternative length) c/	0.00 (0.0%)	0.02 (6.7%)
Late Successional Reserve - Federal Land Use Designation (acres)	0.0	0.0
Matrix (Federal Land Use Designation (acres)	4.63	4.75
Riparian Reserves - Federal Land Use Designation (acres)	4.41	4.26
Riparian Reserves Cleared (acres)	3.0	3.06
Riparian Reserves Parallel (miles)	0.0	0.23
Waterbodies and Wetlands		
Number of waterbodies crossed d/	2	2
Length of waterbody crossings (feet) e/	12	7
Alignment parallel to waterbody (feet) d/	0	535
Number of wetlands crossed	0	0
Vegetation		
Total forest clearing (acres)		
Acres clear-cut/regenerating (0-40 years)	2.19	2.22
Acres mid-seral forest (40-80 years)	0.51	0.26
Acres Late Successional Forest (80-175 years)	0.00	0.00
Old Growth Forest (175 +)	2.65	2.70
Biological Resources		
Northern Spotted Owl Suitable Habitat Crossed (High NRF & NRF) (acres)	2.65	2.70
Northern Spotted Owl nest patch/cores (NSO)	0	0
Northern Spotted Critical Habitat Crossed (acres)	5.66	5.64
Survey & Manage Species Sites Direct Impact	4	8
Survey & Manage Species Indirect Sites Impact	4	0
Survey & Manage Species Total Sites Impacted	8	8

General: All values are rounded (acres to nearest whole acre, miles to nearest tenth of a mile, feet to nearest whole foot).

a/ Acres of Uncleared Storage Areas are not included in the impact comparison (acres) of the various resources because grading and tree clearing will not occur in these areas.

b/ Acres of permanent easement calculated based on a 50-foot width.

c/ Based on inventoried roads included in Umpqua NF Road data and BLM GTRN data (https://www.blm.gov/or/gis/data.php).

d/ Based on field surveys (see Table A.2-3 to Appendix A.2 to Pacific Connector's Resource Report 2, supplemental wetland delineation report filed in May 2018, supplemental Survey and Manage Species surveys available as of October 2018.

e/ Based on the proposed alignment between the tributaries to East Fork Cow Creek (FS-HF-J and FS-HF-K) (MPs 109.7 to 109.8). In this area the alignment follows a narrow ridge.

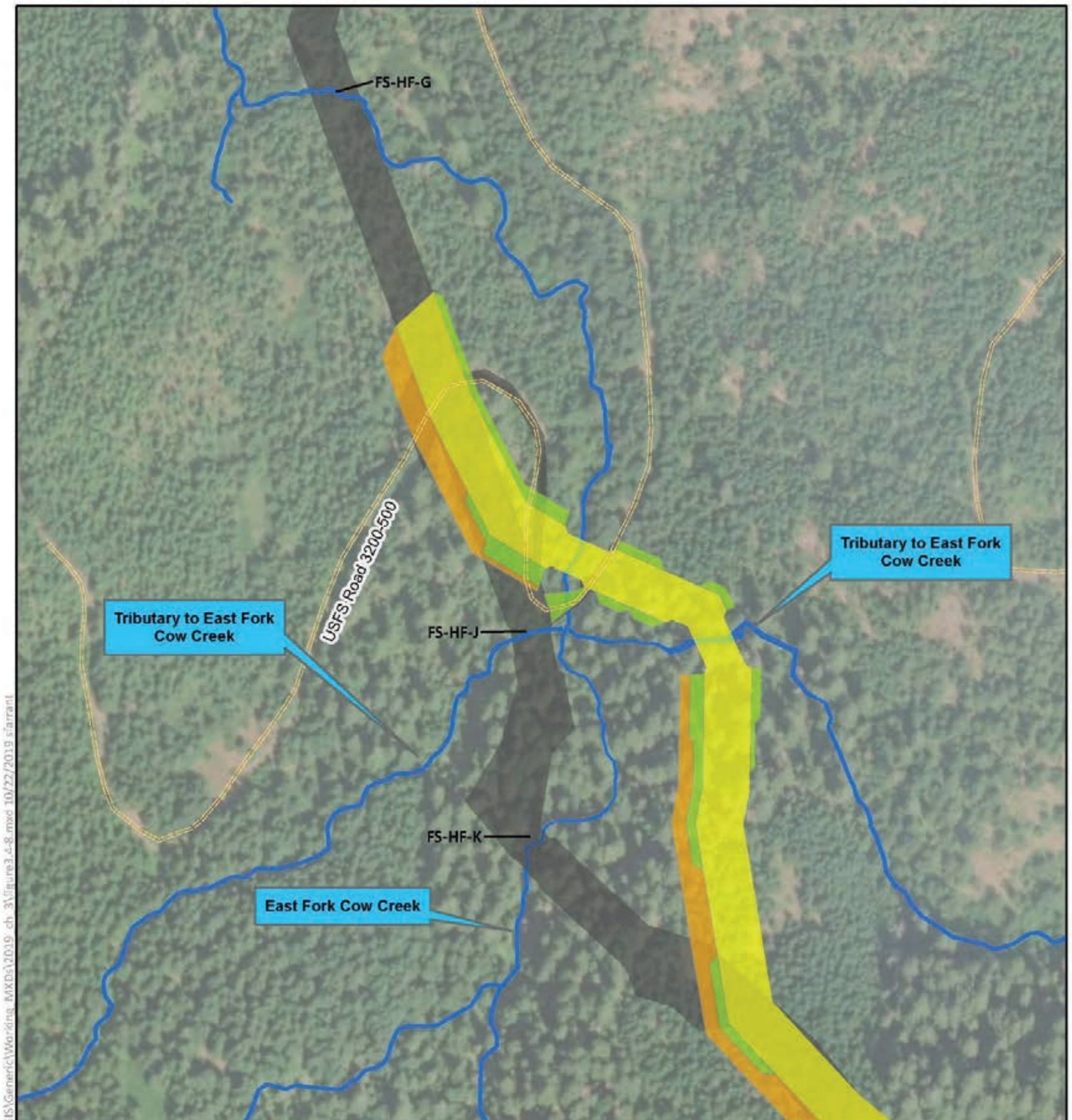

Figure 3.4-8
East Fork Cow Creek Variation

3.4.2.9 Revised Pacific Crest Trail Variation

In the draft EIS, we evaluated the PCT Variation, and based on that evaluation and in consultation with the Forest Service, recommended that Pacific Connector incorporate the variation into its proposed route. Pacific Connector revised the proposed route by incorporating this variation, and this final EIS has been revised as appropriate. Below we evaluate the Revised PCT Variation, which is the previously proposed route as evaluated in the draft EIS, and compare it to the current proposed route in this location.

The variation would begin at about MP 166.4 and run in a southeasterly direction crossing Forest Service Road 3720 at about MP 167.3, then continuing on and crossing the PCT at about 167.8, essentially perpendicular to the PCT (see figure 3.4-9). The variation then continues east until it rejoins the proposed route at about MP 168.1. Near MP 167.7, the variation would be approximately 600 feet north of the South Brown Mountain Shelter, a small log cabin that has a woodstove and a seasonal water supply for various recreational users. Under the Rogue River National Forest LRMP, the existing standards and guidelines for VQOs in Foreground Partial Retention in the area where the variation crosses the PCT require that visual mitigation measures meet the stated VQO within three years of the completion of the project and that management activities be visually subordinate to the landscape. If the variation were used, it would require an amendment to the LRMP to change the VQO objective to Modification, and to allow 15-20 years for amended VQOs to be attained; essentially to allow tree growth adequate to screen the pipeline corridor from PCT users and blend in with the surrounding old-growth forest.

An open-cut crossing of the PCT by the variation would directly affect PCT users for a short duration of time during construction (estimated as 48 hours), and noise associated with construction in the general vicinity of the PCT would be ongoing for several weeks on either side of this crossing, and also audible to occupants of the South Brown Mountain Shelter.

The primary advantage of the Revised PCT Variation would be a slight reduction in length and corresponding decrease in overall acres of NFS lands affected. The variation would also have less impact on the Forest Service road system and less impacts on NSO critical and suitable habitat. The disadvantages of this variation are related to inconsistency with the Rogue River National Forest LRMP VQOs, direct and indirect impacts on PCT users during construction, visual impacts on PCT users extending over a decade after construction, impacts on old-growth forest, and direct and indirect impacts on Survey and Manage species. Table 3.4.2.9-1 provides a comparison of the proposed route and the Revised PCT Variation.

As described above, the Revised PCT Variation would include some environmental advantages and some disadvantages compared to the proposed route. However, for the reasons described above, the disadvantages of the variation would outweigh the advantages, and the Revised PCT Variation would not result in a significant environmental advantage and would not be preferable to the corresponding proposed route.

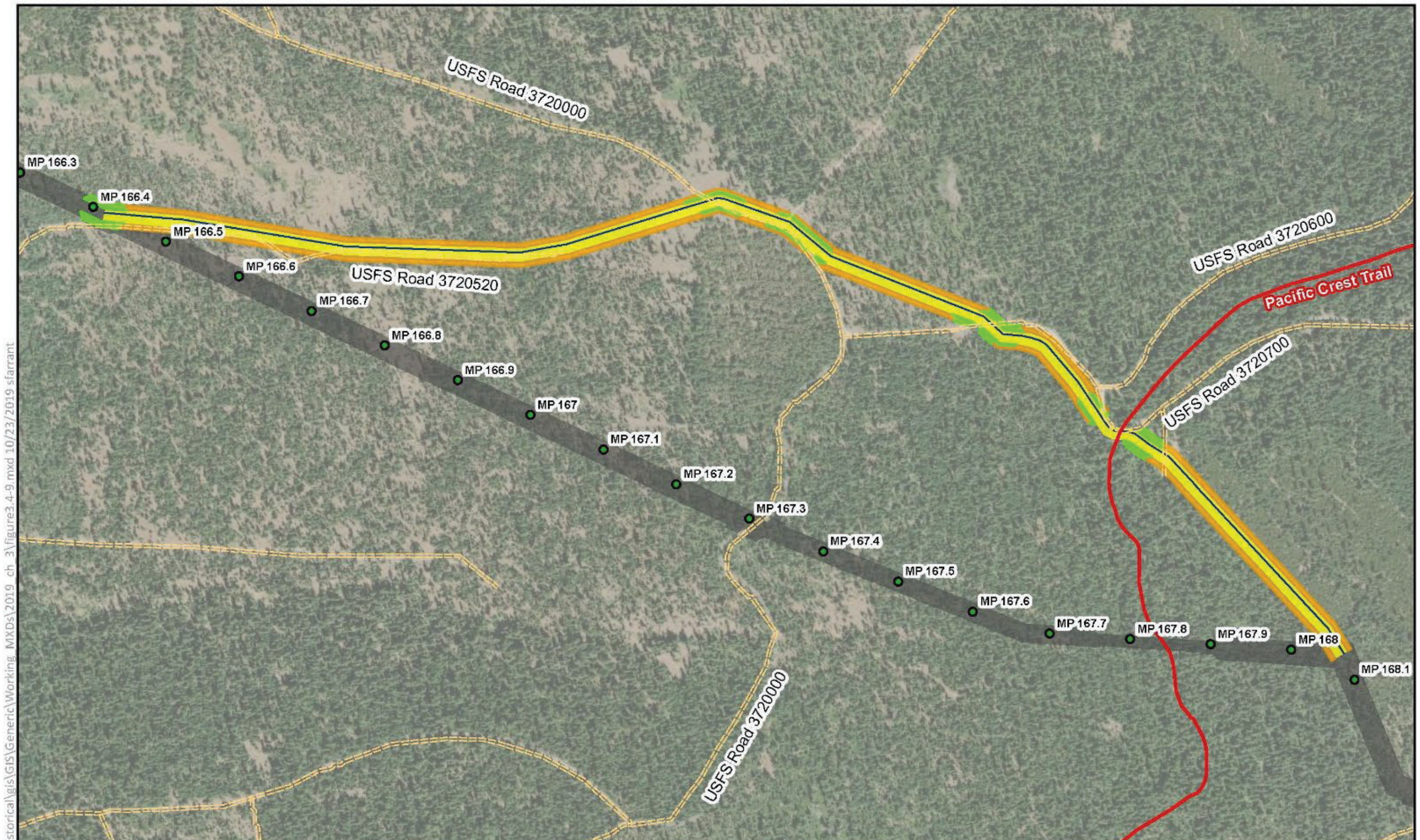

Figure 3.4-9
Pacific Crest Trail Variation

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TABLE 3.4.2.9-1

Comparison of the Revised Pacific Crest Trail Variation with the Proposed Route

Alternatives Analysis		Proposed Route	Revised PCT Variation
General			
Length (miles)		1.77	1.65
Construction right-of-way (acres)		20.14	18.64
Number of temporary extra work areas (TEWAs)		15	7
Acres of TEWAs		1.81	1.16
Number of Uncleared Storage Areas (acres) a/		8 (10.61)	5 (8.72)
Total NFS lands Cleared (acres)		21.95	19.8
Permanent Easement (acres) b/		10.73	10.00
NFS total acres impacted		32.56	28.52
Land Use			
Land Ownership (miles)	Private	0	0
	State	0	0
	Federal (Rogue River-Siskiyou NF)	1.73	1.59
	Federal (Fremont-Winema NF)	0.04	0.06
Number of landowner parcels crossed		1	1
Number of road crossings (centerline) c/		6 (1 is bored)	3
Miles parallel or adjacent to existing ROWs (acres of construction ROW) d/		1.37 (14.46)	0.19 (0.25)
Late Successional Reserve cleared/modified (acres)		20.14/10.61	18.64/8.72
Riparian Reserves cleared (acres)		0.0	0.0
Matrix cleared/modified(acres)		1.38/0.28	0.24/0.39
Visual Quality Objective (miles) e/		0.53-FGPR 0.13-FGR	0.52-FGPR
Waterbodies and Wetlands			
Number of waterbodies crossed f/		1 (bored)	0
Length of waterbody crossings (feet) f/		4 (bored)	0
Vegetation			
Acres clear-cut/regenerating (0-40 years)		8.70	16.95
Acres mid-seral forest (40-80 years)		5.64	0.00
Acres Late Successional Forest (80-175 years)		2.15	0.00
Old Growth Forest (175 + years)		0.44	2.75
Biological Resources			
Northern Spotted Owl Suitable Habitat Crossed (High NRF & NRF) (acres) g/		4.60	2.75
Northern Spotted Owl nest patch/core area (NSO) (acres)		2.87	3.39
Northern Spotted Critical Habitat Crossed (acres)		21.47	20.01
Survey & Manage Species Sites Direct Impact		0	5
Survey & Manage Species Indirect Sites Impact		1	2
Survey & Manage Species Total Sites Impacted		1	7

a/ Acres of UCSA are not included in the impact comparison of the various resources because grading and tree clearing would not occur in these areas. Acres modified equates to UCSA impacts.
b/ Acres of permanent easement calculated based on a 50-foot width.
c/ Based on inventoried roads included in Rogue River-Siskiyou NF travel route data and BLM GTRN data (https://www.blm.gov/or/gis/data.php).
d/ Based on inventoried roads included in Rogue River-Siskiyou NF travel route data and BLM GTRN data (https://www.blm.gov/or/gis/data.php), as well as non-inventoried roads identified during civil surveys (June 2018).
e/ FGPR = Foreground Partial Retention; FGR = Foreground Retention
f/ Based on field surveys (see Table A.2-3 to Appendix A.2 to Pacific Connector's Resource Report 2 and supplemental wetland delineation report filed in May 2018) and subsequent site visit (May 31, 2018). The pipeline centerline stream crossing on the proposed route would occur within the FS 3720700 Road, where the stream is culverted.
g/ Rogue River-Siskiyou National Forest (Forest Service 2017a).

3.5 CONCLUSION

We reviewed alternatives to the proposed action based on our independent analysis and comments received. Although many alternatives are technically feasible, we identified only one alternative that would provide a significant environmental advantage over the corresponding proposed route (i.e., the Blue Ridge Variation). We have included a recommendation that this alternative be adopted. Based on these findings, we conclude that the proposed Project, as modified by our recommendation, is the preferred alternative that can meet the Project purpose.

F.10 of this EIS]) to reduce potential adverse impacts on the environment, nearby water sources, structures, or utilities. As stated in the *Blasting Plan*, licensed blasting contractors would conduct the blasting activities in accordance with all applicable federal, state, and local regulations. Pacific Connector would obtain all necessary permits if blasting is required.

Constructing the Project could affect springs, seeps, and wells. Depending on the location of a well, spring or seep relative to the pipeline, the flow of the feature could be temporarily or permanently affected. These resources could be redirected and experience changes in quantity and quality. To reduce potential impacts, prior to construction, Pacific Connector would implement the measures described in its *Groundwater Supply Monitoring and Mitigation Plan.* Landowners would be supplied with documentation that explains the proposed pipeline construction methods, and outlines the pre-construction field investigation for the identification and monitoring of groundwater supplies. Pre-construction surveys would be conducted to confirm the presence and locations of all groundwater supplies for landowners within and adjacent to construction workspace. In addition, during easement negotiations, the landowner can work with Pacific Connector on siting the alignment to increase the distance between the pipeline and any springs or wells. Pacific Connector would conduct post-construction sampling if requested by the landowner or in disputed situations to determine the effects of construction, if any, on the groundwater supply. The landowner would be provided with a point of contact with Pacific Connector to report potential problems with wells, springs, and seeps believed to be the result of construction. If a groundwater supply is affected by the Project, Pacific Connector would work with the landowner to provide a temporary supply of water; if determined necessary, Pacific Connector would provide a permanent water supply to replace affected groundwater supplies (restore, repair, or replace). Mitigation measures would be coordinated with the individual landowner to meet the landowner's specific needs and be specific to each property.

Operation of the aboveground pipeline facilities would include connections to fixed belowground pipes. Pacific Connector would conduct monitoring in accordance with the DOT requirements during operations to reduce the potential of corrosion and leaks that could affect groundwater. Additionally, Pacific Connector would implement BMPs as detailed in the ECRP and SPCC Plan to avoid, reduce, and mitigate the spill of any hazardous substances that could affect shallow groundwater and/or unconsolidated aquifers.

4.3.1.3 Conclusion

The effects of the Project on groundwater would primarily be temporary. However, based on the characteristics of underlying groundwater, the Applicants' proposed construction and operations procedures and methods, and their implementation of impact minimization and mitigation measures, we conclude that constructing and operating the Project would not significantly affect groundwater resources.

4.3.2 Surface Water

The surface waters in the Project area include marine waters along the shipping route within 3 nautical miles of the coast, Coos Bay, and adjoining surface waters, and streams crossed by or near Project facilities extending from Coos Bay about 229 miles to the connecting point of the proposed pipeline in Klamath County in eastern Oregon. State and federal laws and regulations that will affect Project actions related to surface waters are discussed in section 1. Waters having special status relative to some of these laws and regulations are discussed below. The discussion is separated into two sections, the first dealing with effects on waters from actions relating to the development and operation of the Jordan Cove LNG Project and the second addressing actions related to the development and operation of the Pacific Connector pipeline.

4.3.2.1 Jordan Cove LNG Project

The Jordan Cove LNG Project would be located in Coos Bay, Oregon. Coos Bay is a major coastal estuary with a surface area of about 12,380 acres at mean high water. Coos Bay is fed by about 30 tributaries, including the Coos River, Millicoma River, Catching Slough, Isthmus Slough, Pony Slough, South Slough, North Slough, Kentuck Slough, and Haynes Inlet. The estimated average annual discharge at the mouth of Coos Bay is 2.2 million acre-feet of fresh water (Roye 1979). The Coos Bay watershed covers an area of approximately 739 square miles of Oregon's southern coastal range and is included in the larger South Coast Watershed Basin (ODEQ 2012b).

The existing Federal Navigational Channel is used by recreational, fishing, and major transport vessels to access multiple locations within Coos Bay from the open ocean and coastal marine waters. Four areas adjacent to the Federal Navigation Channel would be modified (see section 2 of this EIS) and used by LNG carriers transiting to the Jordan Cove LNG Project. Between the existing navigation channel and the terminal marine slip, Jordan Cove would create a new access channel. The Oregon Institute of Marine Biology (OIMB) sampled physical oceanographic data in Coos Bay, near the proposed location of the terminal access channel, from August 2009 through December 2010 (Shanks et al. 2010, 2011). The OIMB data set included salinity, temperature, and Chlorophyll a. The OIMB data show there is little variation exhibited in salinity during the tidal cycle, but slightly lower salinity levels occur during low tides and slightly higher salinity levels during high tides. In contrast, temperatures are markedly higher during low tides than high tides. In effect, the results of the OIMB sampling program indicate that there is a great amount of seasonal, but only moderate daily, variability in the physical oceanographic data of the waters of Coos Bay near the Jordan Cove LNG Project.

Impact and Mitigation

The potential impacts and mitigation associated with the construction of the Jordan Cove LNG Project and LNG carrier traffic are related primarily to Project-related dredging, stormwater management, carrier travel, and carrier water use. The effects are related to increases in turbidity, suspended and deposited sediment, bottom and shoreline erosion, toxic substance releases, and water temperature changes.

Jordan Cove would not use surface water sources during construction[85] or operation of the terminal, and all waters discharged from the site would be treated prior to release, including decant water[86] returning from on-land dredge deposits. Permits would be obtained for all wastewater discharges as required by ODEQ. A more detailed presentation of water supply needs for both construction and operation is provided in section 4.3.1.1 and table 4.3.1.1-1.

[85] Water from Coos Bay would be included with estuarine dredged bottom sediment transported to land storage areas; no reduction in Coos Bay water volume would occur from this water use.
[86] Water that is included with dredge bottom material from the bay that goes to on-land deposition areas will be held until sediment settles before it is returned to the access slip or adjacent bay areas. ESCP procedures will be implemented to meet turbidity discharge standards.

There are no process water discharges anticipated from the liquefaction process. There would be some wastewater discharges from the oil-water separators that would be directed to the IWWP. There are no anticipated changes to water quality in Coos Bay from the release of wastewater from the Jordan Cove LNG Project.

The ODEQ's Integrated Report includes Coos Bay on the Section 303(d) list of waterbodies not meeting the criteria for shellfish growing since 2004, due to elevated fecal coliform measurements. Coos Bay is listed as Category 5, water quality limited, and a Total Maximum Daily Load (TMDL) is needed (ODEQ 2012c). Wastewater generated during construction and operation of the Jordan Cove LNG Project would be treated by the City of North Bend's wastewater treatment system via a new industrial wastewater sewer line, and therefore the Project is not likely to add fecal coliform to Coos Bay.

Turbidity and Sedimentation

Dredging and construction activities at the Jordan Cove LNG Project would result in temporary increases in turbidity and sedimentation in Coos Bay. Details on marine facility construction, including dredging activities, are provided in section 2 of this EIS. Dredging activity, primarily associated with slip, access channel, temporary material barge berth, MOF, and marine waterway modifications would be the major sources of turbidity and suspended sediment in Coos Bay. The construction of the marine slip would have most of the slip dredging separated from the bay by an earthen berm and would not affect bay turbidity. Other sources of turbidity would include a dike rock pile apron, Trans-Pacific Parkway/U.S. 101 intersection widening, Kentuck Slough development, and various construction-related tailing lines placements.

All work in the bay would be done during the ODFW recommended in-water window between October 1 to February 15[87]. Within the access channel, dredging would be conducted using a preferred hydraulic (e.g., suction) dredge with a cutterhead or secondary method of mechanical (e.g., clamshell) dredge. The Applicant has indicated that the hydraulic cutter suction dredge is their preferred dredging method (due to the lower turbidity that would be generated) and would be used as the primary method; however, the mechanical dredge would need to be used in certain locations due to the presence of buried woody debris or other materials in the substrates that could not be removed using hydraulic methods (e.g., the mechanical dredging methods would be used in parts of the access channel near the shoreline and along the proposed modifications to the marine waterway). Dredged material from the access channel would consist of dense sand, some gravel, and traces of silt. The navigation channel bottom area to be dredged consists primarily of sand and, depending on location, some siltstone and sandstone below surface sand (see *Dredged Material Management Plan*[88]).

Jordan Cove commissioned modeling efforts to estimate the range of turbidity and suspended sediment that would result from Project-related dredging (Moffatt and Nichol 2006, 2017c). The models were developed based on a sediment analysis conducted at the site of the dredging and took into consideration wind, tidal currents, and seasonal flows and were developed without inclusion of potential turbidity control measures that could be implemented such as those described in dredging pollution control plans (Jordan Cove LNG 2019b, 2019d). Moffatt & Nichol (2006)

[87] Based on their draft EIS comments of July 3, 2019, ODFW will require that the in-water work window in the slip area be changed to October 1 to January 31 to accommodate unlikely eulachon spawning.
[88] Included as Appendix N.7 of Resource Report 7 as part of Jordan Cove's September 2017 application to the FERC.

indicated that constructing the access channel via mechanical dredging would result in a maximum concentration of turbidity of 600 to 6,000 mg/l depending on tidal velocity, decreasing substantially farther away from the site. The latest model (i.e., Moffat & Nichol 2017c) addresses suspended sediment concentrations from the proposed dredging operations. Constructing the slip and access channel would result in suspended sediment that would exceed about 20 mg/l over background levels within about 0.2 to 0.3 mile of the dredging site and exceed about 400 mg/l within about 0.1 mile with either dredging method (clamshell or cutter suction dredge) (Moffat & Nichol 2017c). Moffat & Nichol (2006) model estimates found that, depending on current velocity, peak suspended sediment concentrations with clamshell dredging ranged from about 500 to 6,000 mg/l at the dredge site, decreasing to less than 50 mg/l within about 0.1 mile. Hydraulic dredging would result in lower values ranging from about 250 to 500 mg/l at the dredging site, decreasing to less than 14 mg/l in less than 0.1 mile.

Moffat & Nichol (2006) noted maximum concentrations outside of the specific dredge location would only occur for about 2 hours or less over the daily tidal cycle with the plume moving upstream or downstream of the dredge site on flood or ebb tide, respectively. Moffatt & Nichol (2006) indicated that due to this limited period of elevated suspended sediment in any site-specific area of the plume, other than the actual dredge area, average daily turbidity levels would remain near background values for the mechanical dredge at the slip during active dredging.

Turbidity models for both construction and maintenance of the four Marine Waterway Modifications areas were developed using the three possible dredging methods. Generally, suspended sediment levels would be similar to those modeled for the access channel, but distribution of sediment plumes would be more extensive. The cutter suction dredge would generally have lower concentrations of sediment than other options, but the overall maximum distribution of areas over background suspended sediment (about 20 mg/l) would be similar, averaging about 1.2 miles[89] from the specific active dredging site of the four channel expansion areas with any dredging methods. Turbidity levels and distribution would be similar for both construction or maintenance dredging. Overall levels of peak concentration dependent on method used, with cutter suction the lowest and hopper dredge the highest. Areas of high concentrations, over about 500 mg/l based on averages of the four main channel dredged areas, would generally extend about 0.1 mile from the dredge site for cutter suction and clamshell dredges and less than about 1.0 mile for hopper dredge, based on figures of elevated turbidity distribution presented in Moffat & Nichol (2017c). Based on the Moffat & Nichol (2006) model of the access channel dredging, it would be expected that these peak levels would be short lived at any specific location. Given that, as noted above, tides would move the location of the sediment plume, higher concentrations in any location, other than near actual dredge location, would only last about 2 hours.

The model of the Eelgrass Mitigation site (Moffat & Nichol 2017c) assumed an excavator would be used, which would result in a confined area of elevated suspended sediment extending less than 0.1 mile from point of dredging, and would be less if the preferred hydraulic dredge is used. The more limited effect of tidal flow over the area would help confine the distribution of the elevated sediment plume. These elevated levels would be short term and highly localized to the nearshore area, likely returning to background levels in less than a day after dredging stopped.

[89] Plume distance noted includes total spread both upstream and downstream of dredge site.

As noted above, sedimentation and turbidity would be higher during clamshell dredging than during hydraulic dredging operation. Clamshell dredging is also proposed for maintenance dredging of the slip and access channel, and potential effects are discussed below. Construction and maintenance dredging at the four marine waterway modification areas would be done via hydraulic dredging (cutter suction or hopper) or clamshell dredging, or a combination of these. Hydraulic placement of materials at the upland sites (e.g., APCO Sites 1 and 2, and Kentuck project site) is the preferred method for dredging including material transport with temporary subtidal dredge material transport pipelines (see *Dredged Material Management Plan).*

In addition to several structural actions taken to reduce turbidity, like dredging behind a berm and allowing settling of decant return water to state-required levels before return to the bay, the Applicant has indicated several operational controls that may be implemented as needed to reduce the chance of elevated turbidity exceeding state considered unacceptable levels. These controls include:

- decreasing cutter head speed, decreasing suction flow rate, using different size or type of dredge, lowering crest elevation, and/or avoiding stockpiling during peak ebb conditions;
- scheduling or phasing work activities and duration;
- preventing resuspension of sediment;
- no dumping of partially full buckets in the bay;
- adjusting volume or speed of loading or suction where applicable; and
- limiting the number and location of bay access events with equipment.

As discussed above, the modeling conducted by Moffatt and Nichol (2017d) was done to determine the potential effects of all proposed actions including slip and access channel excavation, marine waterway modifications, and Eelgrass Mitigation site dredging on flow hydraulics in the bay. Construction in these areas would produce no or negligible impacts on overall tidal flow, tidal range, current velocity, and circulation in Coos Bay. Additionally, the result of the tidal flow circulation modeling and analysis predicts that there would be localized velocity reduction as well as localized small increases in velocity in portions of the bay. These would include slight velocity increases near the pile dikes at the western corner of the access channel. The planned construction of the new pile dike rock apron is intended to moderate local velocity changes that may affect erosion. The deepening of the channel near the mouth of the bay (NRI 1 channel deepening area) at the entrance turn also appears to have resulted in locally increased currents to the north in Log-Spiral Bay. However, the model did not include effects of ocean waves that influence current velocity in this outer region of Coos Bay. Overall the effects of Project actions on the Coos Bay tidal prism were unsubstantial, and effects on tidal current velocity changes were also negligible except for a few localized areas.

Using available information on Coos Bay characteristics and the output from the hydrodynamic model, the MIKE-21 sediment transport simulation model was used to determine Project channel modification effects on the rate of sedimentation in the bay (Moffat and Nichols 2017e). The model found that overall sedimentation shoaling rates in the navigation channel within the bay would not change, although there were some local changes associated with project-related actions including a slight increase in deposition by the constructed MOF and some erosion sedimentation on the western side of the slip. While some changes in sedimentation were predicted near the two northernmost pile dikes, the projected changes in this area and rest of the bay from the Project actions were within the natural range of sedimentation rate variability.

Based on the turbidity modeling conducted for both construction and maintenance dredging, without consideration of potential turbidity control methods being implemented, the effects of maintenance dredging and disposal are predicted to be localized and relatively short term, likely lasting less than a day after dredging stops. Effects of maintenance dredging on suspended sediment concentrations and distribution in the slip, access channel, and Federal Navigation Channel would be similar to those discussed for the respective type of dredging methods used (Moffat & Nichol 2017c). However, the duration would be shorter for maintenance as less material would be removed than during construction.

Propeller wash from LNG carriers and tug boats associated with the Project, as well as ship wakes (waves) breaking on shore, could increase erosion along the shoreline and resuspend loose sediment along the shallow shoreline area, resulting in temporary increases of turbidity and sedimentation in the bay, both of which would affect water quality. The effects of these actions relating to sediment, bottom disturbance, and wave actions on marine aquatic resources are discussed in section 4.5 of this EIS.

Jordan Cove developed two models to assess propeller wash effect along the channel (Moffat & Nichol 2008; Coast and Harbor Engineering [CHE] 2011). The Moffat & Nichol (2008) model indicated propeller wash–induced bottom velocity along most of the main channel would be similar to the maximum velocity of peak tides (about 4 feet per second [fps]) whereas the CHE (2011) model indicated higher bottom velocities (13 fps) but in a very narrow range (about 80 feet wide). Both models, however, indicated that along most of the route, because the bottom of the channel consists of coarse materials (sand and sandstone), bottom material suspension would be limited and would settle rapidly, and elevated turbidity would be unlikely to occur. Moffat & Nichol (2008) estimated that near the docking location (about 0.5 mile), estimated bottom velocity would increase to about 7 to 8 fps. Some increased bottom scour and locally elevated turbidity may occur in this area, but the effects would be limited in dimension. This disturbance would occur below the intertidal area. CHE (2011) also modeled likely bottom disturbance from existing large vessel transit (assumed 106 round trips [212 channel passages] annually) in the bay and found that bottom velocity from these would be slightly greater than that of the LNG carriers (projected 120 round trips [240 channel passages] annually) so LNG effects on disturbance would be less than existing vessel traffic.

An additional model by Moffat and Nichol (2017g) estimated potential for scour and elevated turbidity while carriers are berthing and unberthing at the access channel and slip. The model assumed the LNG carrier engines and propeller would be used in addition to that of tugs for this action. While berthing had low potential for scour, unberthing, with the use of LNG carrier propeller engagement, could cause high potential for scour in the access channel and slip area. They estimate that maximum bottom velocity could be about 13.6 fps during unberthing, but less than 5.4 fps during berthing in the slip and access channel. They estimated that scour depth, with a substrate consisting of mostly medium size sand, could be up to 0.46 foot in the eastern portion of the access channel. Overall, about 12 acres of bottom could be scoured to a depth over 0.2 foot in general on a periodic basis. The bank areas of the slip would be armored, which would prevent scour there. Likely plumes of turbidity could occur briefly near the slip and access channel primarily near the bottom during the period of unberthing. The turbidity increase would be local and settle once the propellers stopped.

Jordan Cove modeled the likely effects of LNG carrier traffic on shoreline waves (Moffatt and Nichol 2017f). Wave height effects were evaluated from the access channel and slip to the mouth of the navigation channel. Moffat & Nichol estimated that the existing large bulk carriers would cause shoreline wave heights of about 0.3-0.6 foot under existing conditions. The LNG carrier transit wave height would be less under proposed channel changes, about 0.2 to 0.3 foot. These vessels' induced waves would likely occur for about 106 bulk carrier and 120 LNG carrier round trips a year CHE (2011). Tug vessels traveling at the same speed as LNG carriers would have similar wave height, but when tug vessels depart Coos Bay to bring in large vessels they may travel at about 10 knots, resulting in shoreline wave heights of about 0.5 to 0.8 foot. Day-to-day natural wave heights near the more protected bay area near the slip entrance are about 0.3 to 0.4 foot, while under windy conditions, much of Coos Bay's shoreline would have shoreline waves of 0.8 to 0.9 foot, and under severe storms even the area near the slip entrance would have wave height of about 2 feet (CHE 2011). Wave actions could also affect local turbidity. CHE (2011) estimated that, considering the annual frequency of LNG carriers, shoreline sediment transport potential may increase by 5 to 8 percent and, considering natural range of variable wave energy, would be unmeasurable. Considering these waves would be mostly in the range of natural conditions and the shoreline is a naturally high energy area, changes to turbidity would likely be minor as well. This model assessment did not, however, consider higher speed tug transit. The tug vessel trips at these higher speeds would be about equal to LNG carrier entries (about 120 channel round trips) but may not all be made at speeds as high as 10 knots. Each vessel passage would generate some form of wave for about 15 minutes (CHE 2011), with the peak wave period much less in duration. This compares to a natural wave frequency that would last much longer (e.g., hours or days). The induced waves from these additional vessels, with the possible exception of outgoing tugs, would have an unsubstantial effect on shoreline erosion and local elevation of turbidity as they are well within the naturally occurring, wind-generated wave heights (CHE 2011). The NMFS has concerns that higher vessel speeds may adversely increase shoreline erosion and fish stranding, potentially adversely affecting marine habitat. The NMFS recommended that vessel speeds not exceeding 8 knots within Coos Bay would be more protective. The FERC does not have the regulatory ability to dictate operational speeds of LNG carriers or tugs; however, the independent carrier operators would be required to follow all Coast Guard requirements regarding the operation of LNG carriers, including carrier speeds.

Spills or Leaks of Hazardous Materials

Project-related fluids that enter Coos Bay could affect state water quality standards. During construction of the Jordan Cove LNG Project, stormwater runoff could transport sediment and hazardous materials into Coos Bay. The introduction of sediment into Coos Bay would increase turbidity and sedimentation as discussed above and the introduction of hazardous materials would affect local water quality. To reduce stormwater runoff, construction activities would be conducted in compliance with the State of Oregon's General NPDES permit (1200-C). Additionally, stormwater runoff would be managed in accordance with a site-specific SPCC Plan. Stormwater collected in areas that have no potential for contamination would be allowed to flow or be pumped to ditches that ultimately drain to the slip or Coos Bay. Stormwater collected in areas that are potentially contaminated with oil or grease would be pumped or would flow to the oily water collection sumps. Collected stormwater from these sumps would flow to the oil-water separator packages before discharge to the IWWP. Jordan Cove would apply for a new NPDES permit for this discharge prior to Project initiation. No untreated stormwater collected in areas that are potentially contaminated with oil or grease would be allowed to enter federal or state surface waters.

An inadvertent release of construction equipment–related fluids (fuel storage, equipment refueling, and equipment maintenance) could adversely affect water quality in Coos Bay. As described previously, Jordan Cove has prepared a site-specific SPCC Plan. The purpose of this SPCC Plan is to reduce the potential for accidental releases of hazardous materials and to establish proper protocols for minimization, containment, remediation, and reporting of any releases that might occur. Jordan Cove's proposed measures to reduce the risk of hazardous material spills and reduce impacts should a spill occur (which apply Project-wide, including along the pipeline) include, but are not limited to:

- establishing training requirements for all employees handling fuels and other hazardous substances;
- providing storage location requirements for all hazardous substances, including chemicals, oils, and fuels, of a minimum of 150 feet from a waterbody or wetland boundary;
- requiring overnight equipment parking or any refueling operations to be located a minimum of 150 feet from a waterbody or a wetland boundary;
- requiring containment or diversionary devices for any container with a capacity of 55 gallons or larger, and providing discharge prevention measures like dikes, retaining walls, curbing, weirs, booms, diversion ponds, retention ponds, and absorbent materials;
- stipulating all secondary containment systems be capable of containing a volume equivalent to the largest container plus sufficient freeboard for precipitation (i.e., 110 percent); and
- providing for inspections to ensure no visible sheen is present on accumulated stormwater in containment systems, and the condition documented, prior to discharge.

While a hazardous material spill has the potential for adverse environmental impacts, adherence to the SPCC Plan would greatly reduce the likelihood of such impacts, as well as reduce the resulting impacts should a spill occur. As such, significant adverse impacts on surface water due to contamination from hazardous material spills or releases are not expected to occur.

Numerous commenters expressed concern about the impacts of an LNG spill into Coos Bay. If LNG spilled or leaked, it would turn to vapor when exposed to the warmer atmosphere, and these vapors would rise as they would be lighter than air. LNG is not soluble, would not mix with water, and would not contaminate surface water. Spills or releases of fuel or other oils into surface waters from LNG carriers are more likely to occur during fueling or bunkering at the dock when the materials are being transferred onto the carrier.

In compliance with guidelines outlined by the International Maritime Organization (IMO) under the Marine Environmental Protection Committee, vessels with 400 gross tonnage and above, like LNG carriers, are also required to develop and implement a Shipboard Oil Pollution Emergency Plan, which includes measures to be taken when an oil pollution incident has occurred or a ship is at risk of one. With the implementation each LNG carrier's shipboard oil pollution emergency plan, impacts resulting from the spill of fuel, or oil, or other hazardous liquids would be reduced.

Temperature, Chemical, and Biological Effects

While berthed, LNG carriers would release ballast water and engine cooling water into the marine slip. No wastewater would be discharged from the LNG carriers into the slip. The LNG carriers may arrange with licensed private entities for refueling, provisioning, and collection of sanitary and other waste waters contained within the carrier. The licensed private entities would transport the waste to a permitted treatment facility. Discharges from vessels are subject to regulation by EPA. EPA currently regulates these discharges via the Vessel General Permit.

Once arriving in Coos Bay, LNG carriers at the terminal slip would discharge ballast concurrently with the LNG cargo loading. The amount of ballast water discharged must, at a minimum, be adequate to maintain the LNG carrier in a condition of positive stability and with an adequate operating draft while the LNG cargo is loaded. Each LNG carrier would discharge approximately 9.2 million gallons of ballast water during the loading cycle to compensate for 50 percent of the mass of LNG cargo loaded.[90]

The LNG loading rate is designed to be 10,000 m^3/hr (with a peak capacity of 12,000 m^3/hr), or 4,600 metric tons per hour (t/hr) (5,520 t/hr peak); consequently, the ballast water discharge rate would be approximately 20,250 gallons per minute (gpm). The typical ballast water discharge port is approximately 3.5 to 4.2 square meters covered by a screen with 4.5 mm bars, spaced every 20 to 25 mm.

LNG carriers and marine barges utilized for this Project must meet the requirements of the EPA and Coast Guard regulations. Coast Guard regulations (33 CFR 151, subpart D and 46 CFR 162.060 on "Standards for Living Organisms in Ships' Ballast Water Discharged in U.S. Waters; Final Rule" [77 FR 17254 (Mar. 23, 2012)] and Navigation and Vessel Inspection Circular 01 18) provide guidance to the maritime industry and Coast Guard personnel relative to the implementation of Ballast Water Management (BWM) system requirements. These governing regulations apply to all vessels that enter or operate within U.S. waters and are equipped with a ballast water system that has been approved by the Coast Guard and meets the applicable ballast water discharge standards.

The Coast Guard regulations require the same discharge standards as the IMO regulations, but the Coast Guard regulations also contain some requirements pertaining to a ship's operational procedures that are additional to the IMO's regulations (DNV GL 2018). These include the following:

- ballast tanks must be cleaned regularly to remove sediments;
- when retrieved, anchors and chains must be rinsed;
- fouling must be removed from the hull, piping, and tanks on a regular basis;
- a BWM Plan that includes the above in addition to BWM must be maintained (however, there is no requirement that the BWM Plan be approved);

[90] One cubic meter of LNG is 0.46 metric tons (t), which for the maximum size of LNG carrier authorized to call on the LNG terminal (148,000 m^3) would be 68,080 t of LNG per ship. Assuming 1 t of seawater is 1.027 m^3, the amount of seawater ballast discharged (50 percent of the weight of the LNG loaded) would be approximately 34,959 m^3 (approximately 9.2 million gallons).

- records of ballast and fouling management must be maintained; and
- a report form must be submitted 24 hours before calling at a U.S. port.

The EPA has additional requirements for periodic sampling, including calibration of sensors, sampling of biological indicators, and sampling of residual biocides.

The Coast Guard requires that vessels equipped with ballast tanks and bound for ports or places in the United States (except for the Great Lakes), regardless of whether the vessel operated outside the Exclusive Economic Zone (EEZ), submit the ships' BWM information to the Coast Guard no later than 6 hours after arrival at the port or place of destination, or prior to departure from that port or place of destination, whichever is earlier.

In 2017, the International Convention for the Control and Management of Ships' Ballast Water and Sediments developed measures that must be implemented to reduce the potential for introduction of non-native species through ballast water. These measures have since been adopted by the IMO and are required to be implemented in all ships engaged in international trade. While the open sea exchange of ballast water has been used in the past and reduces the potential for non-native species introductions, on-board ballast water treatment systems are more effective at removing potential non-native species from ballast water. There are two different standards that ships must meet. All new ships must meet the "D-2" performance standard, which establishes the maximum number of viable organisms allowed to be discharged in ballast water. Conformity with the D-2 standard requires ships to utilize on-board ballast water treatment systems. Existing ships that do not currently have on-board ballast water treatment systems must continue to, at a minimum, conduct open sea exchanges of ballast water ("D-1" standard). Eventually, all ships will be required to conform with the D-2 standard. The timetable for conformity with the D-2 standard for existing ships is based on the date of the ship's International Oil Pollution Prevention Certificate renewal survey, which occurs every five years (IMO 2017). Therefore, most ships calling on the Project, estimated to begin in 2023 at the earliest, would be expected to have conformed to D-2 standards.

Any discharge of a pollutant into the navigable waters of the United States requires authorization under the CWA. Although discharges of ballast waters were historically excluded from the CWA, in 2013 the EPA issued a NPDES permit, the General Permit for Discharges Incidental to the Normal Operation of Vessels (VGP). The VGP, effective December 19, 2013, sets numeric effluent limits for ballast water discharges from certain large commercial vessels under a staggered implementation schedule. The standard is expressed as the maximum concentrations of living organisms in ballast water. The permit also includes maximum discharge limitations for biocides and residues.

Coast Guard regulations (46 CFR 162.060) were enacted in June 2012 in an effort to phase out ballast water exchange practices. The ballast water discharge standard (33 CFR 151.2030(a)) requires vessels calling at all U.S. ports to be equipped with a Coast Guard-approved BWM system. This applies to all new ships constructed on or after December 2013. All vessels over 300 gross tons or that have the capacity to discharge 2,113 gallons of ballast water must submit a notice of intent to the EPA requesting authorization under the 2013 VGP.

Discharging ballast water would not substantially affect water quality in Coos Bay. At the point of discharge, the interface with Coos Bay would experience temporary changes in salinity, temperature, pH, and dissolved oxygen. However, these changes to water quality would be highly localized and would quickly dissipate. While open ocean water has generally higher salinity (e.g., 35 practical salinity units [psu]) than typically occurs in Coos Bay (range 16 to 33 psu; Shanks et al. 2010, 2011) due to the high volume of water passing by the loading area, the contribution of ballast water would be only about 0.3 percent of the water passing by the terminal. Therefore, no measurable changes in salinity, other than directly at the discharge port, would occur.

Water temperatures are also unlikely to be significantly altered from release of ballast water. The temperature of the water in Coos Bay undergoes both seasonal and diurnal fluctuations. In December and March, the ocean and fresh water entering the estuary had similar temperatures, around 50°F. In summer, low stream flows results in a rise of temperatures in the bay, to above 60°F in September at NCM 8 (Roye 1979). Based on LNG carrier design, a substantial difference in temperature between ballast water and ambient waters is not anticipated. LNG carriers are constructed with double hulls, which increases the structural integrity of the hull system and provides protection for the cargo tanks in case of an incident. The space between the inner and outer hulls is used for water ballast. Because ballast water is stored in the ship's outer hull below the waterline, discharged water temperatures would not be expected to deviate significantly from ambient water temperatures; rather, it is anticipated that the ballast water would be equilibrated to the surrounding water temperature before being discharged. Therefore, thermal impacts from LNG carrier ballast water discharge would not be anticipated. The pH of the ballast water (reflective of open ocean conditions) may be slightly higher as compared to that of freshwater estuaries; however, this slight variation is not expected to have any impacts on existing marine organisms.

Dissolved oxygen levels are a critical component for the respiration of aquatic organisms. Among other factors, dissolved oxygen levels in water can be influenced by water temperature, water depth, phytoplankton, wind, and current. Typical water column profiles indicate a decrease in dissolved oxygen with an increase in depth. Some factors that often influence this stratification include sunlight attenuation for photosynthetic organisms that can produce oxygen, wind, wave, and current that results in mixing. Water that is collected within the ballast tanks of a ship would lack many of these important influences and could suppress dissolved oxygen levels. However, ballast water that is discharged is not expected to be anoxic (i.e., lacking all oxygen), just lower than what levels would likely be at the surface. In addition, ballast water would be discharged near the bottom of the slip where dissolved oxygen levels may already be lower due to natural stratification. Therefore, no significant impacts are likely to occur as a result of discharging ocean water with potentially suppressed dissolved oxygen levels.

Cooling water flows while at the berth are approximately 11,000 cubic meters per hour (m^3/hr; 2.91 million gallons per hour or 48,000 gpm). For a 148,000 m^3 vessel, this would total approximately 69.7 million gallons while at berth (for 24 hours). Although LNG carriers vary in design, generally the intake port for this engine cooling water is approximately the same size and at the same location as the ballast water intake port and approximately 32 feet below the water line, or 5.6 feet from the keel of the LNG carrier. The size may vary but it is generally 3.5 to 4.2 square meters covered by a screen with 4.5 mm bars, spaced every 25 mm. The engines would be running to provide power for standard hoteling activities as well as running the ballast water pumps.

Using the numerical thermal plume dispersal model from EPA (2003) in combination with the Coos Bay hydrodynamic model (Moffat & Nichol 2017d), Jordan Cove modeled possible slip temperature changes resulting from the discharge of engine cooling water by an LNG carrier. The model assessed the temperature effects of eight different combinations of vessel type, ambient temperature, volume discharged, temperature, and velocity of discharge water were run (Moffat & Nichol 2017h). The modeling results showed that for typical ambient flow conditions the estimated water temperature of the discharged water would be up to about 2 to 3 degrees Celsius (°C; 3.6 to 5.4°F) warmer at the discharge port than ambient water. At about 40 to 80 feet from the discharge port (LNG carrier sea chest), temperatures would not exceed 0.3°C (0.54°F) above the ambient temperature (CHE 2011; Moffat & Nichol 2017h). The model results for the steam turbine power vessels typically were in the upper portion of these distance ranges. This temperature difference would decrease further with distance from the point of discharge. The average water temperature increases for the total slip volume for one day when an LNG carrier using the larger volume (steam turbine vessel) is at dock would range from 0.03 to 0.06°F. Tidal mixing would also decrease maximum slip temperature.

Potential effects of temperature increase from elevated cooling water releases would be further reduced from the cold LNG temperature entering the LNG carrier while at the terminal berth. Because of the extreme differential of the temperature of the cargo in the LNG carrier (-260°F) and that of the surrounding bay water (nominally 50°F), there is a constant uptake of heat by the LNG carrier while loading. This heat uptake is affected by LNG cargo that changes states from liquid to vapor daily. The typical LNG carrier sees 0.25 percent of its liquid cargo converted to the gaseous state each 24 hours, which requires heat uptake from the surrounding environment. It is reasonable to assume that 50 percent or more of the heat uptake by the carrier is extracted from the water during the full 24 hours of stay. Considering the volume of water in the Jordan Cove marine slip (an estimated 384 million gallons), tidal mixing in Coos Bay, and vessel hull cooling from the gas, the release of heated water from LNG carrier engine cooling operations would not substantially increase ambient bay water temperatures. In addition, ballast water discharged from the LNG carrier would also comprise some portion of the water withdrawn for cooling and affected by its discharge. The predicted temperature increases from the release of engine cooling water at the edge of the mixing zone (about 40 to 80 feet from the vessel) is only about 0.5°F above ambient temperature and that increase would be reduced farther away from the LNG carrier. We conclude that the thermal effect of LNG carrier operations at the berth would have very minimal impact on background water temperatures.

Salinity and dissolved oxygen changes from channel morphology modification would not result in substantial change in these parameters in Coos Bay. As discussed above, changes in tidal levels and current velocities in the bay would not occur except in a very limited area by the access channel. Thus, tidal exchange rates, which are a main factor affecting these parameters in the bay, would remain substantially unchanged. In addition, recent models of these parameters by the COE (Port of Coos Bay and COE 2019 [unpublished]) of a much greater main channel dredging activity than the proposed Project in the bay (in regards to scope of dredging) found only slight differences in bay areas (less than 0.7 psu salinity, and less than 0.2 mg/l dissolved oxygen). All dissolved oxygen levels, even during periods of lowest levels, would remain over 7.7 mg/l. Because the scope of Project dredging would be less, we would expect less changes than these model results.

During construction and operation, sanitary wastewater would either be directed to a holding tank and disposed of by a sanitary waste contractor as necessary, or would be treated by a packaged treatment system and directed to an existing IWWP. Discharges of any type would be regulated through NPDES permits. The result is that no hazardous substances, including fecal bacteria, would be discharged to Coos Bay, thus having no effect on bacterial load to the bay.

4.3.2.2 Pacific Connector Pipeline Project

The pipeline, associated workspace, and equipment bridges would be located across 19 Hydrologic Unit Code (HUC) level-5 watersheds (see table 4.3.2.2-1). An additional 5 watersheds would be crossed by the proposed access roads.

TABLE 4.3.2.2-1

Subbasins and Watersheds Crossed by Proposed Pacific Connector Pipeline

	Level 5 Watershed		
Subbasin	**Watershed Name**	**HUC a/**	**Miles Crossed b/**
Coos	Coos Bay- Frontal Pacific Ocean	1710030403	15.3
	South Fork Coos River c/	1710030401	2.1
Coquille	North Fork Coquille River	1710030504	11.5
	East Fork Coquille River	1710030503	9.6
	Middle Fork Coquille River	1710030501	15.9
South Umpqua	Olalla Creek-Lookingglass Creek	1710030212	8.8
	Clark Branch - South Umpqua River	1710030211	13.0
	Myrtle Creek	1710030210	8.9
	Days Creek - South Umpqua River	1710030205	19.2
	Elk Creek c/	1710030204	3.2
	Upper Cow Creek	1710030206	5.3
Upper Rogue	Trail Creek	1710030706	10.7
	Shady Cove - Rogue River	1710030707	8.1
	Big Butte Creek	1710030704	5.1
	Little Butte Creek	1710030708	33.0
Upper Klamath	Spencer Creek	1801020601	15.1
	John C. Boyle Reservoir - Klamath River-	1801020602	5.4
Lost River	Lake Ewauna-Upper Klamath River	1801020412	16.2
	Mills Creek - Lost River	1801020409	23.0
		Total	**229.4**

a/ Hydrologic Unit Code (USGS 1987).
b/ Total miles of watershed area crossed by the pipeline in each HUC, rounded to nearest tenth of a mile.
c/ There are no waterbodies crossed in these watersheds.

The pipeline would be constructed across or near 337 waterbodies. Of the 337 waterbodies, only about 20 percent (68) are identified as perennial streams[91]. Of the remaining affected waterbodies, 257 are intermittent streams (which includes 87 intermittent ditches[92]), 8 are perennial ponds (including stock ponds, an industrial pond, and excavated depressions), and 4 are estuaries. In Coos County, the Project would affect 52 waterbodies, in Douglas County 89 waterbodies, in Jackson County 92 waterbodies, and in Klamath County 105 waterbodies. A table of waterbody crossings, including the proposed crossing method, is included in appendix H (table H-3).

Pacific Connector proposes to use several different methods to install the pipeline across waterbodies depending on site-specific conditions (see section 2). Many of the waterbodies crossed by the pipeline are minor intermittent streams or ditches that are expected to be dry or non-flowing at the time of construction. For all waterbodies without flow at the time of construction, Pacific Connector would utilize standard upland, cross-country construction methods identified in

[91] Perennial streams have flow in some parts all year; intermittent streams carry flow some of the year but cease flowing occasionally or seasonally.
[92] "Ditches" include irrigation canals and laterals, roadside ditches, and pasture ditches.

Pacific Connector's ECRP. Waterbody crossing methods are characterized as dry open cut, wet open cut, diverted open cut, direct pipe, bore, and HDD. Most streams would be crossed with dry open-cut methods using dam-and-pump or flume methods which generally allow trenching across streams in the dry, minimizing potential turbidity. HDD crossings are primarily used on the largest streams and estuarine crossings in the Project area (see table 4.3.2.2-2). Only one diverted open-cut crossing would be done (South Umpqua River, table 4.3.2.2-2). No planned wet open-cut crossing, where pipeline trenching occurs with flowing water present, is planned. However, a wet open-cut crossing method may be required if all other crossing methods are attempted and fail. If a wet open-cut crossing method is required, then additional permitting and impact analysis may be required.

TABLE 4.3.2.2-2

FERC Designated Major Waterbodies Crossed by Pacific Connector Pipeline by County and Fifth-Field Watershed a/

County - Fifth-Field Watershed (Fifth-Field HUC)	Major Waterbody	Approximate Milepost	Water Type	Length of Crossing (feet)	Crossing Type
Coos County - Coos Bay Frontal (1710030403)	Coos Bay	0.28-1.00	Estuarine	3,751	HDD
	Coos Bay	1.46-3.02	Estuarine	8,170	HDD
	Coos River	11.13R	Estuarine	516	HDD
Douglas County - Clark Branch-South Umpqua River (1710030211)	South Umpqua River	71.27	Perennial	200	Direct Pipe
Douglas County - Days Cr. South Umpqua River (1710030205)	South Umpqua River	94.73	Perennial	123	Diverted Open Cut
Jackson County - Rogue River-Shady Cove (1710030707)	Rough River	122.65	Perennial	143	HDD
Lake Ewauna-Upper Klamath (1801020412)	Klamath River	199.38	Perennial	973	HDD

a/ FERC designated major waterbodies are those greater than 100 feet wide at the water's edge at the time of construction.

Oregon Water Quality Regulations and Standards

Section 303(c) of the CWA requires states to establish, review, and revise water quality standards for all surface waters. To comply with these standards, the ODEQ has developed a classification system to describe the highest beneficial use(s) and associated minimum water quality standards of identified surface waterbodies within the state. The Oregon Water Quality Standards include beneficial use(s), fish use designations, narrative and numeric criteria to support the beneficial use(s), and anti-degradation policies. The purpose of the Anti-degradation Policy is to guide decisions that affect water quality such that unnecessary further degradation from new or increased point and nonpoint sources of pollution is prevented, and to protect, maintain, and enhance existing surface water quality to ensure the full protection of all existing beneficial uses. The state-designated beneficial use classifications for the basins crossed by the proposed Pacific Connector pipeline are similar among the basins. They include beneficial uses such as domestic and irrigation and livestock water use (excluding Coos Bay waters), industrial water, fishing and boating, wildlife and hunting, fish and aquatic life, and in some basins navigation and transportation (e.g., Coos Bay), as well as varied other uses.

Each state is required, under Section 305(b) of the CWA, to submit a report to the EPA describing the status of surface waters in the state biennially. Waterbodies are assessed to determine if their use is "fully supported," "fully supported but threatened," "partially supported," or "not supported" in accordance with the water quality standards. A use is said to be "impaired" when it is not supported or only partially supported. A list of waters that are impaired is required by Section 303(d) of the CWA, and it is provided in the 305(b) report (ODEQ 2016). To restore a waterbody to its use classification, a state may elect to impose restrictions more stringent than those normally required by the NPDES or other permitting programs, or even deny a permit for activities that could adversely affect an "impaired" waterbody.

States are also required to develop TMDLs for the impaired waterbodies. TMDLs describe the amount of each pollutant a waterbody can receive and not violate water quality standards. To comply with EPA requirements, the State of Oregon produced a combined report entitled Oregon's 2012 Integrated Report on Water Quality (Integrated Report).

The GIS coverage for the 2010 Integrated Report was reviewed to determine the locations of the water quality limited waters for Water Quality Assessment Categories 4 and 5 to determine if they are in the vicinity of Project components. Based on the ODEQ 2012 Integrated Report GIS coverage, 31 Category 4 and 5 water quality impaired waterbodies would be crossed by the pipeline and are listed in table H-5 in appendix H (ODEQ 2012c).

- TMDLs for the South Umpqua subbasin were completed in October 2006.
- TMDLs for the Upper Rogue subbasin were completed in December 2008.
- TMDLs for the Upper Klamath River, and Lost River subbasins were approved in December 2010.
- TMDLs for the Coos and Coquille Subbasins are currently in progress.

Pacific Connector proposes to cross 26 impaired waterbodies using dry/diverted open-cut crossing techniques. Conventional boring, DP, or HDD methods would be used to cross 5 of the impaired waterbodies.

Contaminated Surface Water or Sediments

As discussed in section 2 as well as sections 4.2 and 4.4 of this EIS, Pacific Connector has BMPs and plans in place to control runoff of any potential hazardous material found at all Project areas including TEWAs, pipe storage sites, hydrostatic test discharge sites, and right-of-way clearing areas. These procedures are intended to prevent unacceptable quantities of material (sediment, toxic substances, oils, concrete water) from entering surface waters. Additionally, sites along the pipeline project route were assessed for their potential to contain hazardous substances.

As discussed in section 4.2, a review of ODEQ's ECSI database and EPA's EnviroMapper - Facility Detail Report indicated there are numerous locations within 0.25 mile of the route (see table G-2 in appendix G) primarily considered pipeline storage sites with either cleaned-up, potential, or confirmed soil and/or groundwater contamination. As noted in section 4.2, many of these sites have the potential to encounter contaminated soil or groundwater during construction. This includes about 12 considered pipe storage sites and three near (but not on) the pipeline route. The FERC has made recommendations that Pacific Connector consult with the ODEQ regarding existing soil and groundwater contamination at these sites (see section 4.2 for the complete list of sites).

Pacific Connector's SPCC Plan is intended to prevent contamination from pipeline activities. Pacific Connector has developed a *Contaminated Substances Discovery Plan* that specifies the measures that would be implemented if unanticipated contaminated soil, surface water, or groundwater are encountered during construction. Some of the measures outlined in that plan include that all construction work in the immediate vicinity of areas where hazardous or unknown wastes are encountered would be halted. The procedures would greatly reduce the risk of hazardous substance entering water bodies along the route.

Additionally, a site with elevated natural mercury levels was found on the originally proposed pipeline route crossing East Fork Cow Creek (MP 109), and concern was expressed that disturbed soil from the crossing could cause human health risk or enter the adjacent stream. Thomason mining claims near East Fork Cow Creek have been determined to have very low concentrations of naturally occurring mercury mineralization (GeoEngineers 2017k). The pipeline route subsequently was rerouted approximately 2,500 feet from where the elevated mercury samples were taken. GeoEngineers (2017k) stated that the soils underlying the currently proposed crossing of East Fork Cow Creek would likely avoid the elevated mercury areas. The ECRP has a number of temporary and permanent erosion control and equipment-cleaning measures to reduce the potential for sediment or contaminated substances to enter wetlands or waterbodies, further reducing potential mercury contamination concerns at this crossing. Additionally, Pacific Connector would implement various site-specific actions at this crossing as recommended by the Forest Service, including:

- Provide 100 percent post-construction ground cover on all disturbed areas. Wood fiber is the preferred material. In addition, construct water bars at 50-foot intervals.
- Ensure that erosion control measures are in place before the fall rains and monitor for rilling, gullying, and other forms of active erosion and issues to improve erosion control measures to preclude sedimentation.
- Inspect the construction corridor for sedimentation after each substantial storm event and, if erosion issues are found, correct them

Drinking Water Source Areas and Public Intakes

As identified in table 4.3.2.2-3, the pipeline would cross or be adjacent to 12 public drinking water source areas (DWSAs) (ODEQ 2012e). In some locations, the pipeline would be located within a particular source area for several miles, but in other locations the pipeline would be located along ridgelines meandering in and out of source areas.

TABLE 4.3.2.2-3

Surface Water Public DWSAs Crossed by the Proposed Pacific Connector Pipeline

Starting Milepost	Ending Milepost	County	Drinking Water Source Area a/	Public Drinking Water System ID	Source Water
20.06BR	35.81	Coos	City of Myrtle Point	4100551	N. F. Coquille River
35.81	41.69	Coos	City of Coquille City of Myrtle Point	4100213 4100551	Coquille River Coquille River
41.69	53.21	Coos	City of Coquille	4100213	N.F. Coquille River
53.21	64.71	Douglas	Winston-Dillard Water District	4100957	S. Umpqua River
64.71 73.37	70.51 74.31	Douglas	Roseburg Forest Products-Dillard	4194300	S. Umpqua River
70.51 74.31	73.37 82.94	Douglas	Clarks Branch Water Association	4100548	S. Umpqua River
82.94	95.41	Douglas	Tri-City Water District	4100549	S. Umpqua River
95.41	102.74	Douglas	Milo Academy Tri-City Water District	4100250 4100549	S. Umpqua River S. Umpqua River
102.74	110.52	Douglas	Milo Academy City of Glendale	4100250 4100323	S. Umpqua River Cow Creek
110.52	124.63	Jackson	Country View Mountain Home Estates	4100808	Rogue River
124.63	124.98	Jackson	Country View Mountain Home Estates Anglers Cove	4100808 4101483	Rogue River Rogue River
124.98	130.07	Jackson	Country View Mountain Home Estates Hiland WC – Shady Cove	4100808 4101520	Rogue River Rogue River
130.07	135.04	Jackson	Country View Mountain Home Estates	4100808	Rogue River
135.04	168.02	Jackson	Medford Water Commission	4100513	Rogue River

a/ The proposed route meanders in and out of Surface Water DWSAs where there are two DWSAs listed.

Table 4.3.2.2-4 lists the public water systems with surface water intakes within 3 miles downstream of waterbodies that would be crossed by the pipeline (ODEQ 2013a).

TABLE 4.3.2.2-4

Surface Water Intakes for Potable Drinking Water Supply

Intake	Public Water System	Source Water for Intake	Waterbody Crossing	Intake Distance Downstream a/	County
4194300	Roseburg Forest Products – Dillard	S. Umpqua River	Rice Creek – MP 65.76 Tributary to S. Umpqua River	0.8 mile	Douglas
4194300	Roseburg Forest Products – Dillard	S. Umpqua River	Willis Creek MP 66.95 Tributary to S. Umpqua River	1.8 miles	Douglas
4100808	Country View Mountain Home Estates	Rogue River	Rogue River MP 122.65	1.4 miles	Jackson
4101483	Anglers Cove Subdivision	Rogue River	Rogue River MP 122.65	Approx. 3 miles	Jackson

Note: All intakes located within 3 miles downstream of proposed waterbody crossings for the Pacific Connector pipeline.
a/ Location of intake downstream from proposed waterbody crossing.

Points of Diversion

Surface water diversions for irrigation, livestock watering, and industry are located within 150 feet of 44 waterbody crossings (see table 4.3.2.2-5).

TABLE 4.3.2.2-5

Points of Diversion within 150 feet of Pacific Connector Construction Work Area

Water Right Type	Water Right Owner	County	Nearest Milepost	Permit/ Certificate Number	Type of Diversion	Diversion Source	Usage Description	Distance to Construction Work Area (feet)	Type of Construction Work Area Containing Points of Diversion a/	Number of Water Rights
Storage	Private	Douglas	60.73	44288	Stream	Perron Creek	Livestock	35.90	-	1
			65.35	T 6708	Stream	South Umpqua River/Reservoir 1	Industrial/manufacturing uses	0.00	Pipe Yards	1
			67.12	R 14589	Stream	Unnamed Stream	Multiple purpose	108.39	-	2
			74.20	69536	Winter Runoff	Runoff/Reservoir 13	Fire protection	0.00	Construction Right-of-Way	1
			74.20	69536	Winter Runoff	Runoff/Reservoir 13	Livestock	0.00	Construction Right-of-Way	1
			75.49	17241	Stream	Sutherlin Creek	Industrial/manufacturing uses	0.00	Pipe Yards	1
			75.49	30362	Stream	Sutherlin Creek	Industrial/manufacturing uses	0.00	Pipe Yards	1
									Storage Total	***8***
Surface Water	Private	Coos	12.07	53679	Stream	Unnamed Stream	Domestic including Lawn and Garden	79.83	-	1
			13.80	36042	Spring	A spring	Domestic	0.00	Construction Right-of-Way	1
			29.48	S 44450	Stream	Stemmler Creek	Domestic including Lawn and Garden	134.81	-	1
			29.48	S 44450	Stream	Stemmler Creek	Livestock	134.81	-	1
			29.86	60877	Stream	East Fork Coquille River	Irrigation	56.92	-	1
			30.00	39940	Stream	East Fork Coquille River	Irrigation	0.00	Construction Right-of-Way	1
		Douglas	49.53	44065	Stream	Lang Creek	Irrigation	109.26	-	1
			58.64	S 54735	Stream	Olalla Creek	Domestic Expanded	117.96	-	1
			67.19	15423	Stream	South Umpqua River	Irrigation	132.51	-	1
			67.19	22390	Stream	South Umpqua River	Irrigation	67.80	-	1
			67.19	23826	Stream	South Umpqua River	Industrial/Manufacturing Uses	0.00	Pipe Yards	1
			70.36	29340	Stream	South Umpqua River	Irrigation	120.06	-	1
			70.36	65231	Stream	South Umpqua River	Irrigation	64.53	-	1
			70.36	68634	Stream	South Umpqua River	Irrigation	64.53	-	1
			75.49	15598	Stream	Sutherlin Creek	Industrial/Manufacturing Uses	0.00	Pipe Yards	2
			75.49	17292	Stream	Camas Swale/Log Pond	Industrial/Manufacturing Uses	0.00	Pipe Yards	1
			75.49	30363	Stream	Sutherlin Cr/Pond	Industrial/Manufacturing Uses	0.00	Pipe Yards	1
			81.23	55163	Stream	South Myrtle Creek	Irrigation	67.96	-	1
			82.27	80544	Stream	South Umpqua River	Irrigation	0.00	Pipe Yards	1
			88.16	43561	Stream	Fate Creek	Irrigation	90.46	-	1
			88.16	52977	Stream	Fate Creek	Irrigation	90.46	-	1
			88.52	56872	Stream	Fate Creek	Irrigation	147.03	-	1

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TABLE 4.3.2.2-5 (continued)

Points of Diversion within 150 feet of Pacific Connector Construction Work Area

Water Right Type	Water Right Owner	County	Nearest Milepost	Permit/ Certificate Number	Type of Diversion	Diversion Source	Usage Description	Distance to Construction Work Area (feet)	Type of Construction Work Area Containing Points of Diversion a/	Number of Water Rights
Surface Water (cont.)		Jackson	122.67	34473	Stream	Rogue River	Irrigation	132.95	-	1
			122.83	65482	Stream	Rogue River	Irrigation	22.39	-	1
			145.77	2170	Stream	Little Butte Creek	Irrigation	100.10	-	1
			145.77	2470	Stream	Little Butte Creek	Irrigation	129.80	-	1
			145.77	57753	Stream	North Fork Little Butte Creek	Irrigation	129.80	-	1
			145.82	17215	Stream	North Fork Little Butte Creek	Irrigation	103.16	-	1
		Klamath	199.96	67512	Stream	Klamath River	Fire Protection	23.69	-	1
	State	Coos	22.30	9712	Spring	A spring	Domestic	119.11	-	1
			27.20	60812	Stream	Middle Creek	Irrigation	127.86	-	1
		Douglas	67.19	S 51632	Stream	South Umpqua River/Con 18714	Primary and Supplemental Irrigation	0.00	Pipe Yards	1
			67.30	S 51924	Reservoir	South Umpqua/Galesville	Supplemental Irrigation	0.00	Pipe Yards	1
			70.36	S 52930	Stream	South Umpqua River	Primary and Supplemental Irrigation	0.00	Pipe Yards	1
			71.31	S 51924	Stream	South Umpqua River	Irrigation	0.00	Temporary Extra Work Space	1
		Jackson	128.61	73043	Stream	Indian Creek	Anadromous and Resident Fish Rearing	9.87	-	12
			135.65	41308	Reservoir	Reservoir	Wildlife	100.42	-	1
									Surface Water Total	***49***
									Grand Total	**57**

a/ Dash indicated a facility (e.g., pipe yard, ROW, TEWA) that does not intersect a water right location.

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Floodplains

EO 11988 (10 CFR 1022) requires federal agencies to avoid to the extent possible the long- and short-term adverse impacts associated with the occupancy and modification of floodplains and to avoid direct and indirect support of floodplain development wherever there is a practicable alternative. Potential effects of the project located within a floodplain should be evaluated and project design should consider flood hazards and floodplain management. It is reasonable to assume that all watercourses that convey natural flows, whether mapped as floodplains, flood hazard areas, or not, present some level of flood hazard. The flood hazard is not limited to inundation; bank erosion and bed scour (a lowering or destabilization of the channel bed during a flow event) are also hazards that can occur due to flooding.

Portions of the pipeline would be located within floodplains. However, because the pipeline would occupy a very limited space within the floodplain, it would not result in a discernable reduction in flood storage capacity. With the exception of the terminal (which would permanently occupy about 200 acers of floodplain; see section 2) there are no permanent facilities in floodplains and PARs would not substantially impact floodplains. Therefore, the Project is not likely to substantially impact flood attenuation and dispersal in each watershed as a result of the small footprint of the Project within each watershed floodplain.

Nationwide Rivers Inventory

The Nationwide Rivers Inventory lists more than 3,400 free-flowing river segments in the United States characterized as possessing one or more “outstandingly remarkable” natural or cultural values judged to be of more than local or regional significance. The proposed pipeline would cross three rivers that are listed on the Nationwide Rivers Inventory (NPS 2013):

- The **North Fork of the Coquille River** listing includes its headwaters in Section 16, T.26S., R.10W. and extends to the confluence with the South Fork Coquille River in Section 5, T.29S., R.12W. This segment was added to the list in 1993 for outstandingly remarkable fish, wildlife, and cultural (prehistoric Indian sites) values. The pipeline would cross this river segment at MP 23.1.
- The **East Fork of the Coquille River** listing extends from its headwaters in Section 18, T.28S., R.8W. to the confluence with the North Fork of the Coquille River in Section 36, T.28S., R.12W. It was added to the list in 1993 for outstandingly remarkable fish, wildlife, boating and fishing. The pipeline would cross this river at MP 29.9.
- The **South Umpqua River** listing includes the reach from Tiller (Section 33, T.30S., R.2W.) downstream to the confluence with the North Umpqua River at River Forks (Sections 31 and 32, T.26S., R.6W.). This reach was added to the list in 1993 for outstanding and remarkable fish and historical values. The pipeline would cross this section of river in two locations, MP 71.3 and MP 94.7.

Impacts and Mitigation

Impacts resulting from the pipeline’s construction (see section 2 for a description of the pipeline’s construction techniques) would be temporary and would affect crossed waterbodies. Construction actions may affect the following parameters:

- turbidity and sedimentation;
- channel and streambank integrity and stability

- in-stream flow
- risk of hazardous material spills and
- waterbody status and water use related to:
  - Oregon Water Quality Regulations and Standards effects
  - contaminated surface water or sediment effects
  - drinking water sources areas and public intakes effects
  - point of diversion effects
  - National Rivers Inventory effects

To reduce potential adverse impacts along the construction right-of-way and at waterbody crossings, Pacific Connector would implement its ECRP during construction, restoration, and operation of its proposed facilities. This would include installing temporary equipment bridges across perennial or intermittent waterbodies flowing at the time of construction to prevent sedimentation caused by construction and vehicular traffic. The ECRP outlines the erosion control procedures that Pacific Connector would utilize.

Trench spoil excavated from within the waterbody would be placed at least 10 feet from the water's edge or in a TEWA if possible (i.e., if the TEWA can adequately support and store the spoil). Staging areas and additional spoil storage areas would be located at least 50 feet from waterbody boundaries, where topographic conditions and other site-specific conditions allow. Where topographic conditions do not allow a 50-foot setback, spoil storage areas would be located at least 10 feet from the water's edge. Sediment control devices, such as silt fences and straw bales, would be placed around the spoil piles to prevent spoil flow back into the waterbody. Pacific Connector would utilize BMPs as necessary, as discussed in the ECRP, to prevent sedimentation entering into waterbodies or wetlands. Mulch would also be used to apply effective ground cover to reduce erosion potential. "Effective ground cover" is considered to be the amount of cover necessary for maintaining a disturbed site in a low hazard category for erosion. The on-site EI would be responsible for ensuring that designated erosion control measured are properly implemented for the site-specific conditions.

Project-specific stream crossing evaluations have been conducted and crossing procedures and mitigative actions would also be implemented. Pacific Connector conducted an initial assessment of crossing conditions of all streams suitable for this analysis (GeoEngineers 2017d, 2018b, 2018c). GeoEngineers (2017d) applied the FWS's Stream Crossing Screening Matrix to all stream crossings that display fluvial characteristics. This assessment was intended to determine where stream crossings may pose a substantial risk of increasing streambank erosion and streambed instability. GeoEngineers, using a combination of field and GIS data, rated the 173 fluvial pipeline stream crossings based on the matrix (GeoEngineers 2018b). Some streams could not be accessed, and evaluation was based on desktop analysis for those streams. The matrix has two axes rating the crossing based on the potential Project effects on the crossing and the relative stream response at the crossing. Each crossing was rated as low, medium, or high for each of the two axes (all stream crossings were placed into one of nine categories, such as Low–Low, Low–Medium, or Medium–High). Category ratings were based on summing numeric ranking (1=lowest risk to 5=highest risk) for multiple metrics for each of the two axes (see GeoEngineers 2017d for details).

No crossing was rated as having both high risk of Project impact potential (i.e., high risk of Project impacts) and high risk of site response potential (high risk of stream and site response). If any crossing had been in this category, Pacific Connector indicated that a site-specific crossing plan would be developed. Should later assessment of the crossings (see below) find that a crossing is in this category, a site-specific plan would be developed prior to construction and reviewed and approved by FERC.

GeoEngineers (2017d, 2018c) grouped the nine risk categories into five categories based on generally similar risk of streams being affected and labeled these as color management categories (Blue, Green, Yellow, Orange, and Red). The assessments included an initial survey and follow-up surveys that resulted in the current assessment of streams into these categories.

After the follow-up surveys, stream crossings with the lowest stream response potential and a low or moderate project impact potential (94 total) were designated as the Blue category and would be crossed using project-typical BMPs. These project-typical BMPs would be applied to all streams while additional BMPs would be applied to the other crossings depending on their rated category of risk. The remaining stream crossings (79) included 68 Yellow and 11 Orange crossings with some greater risk potential at the crossings than Blue crossings. These two categories would have specific additional BMPs applied in addition to the project typical BMPs with the purpose of protecting stream and bank processes following pipeline installation at sites with this category of potential risks. The details of these category specific actions are described in GeoEngineers (2017d, 2018c). After follow-up survey some additional BMPs were added to some of these streams including seven surveyed Orange category crossings (Middle Creek [MP 27.04], Elk Creek [MP 32.40], Tributary to Big Creek [MP 37.35], Upper Rock Creek [MP 44.21], East Fork Cow Creek [MP 109.47], West Fork Trail Creek [MP 118.89], and South Fork Little Butte Creek [MP 162.45]), and had specific crossing plans developed that designate the types of bed and bank restoration that would occur at each of these sites GeoEngineers (2017b, 2018b). Additional specific actions would occur at some streams on federal lands (see section 4.7 and appendix F).

Substrate characteristics and physical habitat features have been or would be determined through pre-construction surveys[93], and the upper 1 foot of existing substrate would be replaced, and other physical conditions matched during reconstruction after pipe installation. Clean spawning gravel would be top dressed as appropriate, and composition would be based on pebble counts or other appropriate methods on a site-specific basis; this would require review and approval by agency staff prior to implementation. Many of these actions would be determined prior to construction based on results of the pre-construction survey (see below) and determined by a qualified EI specifically trained to determine proper restoration actions to implement based on river channel processes or a suitably trained professional. On non-federal lands, this person would have the authority to select appropriate additional BMP construction methods, bank stability actions, revegetation types and methods to help reduce the risk of instability of the crossing and potential for future erosion (GeoEngineers 2017d, 2018b).

A pre-construction survey[94] would be conducted by a technically qualified team on all stream crossings to confirm and clarify conditions developed in the aforementioned matrix analysis. This would include surveys of sites currently not accessible due to property ownership issues. Following these surveys, if significant changes were to occur to parameters of the risk matrix for

[93] Some stream crossings were not accessible and would be surveyed prior to construction once approval and land owner access agreements are obtained.
[94] Some stream crossing were not accessible and will be surveyed prior to construction once approval and land owner access agreements are obtained

a crossing, changes would be made to risk level and appropriate final methods of crossing and BMPs made at each stream crossing. If any crossing is moved into the "high" project impact and "high" stream response risk matrix category, a site-specific crossing design would be developed for that site. Following the final surveys, special additional BMPs, as described in GeoEngineers (2017d, 2018b), would be implemented depending on individual site conditions and may include such actions as changes in bank material and bank angle modifications, specific substrate composition used, plants used on the bank, artificial stabilizing bank material, rootwad enhancement, type of bed and bank restoration structure, and various other actions.

The approach described above, which would include more site-specific information and possibly more site-specific designs based on the pre-construction survey, is expected to be suitable for the protection of aquatic resources at waterbody crossings. The final procedures would ultimately need to obtain other permit-process approval (e.g., Section 401 water quality certification) before construction is conducted at specific sites.

As a measure to help ensure crossing actions would not adversely affect stream bank and channel structure, Pacific Connector, as part of their pipeline integrity monitoring, would observe all stream crossings, regardless of risk rating category, annually for the life of the Project and note any obvious signs of channel erosion, pipeline exposure, or major shifts in restoration elements. Where any problems were noted during this annual assessment, a follow-up visit by geo-professionals would occur (GeoEngineers 2018b). On a quarterly basis, over two years after construction at all perennial crossings on federal lands as well as the highest risk sites identified on non-federal lands (Orange category), monitoring of vegetation success, stability of restoration elements, fish passage status, channel migration, erosion, head cutting, and other channel characteristics would be conducted. Additional forms of monitoring (e.g., vegetation, animal browse, and continued channel/restoration status) would occur at varied sites over varied intermittent periods over a 10-year period, with the highest frequency and intensity of monitoring effort at those sites of greatest risk of channel and bank instability. Frequency and type of monitoring may be adjusted based on site-specific conditions. In addition, flow and rainfall events would be recorded to understand the response of sites to flow events. Additional monitoring would occur on streams on federal lands. Remediation of adverse conditions with channel stability or habitat found during the monitoring would occur. Reports of the monitoring would be developed for years 1, 2, 3, 5, 7, and 10 after construction describing observations made and any remedial actions taken.

<u>Construction of New TARs, New PARs, Existing Access Roads (EAR), and TEWAs</u>

Construction of roads and facilities have the potential to contribute sediment to streams. Of the existing roads that would be used for construction that would need improvements, approximately 56 road segments would be within 100 feet of streams, with 47 of these directly crossing waterbodies. The total road area that would be within 100 feet of streams and that would be expanded (e.g., widened or turnouts added) include 5.6, 0.15, and 0.68 acres for EARs, TARs, and PARs, respectively.[95] A portion of these areas are within regions with the greatest potential to contribute sediment to streams (see below). All access roads would use the existing crossing facility (e.g., bridge, culvert, ford), except for one that would use a temporary bridge and another with a temporary culvert. It is possible that other crossings may need to be improved or replaced,

[95] Total acres on the road segments that would be widened, not just the area within 100 feet of streams (see Pacific Connector Resource Report 2, Appendix Table A.2-6).

once final plans are developed prior to construction. These crossings would have to be reviewed and approved by the applicable agencies prior to their implementation.

Currently, there are 8 TARs and 11 PARs that would be built in the range of coho salmon–bearing watersheds along the proposed route. Of these, 2 PARs would directly cross streams and 4 TARs and 3 PARs would be within 200 feet of streams in these watersheds. There would be about 23 EAR segments that would be improved (e.g., by widening, resurfacing, or brush removal) that are within 200 feet of coho salmon-bearing streams, 7 of which would directly cross streams. Potential sediment delivery to streams would occur from gravel and dirt roads, either newly built or improved ones. Dube et al. (2004) provided a summary table of distance categories for sediment delivery. The table indicated that where roads directly cross streams all sediment (100 percent) that runs off the road at the crossing would be considered to enter the streams, while potential sediment delivery to streams from road runoff decreases exponentially by distance from a stream. Dube et al. (2004) indicated that, from about 1 to 100 feet from a stream, 35 percent of road runoff would reach a stream; between 100 and 200 feet about 10 percent; and beyond 200 feet, no runoff would be considered to reach a stream. Given the locations of these roads, a total of 4 TARs, 3 PARs, and 21 EAR road segments related to the Project could potentially deliver sediment to coho salmon streams, either from directly crossing streams or being with 200 feet upslope of stream channels. There are likely other road areas outside of the 200-foot area that, depending on road ditching, road surface, and whether the hillslope would be channelized between road and streams, could also contribute some sediment to streams from construction or use. Additional streams other than coho salmon streams could also have some road-induced sediment delivery from construction and use. Such sediment delivery could increase turbidity and fine sediment deposits to streams, especially if BMPs were not properly instituted in these areas.

Several actions would be taken to reduce sediment runoff from roads, right-of-way clearing, and stream crossing structures. Where road improvements would be required, Pacific Connector would ensure that existing drainage features (e.g., culverts, ditches, dips, and grade sags) continue to function properly or they would employ suitable substitute measures to ensure that drainage is controlled to prevent off-site erosion or other resource damage. Surfaces of all new PARs would be graveled, thereby decreasing their erosion potential. Further, PARs and TARs would meet land-managing agencies’ engineering design and road management standards consistent with the intended use of the road, and all applicable agency BMPs for erosion control would be implemented. All TARs would also be restored to preconstruction conditions following completion of construction.

TEWAs, which are common along the route, many near streams, represent another potential source of elevated sediment runoff. To reduce the chance of sediment entry to streams from TEWAs, Pacific Connector would install BMPs according to their ECRP for all related construction actions. BMPs may include silt fence/straw bale, sediment barriers, temporary slope breakers, or prefabricated construction mats to prevent rutting/compaction impacts and mulch, dust control, and permanent erosion control measures that would further reduce sediment discharges from a site after construction is complete including right-of-way areas. In forested areas, slash-filter windrows may be constructed on the downhill edge of the construction right-of-way and TEWAs, as directed by the EI.

While some additional sediment would enter streams, several factors would reduce these occurrences:

- the relatively small area that would be disturbed from these actions;
- the provisions in the TMP that would be followed, which include meeting local, state, and federal road construction and maintenance procedures as appropriate;
- the ECRP and BMPs that would be implemented for Project roads, right-of-way clearing, and TEWAs;
- inspection of erosion control measures at least daily during active construction and weekly in non-active construction areas and within a day of intensive rain (more than 0.5 inches rain);
- active maintenance of temporary erosion control measures until permanent vegetation is established; and
- inspection, when possible, of erosion control measures prior to forecast storms and taking of corrective actions as needed.

The result would be that noticeable adverse effects on stream sediment or water quality are unlikely to occur.

<u>Turbidity and Sedimentation</u>

Turbidity and sedimentation affect water clarity and future substrate characteristics. Increases in both can be detrimental to drinking water quality and adversely affect aquatic organisms by impeding light penetration, benthic organism survival, and quality of substrate for invertebrate production and fish spawning success (see section 4.5). Turbidity in streams is often regulated, and levels allowed are usually designated in state water quality certification permits. To reduce increases in turbidity and suspended sediment at waterbody crossings, Pacific Connector would utilize the dry crossing methods (i.e., flume and dam-and-pump) for most of the flowing waterbodies crossed by the pipeline (as discussed above). The remainder would be crossed by conventional bore, diverted open-cut, HDD, and DP. Turbidity and sedimentation resulting from dry open-cut methods are generally minor and temporary and are associated with (1) installation and removal of the upstream and downstream dams used to isolate the construction area; (2) water leaking through the upstream dam and collecting sediments as it flows across the work area and continues through the downstream dam; (3) movement of in-stream rocks and boulders to allow proper alignment and installation of the flume and dams; and (4) when streamflow is returned to the construction work area after the crossing is complete and the dams and flume are removed. Dry methods have been reported to produce one-seventh the suspended sediment in streams than "wet" methods (Reid et al. 2002). According to Pacific Connector, during construction of Williams Northwest Pipeline's Capacity Replacement Project in Washington State (completed in 2006), a total of 67 waterbodies were crossed using dry open-cut crossing methods (fluming and/or dam and pump). During these crossings, there was only one event where state water quality turbidity limits were exceeded. The exceedance occurred through a failure of the pumps during the night when a monitor was not on site to restart the pump.

Some turbidity would result during instream activities and when the water is diverted to the backfilled areas. GeoEngineers (2017e) evaluated the potential risk of turbidity during construction across waterbodies and assigned waterbodies a score from 1 (low) to 5 (high). Of

299 waterbodies evaluated[96], 110 were scored with a low risk (score of 1 or 2) of turbidity increase over a 24-hour period and 189 were scored with a moderate risk (score of 3 or 4), generally due to soil erosion potential, presence of clay or mud, and/or the presence of steep slope or an incised channel that would require construction of a deep trench.

Monitoring studies of varied dry stream crossing pipeline activities have found moderately elevated suspended sediment near these crossings sites. Reid et al. (2004) measured suspended sediment downstream from 12 flumed pipeline crossings and 23 dam-and-pump crossings in North American streams. The study estimated that suspended sediment concentrations averaged 99 mg/l for flumed crossings and 23 mg/l at the dam-and-pump crossings. Reid et al. (2002) found that below four separate dam-and-pump crossings, mean suspended sediment was less than 20 mg/l within 30 meters (100 feet) downstream.

For Project area streams, average watershed suspended sediment values within 50 meters downstream of the stream crossings were modeled.[97] During a standard crossing using dam-and-pump or flumed crossing methods, when water diversion and sediment control methods are in place, values would range from 27 to 153 mg/l for flumed crossing and 7 to 35 mg/l with dam-and-pump crossings for the affected watersheds. These values are similar to those found by Reid et al. (2004) noted above. However, values would be much higher should the crossing sediment control method fail, with modeled suspended sediment values ranging from 712 to 4,102 mg/l if wet open cut methods were used during crossing failure. Duration of elevated values from failure would likely be short, less than about 2 to 4 hours for small streams and possibly up to about 6 hours for large stream crossings. While failures of diversion control systems during crossings are uncommon (Reid et al. 2004), they would likely occur at some crossings during construction. Suspended sediment concentrations from any crossing method would decrease to background levels (about 2 mg/l) within about 0.6 to 19 km (approximately 0.4 to 11.8 miles) downstream of a crossing, among the 14 watersheds.

The South Umpqua River diverted open-cut crossing would have similar effects on downstream sediment and turbidity, in the short term, to those from other dry crossings. These effects would mostly end once the diversion is in place as stream construction would occur in the dry. There would be short-term turbidity increases for short distances, lasting for several hours during portions of the installation and removal of the diversion structures for the proposed diverted open-cut crossing. The dominant substrate at the crossing is gravel and cobble. Local borings indicated that the upper strata is characterized as sandy gravel and cobble with some silt, while pebble counts at the crossing indicated that the surface substrate is mostly (over 16 percent) 1.6 inches or larger (i.e., small gravel or larger). While total composition of all substrate that would be trenched is not completely characterized, information suggests abundant fines are likely very low. With limited fines present, the downstream distribution of elevated fines and fine material that would settle are expected to be low from the diverted open cut. While there would be some fine material that would be suspended and travel farther downstream, it is likely to be very limited based on the available sediment assessment. The settled substrate would have limited change on existing substrate characteristics.

[96] Excludes ponds, estuaries, streams and canals crossed using trenchless methods and water bodies in right way not crossed.
[97] See Pacific Connector's response to a FERC information request related to Resource Report 2, filed May 4, 2018.

Temporary bridge installation may occasionally add turbidity to streams. Temporary stream crossings may occur outside of the fish in-water work window. Pacific Connector's crossing plans include installing temporary bridges from the bank without entering the water. These may include such items as flat-beds that are typically 30 to 40 feet long, some as long as 90 feet. If such bridges are not considered safe to install from the bank, only the equipment needed to cross the stream to install the bridge would cross the stream. Once installed, no further vehicle passage would occur in the channel. Therefore, while a small number of stream channels may be disturbed during installation causing elevated sediment levels, the limited vehicle traffic and number of such crossing locations would reduce water quality effects from turbidity in location and duration along the proposed route.

Potential effects from turbidity from construction across streams are expected to be temporary (most within days of actual construction) and minor (relatively low increase in turbidity beyond the construction area) for the following reasons:

- all but one crossing of perennial streams would be completed either using dry open-cut crossing methods or methods that avoid impacts altogether;
- crossings would be completed during ODFW and NMFS recommended in-water work periods when the flow volumes and velocities will be low;
- headwater streams are typically dominated by gravel/cobble substrates reducing the potential to generate turbidity during crossings;
- crossings (including crossings in the same watershed) would be scheduled individually, several days apart, and not completed concurrently;
- erosion control BMPs, as outlined in Pacific Connector's ECRP, would be implemented to reduce the potential for erosion and sedimentation; and
- bridge installation where vehicles enter streams would only occur in limited locations and duration, with most areas spanned by bridges without water entry, and Pacific Connector would follow BMPs and procedures approved by state and applicable federal agencies where temporary bridges would be installed.

The *Turbidity-Nutrients-Metals Water Quality Impact Analysis* (GeoEngineers 2017e) concluded that turbidity may exceed Oregon numerical water quality standards for short distances and short durations downstream from each crossing, either during and shortly after construction (in perennial waterbodies) or after fall rains begin (for intermittent and ephemeral streams). Such exceedances are allowed as part of the narrative turbidity standard if recognized in a CWA Section 401 water quality certification if every practicable means to control turbidity has been used.

Contribution of turbidity or sediment from other crossing methods, including DP, bore, and HDD, would be unlikely. DPs and bores would go under waterbodies and avoid contact with flowing streams. Start and end points would be back from the stream banks so standard BMPs for erosion control would reduce potential for sediment to enter streams from their use.

The details of the HDD crossing are described in section 2. Pacific Connector proposes to use the HDD method to cross under two spans of 0.7 and 1.6 miles of Coos Bay, and also the Coos, Rogue, and Klamath Rivers. Generally, an HDD would avoid direct effects on the bay and associated estuarine resources; stream habitat and water quality. However, an HDD requires the use of drilling mud as a lubricant during the process. This fluid is under pressure and there is a possibility of an inadvertent release of drilling mud through a substrata fracture, allowing it to rise to the surface (frac-out). The drilling fluid is typically comprised of inert muds, so an inadvertent release would likely be non-toxic to aquatic life. Drilling mud may accumulate locally and be washed downstream, temporarily increasing rates of turbidity and sedimentation. In addition, inadvertent releases most often occur near the entry and exit locations, which are often landward of the stream or estuarine channels, reducing the likelihood that drilling mud would enter surface waters. Pacific Connector prepared detailed surveys and crossing plans[98] for each of the HDD crossing sites, further reducing the chances of HDD crossing problems. To prevent an inadvertent release or address impacts should one occur, Pacific Connector developed its *Drilling Fluid Contingency Plan for Horizontal Directional Drilling Operations*[99] as discussed in section 2.

The exact composition of the drilling fluid would primarily consist of water and bentonite clay; however, additional drilling fluids additives, grout, or LCM may be necessary to control subsurface conditions encountered during drilling. Other than bentonite, Pacific Connector has not identified drilling fluid additives, grout or LCM materials or provided safety data sheets for these materials. Therefore, **we recommend that:**

- **<u>Prior to construction</u>, Pacific Connector should file with the Secretary, for review and written approval by the Director of OEP, a listing of all drilling fluid additives, grout, and LCM that may be used during HDD activities, provide safety data sheets for these materials, and indicate the ecotoxicity of each additive mixed in the drilling fluid to the identified toxicity for relevant biotic receptors.**

Based on known flow regimes within the HDD river crossings (Coos, Rouge, and Klamath Rivers), a small volume of drilling fluid released into the river would quickly dissipate. However, in the event drilling fluid is detected in a waterbody, Pacific Connector would notify the appropriate agencies, including the FERC project manager, and an assessment would be made to determine the most appropriate containment structure to be erected to reduce impacts on the waterbody (by limiting additional releases and containing the ones already in the waterbody).

In the event of a release of drilling fluids into the Coos Bay intertidal mud flats or subtidal areas, the drilling fluid may not likely mobilize as it would in a rapidly moving river. Coos Bay is relatively shallow throughout much of the HDD alignment, and the mudline becomes exposed during low tides across much of the alignment except within the dredged shipping channel. In the event of a drilling fluid release into Coos Bay, the drilling fluid would likely settle onto the bay floor.

The areas along the drill alignment and downstream of the Project site would be monitored to identify areas that may have substantial accumulations of drilling fluid. Potential accumulations would likely only occur in slow-flowing areas that allow enough time for the suspended particulates to settle out of the water column. Jordan Cove would attempt to remove drilling fluid volumes that represent substantial adverse impacts on aquatic habitat. Areas where bentonite accumulations are removed would be monitored to assess the need for additional substrate. If the

[98] See Appendix G.2 of Pacific Connector's Resource Report 2.
[99] This plan was attached as Appendix 2.H of Resource Report 2, in Pacific Connector's September 2017 application to the FERC.

areas identified lack essential substrate materials including spawning gravels, these materials may be added to mitigate the impacts of the bentonite removal activities.

Overall, drilling mud releases to any waterbody would be short term, likely less than a day, and would be diluted from large river water volumes and swift flows. We conclude that an inadvertent release of drilling mud from an HDD would have minor, short-term adverse effects on resources in estuarine channels or rivers.

Trench spoil excavated from within the waterbody would be placed at least 10 feet from the water's edge or in a TEWA and may have the potential to contribute sediment and turbidity to streams. In some waterbodies, native washed streambed boulders, cobbles, and gravels removed from the surface of the trench may be stored within the construction right-of-way in the streambed in areas isolated from streamflow (i.e., within the dammed area for flumes or dam-and-pump crossing). Storing this material in the streambed would reduce handling and help to ensure the material would be available for backfill and streambed restoration. This storage procedure requires a modification from Section V.B.4.a. of the FERC's *Procedures* (which require spoil store more than 10 feet from the edge of waterbody). This modification has been requested as part of the license application (see appendix E). Staging areas and additional spoil storage areas would be located at least 50 feet away from waterbody boundaries, where topographic conditions and other site-specific conditions allow. Where topographic conditions do not allow a 50-foot setback, spoil storage areas would be located at least 10 feet from the water's edge. Sediment control devices, such as silt fences and straw bales, would be placed around the spoil piles to prevent spoil flow back into the waterbody reducing the chance of increasing turbidity.

Channel and Stream Bank Integrity

Constructing the pipeline would modify streambanks, resulting in an increase in the rates of erosion, turbidity, and sedimentation into the crossed waterbody. An increase in soil compaction and vegetation clearing could also potentially increase runoff and subsequent streamflow or peak flows. The extent of these impacts would depend on streambank composition and vegetation stream type, velocity, and sediment particle size.

To reduce these impacts, equipment bridges and mats would be used, as necessary, to provide stable work areas and isolate equipment from waterbodies. TEWAs for spoil storage and pipe staging would be set back from the bank as discussed below, and temporary sediment barriers would be installed around disturbed areas, where necessary, in accordance with Pacific Connector's ECRP.

To restore streambanks on non-federal lands, Pacific Connector would return affected lands to preconstruction contours or shaped to a stable angle (see section 4.3.4 for a discussion of requirements on federal lands). Erosion control measures including fiber fabric or matting would be installed on slopes adjacent to streams. On some banks, depending on site-specific conditions, fiber rolls may also be installed to stabilize bank toes. The streambanks would be seeded, and woody riparian vegetation planted for stabilization according to Pacific Connector's ECRP. Pacific Connector does not anticipate that riprap would be required for streambank stabilization, but if used would be limited to the areas where flow conditions preclude effective vegetation stabilization techniques. Pacific Connector may also implement tree revetments, stream barbs/flow deflectors, toe-rock, and vegetation riprap before using hard bank protection. The

NMFS has expressed concern with the potential use of riprap or barb/flow deflectors for this Project and has requested that only bioengineered methods (such as LWD) be used for bank protection or flow control for the Project. This NMFS request may also become a condition within their BO for the Project or a requirement during the NMFS permitting process.

Fluvial erosion represents a potential hazard to the pipeline where streams can expose the pipe as a result of channel migration, avulsion, widening, and/or streambed scour. The pipeline would be designed to ensure it does not become exposed from bed scour or channel migration, which may include increasing the depth of cover to more than the 5-foot minimum to accommodate the potential for long-term channel changes. A channel migration and scour analysis was performed and rated crossings as to their risk of pipe exposure. Those sites considered to have potential risk of pipe exposure were evaluated in more detail including site-specific data and, where deemed necessary, would have additional procedures taken to ensure that likelihood of pipe exposure is substantially reduced. Ten crossings were identified as Level 2 (listed below on table 4.3.2.2-6), which have large or complex channels with a high potential for migration, avulsion, or scour, and required site-specific additional analyses. From the results of the channel migration and scour analysis, Pacific Connector would design all crossings that were assessed in detail to bury the pipe below the 100-year scour depth or into competent bedrock, whichever is shallower, and for streams likely to have channel migration, bury the pipe below the projected depth of the channel thalweg (lowest streambed elevation) within the 50-year channel migration zone. Additional analysis prior to construction would be needed for sites that were not accessible due to property rights. All crossing sites would have pre- and post-construction surveys conducted to document (by post-construction conditions monitoring) that each crossing has been restored to pre-construction conditions (or better) after project construction. A summary of the survey findings would be filed with the FERC. Crossing of various risk categories would have additional BMPs as described below.

TABLE 4.3.2.2-6

Streams Crossed by the Pacific Connector Pipeline Route That Have a High Potential for Scour or Migration

Watershed	Stream Name	MP	Maximum Scour Depth a/	Other Hazards	Mitigation Measures
Coquille	Middle Park Creek	27.0	10.5 feet	Channel widening	Dry open-cut
Coquille	Elk Creek	34.40	6.0 feet	Channel widening	Bury in bedrock
S. Umpqua	Olalla Creek	58.8	7.5 feet	Migration	Bury in bedrock
S. Umpqua	Western Crossing of the South Fork Umpqua River	71.3	unknown	unknown	DP
S. Umpqua	North Myrtle Creek	79.1	6.5 feet	Migration	Bury in bedrock
S. Umpqua	South Myrtle Creek	81.2	unknown	Migration	Bury in bedrock
S. Umpqua	Eastern Crossing of the South Fork Umpqua River	94.7	18.0 feet	unknown	Diverted open-cut
Rogue	West Fork Trail Creek	118.9	unknown	unknown	Bury in bedrock
Rogue	Rogue River	122.7	20.5 feet	Channel widening	HDD
Rogue	North Fork Little Butte Creek	145.7	unknown	unknown	Dry open-cut

a/ 100-year flood recurrence

Pacific Connector would follow the procedures described in section 2 for placement of sediment cover in streams but has requested a modification, where the existing substrate is not gravel or cobbles and site access is limited, only native materials removed from the stream be used for backfilling. Pacific Connector has provided site-specific modification to our *Procedures* (see appendix E). Any subsequent need to place fill within a stream may require a permit from the COE under Section 404 of the CWA and from the ODSL under the ORS.

In-Stream Flow

Flow changes because of Project actions can have effects on water user's access to water and physical and biological conditions of streams. Flow reductions can partially affect stream temperature as well as aquatic habitat.

Project water withdrawal from waterbodies would occur from two main activities: hydrostatic testing and water needed for project dust control. Pacific Connector estimates between 31 and 65 million gallons of water would be required to test the pipeline during hydrostatic testing (see table 4.3.2.2-7).

Water for hydrostatic testing would be primarily obtained from surface water sources, but some private supply wells or other surface water rights may be drawn upon as well (see table 4.3.2.2-7). If water for hydrostatic testing would be acquired from any source other than a municipality, including surface water sources as noted in table 4.3.2.2-7, Pacific Connector would obtain all necessary appropriations and withdrawal permits, including from the OWRD, prior to use.

Pacific Connector would apply for permission from ODEQ to discharge the hydrostatic test water. State water withdrawal permits require review by OWRD, ODEQ, and ODFW to ensure potential impacts from withdrawal do not occur. The review includes volume, timing, and duration of the withdrawal. The withdrawal permit ensures that the proposed impact on existing water rights or beneficial uses of the water body do not occur. Where test water cannot be returned to its withdrawal source, the water would be treated with a mild chlorine treatment and discharged to an upland location (at least 150 feet from streams with no direct discharge features) through a dewatering structure at a rate to prevent scour and erosion and to promote infiltration. If necessary multiple discharge locations could be used to ensure proper dissipation of discharges. The final details of chlorine concentration have not been finalized but will be developed during permitting process. Water treated with chlorine would be released according to ODEQ criteria and what is allowed in the ODEQ WPCF permit to prevent water quality or potential impacts on aquatic species. If needed this water would be treated to prevent impacts from chlorinated water on the environment (*Hydrostatic Test Plan*, Appendix M of the POD [appendix F.10 of this EIS]). Hydrostatic discharge points have been located in upland areas where feasible, and at an appropriate distance from wetlands and waterbodies to promote infiltration and to ensure that sedimentation of wetlands, waterbodies, or other sensitive areas do not occur (identified in table D-3 in appendix D). Pacific Connector's EIs would visually monitor the release of hydrostatic test water and trench dewatering activities to ensure that no erosion or sedimentation occurs. In addition, the EIs would ensure that turbid water is not discharged to waters of the state. If an EI determines that a discharge is occurring from trench dewatering, the receiving water would be visually monitored for turbidity. If a turbidity plume is observed, the trench dewatering operations would be immediately adjusted/reinstalled/maintained to ensure that the discharge of sediment to surface water is stopped and water quality standards are not exceeded. In addition, a total of 32 test header section breaks where water would be discharged are located within the construction right-of-way or TEWAs (identified in table D-3 in appendix D).

TABLE 4.3.2.2-7

Potential Hydrostatic Test Water Quantity and Source Locations

Spread	Test Sections	MP Range	Estimated Volume (gal) a/	Additional Water Required for HDD/Direct Pipe Pre-Test	Minimum + Additional Pre-Test Water b/	Source c/	Additional Potential Sources Recently Sited by Construction Management Team
South Coast Water Basin (MP 0.00 – 53.15)							
EW.	1-2	0.00-8.35R	1,547,000	757,000	1,938,000	MP 0.00 – North Spit Pump House (Coos Bay) MP 1.31 – Fire Hydrant on Westside of Hwy 101 Bridge	–
1	3-6	8.35R-29.54	6,836,000	276,000	2,825,000	MP 11.08R – Coos River MP 29.64 – East Fork Coquille River	Steinnon Creek: North Fork of Coquille River
2	7-10	29.54-51.58	6,154,000	85,000	2,458,000	MP 29.64 – East Fork Coquille River MP 50.28 – Middle Fork Coquille River	Upper Rock Creek
Umpqua Water Basin (MP 53.15 – 111.11)							
3	11-12	51.58-71.37	5.692.000	75,000	4,042000	MP 57.30 – Ben Irving Reservoir MP 58.79 – Ollala Creek MP 71.25 – South Umpqua River	Middle Fork Coquille
4	13-17	71.37-94.65	6,499,000	106,000	2,878,000	MP 71.25 – South Umpqua River MP 94.70 – South Umpqua River	South Myrtle Creek
5	18-20	94.65-110.23	4,350,000	–	2,535,000	MP 94.70 – South Umpqua River	South Myrtle Creek; Indian Lake
Rogue Water Basin (MP 111.11 – 167.58)							
5	21-24	110.23-132.50	6,218,000	164,000	2,872,000	MP 122.80 – Roque River	South Myrtle Creek; Indian Lake
6	25-27	132.50-162.00	8,348,000	–	3,060,000	MP 141 .00 – Star Lake MP 133.4 – Medford Aquifer (if this is used, will have to cut in another test)	–
7	28	162.00-179.00	4,635,000	124,000	4,817,000	MP 199.2 – Klamath River MP 212.00 – Lost River	–
Klamath Water Basin (MP 167.58–228.81)							
7	29-32	179.00-228.81	13,906,000	124,000	4,817,000	MP 199.2 – Klamath River MP 212.00 – Lost River	Lost River Anthony Blair Deep Well Gavin Rajnus Deep Well Ryan Hartmen Deep Well
Total			**64,185,000**	**1,711,000**	**32,242,000**		

a/ Total amount of water needed without any cascading of water between sections, which would not occur.
b/ Total assuming likely cascading of water between test section
c/ Currently expected sources of water but alternative or additions sources may be used as noted.
Source: Data response table based on April 12, 2018 design (Pacific Connector Response date May 24, 2018 from Attachment – FERC-PCGP-RR10-1)

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To address concerns regarding water withdrawals and hydrostatic testing, Pacific Connector developed a *Hydrostatic Test Plan* (Appendix M of the POD [appendix F.10 of this EIS]). The plan would be updated in consultation with the BLM and Forest Service, as well as the Center for Lakes and Reservoirs and Aquatic Bioinvasion Research and Policy Institute (Portland State University). The plan includes measures to prevent the transfer of aquatic invasive species and pathogens from one watershed to another. Where possible, test water would be released within the same basin from which it was withdrawn. However, cascading water from one test section to another to reduce water withdrawal requirements may make it impractical to release water within the same basin where the water was withdrawn in all cases. If hydrostatic test source water cannot be returned to the same water basin from where it was withdrawn, Pacific Connector would disinfect the water that would be transferred across water basin boundaries. The hydrostatic test water treatment process would incorporate screening during water withdrawal that would meet NMFS and ODFW criteria to prevent the entrainment of small fish. Water would be discharged according to ODEQ requirements for chlorinated water discharges as noted in the *Hydrostatic Testing Plan*. All discharge locations would be monitored after construction for potential noxious weed establishment and treated if necessary.

Potential effects on stream flow associated with hydrostatic testing include reduced downstream flows, erosion and scouring at release points, and the transfer of aquatic nuisance species through the test water from one water basin to another. Estimates of potential water intake amounts from streams indicate flows below intake would be reduced by less than 10 percent of typical monthly instantaneous flow rates during the month of withdrawal for all but one (at 35 percent of flow) potential locations during withdrawal (duration about 6 to 11 days at each potential location; Ambrose 2018, see also table 4.5.2.3-6 in section 4.5 for withdrawal amounts by stream and additional recommendations by FERC). Final selection of intake rates and sites would be reviewed by ODFW and OWRD prior to testing, so that potential effects from flow reductions would be unlikely.

It is not possible to estimate the total loss of water from a basin because exact locations have not been determined for both withdrawal and discharge. Given that relatively small portions of any individual stream flow (less than 10 percent) would be used daily, the short duration at any one stream withdrawal (6 to 11 days), that some if not all of the water withdrawn would be returned to the basin where withdrawn, and that there are substantial additional streams without water withdrawal in each basin, the total loss of basin water would not be substantial. Additionally, once final plans are developed, the state permitting process for water withdrawal and discharge would ensure that substantial impacts are not allowed.

While it is not possible to know how much water would be needed for dust suppression on the pipeline construction right-of-way, during dry seasons, Pacific Connector estimates that there would be approximately five 3,000-gallon water trucks per construction spread on a given day. Pacific Connector anticipates using five construction spreads, which would total 75,000 gallons for 25 water trucks per day. While the total amount of water needed is unknown, the amount needed for each truck is relatively small. For example, if filling one truck occurred in 30 minutes of water withdrawal, the rate would be about 1.7 gallons per second or 0.2 cfs. This flow reduction would be a small portion of the flow of perennial streams or rivers that are likely to be used for water supply. Therefore, the overall change in any specific reduction in streamflow from this water use would likely be unsubstantial.

Watering trucks would spray only enough water to control the dust or to reach the optimum soil moisture content to create a surface crust. Runoff should not be generated during this operation. All appropriate permits/approvals would be obtained prior to withdrawal. Table 4.3.2.2-8 lists potential dust control water sources that have been identified by Pacific Connector.

TABLE 4.3.2.2-8

Potential Dust Control Water Sources for the Pacific Connector Pipeline

County	Nearest PM	Source
Coos	16.5	Aqueduct Lake
Coos	37.0	Brewster Lake (WI-602)
Douglas	50.2	Lang Creek Reservoir
Douglas	79.0	Big Lick Reservoir
Jackson	128.5	Indian Lake Reservoir
Jackson	133.4	Eagle Point Irrigation Canal Crossing
Jackson	141.0	Star Ranch Lake
Jackson	144.0	Unnamed Reservoir
Jackson	145.0	Gardener Reservoir
Klamath	228.5	High Line Canal
Klamath	228.7	Capek Reservoir
Klamath	229.4	Low Line Canal

Additionally, Pacific Connector has indicated it may utilize a synthetic product such as Dustlock®, in addition to water, for dust control. Dustlock is a naturally occurring byproduct of the vegetable oil refining process. Dustlock penetrates the bed of the material and bonds to make a barrier that is naturally biodegradable, ensuring that the surrounding ground and water are not contaminated, and minimizing any potential effects on fish and wildlife. However, Pacific Connector would not use Dustlock within 150 feet of riparian areas or wetlands.

For dust control water use Pacific connector would be restricted to water withdrawal from permitted waterbodies where flows would not be adversely affected as they would obtain. If water for dust control would be acquired from any source other than a municipality, including surface water sources as noted in table 4.3.2.2-8, Pacific Connector would obtain all necessary appropriations and withdrawal permits, including from the OWRD, prior to use.

According to the Forest Service, vegetation clearing and management that creates sizable canopy openings can increase water yields and subsequently, waterbody flows (Forest Service 2000). Sizeable canopy openings can result in other factors affecting watershed water storage and runoff amount, peak amount and time of runoff (Forest Service 2008). The relatively small percentage of the watersheds affected by the right-of-way and the total area of the watershed within the transient snow zone would, however, greatly limit this potential effect. Although permanent canopy removal in forested areas along the right-of-way would increase the potential for snow accumulation, the forest clearing within any of the watersheds would be so small as to not have a measurable influence on peak flows.

Surface waters could be affected due to alteration of groundwater flow where the pipeline intersects waterbodies. The hyporheic zone is a region beneath and alongside a stream bed where there is mixing of shallow groundwater and surface water. The flow dynamics and behavior in this zone is recognized to be important for surface water and groundwater interactions, as well as fish spawning, among other processes. Pacific Connector conducted a hyporheic exchange analysis on the waterbodies crossed by the pipeline (GeoEngineers 2017g). The assessment focused on determining if construction has the potential to affect the structure and function of the hyporheic zone, and if so, which stream crossing may be most sensitive to changes in hyporheic zone structure and organization. Historically, pipeline construction has not typically been considered as having a potential effect on hyporheic zone function, presumably because of the nature of the construction process having relatively limited, localized and temporary change to the subsurface conditions under streams and rivers. It is difficult to measure hyporheic exchange without detailed site-specific study, but qualitative observations of bed and bank material, stream gradient, location within a watershed, and morphological features can help indicate whether a stream has an active and functional hyporheic zone. GeoEngineers (2017g) developed weighting factors to assign criteria of high, moderate, and low sensitivity to the crossing locations. The analysis used these qualitative parameters to rank how sensitive a stream crossing may be to potential hyporheic zone alteration.

Fourteen stream crossings were categorized as having a high sensitivity to hyporheic zone alteration, which would suggest a high likelihood of a functioning hyporheic zone, mostly associated with larger waterbodies with greater floodplain widths and instream morphologic features. Two of the ‘high’ sensitivity crossings, including the Coos River crossing at MP 11.13R and the Rogue River crossing at MP 122.65, would be crossed by HDD rather than open trenching across the stream channel.

A “moderate” sensitivity indicates that the stream crossing displays some indicators that a hyporheic zone is active and functional; approximately 63 crossings fit this category, most of them upper to middle watershed streams. A “low” sensitivity indicates that the stream crossing does not likely support either an extensive or functional hyporheic zone; approximately 127 stream crossings fit into this category. Many of these low scoring stream crossings are bedrock-controlled, are dominated by finer-grained material, or are canals and ditches. Eleven stream crossings were not assigned any point values or ranking due to there being no channel or channel forming processes observed at the crossing location in the field.

Water quality parameters, including water temperature and intragravel dissolved oxygen, might potentially be affected at crossings where hyporheic exchange is extensive and active. Thus, streams with a “high” and “moderate” sensitivity would be the streams where water quality could potentially be compromised due to alteration of the hyporheic zone. Those crossings with a ‘low’ sensitivity indicate that little hyporheic exchange is currently operating in the stream, and thus would not likely impact water quality. Overall, most of the Pacific Connector pipeline crossings fall into a “low” sensitivity category, where water quality (including water temperature and intragravel dissolved oxygen) is unlikely to be significantly or measurably altered by pipeline construction.

The pipeline construction methods and BMPs described in the GeoEngineers (2017g) report, as well as the site-specific restoration plans for crossings of perennial stream on federal lands (NSR 2014) further reduce the potential for pipeline construction to adversely alter the hyporheic zone. Specifically, the BMPs which are of importance to reduce the potential impacts on the hyporheic zone include the following:

- native material that is removed from the pipeline trench during excavation across stream channels would be used to backfill once the pipe is in place to reduce potential changes to preconstruction permeability; and

- trench plugs would be installed at the base of slopes adjacent to wetlands and waterbodies and where needed to avoid draining of wetlands or affecting the original wetland or waterbody hydrology.

While the potential impact of pipeline construction on hyporheic exchange is considered to be low, Pacific Connector would implement the following measures to further reduce this potential:

- Document streambed stratigraphy prior to construction to aid in site restoration.
- As described in the *Stream Crossing Risk Analysis* and *Stream Crossing Risk Analysis Addendum* (GeoEngineers 2017d, 2018b), implement additional site-specific stream crossing restorations plans, of streams not yet field surveyed, after final pre-construction surveys.
- Segregate actively movable streambed gravels and cobbles from underlying streambed materials (including fractured bedrock; i.e., do not mix actively moveable stream bed material with that below that depth). Replace all removed material to their natural pre-construction depths, including removed gravels/cobbles.
- Below active stream gravels, replace native material in a manner to match upstream and downstream stratigraphy and permeability to the maximum extent practicable.

Blasting could alter the in-channel characteristics and hydrology of the stream, potentially decreasing flows due to increased infiltration where bedrock would be fractured. Where blasting is required in streambeds, Pacific Connector would use the dam-and-pump crossing method so that blasting activities can be completed in the dry. For further discussion on minimizing impacts related to blasting, see the *Blasting Plan* discussed in section 2.

Stream Temperature

Several comments received by the Commission expressed concern that the removal of vegetation near waterbodies would result in changes to waterbody temperatures. However, available information on the effects of linear pipeline crossings of streams on water temperature indicates there is little to no change. Water has a very high specific heat capacity. That is, the amount of heat needed to raise its temperature is relatively high. Typically pipeline rights-of-way are narrow, and water would flow quickly through the crossing locations, Smaller, slower moving streams have a longer exposure time, but typically do not support temperature sensitive fish species. In general, streamwater exposure to the lack of shade at pipeline crossings would be temporary and limited (see an expanded discussion in section 4.3.4.2 for federal lands).

Pacific Connector conducted research on the potential for its pipeline crossings to increase stream water temperatures (GeoEngineers 2017d). This analysis also used the Stream Segment Temperature Model (SSTEMP) by Bartholow (2002) to estimate potential temperature effects at 15 pipeline crossing locations (each was modeled using a 75-foot-wide clearing) along the whole route (table 4.3.2.2-9). The streams selected varied in size from 2 to 135 feet wide with only eight of these having less than a 10-foot flowing width. Conditions modeled were based on conditions measured during late August 2010. The average modeled temperature increase across a cleared right-of-way for these 15 streams were slight, 0.03°F, and the maximum increase among the streams was 0.3°F.

TABLE 4.3.2.2-9

Predicted Modeled Temperatures at Selected Stream Crossings Along the Pacific Connector Pipeline Route

MP	Watershed	Stream	Width (feet)	Ambient Water Temperature (°F)	Post-Construction Water Temperature (°F)	Temperature Change (°F)
10.3 a/	Coos	Stock Slough	18	56.30	56.32	0.01
17.5 a/	Coos	Catching Creek	7	56.30	56.30	<0.01
23.1	Coquille	North Fork Coquille River	44	74.30	74.23	-0.07
29.2 a/	Coquille	Tributary to East Fork Coquille River	9	58.82	58.78	-0.04
29.5 a/	Coquille	Tributary to East Fork Coquille River	6	59.72	59.72	<0.01
29.9	Coquille	East Fork Coquille River	74	64.22	64.24	0.02
32.4	Coquille	Elk Creek	7	58.46	58.47	0.01
58.8	South Umpqua	Ollalla Creek	84	58.46	58.48	0.02
73.2	South Umpqua	Tributary to South Umpqua River	2	58.46	58.59	0.13
84.2	South Umpqua	Wood Creek	7	58.46	58.5	0.04
94.7	South Umpqua	South Fork Umpqua River	135	58.46	58.49	0.03
109.5	South Umpqua	East Fork Cow Creek	6	55.40	55.44	0.04
132.8	Rogue	Quartz Creek	6	58.64	58.94	0.30
162.5	Upper Rogue	South Fork Little Butte Creek	13			0.01
212.1	Lost River	Lost Rover	73	70.70	70.68	-0.02

a/ Not crossed with current route

The total amount of riparian vegetation within one site potential tree height that would be reduced during construction and operations is discussed in section 4.5.2 of this EIS. The reduction occurs primarily from construction of the pipeline right-of-way clearing over streams but also includes right-of-way clearing that does not cross streams, and development of TARs, PARs, and TEWAs outside of the right-of-way clearing. This would include loss of about of forest during construction and operations, which would remain as non-forested habitat along the route (see table 4.5.2.3-5 in section 4.5.2 of this EIS). This cleared acreage is spread across the entire pipeline route and includes loss from all sources of construction and operations as well as vegetation that would potentially help shade streams. As discussed below, loss of this vegetation is not likely to have a marked cumulative effect on stream temperature, although some local stream increases may occur.

Potential cumulative watershed temperature increases from project riparian clearing would be unlikely. The number of crossings resulting in riparian shade area cleared in any watershed would be slight. No more than nine perennial streams would be crossed in any one of the 19 watersheds crossed by the pipeline route. Primarily perennial stream clearings are likely to have effects on temperature during the warmest part of the year, because many intermittent streams would be dry during the peak temperature periods (July–September). Thus, peak seasonal temperatures would be unlikely to affect many intermittent streams. Even considering the total number of streams crossed in watersheds, which ranges from 3 to 44 crossings per watershed, most watersheds would have less than 16 crossings (see section 4.5.2.3). The riparian area lost that could affect watershed stream temperature relative to all available riparian areas in the watershed would be slight. About

9 linear stream miles of streambank could be affected along the whole Project route (GeoEngineers 2017f; note this counts both banks separately so stream length affected would be half of this value).

To reduce the potential effects of pipeline construction on stream temperatures by the removal of riparian vegetation, Pacific Connector has incorporated the following measures into its Project design:

- narrowing the construction right-of-way at waterbody crossings to 75 feet where feasible based on site-specific topographic conditions;
- locating TEWAs 50 feet back from waterbody crossings to reduce impacts on riparian vegetation, where feasible;
- replanting the streambanks after construction to stabilize banks and to re-establish a riparian strip across the right-of-way for a minimum width of 25 feet back from the streambanks; and
- replanting riparian areas equal to 1:1 ratio to temporary riparian shading vegetation losses and 2:1 ratio for permanent riparian losses from the 30-foot operational easement clearing.

Based on these measures and the studies summarized above, we conclude that the construction and operation of the pipeline would have no discernible effect on stream temperature.

Spills of Hazardous Materials

An inadvertent release of equipment-related fluids would temporarily impact surface water quality. Equipment fluids such as gas and oil can be toxic to aquatic organisms and can affect downstream water uses including drinking water and crop irrigation. Pacific Connector has developed a SPCC Plan that describes measures to be implemented by Project personnel and contractors to prevent and, if necessary, control any inadvertent spill of hazardous materials.

Waterbody Status and Water Use

The construction and operation of the pipeline route could have effects on the status of special features including the water quality limited conditions and special uses, including water diversions and national river status. Actions described below indicate potential effects on these and Project mitigative actions implemented to aid in maintaining the current conditions and regulatory requirements relative to surface waters.

Oregon Water Quality Regulations and Standards Effects

Studies requested by ODEQ are part of a broad evaluation of potential impacts on water quality, stream channel stability, and riparian zones resulting from pipeline construction and maintenance activities. GeoEngineers conducted studies to help evaluate potential impacts including a stream crossing risk analysis, a hyporheic exchange impacts analysis, and a study of the impact on water quality from additional turbidity, nutrients, and metals caused by pipeline construction activities at stream crossings (GeoEngineers 2013a, 2013b, 2013c, and 2018b). The intent of the evaluations is to help focus management resources on those waterbody crossings to which the pipeline would present the greatest risk of impacting beneficial uses. ODEQ’s regulatory authority under the CWA and OAR is provided to maintain beneficial uses through enforcement of water quality standards.

During the ODEQ CWA Section 401 process, Pacific Connector would develop a source-specific implementation plan in accordance with OAR 340-042-0080 for areas with existing TMDLs, and Pacific Connector would be identified as a new nonpoint source. The source-specific implementation plan would be reviewed and approved by ODEQ.

BMPs to reduce sedimentation during construction would be employed on all streams. However, to reduce potential stream channel impacts, including increased erosion/sedimentation, additional site-specific BMPs would be installed at sites considered to be at higher potential risk, as discussed earlier under Impacts and Mitigation based on the risk matrix analysis. These additional protections may include such items as additional upslope bank protections, hillslope drainage structures, additional wood instream or on bank, wood armoring, enhanced substrate, or reduction in bank slope to further ensure reduced erosion. The plans to keep riparian stream crossing clearing to a minimum (75 feet wide at most crossings) would also result in less removal of woody riparian vegetation and help temperature-impaired streams. Because of the water quality and stream habitat benefits, the NMFS endorses keeping near stream riparian vegetation clearing to a minimum, as is currently proposed; this NMFS request may become a condition within their BO for the Project or a requirement during the NMFS permitting process. Overall, the small reduction in shade is not likely to change stream temperatures substantially downstream of the pipeline crossing in temperature limited streams. However, removal of vegetation that once shaded the stream could cause slight local and temporary (daily) increases in temperature, in small streams with low flow discharge rates during the warm summer months. However, discernible temperature changes are very unlikely due to the limited exposure time as water passes through the 75-foot-wide clearing and the high specific heat capacity of water.

A potential new nonpoint source of nutrients and/or oxygen-demanding pollutants would be the use of fertilizer for revegetation of disturbed areas. Pacific Connector plans to apply fertilizer to disturbed areas to be reseeded, as needed. Additionally, some BLM districts along the Project route have specific recommendation for slow release fertilizer application in specific soil types in planting holes as part of any reforestation. Fertilizer would only be applied at the recommended rates of the land-managing agencies and, if applied by broadcast spreader, worked into the upper 2 inches of soil as soon as practical (see Pacific Connector's ECRP). Application would need approval by the land-managing agency or landowner. No application would occur within 100 feet of flowing water and would be avoided during heavy rain and windy conditions. Aerial broadcast spreaders would only occur with federal land-managing agency approval. Fertilizer would be added directly to hydroseeding slurry. Fertilizer would be stored away from streams and outside of federal Riparian Reserves. The NMFS has expressed concern that fertilizer application has the potential to enter waters and recommends that no application within 150 feet of waterbodies occur; this NMFS request may become a condition within their BO for the Project or a requirement during the NMFS permitting process. Any monitoring required for nutrients at locations where fertilizer is likely to contribute to run-off to waterbodies will be addressed in the state permit process and be included in a source-specific implementation plan as required by OAR 340-042-0080.

Drinking Water Sources Areas and Public Intakes Effects

Prior to construction, Pacific Connector would consult with all surface water intake operators listed in table 4.3.2.2-5 that are still active and establish a process for advanced notification of instream work. A summary of the consultations will be filed with the FERC prior to construction of the pipeline. In the event of an inadvertent spill, or a disruption of flow and/or a possible introduction of sediments into waters upstream of the intakes, Pacific Connector would notify potable water intake users of the conditions so that necessary precautions could be implemented.

Point of Diversion Effects

Pacific Connector would consult with the landowner if impacts on a water supply's point of diversion cannot be avoided, and prior to construction would work together to identify an alternate location to establish the diversion that would not violate existing state water rights for the system or cause aquatic habitat impacts. Should that landowner determined that there has been an impact on the water supply, Pacific Connector would work with the landowner to ensure a temporary supply of water. In addition, if deemed necessary, Pacific Connector would replace the affected water supply with a replacement, permanent water supply.[100] Mitigation measures would be specific to each property and would be determined during landowner negotiations. Points of diversion (both public and private) beyond 150 feet of the construction work areas are not expected to be affected by the pipeline.

National Rivers Inventory Effects

As noted earlier, the pipeline would cross three rivers that are listed on the Nationwide Rivers Inventory. Pacific Connector has developed specific plans for each of these crossing to maintain the quality of these rivers. For the North Fork of the Coquille River and East Fork of the Coquille River, Pacific Connector has developed a site-specific crossing plan for both rivers using a dry open-cut method to contain disturbed sediments. The western South Umpqua River crossing would use a DP installation process to eliminate an open-cut and reduce impacts by drilling under both the river and I-5 in a single operation. The site-specific crossing plan developed for the eastern South Umpqua River crossing would use a diverted open-cut method to limit water quality impacts by creating a "dry" working area isolated from the river. These procedures would maintain stream conditions and quality, and would not adversely affecting the streams' river status (i.e., the National River Inventory status).

4.3.2.3 Conclusion

Constructing and operating the Project would result in short-term and long-term impacts on surface water resources. However, based on Jordan Cove's proposed dredging and vessel operation methods and its impact minimization and mitigation measures (including its implementation of erosion controls, dredging procedures, construction and stormwater management procedures, and construction timing), as well as Pacific Connector's proposed waterbody crossing and restoration methods and its impact minimization and mitigation measures, we conclude that the Project would result in short-term, localized, construction-related water quality impacts, but would not significantly affect surface water resources.

4.3.3 Wetlands

Wetlands are defined by the *Corps of Engineers Wetland Delineation Manual* (Environmental Laboratory 1987) as those areas that are inundated or saturated by surface or groundwater at a

[100] *Groundwater Supply and Mitigation Plan,* which was attached as Appendix F.2 of Resource Report 2, in Pacific Connector's September 2017 application to the FERC.

unaltered wetlands. If revegetation is not successful at the end of three years, Pacific Connector would develop and implement a remedial revegetation plan to actively revegetate the wetland and would continue revegetation efforts until wetland revegetation is successful; and

- vegetation maintenance would not be conducted over the full width of the operational right-of-way within wetlands, but limited to a 10-foot-wide corridor.[104]

The COE and ODSL may require additional mitigation (beyond what is required in this EIS) during their permitting process, which could include creating, restoring, or enhancing wetlands to replace the wetland functions and areas connectivity lost due to Project activities, or purchasing credits from a mitigation bank. ODSL administrative rules (OAR 141-085-0690) include minimum ratios for acres required for compensation that varies by type of mitigation proposed (e.g., restoration is 1 acre for each acre lost, creation is 1.5 for 1, and enhancement is 3 for 1). Pacific Connector has developed a *Compensatory Wetland Mitigation Plan* to mitigate for unavoidable impacts on wetlands affected by construction and operation of the pipeline (see section 4.3.3.1). The adequacy of wetland mitigation, including the scope and location of mitigation, would be determined by the COE.

4.3.3.3 Conclusion

In total, the Project would impact approximately 198 acres of wetlands, about 27 acres of which would be permanently lost. Based on our review of the Project and Jordan Cove and Pacific Connector's implementation of measures to reduce impacts on wetlands, we conclude that constructing and operating the Project would not significantly affect wetlands. Additionally, to mitigate wetlands impacts, Jordan Cove and Pacific Connector have prepared a Compensatory Wetland Mitigation Plan.

4.3.4 Environmental Consequences on Federal Lands

4.3.4.1 Groundwater

Shallow Groundwater

As indicated in section 4.3.1.2, the Pacific Connector Pipeline Project would cross areas where the groundwater is 0-6 feet bgs. The BLM and Forest Service may require that trench dewatering through a well point pumping system with a groundwater treatment plan be used, depending on if the groundwater is emanating from a pressurized or non-pressurized source point. On federal lands, dewatering activities would be coordinated with the BLM or Forest Service.

Springs, Seeps, and Drains

Pacific Connector surveys have identified a number of springs and seeps, as noted in appendix H of this EIS. Pacific Connector has stated that it would further verify exact locations of springs and seeps during easement negotiations with land managers. Nearby springs and seeps supplied by deeper pressurized groundwater zones would generally not be affected by the trenching activities

[104] Additionally, trees may be selectively removed if they are within 15 feet of the pipeline that could compromise the pipeline coating integrity.

pine, ponderosa pine, and Swiss), and Port Orford cedar root disease.[114] Within the pipeline Project area, the flatheaded borer, western pine beetle, and fir engraver are most prevalent. Other diseases that may occur or have potential to occur are annosus root and butt rot, laminated root rot, dwarf mistletoe, sudden oak death, and the black stain root disease. As indicated in table 4.4.2.6-1, multiple infestations of insect parasites and tree pathogens already exist along the pipeline route.

TABLE 4.4.2.6-1

Summary of Known Infestations of Insect Parasites and Tree Diseases Along the Pacific Connector Pipeline Route a/

Tree Insect or Disease	Land Ownership	Number of Incidences Along Pipeline Route	Approximate Mileposts (MP) of ROW Affected
Douglas-fir Beetle	BLM/Private/Forest Service	7	MP 32.1-32.2; MP 48.0; MP 98.4 – 102.2
Fir Engraver	BLM/Private/Forest Service	18	MP 48.3; MP 82.0 – 84.5; MP 103.9 – 113.7; MP 152.3-177.7
Flatheaded Borer	BLM/Private/Forest Service	27	MP 30.5 – 40.9; MP 50.8 – 51.1; MP 104.4 – 158.1
Laminated Root Rot	Forest Service	1	MP 154.2 – 154.5
Mountain Pine Beetle	BLM/Private/Forest Service	9	MP 112.3; MP 159.5 – 173.8; MP 224.2 – 224.9
Needle Cast	BLM/Private/Forest Service	7	MP 6.7R – 22.0; MP 161.5 – 168.7
Pine Engraver	Private	1	126.8
Port Orford Cedar Root Disease	Private	4	MP 23.1; MP 30.4 – 30.9; MP 39.65
Western Pine Beetle	BLM/Private/Forest Service	13	MP 96.9 – 97.0; MP 116.6 – 127.1; MP 139.9 – 154.0

Mileages rounded to nearest tenth of a mile.
a/ Summarized from Table 1-2 in the *Integrated Pest Management Plan* (Appendix N to the POD).
Source Data: ODF 2004 through 2017 aerial GIS data.

The introduction and/or spread of insects and diseases from construction equipment, activities, and personnel can adversely affect vegetation. Impacts include loss, reduced species fitness and diversity, and changes to habitat characteristics and subsequent wildlife use. To reduce the introduction and spread of insects and disease, Pacific Connector would implement measures described in its *Integrated Pest Management Plan*. Pacific Connector would identify/verify areas infested with forest pathogens during timber cruises prior to construction and implement minimization measures, including but not limited to cleaning equipment and vehicles upon entering/departing infested areas, applying sporax/borax on freshly cut stumps and wounds to reduce spread of root rot, and utilizing standard logging practices that reduce or prevent damage to standing trees adjacent to the pipeline.

4.4.2.7 Fire Regimes and Emergency Fire Response

Fires play a substantial role in shaping the composition and structure of vegetative communities. The pipeline would pass through numerous fire regimes. Table 4.4.2.7-1 lists the mean fire return interval (i.e., mean fire frequency in the area) as well as the total acres that have burned between 2000 and 2015 (based on existing fire data) for the fifth field watersheds crossed by the pipeline. The most notable recent fire event in the region is the Stouts Creek fire, which burned 26,452 acres in and around the pipeline project area in 2015 in the Days Creek-South Umpqua River and Elk Creek watersheds (Northwest Interagency Coordination Center 2015). Approximately 10.7 miles

[114] Table C.3-3 in Appendix C.3 of Pacific Connector's Resource Report 3 lists the location (by MP when known) of each identified pathogen near the pipeline route.

(227 acres) of the pipeline crosses the area burned by the Stouts Creek fire, generally between MP 95.5 through MP 108.8.

TABLE 4.4.2.7-1

Historic Average Fire Frequency and Extent of Acreage Burned in Watersheds Crossed by the Proposed Pacific Connector Pipeline

Ecoregion	HUC – Fifth-Field Watershed	Mean Fire Return Interval a/	Total Acres Burned (2000–2015) b/
Coast Range	Coos Bay-Frontal Pacific Ocean	126-150 Years	0
	Coquille River	81-90 Years	0
	North Fork Coquille River	151-200 Years	0
	East Fork Coquille River	126-150 Years	0
	Middle Fork Coquille River	61-70 Years	827
Klamath Mountains	Olalla Creek-Lookingglass Creek	21-25 Years	0
	Clark Branch-South Umpqua River	26-30 Years	56
	Myrtle Creek	61-70 Years	0
	Days Creek-South Umpqua River	46-50 Years	17,753
	Lower Cow Creek	41-45 Years	11,551
	Upper Cow Creek	41-45 Years	897
	Elk Creek	36-40 Years	13,504
	Trail Creek	26-30 Years	835
	Shady Cove-Rogue River	21-25 Years	48,677
	Bear Creek	21-25 Years	2,379
	Gold Hill-Rogue River	21-25 Years	1,870
	Big Butte Creek	26-30 Years	986
	Little Butte Creek	26-30 Years	3,644
Eastern Cascades Slopes and Foothills	Spencer Creek	31-35 Years	0
	John C Boyle Reservoir-Klamath River	26-30 Years	5,529
	Lake Ewauna-Klamath River	61-70 Years	26
	Mills Creek-Lost River	91-100 Years	13

a/ Data from LANDFIRE (2017).
b/ Data from BLM_Fire_History shapefile (BLM 2017b). Acres rounded to nearest whole acre.

The use of heavy equipment to construct the pipeline would increase the potential for a wildfire. Specifically, prescribed burning of slash, mowing, welding, refueling with flammable liquids, and parking vehicles with hot mufflers or tailpipes on tall dry grass would increase the risk of wildfires. A wildfire would result in additional loss of vegetation.

Certain activities associated with construction and operation of the Pacific Connector project (such as prescribed burning of slash, mowing, welding, refueling with flammable liquids, and parking vehicles with hot mufflers or tailpipes on tall dry grass) could increase the risk of wildland fires, especially if these activities occur within the fire season. Even small fires, created during these activities, could have far-reaching consequences on vegetative communities. For example, large forest fires could occur if small, low-intensity surface fires, ignited within the herbaceous or low-shrub cover maintained along the permanent right-of-way, spread to ladder fuels near forest edges, allowing access to the forest's canopy. This could trigger a high intensity crown fire that could spread to adjacent areas, away from the pipeline's route. If fire frequencies were to increase due to Project activities, vegetative communities could shift over time to a species composition more adapted to higher fire frequencies. It is also possible that the cleared right-of-way could serve as a fire break for large crown fires, thereby reducing the extent of a fire's spread; however, as discussed above, the presence of the cleared right-of-way could also increase the risk of crown fires occurring in the first place. Implementation of measures outlined in the *Fire Prevention and Suppression Plan* (Appendix K of the POD [appendix F.10 of this EIS]) would reduce the risk of fires associated with construction and operation of the Project. Additionally, this plan includes fire response procedures to be implemented in the event of a fire.

4.4.3 Environmental Consequences on Federal Lands

The Pacific Connector pipeline route would cross lands managed by federal agencies including the Forest Service, BLM, and Reclamation. The pipeline would pass through portions of federal land designations that are intended to protect vegetation or habitats: such as Riparian Reserves and LSRs. These federal land designations, as well as the effects that the pipeline would have on these areas, are addressed in section 4.7.

4.4.3.1 BLM – Forest Operations Inventory

The BLM tracks vegetation, land management treatments, and disturbance within each district during operations inventories. These data and/or attributes are then transferred to a GIS coverage called the FOI. The FOI describes and classifies forest cover (vegetation), site class, denudation cause, dominant species, understory species, treatments, age class, and stand condition (BLM 2016c).

Table I-6 in appendix I lists the acres of impact that would occur to FOIs from both construction and operation of the pipeline. As shown in table I-6, there would be approximately 893 acres of impact during construction of the pipeline to FOIs, which includes about 285 acres on the Coos Bay District (approximately 238 acres of conifer forest, 7 acres of hardwood forest, 31 acres of mixed conifer and hardwood forest, and 9 acres of non-forest/other), 316 acres on the Roseburg District (approximately 273 acres of conifer forest, 37 acres of mixed conifer and hardwood forest, and 7 acres of non-forest/other), 274 acres on the Medford District (approximately 107 acres of conifer forest, 34 acres of hardwood forest, 83 acres of mixed conifer and hardwood forest, and 50 acres of non-forest/other), and 18 acres on the Lakeview District (all conifer forest).

4.4.3.2 Forest Service – Plant Series and Plant Association Groups

The Forest Service classifies potential vegetation based on plant series, and plant association groups (PAGs). Plant series are based on the climax dominant trees of a stand (e.g., the Douglas-fir series). Plant series can be subdivided into PAGs, which are described primarily by the presence or absence of plant species, as well as the abundance of a species based on environmental variables, including soil, aspect, slope, slope position, and moisture. Not all of the three National Forests crossed by the Pacific Connector pipeline route have identified PAGs or plant series, and these unidentified areas are noted as “not in series” (Forest Service 1996a). Table I-7 lists the acres of impact that would occur on PAGs and plant series from both construction and operation of the pipeline. As shown in table I-7, there would be approximately 585 acres of impacts during construction of the pipeline on PAGs and plant series, which includes about 211 acres on the Umpqua National Forest, 276 acres on the Rogue River-Siskiyou National Forest, and 98 acres on the Fremont-Winema National Forest. White fir and Douglas-fir series would be the most heavily affected PAGs.

The following describes the seven plant series that would be crossed by the pipeline, based on GIS coverage.

There are currently no planned residential or commercial developments identified within 0.25 mile of the Jordan Cove Project site. However, the Coos County Airport District is planning to extend one of the runways at the Southwest Oregon Regional Airport, which is approximately 0.55 mile south of the LNG terminal site. According to the October 2013 Southwest Oregon Regional Airport Master Plan Update (Coos County Airport District 2013), the Airport Layout Plan and the implementation plan included a proposed 400-foot-long extension of Runway 4-22; however, current plans do not identify this large of an extension. Current proposals are limited to cordoning off the northeast corner of the existing runway to gain land acreage for safety purposes to meet FAA regulations (Krug 2018).

The City of North Bend has indicated that it expects to consider adoption of a proposed North Point Area Master Plan for the North Point District in the near future. The North Point District consists of approximately 80 acres made up of the northernmost parcels of North Point. The District is located southeast across Coos Bay from the LNG terminal site, and east across Pont Slough from the airport. The City of North Bend is also proposing to redevelop Simpson Park along Highway 101 to include a new Visitor Information Center and Parks Department facilities. The closest Project components to these areas would be the APCO sites. Advanced Health has demolished the McAuley Hospital in downtown Coos Bay, approximately 3 miles south of the proposed LNG terminal site, and is redeveloping the site to provide housing for Oregon Health and Science University medical students (Johnson 2018). Construction and operation of the LNG terminal is not expected to affect these plans or future uses.

4.7.1.4 Timber

The dune areas at the LNG terminal site currently contain non-merchantable timber. Before mobilizing earth-moving equipment, the trees would be felled and selectively processed for commercial timber. Scrub and stumps from across the site would be processed into mulch for use during construction operations.

4.7.2 Pacific Connector Pipeline and Associated Facilities

4.7.2.1 Land Ownership

The pipeline would cross public and private lands. Approximately 64 percent of the land crossed is privately owned, 34 percent is federal land and 2 percent is state lands (table 4.7.2.1-1). No tribal-owned lands or county lands would be crossed. Federally managed lands are discussed below.

TABLE 4.7.2.1-1

Land Crossed by the Pacific Connector Pipeline by Ownership

County	Federal Land		State Land		Private Land		Total
	Miles	Percent of Overall Total	Miles	Percent of Overall Total	Miles	Percent of Overall Total	
Coos	17.1	7.4	3.4	1.5	26.4	11.5	**46.9**
Douglas	21.3	9.3	0.0	0.0	43.7	19.0	**65.0**
Jackson	30.2	13.1	0.2	0.1	25.6	11.2	**56.0**
Klamath	9.4	4.1	0.0	0.0	52.1	22.7	**61.5**
Total	**78.0**	**33.9**	**3.6**	**1.6**	**147.8**	**64.4**	**229.4**

Specific studies that assess the impact of LNG export terminals on property values are unavailable. However, a study conducted by the Argonne National Laboratory (Clark and Nieves 1994) examined the economic impacts of eight types of "noxious" facilities on local wages and property values. The study examined the effects of 262 facilities, 11 of which were LNG facilities. The study concluded that the presence of five of the eight types of "noxious" facilities has a substantial negative effect on property values and a positive effect on wages. LNG facilities were not one of these five types of facilities. Furthermore, the study concluded that the presence of an LNG facility did not have a substantial positive or negative effect on either wages or property values (Clark and Nieves 1994). More recently, Davis (2011) assessed the impact of 92 large power plants that opened in the U.S. between 1993 and 2000. Using the hedonic price method, Davis estimated impacts on housing values and rents within 2 miles of each new facility and found "modest declines" of 4 to 7 percent, with somewhat larger decreases within 1 mile. To address concerns for this Project, ECONorthwest (2006) reviewed property values within 1 mile of existing LNG "peak storage" facilities in Newport and Portland, Oregon. Using data from the Lincoln County Tax Assessors Office, ECONorthwest found that property values around the Newport LNG plant were not depressed and 25 homes within 0.5 mile and overlooking the facility had above average market values. They also argue that the presence of many other industrial and commercial properties around the Portland LNG facility, including the second-largest industrial employer in the city, suggest that the presence of this facility has not discouraged other businesses from locating in the area (ECONorthwest 2006).

Based on the above review, the limited available studies that specifically address LNG facilities have found no impacts on property values (Clark and Nieves 1994; ECONorthwest 2006), while a more recent study of large power plants found modest declines in property values within 2 miles, with somewhat larger decreases within 1 mile (Davis 2011). There are no residences within 1 mile of the LNG Terminal site, but moderate to high long-term visual impacts are anticipated for residential communities in Coos Bay and North Bend, more than a mile south of the terminal site. While it is not possible to ascertain from the limited available literature if property values would be affected by the Project, effects were they to occur would likely coincide with residential areas expected to experience visual impacts.

4.9.1.4 Economy and Employment

Coos County had a total estimated civilian labor force of 26,460 in 2018 (Oregon Employment Department 2019). The average annual unemployment rate in Coos County in 2016 was higher than the statewide average, 5.4 percent versus 4.2 percent. State and local government and health care and social assistance were the two largest economic sectors in the county in 2017 based on employment (U.S. Bureau of Economic Analysis 2018). Median household income in Coos County ($42,464) was lower than the statewide median of $60,123 in 2017 (U.S. Census Bureau 2018).

Jordan Cove estimates that construction of the Jordan Cove LNG Project would cost about $7.3 billion over the 53-month construction period, with an estimated $2.99 billion expected to be spent in Oregon (ECONorthwest 2017c).

Using Impact Analysis for Planning (IMPLAN) economic modeling software, ECONorthwest (2017c) estimated the total (direct, indirect, and induced) regional economic impacts of Project construction (table 4.9.1.4-1). Direct impacts are those that happen at the initial source of the economic activity, in this case the project construction sites. Indirect impacts are generated by the expenditures on goods and services by suppliers who provide goods and services to the construction project. Indirect effects are often referred to as "supply-chain" impacts because they involve interactions among businesses. Induced impacts are generated by the spending of households associated either directly or indirectly with the Project. Workers employed during construction, for example, will use their income to purchase groceries and other household goods and services. Workers at businesses that supply the facility during construction or operation will do the same. Induced effects are sometimes referred to as "consumption-driven" impacts. Spending associated with the Project produces multiplier spending effects for other sectors of the state economy as businesses respond to supply-chain and consumption-driven demands for goods and services.

TABLE 4.9.1.4-1

Regional Economic Impacts of Construction of the Jordan Cove Project in Oregon

Impact Type	Output b/	Value Added b/	Labor Income b/	FTE Jobs b/	Average Number of Jobs per Year c/
Total Direct Impacts	$7,300	na	$1,235	4,527	1,023
Local Impacts (State of Oregon) a/					
Direct	$2,990	$1,027	$967	3,531	798
Indirect	$1,743	$992	$776	14,107	3,194
Induced	$1,725	$982	$571	13,435	3,042
Total d/	**$6,458**	**$3,001**	**$2,314**	**31,073**	**7,034**

Notes:
FTE = full-time equivalent; na = not applicable
a/ Local impacts in this context are impacts that would occur within the state of Oregon. Direct impacts are the share of the total direct impacts expected to occur in Oregon.
b/ Impacts are presented for the entire 53-month construction period. Output, value added, and labor income are expressed in millions of dollars.
c/ Average number of jobs per year based on 53 months of construction.
d/ Totals may not sum due to rounding.
Source: ECONorthwest 2017c

Total impacts are estimated in terms of economic output, value added, labor income, full-time equivalent (FTE) jobs, and average jobs per year. Economic output represents the dollar value of goods and services produced. Value added represents the net contribution of industries to the local economy and consists of revenues less intermediate inputs. Labor income is the sum of employee compensation and proprietary (self-employed) income. FTE jobs represent employment for 2,080 hours per year; FTE jobs do not necessarily translate into the number of affected workers. Two jobs that last 6 months each, for example, count as one FTE job.

As stated in section 4.9.1.1, Jordan Cove estimated that they would employ an annual average of 1,023 workers over the 53-month-long construction period, with a peak of 1,996 employees during month 30. Total direct employment over the 53-month construction period was estimated to be equivalent to 4,527 FTE jobs, with the equivalent of 3,531 FTE jobs expected to be filled by Oregon workers. Construction of the Jordan Cove LNG Project would be a union project, with Jordan Cove requiring the major contractor to sign a project labor agreement with the key signatory unions to the National Construction Agreement. Union locals have reportedly indicated that they believe the majority of skilled crafts workers can be supplied from within Oregon (ECONorthwest 2017a). ECONorthwest (2017a), in an analysis prepared on behalf of Jordan Cove, assumed that almost four-fifths of all construction workers, managers, and staff for the Jordan Cove LNG

Project would come from Oregon. In addition, ECONorthwest (2017a) estimated that Project construction would support a total of 14,107 indirect and 13,435 induced FTE jobs in Oregon over the life of the construction period (table 4.9.1.4-1).

Based on the share of workers expected to commute daily to and from the LNG terminal work site, an estimated 372 of the 1,023 annual average direct FTE jobs would be filled by local workers (i.e., workers typically residing in Coos County or nearby) (ECONorthwest 2019). ECONorthwest (2019) estimated that construction employees (including resident, itinerant, and commuting employees) for the LNG terminal and pipeline would together spend an annual average of $51.9 million in Coos County and support annual average business sales of $70.3 million and 642 local jobs.

During the first full year of operations, Jordan Cove would directly employ 200 workers in Oregon, 180 for the LNG terminal, and 20 for the company office in Portland, with total labor compensation (including benefits and payroll taxes) expected to exceed $44.8 million. This direct employment in conjunction with facility expenditures on Oregon sourced goods and services would support additional economic activity in Coos County and elsewhere in Oregon. Using expenditure data provided by Jordan Cove, ECONorthwest (2017d) estimated that annual Project operation would support total (direct, indirect, and induced) employment of 1,602 FTE jobs in Oregon in the first full year of operations, with total associated labor compensation of approximately $132.3 million. Viewed in 2017 dollars, total compensation would be about $111.3 million or $69,477 per FTE job (ECONorthwest 2017d).

All of the full-time LNG terminal employees would likely reside in Coos County or nearby. ECONorthwest (2019) estimated that operation employees for the LNG terminal (180 FTEs) and pipeline (15 FTEs) would together spend an annual average of $12.2 million in Coos County and support annual average local business sales of $29.5 million and 120 local jobs.

Indirect and induced impact estimates developed by ECONorthwest (2017c, 2017d) are based on the share of construction and operation expenditures that Jordan Cove estimates would occur in Oregon. Changes in actual levels of in-state spending would result in changes to the indirect and induced impact estimates.

No commercial enterprises would be displaced by the Project, and construction and operation of the terminal would not result in the loss of local business revenues or taxes.

4.9.1.5 Tax Revenues

Total revenues for Coos County were approximately $58.9 million in fiscal year 2018. Tax revenues accounted for $12.5 million of this total, with 87 percent of tax revenues generated by property taxes (Coos County 2019). Other sources of revenue included intergovernmental transfers (state and federal funds); licenses, fees, and permits; charges for services; and timber sales on county forestlands (table 4.9.2.5-1). The LNG terminal would contribute to the fiscal health of local communities through a local Community Enhancement Plan in Coos County. Construction and operation of the Jordan Cove LNG Project would also generate state and local tax revenues, including revenues from payroll taxes.

mitigation for unforeseen scenarios that develop during construction. We concur with these findings. Therefore, **we recommend that:**

- **<u>Prior to construction</u>, Jordan Cove should file documentation that it has entered into a cooperative improvement agreement with ODOT and traffic development agreements with Coos County and the City of North Bend, as recommended in the Traffic Impact Analysis report.**

The COE has expressed concern that traffic congestion could impair their ability to transport material to the North Spit for North Jetty Major Maintenance. The results of the above analysis indicate that during terminal construction the intersection of U.S. 101 at the Trans-Pacific Parkway would fail to meet operational targets during the midweek PM and Friday PM analysis hours if no mitigation were provided. The intersection would continue to meet operational targets in the AM analysis hours and throughout the day when deliveries to the North Jetty would be expected to occur. Further, mitigation is recommended to address the anticipated traffic congestion during midweek PM and Friday PM analysis hours. As a result, the potential for traffic congestion-related impacts on the COE North Jetty Major Maintenance is anticipated to be low.

During construction of the LNG terminal slip, excavated material would be transported by truck to upland sites. The excavated material truck haul route would be on Jordan Cove or Roseburg Forest Products owned land and would not cross the Trans-Pacific Parkway. The haul trucks and other equipment using the haul road would consist of large off-road vehicles common for large civil infrastructure or mining projects. The only potential conflict would be with Roseburg chip truck traffic, when the Jordan Cove excavated material trucks cross Jordan Cove Road. This potential impact would be mitigated by construction of a temporary traffic overpass that would segregate traffic traveling to and from the Roseburg Forest Products facility from large, off-road haul trucks and equipment.

4.10.1.3 Railroad Traffic

The existing Coos Bay rail line would be used for the delivery of sheet piling. Over the first year 16 deliveries of sheet piling would occur. However, Jordan Cove has indicated that pending further analysis, additional use of the rail line may be necessary. All rail shipments would be off-loaded at an existing rail spur at the Roseburg Forest Products yard, which runs into the construction laydown area. No new rail construction is anticipated for the purpose of transporting materials and equipment to the site. Rail deliveries would be coordinated with Roseburg Forest Products and Coos Bay Rail Link to reduce impacts on their operations.

4.10.1.4 Air Traffic

The Southwest Oregon Regional Airport is located in the city of North Bend, directly across Coos Bay and less than 1 mile from the LNG terminal site. The airport is owned and operated by the Coos County Airport District and provides commercial passenger services. United Airlines currently provides daily flights to and from San Francisco. United Airlines also provides seasonal twice-a-week flights to and from Denver. Federal Express and Ameriflight operate cargo services out of the airport. The Coast Guard has five helicopters based at the airport. The number of fixed wing aircraft based at the Southwest Oregon Regional Airport has ranged from 51 to 68 for the past 20 years, with 51 aircraft based at the airport in 2010.

Because construction would occur near an airport, Jordan Cove is required by 14 CFR 77 to file notice with the FAA. Based on the information provided in the notice, the FAA would determine if the construction would result in an obstruction to air navigation, navigational aids, or navigational facilities. If the FAA determines that the construction is an obstruction, it will presume that this construction is a hazard to air navigation and will advise all known interested persons, unless further aeronautical study concludes that the construction is not a hazard.

On May 7, 2018, the FAA determined that the LNG marine vessels (at multiple locations during transit), LNG storage tanks, Amine regenerator column, and the thermal oxidizer stack are obstructions and would be presumed hazards to air navigation. However, the FAA's Notices of Presumed Hazard are not final determinations and states that if the maximum heights of the structures that exceed obstruction standards were reduced to 167 feet AMSL, 155 feet above ground level, they would not create a substantial adverse effect and a favorable determination could subsequently be issued. Jordan Cove has indicated that it would continue to meet with the FAA to address the presumed hazards to air navigation.

Based on the FAA's determination that multiple Project components would be presumed hazards to air navigation, we expect that takeoffs and landings, and runway operations could be affected by operation of the terminal. Changes to takeoffs and landings could affect flight times. Jordan Cove estimates that flights could be delayed up to 13 minutes if an LNG carrier is in transit in the vicinity of the airport. Also, changes to takeoffs and landings, departures and approaches, could affect the amount of noise experienced by adjacent communities including residences, recreation sites, and natural areas. Lastly, any change to runway operations could affect commercial and cargo flight services. Given these impacts, we conclude that operating the LNG terminal could significantly impact Southwest Oregon Regional Airport operations.

In comments on the draft EIS, concern was expressed regarding the impact of thermal plumes on flight operations. In response to multiple inquiries about this issue, the FAA in 2015 issued a memorandum to staff concerning a technical guidance and assessment tool for evaluation of thermal exhaust plume impacts on airport operations. In this memorandum, the FAA determined that thermal exhaust plumes in the vicinity of airports may pose a unique hazard to aircraft in critical phases of flight are therefore incompatible with airport operations. Based on our review of the Project, we have determined that thermal plumes emanating from the terminal could adversely affect takeoffs and landings. The FAA encourages airport sponsors and land use planning and permitting agencies to evaluate and take into account potential flight impacts from existing and planned development that produce plumes.

4.10.2 Pacific Connector Pipeline Project

4.10.2.1 Access Roads

Pacific Connector would use a variety of vehicles including standard pick-up trucks, earth-moving equipment, tractor trailers, and pipe-stringing (and other materials/equipment) trucks to construct the pipeline. These vehicles would traverse Project-area roadways and access workspaces via existing and new construction access roads. Equipment and materials would be transported from various laydown areas and storage yards to the pipeline right-of-way and associated construction workspaces. Most construction equipment would remain on the right-of-way during construction.

4.11 CULTURAL RESOURCES

According to the FERC's Office of Energy Projects' "Guidelines for Reporting on Cultural Resources Investigations for National Gas Projects," cultural resources include any pre-contact or historic archaeological site, district, object, cultural feature, building or structure, cultural landscape, or TCP. Generally, cultural resources are considered to be historic properties[220] under the NHPA if they are at least 50 years old and meet the criteria for listing on the NRHP (36 CFR Part 60.4). It should be noted that consulted Indian tribes[221] have pointed out that their definition of cultural resources is more expansive than that above and may include natural resources or features.[222] As discussed in subsection 4.11.1.3 below, while resources and issues of concern to Indian tribes that do not meet the above definition of cultural resources are described in this section, the reader is referred to the corresponding section of this EIS for a more detailed discussion.

The regulations for implementing Section 106 of the NHPA, at 36 CFR 800.9, encourage the integration of the Section 106 compliance process with the NEPA process; and we have done this as described herein. This section is broken into several subsections that mirror the Section 106 compliance process. The steps of the process, as outlined in 36 CFR 800 are: 1) consultations; 2) identification of historic properties; 3) assessment of effects; and, 4) the resolution of adverse effects. Our first subsection below is a summary of consultations initiated by the FERC staff, and communications the Applicants had with various consulting parties, including other federal agencies, the Oregon SHPO,[223] and interested Indian tribes. Next, we define the area of potential effects (APE), and summarize the results of literature reviews and site file searches, and the results of cultural resources inventories conducted by the Applicants' consultants. Then we discuss the Unanticipated Discovery Plan (UDP) produced by the Applicants for the Project, and reviews by consulting parties. Lastly, we reach conclusions about the status of our compliance with the NHPA. Appendix L includes a cultural context for the Project, a brief summary of archaeological research in southern Oregon, detailed listings of consultations with the Oregon SHPO and interested Indian tribes, and detailed listings of identified cultural resources in the APE of the terminal and pipeline, anticipated impacts on those resources, and proposed methods to address those effects.

Section 101(d)(6) of the NHPA states that properties of traditional religious and cultural importance to Indian tribes may be determined eligible for the NRHP. In carrying out our responsibilities under Section 106 of the NHPA, the FERC staff consulted with Indian tribes that

[220] Historic properties include any pre-contact or historic district, site, building, structure, or object, and properties of traditional religious or cultural importance to Indian tribes listed on or eligible for listing on the NRHP, as defined in 36 CFR 800.16(l).

[221] Indian tribes are defined in 36 CFR 800.16(m) as: "an Indian tribe, band, nation, or other organized group or community, including a Native village, Regional Corporation, or Village Corporation, as those terms are defined in Section 3 of the Alaska Native Claims Settlement Act (43 U.S.C. 1602), which is recognized as eligible for the special programs and services provided by the United States to Indians because of their special status as Indians."

[222] Although "cultural resources" are not defined in 36 CFR 800, it is a "term-of-art" in the field of historic preservation and archaeological research. Some Indian tribes believe that cultural resources could include natural resources, such as plants and animals of traditional importance to tribes, and topographic features, such as mountains and rivers, and viewsheds that may be sacred. See, for example, the July 2, 2019 letter from the Cow Creek Band to the FERC commenting on our March 29, 2019 draft EIS (accession number 20190711-0021)

[223] In all cases, the SHPO refers to the staff of the Oregon State Historic Preservation Office within the Oregon State Parks and Recreation Department, including the State Archaeologist.

may attach religious and cultural importance to properties in the APE. On behalf of all the federal cooperating agencies, as the lead federal agency, the FERC staff conducted government-to-government consultations with Indian tribes that may be interested in the Project, and may have concerns about potential impacts on cultural resources and historic properties, including traditional religious and cultural properties. Consultations with Indian tribes are detailed below.

As the lead federal agency under Section 106 of the NHPA, the FERC is required to take into account the effect of its undertakings[224] (including authorizations under Sections 3 and 7 of the NGA) on historic properties and afford the Advisory Council on Historic Preservation (ACHP) an opportunity to comment. Jordan Cove and Pacific Connector, as non-federal applicants, are assisting the FERC in meeting its obligations under Section 106 by providing data, analyses, and recommendations in accordance with 36 CFR 800.2(a)(3) and the FERC's regulations at 18 CFR 380.12(f). The Applicants are using the services of a consulting firm (Historical Research Associates, Inc. [HRA]) to gather cultural resources data. The FERC remains responsible for all findings and determinations under the NHPA.

As the lead federal agency for the Project, the FERC will address compliance with Section 106 on behalf of all the federal cooperating agencies in this EIS.[225] However, the federal land-managing agencies still have separate obligations regarding cultural resource management under other federal laws and regulations, including, but not limited to, the Antiquities Act of 1906, Section 110 of the NHPA, Archaeological and Historic Preservation Act of 1974, Archaeological Resources Protection Act of 1979, FLPMA, and the Native American Graves Protection and Repatriation Act.

4.11.1 Consultations

In accordance with Section 106, the FERC staff, on behalf of all of the federal cooperating agencies, identified historic properties potentially affected by the Project in consultation with the Oregon SHPO, interested Indian tribes, and other consulting parties prior to making our determinations of NRHP eligibility and Project effects. We also consulted with the SHPO, interested Indian tribes, and other consulting parties to determine the resolution of adverse effects on historic properties that cannot be avoided. All correspondence related to these consultations can be found in the Commission's administrative record. A detailed listing of communications and comments received from the Oregon SHPO and interested Indian tribes are included in appendix L.

Consultations for the current Project began with the issuance of the NOI on June 9, 2017. The NOI was sent to a wide range of stakeholders, including other federal agencies such as the ACHP, U.S. Department of the Interior Bureau of Indian Affairs (BIA), BLM, COE, Forest Service, Reclamation, and NPS; state and local government agencies, such as the Oregon SHPO; affected landowners; regional environmental groups and non-governmental organizations; and Indian

[224] "Undertaking means a project activity, or program funded in whole or in part under the direct or indirect jurisdiction of a Federal agency, including those carried out by or on behalf of a Federal agency; those carried out with Federal financial assistance; those requiring a Federal permit, license or approval; and those subject to state or local regulation administered pursuant to a delegation or approval by a Federal agency," as defined in 36 CFR 800.16(y).

[225] Pursuant to 36 CFR 800.2(a)(2), the EPAct, and the May 2002 Interagency Agreement on Early Coordination of Required Environmental and Historic Preservation Reviews.

tribes that may have an interest in the Project area. The NOI contained Section 106-specific text initiating consultations with the SHPO and soliciting their views and those of other government agencies, interested Indian tribes, and the public on the Project's potential effects on historic properties.

4.11.1.1 Consultations with the SHPO

FERC Staff Consultations

Consultations between the FERC staff and the Oregon SHPO about the Jordan Cove LNG terminal and Pacific Connector pipeline, including meetings and correspondence, date back to 2006. Consultations between the FERC and the SHPO from 2006 to 2009 were summarized in section 4.10.1.1 of the final EIS we produced in May 2009 for the Jordan Cove LNG import terminal and original Pacific Connector sendout pipeline in Docket Nos. CP07-441-000 and CP07-444-000. Consultations with the SHPO between May 2009 and September 2015 were documented in section 4.11.1.1 of the final EIS we issued in September 2015 for Docket Nos. CP13-483-000 and CP13-492-000. Consultations between the FERC and the SHPO after September 2015, related to Docket Nos. CP17-494-000 and CP17-495-000, are summarized in table L-1 in appendix L.

Communications by the Applicants with the SHPO

Communications between the SHPO and the Applicants after September 2015 are summarized in tables L-2 and L-3 in appendix L.

4.11.1.2 Consultations with Indian Tribes

The unique and distinctive political relationship between the United States government and Indian tribes is defined by treaties, statutes, executive orders, judicial decisions, and agreements. These have resulted in differentiating tribes from other entities that deal with, or are affected by, the federal government. This relationship has given rise to a special federal trust responsibility, involving the legal obligations of the United States government toward Indian tribes and the application of fiduciary standards of due care with respect to Indian lands, tribal trust resources, and the exercise of tribal rights.

The FERC acknowledges that it has trust responsibilities to Indian tribes. The FERC issued a "Policy Statement on Consultations with Indian Tribes in Commission Proceedings" in Order 635 on July 23, 2003, which was supplemented in an October 17, 2019 policy statement.[226] The supplemented policy includes the following key objectives:

- the Commission will endeavor to work with Indian tribes on a government-to-government basis, and will seek to address the effects of proposed project on tribal rights and resources though consultations;
- the Commission will ensure that tribal resources and interests are considered whenever the Commission's actions or decisions have the potential to adversely affect Indian tribes or Indian trust resources;
- the Commission will set forth in its environmental documents and orders how tribal input resulting from consultations is considered in agency decisions for infrastructure projects; and

[226] 169 FERC ¶ 61,063, Docket No. PL20-1-000, Order 863.

- the Commission will consider the effect of its actions on Indian treaty rights in its NEPA and decision documents.

This EIS, below and in appendix L, discusses treaties and consultations with interested Indian tribes.

The FERC contacted Indian tribes that may attach religious or cultural significance to sites in the region or may be interested in potential Project impacts on cultural resources. We identified Indian tribes that historically used or occupied the Project area through standard ethno-historical sources, such as the *Handbook of North American Indians* (Suttles 1990), communications with the SHPO and the Oregon Legislative Commission on Indian Services, input from federal cooperating agencies, information provided by the Applicants, and scoping responses to our June 9, 2017 NOI, including letters from interested Indian tribes.

Indian tribes identified in the region are the Burns Paiute Tribe, Confederated Tribes of the Lower Umpqua, Coos, and Siuslaw Indians (CTCLUSI), Coquille Indian Tribe (Coquille Tribe), Cow Creek Band of Umpqua Tribe of Indians (Cow Creek Tribe), Fort Bidwell Paiute Tribe, Confederated Tribes of the Grand Ronde Community of Oregon (Grand Ronde Tribes), Hoopa Valley Tribe, Karuk Tribe, Klamath Tribes, Modoc Tribe of Oklahoma, Pit River Tribe, Confederated Tribes of Siletz Indians (Siletz Tribes), Tolowa Dee-ni' Nation (formerly Smith River Rancheria), and Yurok Tribe.

A context that identifies Indian tribes that historically used or occupied the area affected by the Project, as well as details of the FERC consultations and the Applicants' communications with Indian tribes, can be found in appendix L.

FERC Staff Consultations with Indian Tribes

Consultations between the FERC and Indian tribes after September 2015, related to Docket Nos. CP17-494-000 and CP17-495-000, are listed in table L-4 in appendix L. Some Indian tribes have questioned the nature of our consultations.[227] Consultations between FERC staff and Indian tribes are still ongoing. Tribal consultation efforts were initiated with an e-mail sent on May 9, 2017 to tribes inviting them to participate in a telephone conference call about the Project. This was followed by the NOI issued by the FERC on June 9, 2017, requesting comments about the Project. On April 5, 2018, the FERC staff sent letters to individual Indian tribal leaders. In response to those letters, the CTCLUSI, Coquille Tribe, Grand Ronde Tribes, Karuk Tribe, and Yurok Tribe requested meetings with FERC staff. FERC staff met in-person with representatives of the CTCLUSI in Coos Bay, Oregon on March 22 and June 28, 2017, July 17, 2018, and June 25, 2019; with the Coquille Tribe in North Bend, Oregon on July 16, 2018 and June 12, 2019; with the Cow Creek Tribe in Roseburg, Oregon on June 28, 2017 and June 12, 2019; with the Grand Ronde Tribes at Grand Ronde, Oregon on June 11, 2019; with the Karuk Tribe in Happy Camp, California on July 18, 2018; with the Klamath Tribes in Chiloquin, Oregon on June 29, 2017 and June 13, 2019; and with the Yurok Tribe in Klamath, California on July 18, 2018. Additional emails and telephone conference calls have occurred between the FERC staff and some of the above tribes to discuss specific concerns about the Project (see appendix L).

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[227] For example, the CTCLUSI, in their July 5, 2019 letter (accession number 20190708-5040) to FERC commenting on our draft EIS issued March 29, 2019, made a distinction between "staff-to-staff" consultations and consultations among decision-makers.

Comments from Native American Individuals

In addition to government-to-government consultations between the FERC staff and leaders of interested Indian tribes, various other tribal members and individual Native Americans commented about the Project in response to our notice of applications, during scoping, and in comments on our March 29, 2019 draft EIS. Communications between Native American individuals and organizations and the FERC are listed in table L-5 in appendix L. Of these communications, 28 were letters from Native American individuals or organizations submitted as motions to intervene.

In addition to the above letters, several individuals identifying themselves as Native Americans spoke at our public scoping sessions for the Project. Gary Jackson, who identified himself as a member of the Cow Creek Tribe, spoke at the public scoping session held on June 28, 2017 in Roseburg. Dale Ann Frye Sherman Yaqui and Margaret Robbins, who identified themselves as members of the Yurok Tribe, spoke at the public scoping session held on June 29, 2017 in Klamath Falls. Also at the Klamath Falls session, Monique Sonoquie identified herself as Chumash and Apache residing at the Yurok reservation in California; Mirinda Hart identified herself as Wylocki-Wintu from the Round Valley Confederation of Tribes in California; Anna Powell identified herself as a member of the Hoopa Valley Tribe in California; and Della Sanchez and Taylor Tupper identified themselves as members of the Klamath Tribes. Concerns voiced during the scoping meetings were similar to those identified in the letters from tribal members and Native American individuals listed in table L-5 in appendix L.

A number of Native American individuals provided comments at the public sessions for taking comments on the draft EIS held by the FERC in southern Oregon the week of June 24-27, 2019.

Applicants' Communications with Indian Tribes

Contacts between the Applicants and Indian tribes are listed in tables L-6 and L-7 in appendix L of this EIS.[228] Specific interested Indian tribes were provided the opportunity by the Applicants to review research designs and cultural resources investigations reports. Some tribal representatives also participated in surveys and monitored subsurface testing.

4.11.1.3 Issues Raised by Indian Tribes

This section summarizes the comments received from consulted Indian tribes. Tribes raised a wide variety of topics, not necessarily limited to historic properties considered under Section 106. In general, issues of concern, outside of the NHPA process, raised by Indian tribes included:

- Indian trust assets;
- traditional lifeways;
- water quality;
- aquatic species/fisheries;
- wildlife;
- forestry and wildfires;
- air quality and climate change;
- aesthetics;
- geologic hazards and general safety of the Project;
- environmental justice and socioeconomics; and
- cumulative impacts of the Project.

[228] These communications were documented in Jordan Cove's and Pacific Connector's September 2017 applications to the FERC and their subsequent responses to staff's multiple environmental information request since January 2018.

We summarize tribal concerns, raised prior to the issuance of our draft EIS on March 29, 2019,[229] in consultations with the FERC, below, by individual tribe. However, where a tribal concern for a natural resource not considered under Section 106 was discussed, the reader is referred to the corresponding section of this EIS for a more detailed description of those resources, and where applicable, the impacts of the Project on those resources under NEPA.

Confederated Tribes of Coos, Lower Umpqua, and Siuslaw Indians

In several different filings with the FERC, the CTCLUSI indicated that they consider the geographic area of the Coos Bay estuary to be a TCP Historic District, known as "*Q'alay ta Kukwis schichdii me*" (Jordan Cove and the Bay of Coos People). The CTCLUSI have issued two resolutions (Resolution No. 2006-097 and Resolution No. 2015-049) mentioning the TCP. The CTCLUSI also began the process of nominating the District to the NRHP. There are no federal laws that would prevent a project from crossing a TCP. However, there are regulations (36 CFR 800) and an NPS bulletin (Parker and King 1998) that provide guidance about evaluation of significance, assessing impacts, and mitigating effects on TCPs.

The CTCLUSI are concerned that Project-related activities at the terminal (Ingram Yard) and South Dunes area, such as drilling, grading, dredging, and vibro-compaction, may impact buried village sites and Indian graves documented in the Tribes' database of cultural resources. In its January 29, 2018 letter to the FERC staff, the CTCLUSI stated that a pre-contact shell midden deposit was found deeply buried in Coos Bay during geotechnical testing conducted for the Pacific Connector pipeline HDD. A report that provided the results of monitoring of geotechnical borings (Derr et al. 2018) did not identify any deeply buried shell middens or cultural resources in Coos Bay, as described by CTCLUSI.

Jordan Cove's consultants have recommended monitoring of construction by professional archaeologists and tribal representatives. Any cultural resources or human remains uncovered during monitoring would be handled according to the Project's UDP. In addition, Jordan Cove has executed a Cultural Resources Protection Agreement (CRPA) with the CTCLUSI that provides for tribal monitoring of construction activities. As articulated in its July 10, 2017 letter to the FERC, the CTCLUSI are concerned that traditional activities of its members in the Project area, including the gathering of plants, harvesting of shell fish, fishing, and hunting, may be restricted by the proposed Project. In this EIS, we address Project-related impacts on upland vegetation and timber in section 4.4, terrestrial wildlife in section 4.5.1, and aquatic resources in section 4.5.2. Some tribal concerns in regard to species gathered, fished, or hunted are addressed in those sections. It should be noted that Jordan Cove's proposed LNG terminal upland facilities would be located on private lands where tribal access has been limited since the Luse family sold its ranch on the North Spit in 1883.[230] Likewise, about 64.4 percent of the Pacific Connector pipeline route would be located on private lands where tribal access may be prohibited.

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[229] Comments from Indian tribes on our draft EIS are addressed elsewhere in this EIS.

[230] William Luse, the son of H.H. Luse, who established a sawmill at Empire in 1855, was once married to a Coos woman, and was involved in the Indian community at Jordan Cove. The Luses acquired the properties of the Henderson, Barnett, Crawford, and Jordan families, which included Coos members. The lands were consolidated into a large ranch on the North Spit. As long as the Luses owned this land, Indian occupation of the North Spit would have been allowed, but this changed once the property was sold to the Oregon Southern Improvement Company.

The CTCLUSI indicated that they would be funding their own independent ethnographic study of the Coos Bay area. However, more recently, Jordan Cove convened a Cultural Resources Working Group that included interested Indian tribes as participants,[231] and offered individual tribes financial support for them to produce their own ethnographic studies of the Project area. As discussed below in section 4.11.3.1 of this EIS, we are recommending that the Commission Order contain an environmental condition requiring Jordan Cove and Pacific Connector to produce a revised ethnographic study. We expect that study to identify HPRCS to Indian tribes, and address what traditionally gathered plants, fisheries, and hunted species may still exist in the Project area.

The CTCLUSI also expressed concerns about crime, sexual exploitation of women, and negative impacts on the native communities of the Coos Bay area as a result of the operation of a “man-camp” (South Dunes Temporary Workers Housing Complex) during terminal construction; similar to the impacts of “man-camps” of the Bakken oil fields of North Dakota (see Harvard 2015; Adler and Hillstrom 2015; Gillette 2016; Briody 2017; Deer and Nagle 2017; Nienaber 2017; Finn et al. 2016). This issue is discussed in section 4.9, Socioeconomics.

In its July 10, 2017 letter to the FERC, the CTCLUSI requested to be a cooperating agency in the preparation of our EIS. However, on October 25, 2017, the CTCLUSI filed a motion to intervene in the proceeding. It is Commission policy that intervenors cannot also be cooperating agencies. As such, the CTCLUSI’s request to be a cooperating agency cannot be granted.

Also in its July 10, 2017 letter, the CTCLUSI requested a meeting between FERC staff and the Tribal Council as part of our government-to-government consultations. Tribal leaders met directly with the Chair of the Commission at FERC headquarters in Washington, D.C., and representatives of the CTCLUSI met face-to-face with Commission staff in Oregon on March 22 and June 28, 2017, July 17, 2018, and June 25, 2019. We consider those meetings, our NOI, our letters to the CTCLUSI, and letters from the Tribes to the Commission to constitute government-to-government consultations.

The CTCLUSI believe that the Project may have negative impacts on Coos Bay’s tourism and fishing industries. Effects on fisheries are addressed in section 4.5.2 of the EIS, and we discuss impacts on the tourism industry in section 4.9.

The CTCLUSI are also concerned about potential safety risks that may be caused by earthquakes related to seismic movements along the CSZ, and that an earthquake-triggered tsunami could hit the North Spit. Potential impacts from earthquakes and a tsunami, and LNG terminal safety are discussed in section 4.13 of the EIS.

The CTCLUSI would like an assessment of potential health impacts on tribal members and the general community of Coos Bay. This includes Project-related impacts on water quality and air quality. Jordan Cove will arrange for on-site medical professionals to provide basic care for terminal construction workers, reducing the potential influx of patients to the local medical facilities. Further, Jordan Cove signed a MOU with the State of Oregon that requires Jordan Cove to equip the Bay Area Hospital according to state policies for all hospitals in treating burns. The

[231] While the Working Group also included the Forest Service, BLM, and COE, the FERC was specifically excluded from the Group by the Applicants (probably for *ex parte* reasons).

EIS addresses water quality effects in sections 4.3.1 and 4.3.2, while air quality effects are discussed in section 4.12.1.

The CTCLUSI raise concerns about the clearing of forest, and the potential for Project-caused wildfires. Effects on forested lands and the potential for wildfires are discussed in in section 4.4.

In a letter to the FERC dated January 22, 2018, the CTCLUSI stated that Jordan Cove was not providing advance notification of geotechnical investigations in a timely manner and did not provide the Tribes with detailed work plans. Jordan Cove responded to these issues in a letter to the FERC dated January 25, 2018, detailing the geotechnical investigation work plan and notifications provided to the Tribes. In addition, the CRPA contains procedures for notifications to the CTCLUSI concerning future geotechnical investigations proposed by Jordan Cove.

According to their January 29, 2018 letter to the FERC, the CTCLUSI would like to be engaged in the discussion of impacts on the Project's viewshed. This section discusses indirect impacts on cultural resources through visual and audible intrusions. Section 4.8.2 of the EIS includes a visual assessment. The CTCLUSI also requested that the cumulative impact assessment in the EIS include the Coos Bay, Oregon Section 408/204(f) Channel Modification, which it does (in section 4.14).

Coquille Indian Tribe

On November 8, 2017, the Coquille Tribe requested to be a cooperator in the production of this EIS. We accepted that request in a letter to the Tribe dated April 4, 2018. On July 16, 2018 and June 12, 2019, the FERC staff met in-person with the Coquille Tribe in North Bend, Oregon.

The Coquille Tribe requested that this EIS address potential indirect impacts on Indian trust assets, such as the Coquille Forest. Although Jordan Cove has stated that there are no Indian trust assets "directly adjacent to the APE," the pipeline route is in close proximity to three parcels of the Coquille Forest which are held in trust by the BIA and managed by the Coquille Tribe. There should be no direct impacts on lands held in trust by the Coquille Tribe. The proposed pipeline right-of-way would be as close as 65 feet upslope of the three parcels of the Coquille Forest. Indirect impacts on the Coquille Forest would be similar to other forested lands, which are discussed in section 4.4 of this EIS.

In a February 26, 2019 e-mail to FERC staff, the Coquille Tribe provided a list of important traditional-cultural plant and animal species. The Tribe noted that plant species provided much of the sustenance, shelter, and safety for their ancestors. The upland vegetation in the Project area and wetlands are discussed in sections 4.4 and 4.3 of this EIS, respectively. Plants traditionally used by the Coquille Tribe are identified in section 4.4.1.5. Some traditionally used plants are also considered special status species, and are discussed in section 4.6.

The Coquille Tribe noted that animals (including fish and birds) provided food and raw materials for shelter, technologies, economies, and ceremonial purposes. The Tribe provided a list of some of the animal species that are culturally important to them. Wildlife and aquatic species are discussed in section 4.5 of this EIS. As with the culturally significant plant species listed above, some traditionally important animals are also considered special status species and are discussed in section 4.6.

Cow Creek Band of Umpqua Tribe of Indians

In a letter to the FERC dated October 20, 2017, the Cow Creek Tribe stated that the Pacific Connector pipeline route would cross about 122 miles of the Tribe's aboriginal territory or ceded lands. The Tribe is concerned about potential Project-related impacts on cultural resources, and is also concerned about river and stream crossings and impacts on water quality and aquatic resources. Proposed waterbody crossings of the Pacific Connector pipeline route are listed by milepost in table H-3 of appendix H of this EIS. This EIS addresses impacts on waterbodies in section 4.3.2 and impacts on aquatic species in section 4.5.2.

As of September 2018, Pacific Connector has identified 79 archaeological sites along the pipeline route within the historic aboriginal territory or ceded lands of the Cow Creek Tribe, from about MP 42 to MP 168. The FERC has determined that 59 of those sites are listed or eligible for the NRHP or are unevaluated; the remaining 20 sites were found not eligible for listing on the NRHP.

The Cow Creek Tribe has reviewed previously filed cultural resources inventory and evaluation reports, and treatment plans. The Tribe also monitored previous archaeological investigations in their ancestral territory. There is additional cultural resource work to be done for the Project, including additional investigatory work and consultations. However, we expect that Pacific Connector should execute an agreement with the Cow Creek Tribe, similar to the CRPA with the CTCLUSI described above, to continue tribal monitoring of future archaeological investigations. In addition, the FERC will require Pacific Connector to provide future reports of cultural resources investigations, and new treatment plans, to the Cow Creek Tribe for review.

Confederated Tribes of the Grand Ronde Community

In its motion to intervene, filed with the FERC on November 15, 2017, the Grand Ronde Tribes stated that they have maintained a deep connection to the resources and sacred places of their treaty homelands. The Tribes are interested in protecting, enhancing, and restoring tribal culture and natural resources affected by the Project. The Tribes listed specific upland wildlife and aquatic species of special concern. This EIS discusses aquatic species in section 4.5.2, upland wildlife in section 4.5.1, and ESA protected and other special status species in section 4.6.

The Grand Ronde Tribes stated that their ancestors once occupied the region between about MPs 50 and 175 along the Pacific Connector pipeline route. As of 2015, Pacific Connector's consultants recorded 81 archaeological sites along that segment of the proposed pipeline route. Of those, 42 sites were either found to be eligible for the NRHP or are unevaluated; the remaining 39 sites were found not eligible for listing on the NRHP. In a January 16, 2018 letter to the FERC commenting on Pacific Connector's Resource Report 4, the Grand Ronde Tribes requested a reassessment of isolated finds, which do not "accurately reflect the historic land use of the landscape, but is a consequence of many years of cultural resource surveys being undertaken in a piecemeal fashion." The identification of archaeological sites and isolated finds is a matter of survey and recordation methodologies, and we note that Pacific Connector's contractor's methods were confirmed with the Oregon SHPO's acceptance research designs, resource forms, and survey reports. In addition, the Grand Ronde Tribes suggested revisions to Pacific Connector's UDP. Pacific Connector has provided the Grand Ronde Tribes with copies of cultural resources investigations reports for their review.

In its May 4, 2018 letter to the FERC, the Grand Ronde Tribes re-asserted their deep connections with the resources and sacred places of their ancestral homelands in southern Oregon, including Usual and Accustomed areas ceded by treaties with the U.S. government. Pacific Connector has convened a Cultural Resources Working Group and offered individual tribes financial support for them to produce their own ethnographic studies. The Grand Ronde Tribes object to the limited funds and expedited time frame for such studies to be conducted by tribal staff.

On July 20, 2018, the FERC staff held a telephone conference call with representatives of the Grand Ronde Tribes. That call discussed the FERC's NEPA process, and our process for complying with the NHPA.

On September 19, 2018 the Grand Ronde Tribes provided the FERC staff with a comment letter regarding the cultural resource studies completed to date and the Cultural Resources Working Group put together by the Applicants. The Tribes noted they were, to date, yet to receive complete materials documenting cultural resource surveys from the Applicant for the Tribes' review. Concerns were expressed for a lack of consideration of historic properties of religious and cultural significance to Indian tribes. The Grand Ronde Tribes have apprehensions about the Applicant-driven Cultural Resources Working Group.

As discussed below in section 4.11.3.1 of this EIS, we are recommending that the Commission Order contain an environmental condition requiring the Applicants to produce a revised ethnographic study. We expect that study to identify HPRCS to the Tribes, and address what traditionally gathered plants, fisheries, and hunted species may still exist in the Project area.

In a letter to FERC dated October 5, 2018, the Grand Ronde Tribes requested an in-person government-to-government meeting. Staff held a face-to-face meeting with representatives of the Grand Ronde Community at the Grand Ronde Reservation on June 11, 2019.

Karuk Tribe

The Karuk Tribe, in comments to the FERC dated July 5, 2017, raised concerns about potential Project-related impacts on water quality and the salmon fishery in the Klamath River. Since the U.S. government never executed a treaty with the Karuk Tribe, and did not set aside an officially designated reservation for the Tribe, the Karuk Tribe does not have special fishing or hunting privileges on ceded lands that are federally protected as treaty rights.

The Karuk Tribe believes that the Pacific Connector pipeline may contribute sediment to and increase the water temperature of streams crossed. We address impacts on waterbodies in section 4.3.2 of this EIS. Likewise, this EIS discusses aquatic resources in section 4.5.2.

The Karuk Tribe also claims that in the case of a break of the Pacific Connector pipeline, waterbodies would be polluted. However, the pipeline would transport natural gas in gaseous form (not liquid) and, in the unlikely event of an incident and release, natural gas, which is lighter than air, would dissipate into the atmosphere and would not contaminate waterbodies. The Karuk Tribe believes that the Jordan Cove export terminal would include a 420-megawatt power plant. This is not so, as the current proposal has eliminated the power plant.

In their May 3, 2018 letter to the FERC, the Karuk Tribe requested a meeting with staff to discuss the Project. Again, the Tribe mentioned its concerns about the pipeline crossing of the Klamath

River, and its potential impacts on the salmon fishery and the lifeways of the Tribe. The FERC staff met in-person with representatives of the Karuk Tribe in Happy Camp, California, on July 18, 2018.

Klamath Tribes

The Klamath Tribes provided comments about the Project to the FERC in filings on June 7 and 26, September 1, and October 20, 2017, and May 3, 2018. The Klamath Tribes assert that the Pacific Connector pipeline route would cross ceded lands that contain cultural resources of importance to the Tribes, and that former villages and graves may be impacted by construction of the pipeline.

As of 2015, Pacific Connector's consultants have identified 10 pre-contact archaeological sites along the pipeline route in Klamath County. Eight of those sites were evaluated as eligible for the NRHP or are unevaluated. Members of the Klamath Tribes participated in Pacific Connector's cultural resources surveys. Pacific Connector has provided the Klamath Tribes with copies of all previous cultural resource reports, for their review. If the terminal and pipeline are authorized by the FERC, and any unanticipated sites or human remains are found during construction, Pacific Connector would follow the procedures outlined in its UDP, that was previously reviewed by the Klamath Tribes.

The Klamath Tribes requested the opportunity to assist in the drafting of a revision of Pacific Connector's Historic Properties Management Plan (HPMP). A draft HPMP was filed with the FERC by Pacific Connector on October 5, 2018. As part of the previous applications, the FERC staff had recommended that Pacific Connector negotiate an agreement with the Klamath Tribes. We expect that Pacific Connector should execute such an agreement with the Klamath Tribes, similar to the CRPA with the CTCLUSI described above.

The Klamath Tribes are also concerned about water quality, the pipeline route crossings of the Rogue and Klamath River, and the potential for the Project to impact fish species that are important to the Tribes. The 1864 treaty with the Klamath Tribes stated that the Tribes hold "…*the exclusive right of taking fish in the streams and lakes, included in said reservation, and of gathering edible roots, seeds, and berries within its limits*…." However, the Pacific Connector pipeline route does not cross the Klamath Reservation. Pacific Connector proposes to cross under the Rogue River and Klamath River using HDDs, to avoid impacts on those rivers and their associated fisheries. The pipeline would also cross 17 streams or creeks that form part of the Klamath River headwaters in Klamath County. Pacific Connector would use dry methods (flumes or dams) to cross other streams. Erosion controls that would be implemented at stream crossings would limit turbidity and sedimentation. These stream crossings would not result in significant long-term impacts on the fishery resources associated with the Klamath River system. See sections 4.3.2 and 4.5.2 in this EIS for more details about impacts on waterbodies and aquatic resources, respectively, and proposed mitigation measures.

The Klamath Tribes raised concerns about impacts on regional air quality, and the Project's potential contributions to global warming. Air quality is discussed in section 4.12.1 of this EIS.

The Klamath Tribes are also concerned about the potential for the Project's facilities to be impacted by earthquakes and landslides. Earthquakes and landslides along the pipeline route are discussed in section 4.1 of this EIS.

The issue of "man camps" and tribal community safety in those settings has also been raised by the Klamath Tribes. There are no proposed worker housing camps along the Pacific Connector pipeline route. Instead, workers would be dispersed along spreads and find housing in RV camps, rental houses and apartments, and hotels, as discussed in the socioeconomics section (4.9) of this EIS.

The Klamath Tribes cite EO 12898 as requiring the study of impacts of the Project on Environmental Justice communities, including Indian tribes. Although the FERC is an independent regulatory agency excluded from compliance with Executive Orders, in order to address this tribal and general public concern, we analyze in section 4.9 of this EIS whether the Project would have disproportional environmental impacts on minority and low-income populations.

The Klamath Tribes are also concerned that the Project may create opportunities for the looting of cultural remains and historical sights. Information related to the location of these resources is considered confidential and privileged, and are not provided to the public. As a result, the risk of the Project and our analysis resulting in looting of these resources is low.

Tolowa Dee-Ni' Nation

The Tolowa Dee-Ni' Nation, in its letter dated December 6, 2018 to the FERC, described the Nation's "strong opposition [to] and concern" regarding the proposed Project. The Nation noted they cannot support the Project based on the proximity of the pipeline to the headwaters of the Rogue River and the perceived potential for pipeline leaks to impact the waters of the river. As noted elsewhere in this section, the pipeline would transport natural gas in gaseous form which, in the event of a release, would dissipate into the atmosphere and would not contaminate waterbodies. The pipeline would cross under the Rogue River with an HDD, and Pacific Connector would use dry methods to cross other headwater streams. Those techniques, as explained in section 4.3 of this EIS, would reduce impacts on waterbodies and their associated fisheries.

Yurok Tribe

The Yurok Tribe, in its letter dated July 6, 2017 to the FERC, and in its motion to intervene filed October 26, 2017, stated that Pacific Connector's proposed crossing of the Klamath River could have potential impacts on tribal trust fish species. Disruption of fish habitat may have negative impacts on the Yurok tribal economy that depends in part on a commercial salmon fishery. Project-related impacts on aquatic species are discussed in sections 4.5 and 4.6 of this EIS.

When the Klamath Reservation in California was created in 1855 for the Yurok and Hupa people, their rights to fish in the rivers running through the reservation were federally protected. In a 1993 opinion issued by the Solicitor for the U.S. Department of the Interior, it was stated that the entitlement of the Yurok and Hoopa Valley Tribes was limited to 50 percent of the harvest of Klamath-Trinity Basin salmon (Leshy 1993). The Pacific Connector pipeline route does not cross through the Klamath-Trinity Basin of California. The pipeline route would cross the Klamath River in Klamath County, Oregon, within the traditional territory of the Klamath Tribes, where Pacific Connector would use an HDD. The HDD would limit impacts on the Klamath River and its fishery resources.

In addition, the Tribe states that the Klamath Riverscape is a district listed on the Yurok Tribe Register of Historic Properties. Pacific Connector's consultants should review the Klamath Riverscape to determine what effects, if any, the Project would have on it. In their May 4, 2018 letter to the FERC, the Yurok Tribe requested a meeting with staff to discuss the Project. On July 18, 2018, the FERC staff met in-person with representatives of the Yurok Tribe in Klamath, California.

4.11.1.4 Communications with Other Agencies

The BLM, Forest Service, Reclamation, COE, EPA, FWS, and NMFS are federal cooperating agencies in the production of this EIS, and consulting parties with regard to the Section 106 compliance process. The federal land-managing agencies previously provided the FERC with their opinions on NRHP eligibility and pipeline effects for sites on federal land. Comments related to cultural resources received by the FERC from other federal agencies between 2012 and 2015 for Docket Nos. CP13-483-000 and CP13-492-000 are discussed in section 4.11.1.3 of our September 2015 final EIS for those projects. Communications between the FERC and other federal agencies related to cultural resources issues for Docket Nos. CP17-494-000 and CP17-494-000 are discussed below.

In response to our June 9, 2017 NOI for the Project, the EPA filed comments, dated July 10, 2017. One of its comments was that the EIS should discuss compliance with the NHPA, including consultations with the SHPO. In addition, the document should discuss Project-related impacts on tribal, cultural, or other treaty resources. We address EPA's issues in this section.

The ACHP wrote a letter to the FERC dated January 25, 2018, in response to the January 22, 2018 letter from the CTCLUSI to the FERC about geotechnical testing. The ACHP stated that, in general, their agency has "interpreted geotechnical testing as part of project planning for undertakings and not, in and of itself, subject to review by federal agencies under Section 106." They requested that the FERC respond to the Tribes and clarify the purpose of the geotechnical investigations and the place of those investigations in the FERC's Section 106 compliance process. The FERC staff agrees with the ACHP position that geotechnical investigations are considered part of the pre-planning process and not subject to Section 106 compliance. It is FERC practice that pre-construction geotechnical investigations be conducted without FERC review or approval and are not considered to be cultural resource studies or part of the Section 106 process (see FERC 2017). As such, the Applicants do not need permission from the FERC to conduct pre-planning geotechnical work, and these activities do not constitute part of the FERC's undertaking. However, the Applicants may need permits from other federal agencies, such as the COE, for those activities.

Jordan Cove's Communications with Other Agencies

Jordan Cove sent email communications to the COE, SHPO, ODEQ, and ODE on May 19 and November 16, 2017, providing a context for the geotechnical work proposed at the APCO site and about sampling at Kentuck Slough, respectively. Project Activity Updates were also provided to the same agencies via email on September 3, 2017 for September 2017; October 2, 2017 for activities scheduled in October; October 13 and 27 and November 9, 2017 for activities in November; December 1, 2017 for activities scheduled for December 2017; and December 14 and 20, 2017 for activities scheduled for January and February 2018. Details of these communications can be found in appendix L.

Pacific Connector's Communications with Other Agencies

On February 24, 2017, Pacific Connector sent an email to the BLM requesting a review of the list of cultural resource sites located along the pipeline route on BLM lands. On February 29, 2017, the Forest Service called HRA to discuss heritage properties on NFS lands that may be affected by the Pacific Connector Project. On May 26, 2017, Pacific Connector sent an email to the COE, ODE, and ODEQ regarding geotechnical testing to support the proposed HDD under Coos Bay. We detail Pacific Connector's communications since 2015 with other federal and state agencies in appendix L.

4.11.2 Area of Potential Effect

As stated in our NOI, we define the direct APE as all areas subject to ground disturbance, including the construction right-of-way, TEWAs, contractor/pipe storage yards, disposal areas, aboveground facilities, and new or to-be-improved access roads. An indirect APE was also established by the Applicants for each project based on each viewshed.

4.11.2.1 Jordan Cove LNG Project

In the case of the Jordan Cove Project, the direct APE includes the footprint of all potential ground-disturbing actions. Specifically, this includes the South Dunes Site, Ingram Yard, Access and Utility Corridor, Meteorological Station, IWWP, Trans-Pacific Parkway/U.S. 101 Intersection, the planned mitigation sites (Kentuck, Eelgrass, Lagoon, Panhandle, and North Bank), Boxcar Hill laydown and parking area, Roseburg Forest Products and Port laydown sites, APCO Sites 1 and 2, Myrtlewood Off-site Park and Ride, and hydraulic dredge slurry pipelines in Coos Bay. In total, construction of the Jordan Cove LNG terminal facilities would impact about 1,355 acres. We agree with the definition of the direct APE, provided in Jordan Cove's application to the FERC. The Jordan Cove Project facilities are described in more detail in section 2 of this EIS.

The indirect APE is defined to include all areas potentially subjected to the introduction of visual, atmospheric, or audible elements that diminish the integrity of a historic property's significant historic features. Jordan Cove's consultants conducted a windshield survey for a 2-mile radius around the proposed LNG terminal. The existing Boxcar Hill Campground and RV Park was noted in this area. Also found in the indirect APE was a house in the Shorewood area at the northern mouth of Haynes Inlet, the Hilltop House restaurant and Bay Bridge Motel on the north side of the McCullough Bridge, and residential neighborhoods in the city of North Bend (Bowden et al. 2017). The consultants concluded that no historic properties would have a view of the aboveground components of the LNG terminal. As such, the indirect APE was recommended to be the same as the direct APE. However, the consultants did not address visual impacts on the NRHP-listed McCullough Bridge.

The indirect APE would overlap with a portion of the CTCLUSI-nominated *Q'aly ta Kukwis schihdii me* TCP historic district that covers most of the Coos Bay estuary and which Jordan Cove's consultants did not take into consideration because the nomination form was filed after their analysis was conducted. In accordance with the Memorandum of Agreement (MOA) for this Project, the FERC staff will assess if the Project could have an adverse effect on the TCP historic district, in consultations with the SHPO and interested Indian tribes.

The direct APE, which is the same as the indirect APE for the Jordan Cove Project, is depicted in Figure 1-1 of the 2017 survey report (Bowden et al. 2017) filed with Jordan Cove's application to the FERC.

4.11.2.2 Pacific Connector Pipeline Project

Pacific Connector defined the direct APE as all geographic areas that will potentially experience ground disturbances from the construction, operation, and maintenance of the pipeline. This includes a 400-foot-wide survey corridor along the 229-mile-long pipeline route; and areas related to the Project outside that corridor, including TEWAs, USCAs, contractor and pipe storage yards, rock source and disposal sites, hydrostatic discharge sites, new and improved access roads, cathodic protection beds, and aboveground facilities, including communication towers. Pacific Connector's cultural resources contractor estimated that the direct APE covers about 17,037 acres (Derr et al. 2018). We agree with this definition of the direct APE. The Pacific Connector Project facilities are described in more detail in section 2 of this EIS.

Pacific Connector defined the indirect APE to include all geographic areas that would potentially experience visual intrusions or changes as a result of the construction, operation, and maintenance of the pipeline. The pipeline will not produce sufficient noise or odors to warrant consideration of audible or atmospheric/olfactory indirect effects in establishing the indirect APE. Section 4.12.2 of this EIS discusses noise impacts related to the construction and operation of Pacific Connector's facilities. Since the pipeline will be buried, the aboveground components of the project will be related to the associated aboveground facilities and the permanent easement itself, which will be maintained as a 50-foot-wide cleared corridor on the landscape. To identify the indirect APE, Pacific Connector's consultants reviewed the pipeline route for instances where the cleared easement may be noticeably visible, considering 1) current heavily vegetated landscapes with adjacent significant topographical differences and 2) landscapes that are relatively unencumbered by modern intrusions. This analysis determined that locations where the indirect effects APE diverges from the direct APE are limited to locations where the permanent easement traverses a steep, heavily vegetated area, then turns sharply so that the permanent easement could be seen directly from a location outside of the direct APE. The SHPO, in a letter to Pacific Connector's consultants dated January 22, 2016, concurred with the methodology for defining the indirect APE. We agree. Section 4.8.2 of this EIS includes a visual impact assessment of the proposed pipeline right-of-way.

Appendix A of the 2017 pipeline addendum survey report (Derr et al. 2017), filed with Pacific Connector's application with the FERC, contains maps that depict the direct and indirect APEs.

4.11.3 Results of Investigations

Archaeological, historical, and ethnographic contexts of the Project area can be found in the numerous survey reports completed for the Project since 2005. A brief context for Native American tribal occupations of the Project area and a historical summary of archaeological studies in the region can be found in appendix L. Studies conducted specifically for the Project are described and listed below.

4.11.3.1 Jordan Cove LNG Project

Jordan Cove has sponsored cultural resources investigations of its proposed LNG terminal since 2005. Table 4.11.3.2-1 lists the surveys and archaeological testing that cover Jordan Cove's proposed facilities. More detailed summary descriptions of Jordan Cove's cultural resources investigations are provided in appendix L of this EIS.

TABLE 4.11.3.1-1

Cultural Resources Surveys and Testing at Jordan Cove's Proposed LNG Terminal Facilities

Facility or Use Area a/	Survey Reports	Inventory Status
Access Channel (Coos Bay)	Byram 2006a, 2006b; Punke, et al.2018b; Rose et al. 2014	Survey complete
Ingram Yard – Marine Slip including LNG Vessel Berth, Tug Berth, and Emergency Lay Berth	Byram 2006a, 2006b; Punke 2018a; Punke et al. 2018a and 2018b; Rose et al. 2014; Simmons 1983; Stubbs 1975	Survey complete
Rock Apron (Coos Bay)	Hulse 2018 (in Bowden 2018)	Survey not complete
Ingram Yard – Material Offloading Berth	Byram 2006a and 2006b; Punke 2018a; Punke et al. 2018a and 2018b; Rose et al. 2014; Simmons 1983	Survey complete
Ingram Yard – Haul Road	Bowden et al. 2017; Byram 2006a and 2006b; Punke 2018a; Punke et al. 2018a and 2018b; Rose et al. 2014; Simmons 1983	Survey complete
Ingram Yard – LNG Loading Platform and Transfer Pipeline	Byram 2006a and 2006b; Punke 2018a; Punke et al. 2018 and 2018b; Rose et al. 2014; Simmons 1983	Survey complete
Ingram Yard – LNG Storage Tanks	Byram 2006a and 2006b, Punke 2018a; Punke et al. 2018a and 2018b; Simmons 1983	Survey complete
Ingram Yard – Liquefaction Processing Area	Bowden et al. 2017; Byram 2006a and 2006b; Punke 2018a; Punke et al. 2018a and 2018b; Simmons 1983	Survey complete
Ingram Yard – Refrigerant Storage Area	Byram 2006a and 2006b; Punke 2018a; Punke et al. 2018a and 2018b; Simmons 1983	Survey complete
Ingram Yard – Gas Processing Area	Byram 2006a and 2006b; Punke 2018a; Punke et al. 2018a and 2018b; Simmons 1983	Survey complete
Ingram Yard – Utilities	Punke 2018a; Punke et al. 2018a and 2018b; Simmons 1983	Survey complete
Ingram Yard – Flare Area	Punke 2018a; Punke et al. 2018a and 2018b; Simmons 1983	Survey complete
Ingram Yard – Secondary Terminal Entrance	Punke 2018a; Punke et al. 2018a and 2018b; Simmons 1983	Survey complete
Ingram Yard – Laydown Area	Byram 2006a and 2006b; Punke 2018a; Punke et al. 2018a and 2018b; Simmons 1983	Survey complete
Ingram Yard – Other	Macfarlane and Skinner 2013 (in Bowden et al. 2017: Appendix C); Punke 2018a; Punke et al. 2018a and 2018b	Survey complete
Fire Station and Ancillary Buildings at west end of Access and Utility Corridor (north of Roseburg Forest Products)	Byram 2006a and 2006b; Byram and Shindruk 2012; Punke 2018a; Punke et al. 2018a and 2018b	Survey complete
Access and Utility Corridor (Between Roseburg Forest Products and South Dunes)	Barner 1978; Byram 2006a and 2006b; Byram 2008; Byram and Purdy 2007; Byram and Shindruk 2012; Punke 2018a; Punke et al. 2018a and 2018b; Rose and Davis 2013 (in Bowden et al. 2017:Appendix C); Simmons 1983	Survey complete
Laydown Areas (Roseburg Forest Products)	Bowden et al. 2009 and 2017; Byram 2006a and 2006b; Punke et al. 2018a	Survey complete
Temporary Dredge Slurry and Water Return Pipelines (Roseburg Forest Products & South Dunes)	Barner 1978; Bowden et al. 2009; Byram 2006a and 2006b; Byram 2008; Byram and Purdy 2007; Byram and Shindruk 2012; Punke 2018a; Punke et al. 2018a and 2018b	Survey complete

TABLE 4.11.3.1-1 (continued)

Cultural Resources Surveys of Jordan Cove's Proposed LNG Terminal Facilities

Facility or Use Area a/	Survey Reports	Inventory Status
Laydown Area and Temporary Workforce Housing Complex (South Dunes)	Barner 1978; Bowden et al. 2009 and 2017; Byram 2008; Byram and Purdy 2007; Hamilton and Ragsdale 2018; Olander et al. 2009; Punke 2018a and 2018b; Punke et al. 2018a and 2018b; Rose et al. 2014	Survey complete
SORSC (South Dunes)	Bowden et al. 2009 and 2017; Byram and Purdy 2007; Punke 2018a and 2018b; Punke et al. 2018a and 2018b	Survey complete
Administration Building (South Dunes)	Bowden et al. 2009 and 2017; Byram and Purdy 2007; Punke 2018a and 2018b; Punke et al. 2018a and 2018b	Survey complete
Industrial Wastewater Pipeline Replacement and new Water Line (Trans-Pacific Parkway)	Rose and Johnson 2014; Simmons 1984	Survey complete
Port Laydown Site (North Spit – south of Southport facility)	Byram and Purdy 2008; Darby 2005 (in Bowden et al. 2017); Hulse 2018	Survey complete
Boxcar Hill Laydown Area (North Spit – east side of Causeway)	Byram 2009; Derr et al. 2017; Punke et al. 2018b	Survey complete
Meteorological Station and Access Road (Lagoon Mitigation Site)	Bowden et al. 2017; Dinwiddie and Bowden 2018	Survey complete
Channel Improvement Areas 1-4 (Coos Bay)	Hulse 2018	Survey complete
Temporary Dredge Line from Channel Improvement Areas to APCO sites (Coos Bay)	Bowden 2018	Survey complete
Temporary Dredge Line to Eel Grass Mitigation Site (Coos Bay)	Bowden 2018	Survey complete
Eel Grass Mitigation Site (Coos Bay)	Bowden 2018	Survey complete
Temporary Dredge Line to Kentuck Slough Mitigation Area (Coos Bay)	Bowden 2018	Survey complete
Trans-Pacific Parkway Causeway and U.S. Highway 101 Intersection Improvements (north of McCullough Bridge)	Bowden et al. 2017; Byram 2006a and 2006b; Byram 2009; Simmons 1984	Survey complete
APCO Sites 1 and 2 (North Point)	Derr and Punke 2019; Punke and Bowden 2018	Survey complete
Kentuck Slough Wetland Mitigation Area (Kentuck Slough)	Bowden et al. 2009; Bowden et al. 2017; Byram and Walker 2010, Derr et al. 2017; Punke 2018b; Ragsdale et al. 2013	Survey complete
Myrtlewood RV Park Off-Site Parking Lot (Hauser)	Bowden et al. 2017	Survey complete
Lagoon Habitat Mitigation Site	Bowden et al. 2009; Dinwiddie and Bowden 2018	Survey not complete
Panhandle Habitat Mitigation Site	Bowden et al. 2009; Dinwiddie and Bowden 2018	Survey not complete
North Bank Habitat Mitigation Site	Bowden et al. 2009; Dinwiddie and Bowden 2018	Survey not complete

a/ Facilities derived from Table 1.4-1 and Figure 1.1-1 of Resource Report 1 attached to Jordan Cove's application to the FERC, and Table 4.2-2 filed November 2, 2018.

Areas that still require additional survey include the Lagoon, Panhandle, and North Bank habitat mitigation sites. Additionally, the Rock Apron area has only been partially surveyed.

Geoarchaeological deep testing and shovel probing have been conducted in Ingram Yard, the Access and Utility Corridor, and the South Dunes area (Punke et al. 2018; Punke 2018a and

2018b), as well as at both APCO sites (Punke and Bowden 2018; Derr and Punke 2019). A piece of bone was found in a shovel probe at the South Dunes area that was identified as "non-human." No other archaeological evidence was uncovered by the geoarchaeological studies. However, buried surfaces suitable for human habitation were identified beneath the fill layers at tested areas.

Appendix L summarizes the identified and reported resources that are within or adjacent to the direct APE for the Jordan Cove Project. We agree with all recommendations of NRHP eligibilities and effects that have been provided thus far by Jordan Cove's consultants. However, not all of these eligibility determinations have received concurrence from the SHPO yet. For those resources where SHPO concurrence has not yet been requested (pending additional investigations) or is pending, the recommended NRHP eligibilities and effects assessments made by Jordan Cove's consultants are preliminarily used for this analysis.

To date (November 2019), eight pre-contact fish weir sites (35CS261, 35CS263, 35CS324, 35CS326, 35CS327, 35CS328, 35CS342, and 35CS343) were identified along one of the proposed dredge slurry pipeline routes in Coos Bay and were evaluated as eligible for the NRHP (Punke et al. December 2018). In a letter to Jordan Cove, dated July 22, 2019, the SHPO concurred that fish weir sites 35CS261, 35CS263, 35CS342, and 35CS343 are eligible for the NRHP. We asked Jordan Cove to file with the FERC avoidance or treatment plans for those historic properties.[232]

In a letter to the FERC staff, dated July 19, 2019, the Oregon SHPO provided its determination that the TCP "*Q'alay ta Kukwis schichdii me*" Historic District is eligible for nomination to the NRHP.[233] However, the Oregon SHPO also found that "*Q'alay ta Kukwis schichdii me*" should not be listed on the NRHP because of objections from landowners (as the District overlaps portions of the cities of Coos Bay and North Bend). The SHPO forwarded the nomination to the NPS on May 23, 2019, who returned it on July 2, 2019 because of process and documentation deficiencies. However, because the SHPO found the TCP to be eligible, we will treat it as an historic property. We will continue to consult with the Oregon SHPO and interested Indian tribes about an assessment of effects and possible future treatment to avoid, reduce, or mitigate impacts on this TCP.

4.11.3.2 Pacific Connector Pipeline Project

Since 2006, Pacific Connector has hired professional cultural resources management consultants Byram Archaeological Consulting, Southern Oregon University Laboratory of Archaeology, and HRA to conduct surveys and testing investigations in the APE. Table 4.11.3.2-1 lists the reports documenting the archaeological and historical investigations of the proposed Pacific Connector facilities.

[232] See FERC Environmental Information Request dated July 22, 2019, Question 13.

[233] The Coquille Tribe, in a letter to FERC staff dated September 4, 2019, objected to the SHPO's determination for the "*Q'alay ta Kukwis schichdii me*" TCP, claiming the SHPO exceeded its jurisdiction, since a portion of the historic district would cross Coquille lands.

TABLE 4.11.3.2-1

Cultural Resources Surveys and Testing Conducted for the Pacific Connector Project

Title	Reference	Type of Study	Subsurface Investigations	Project Component(s) Surveyed or Tested
Pacific Connector Gas Pipeline Project Cultural Resources Survey, Coos, Douglas, Jackson, and Klamath Counties, Oregon	Bowden et al. 2009	Pedestrian and subsurface	Shovel probe, test units	Portion of pipeline corridor, some TEWAs, some UCSAs, some quarries, some laydown areas, some and access roads.
Cultural Resources Survey for the Pacific Connector Gas Pipeline Project, Addendum Report	Olander et al. 2009 (in Bowden et al. 2017)	Pedestrian and subsurface	Shovel probe	Portion of pipeline corridor and alternatives.
Pacific Connector Gas Pipeline Project Cultural Resources Investigations, Coos, Douglas, Jackson, and Klamath Counties, Oregon, Final Phase II Evaluations	Bowden et al. 2010	Subsurface	Test units	Portion of pipeline corridor.
Pacific Connector Gas Pipeline Project Cultural Resources Survey, Coos, Douglas, Jackson, and Klamath Counties, Oregon, Survey Report Addendum for December 2009 FERC Data Request	Knutson et al. 2010	Pedestrian, intertidal/boat	NA	Portion of pipeline corridor and some laydown areas.
Archaeological Survey of the Oregon Gateway Marine Terminal Slip and Access Channel Mitigation Site at Kentuck Slough	Byram and Walker 2010	Pedestrian and subsurface	Shovel probes and auger probes	Portion of pipeline corridor.
Pacific Connector Gas Pipeline Project Cultural Resources Survey, Coos, Douglas, Jackson, and Klamath Counties, Oregon: 2013 Cultural Resources Addendum	Bowden et al. 2013	Pedestrian and subsurface	Shovel probe	Portions of pipeline corridor, Klamath Falls Compressor Station, and some TEWAs.
Pacific Connector Gas Pipeline Project Cultural Resources Survey: 2013 Cultural Resources Addendum #2	Ragsdale et al. 2013	Pedestrian and subsurface	Shovel probe, deep testing, test units	Portion of pipeline corridor and some TEWAs.
Pacific Connector Gas Pipeline Project Cultural Resources Survey: Phase II Evaluation of Site 35DO1284	Willis et al. 2013	Subsurface	Test units	Portion of pipeline corridor and one TEWA.
Pacific Connector Gas Pipeline Project Cultural Resources Survey, Coos, Douglas, Jackson, and Klamath Counties, Oregon. 2014-2015 Cultural Resources Addendum	Derr et al. 2015	Pedestrian and subsurface	Shovel probes, deep testing	Portion of pipeline corridor, some TEWAs, and one laydown area.
Jordan Cove Energy Project LNG Terminal Cultural Resources Survey, Overview, and Evaluation Report	Bowden et al. 2017	Pedestrian, subsurface, and architecture.	Shovel probes and auger probes	Portion of pipeline corridor.
Pacific Connector Gas Pipeline Project Cultural Resources Survey, Coos, Douglas, Jackson, and Klamath Counties, Oregon. 2017 Cultural Resources Addendum.	Derr et al. 2017	Pedestrian, intertidal/boat, windshield, and subsurface	Test units and shovel probes	Portion of pipeline corridor, some TEWAs, and some access roads.

TABLE 4.11.3.2-1 (continued)

Cultural Resources Surveys and Testing Conducted for the Pacific Connector Project

Title	Reference	Type of Study	Subsurface Investigations	Project Component(s) Surveyed or Tested
Phase II Evaluation of Site 35DO1495	Davis et al. 2018a	Pedestrian survey and testing	Test units and shovel probes	Portion of pipeline corridor.
Phase II Evaluation of Site 35KL4330	Davis et al. 2018b	Pedestrian survey and testing	Test units and shovel probes	Portion of pipeline corridor.
Pacific Connector Gas Pipeline Project Cultural Resources Survey, Coos County, Oregon: 2018 Cultural Resource Addendum 1	Derr et al. 2018a	Pedestrian and subsurface	Shovel probes	Portion of pipeline corridor and some TEWAs and access roads outside the pipeline corridor.
Pacific Connector Gas Pipeline Project Cultural Resources Survey, Coos, Douglas, Jackson, and Klamath Counties, Oregon: 2018 Cultural Resource Addendum 2	Derr et al. 2018b	Pedestrian and subsurface	Deep geoarchaeological testing and shovel probes	Portion of pipeline corridor, some workspaces, and some access roads. Monitoring of geotechnical borings
Archaeological Investigations at North Point, North Bend, Oregon	Derr and Punke 2019	Pedestrian and subsurface	Shovel probes, coring and trenching	Portion of pipeline corridor within APCO sites.

Pacific Connector's contractor indicated that, as of December 31, 2018, approximately 209 miles of the pipeline route (91 percent) and 609 miles of access roads were covered by cultural resources surveys (Derr et al. 2018). As of April 2018, a total of 1,557 work spaces (97 percent) have been surveyed. Surveys were completed for 26 pipe yards and 16 rock source and disposal sites. In September 2018, it was estimated that Pacific Connector had inventoried a total of about 560 acres combined for all the extra workspaces and yards surveyed off the pipeline centerline.[234] All 35 hydrostatic test water discharge sites have been surveyed. Inventories have also been completed covering most of the proposed aboveground facilities except for two MLVs and one communication tower (discussed below in section 4.11.5). Geotechnical borings were excavated in Coos Bay for the proposed HDD under the bay; at the upland western approach to the crossing of Kentuck Slough, at the lowland western side of the proposed crossing of the South Umpqua River near Milo, at the crossing of the Southern Pacific Railroad and Reclamation Drain 5-A in the Klamath Basin, and the west side of the Lost River (Derr et al. 2018); and geoarchaeological deep testing was performed at the North Point of North Bend (Derr and Punke 2019) and the Klamath River crossing (Derr et al. 2015). The geotechnical borings were monitored by professional archaeologists and tribal representatives, and no cultural resources were identified.

Inventories for the Pacific Connector Project have identified 179 recorded and reported archaeological and historic architectural sites (see table L-14 in appendix L). Eighty-nine are aboriginal pre-contact archaeological sites; 46 are historic archaeological sites; 11 are historic sites (built environment); 2 are historic cemeteries; 28 are multicomponent, with both pre-contact and historic remains; and 3 are of undetermined time period. Eighty-five are along a pipeline route; 48 are along access roads; 1 is within a TEWA; 7 are within yards; 35 are along a pipeline route and an access road; and 3 are at the Klamath Compressor Station. Forty-eight of these sites are

[234] Pacific Connector filing with the FERC on March 21, 2019.

located on federal lands (see appendix L); the remainder are on non-federal lands. In addition, 152 isolated finds (IFs) were recorded during surveys for the Project. Two of the IFs, HRA-724i and HRA-727i, require additional investigations to confirm their isolated nature. Both are pre-contact IFs on private lands and are considered unevaluated for NRHP eligibility. After consulting with the SHPO through HRA, we determined that the remaining IFs are not eligible for the NRHP and require no further work. However, some tribes have expressed concern that consideration was not given to the importance of some of these IFs (see table L-4 in appendix L).

Of the 134 sites on non-federal lands, 76 require no further work either because they have been evaluated as not eligible for the NRHP, have been avoided, or anticipated effects would not be adverse (two of these has dual landownership with a federal agency). Two additional sites on non-federal lands are unevaluated and NRHP-eligible and can be avoided, but require consultation or additional survey to confirm. Thirty-nine sites on non-federal lands are unevaluated or considered NRHP-eligible and cannot be avoided, so they need additional investigations, either survey or testing (one of these has dual landownership with a federal agency). Avoidance plans for sites that can be avoided can be found in the draft HPMP filed with the FERC on October 5, 2018. The HPMP is subject to revision based on ongoing consultations between Pacific Connector, Indian tribes, SHPO, and federal land-managing agencies. However, not all unevaluated, potentially NRHP-eligible, and NRHP-listed sites that can be avoided by the Project have avoidance plans; therefore, the draft HPMP still needs further revision.

Twenty sites have been determined to be eligible for or listed on the NRHP and cannot be avoided (see table L-12 in appendix L). In most cases, the Applicants prepared treatment plans for these historic properties, which were reviewed by appropriate interested Indian tribes, federal land management agencies, the Oregon SHPO, and the FERC staff.

4.11.3.3 Federal Lands

The industrial wastewater line replacement at the Jordan Cove LNG terminal would cross a piece of land administered by the BLM. The COE has an easement on a portion of the Jordan Cove LNG terminal. No cultural resources were identified on federal lands associated with the Jordan Cove LNG Project.

The proposed Pacific Connector pipeline route would cross about 71 miles of federal lands administered by the BLM, Forest Service, and Reclamation. In total, 46 sites were identified on federal lands or are otherwise managed by one of these federal agencies (three have dual landownership with private landowners). Thirty-six sites are on BLM lands, 9 are on Forest Service lands, and 1 is managed by Reclamation.

Of the 36 sites on BLM lands, 12 are not eligible for the NRHP and require no further work. Eleven of the BLM sites can be avoided (this includes one site with dual private landownership). Seven of the sites on BLM lands are unevaluated for NRHP eligibility and require additional work, either additional survey or testing, prior to their evaluation for eligibility to the NRHP (this includes one site with dual private landownership). An additional three sites are being treated as NRHP-eligible (this includes one site with dual private landownership). Pacific Connector has proposed conducting testing to confirm eligibility of these sites. Five BLM sites (35DO1104, 35DO1105, 35DO1106, 35DO1110, and 35DO1117) have been determined eligible for the NRHP and cannot be avoided by the Project. Pacific Connector's consultants have recommended that data recovery investigations be conducted to mitigate adverse effects at the unavoidable eligible sites.

Of the nine sites on Forest Service lands, two were evaluated as not eligible for the NRHP, and require no further work. Five Forest Service sites are unevaluated and need additional surveys and evaluations. One Forest Service site can be avoided. One site (35DO1107) on NFS lands is eligible for the NRHP and cannot be avoided. Pacific Connector produced a treatment plan to mitigate adverse effects at 35DO1107, which the Forest Service found acceptable.

The Klamath Project, managed by Reclamation, is eligible for the NRHP. The Pacific Connector pipeline route would cross 16 irrigation features associated with the Klamath Project. Pacific Connector proposes to bore under the Klamath Project canals. However, neither Reclamation nor the SHPO have commented to date on this method of reducing impacts on the canals.

4.11.4 Unanticipated Discovery Plans

Jordan Cove included a draft UDP (August 2017) as Appendix B.4 in Resource Report 4 of its September 2017 application to the FERC in Docket No. CP17-495-000. Jordan Cove has stated that it developed its UDP in communications with certain Indian tribes (see appendix L). The Oregon SHPO, as well as the CTCLUSI, Coquille Tribe, Grand Ronde Tribes, and Klamath Tribes, provided Jordan Cove with comments on the plan, and Jordan Cove indicated that it would address those comments.

Pacific Connector included a copy of its August 2017 draft UDP as Appendix B.4 of Resource Report 4, attached to its September 2017 application to the FERC and as an appendix to the draft HPMP submitted in October 2018 in response to a request by the FERC staff. Pacific Connector has indicated that the CTCLUSI, Coquille Tribe, and the Klamath Tribes commented on the draft UDP. Review of the draft UDP by the SHPO has not yet been completed.

A May 7, 2019 version of the UDP was filed by Jordon Cove and Pacific Connector with the FERC on September 18, 2019.[235] Jordan Cove and Pacific Connector continue to solicit feedback from tribes and cooperating agencies on an individual basis and through the Cultural Resources Working Group. We cannot find the UDPs acceptable until we see final versions that address comments from Indian tribes, cooperating federal agencies, and the SHPO.

4.11.5 Compliance with the NHPA

We have not yet completed the process of complying with the NHPA. Additional consultations, investigations, and/or plans remain necessary.

On April 4, 2018, the Applicants filed a first draft Ethnographic Report (Deur 2018). The FERC staff, in environmental information requests dated May 4 and October 23, 2018, requested that the Applicants revise the Ethnographic Report to provide additional information about TCPs, HPRCS, and traditional resources and use areas within the APE. In a filing on November 2, 2018, the Applicants declined to revise the Ethnographic Report, claiming that it is not required for purposes of compliance with Section 106 of the NHPA. The regulations for implementing Section 106 at 36 CFR 800.2(c)(2)(ii) require consultations with Indian tribes to identify sites of religious and

[235] As part of the revised POD.

cultural importance to tribes, in keeping with Section 101(d)(6) of the NHPA. Further, section 6.1 (8) of the FERC staff's guidelines (FERC 2017) directs applicants to produce and file an "ethnographic analysis to identify any living Native American groups or other groups with ties to the project area to identify properties of traditional, religious, or cultural importance to Tribes and other groups." In addition, several interested Indian tribes requested the additional data we asked for in the ethnographic study revision. Below, we have included in our recommended cultural resources environmental condition that a revised Ethnographic Report be filed prior to construction, for the review of the FERC staff, SHPO, cooperating federal land-managing agencies, and interested Indian tribes. The ethnographic study has also been included as a stipulation of the MOA.

For the Jordan Cove LNG Project, the planned Lagoon, Panhandle, and North Bank habitat mitigation sites, and the Rock Apron in Coos Bay still require surveys. Additional geoarchaeological deep testing may be conducted in high probably areas at the terminal. Jordan Cove indicated it would conduct archaeological testing at site 35CS227. Jordan Cove's consultants recommended that construction be monitored by qualified professional archaeologists in the vicinity of sites 35CS221 and 35CS227 at the Ingram Yard and South Dune areas, respectively; and at site BAC-2014-1 near the intersection of Highway 101 with the North Spit Causeway. Monitoring of construction was also recommended at the Boxcar Hill staging area, Roseburg Forest Products staging area, and Port Laydown Site; the crossing of Jordan Cove Road; and APCO sites.

For the Pacific Connector Pipeline Project, as of December 2018, about 20 miles of pipeline route (totaling about 796 acres), 41 workspaces (totaling about 28 acres), 17 yards, and rock source and disposal sites (totaling about 211 acres), and about 148 access roads (totaling about 83 miles) remain unsurveyed. Surveys have not yet been conducted at the following five locations in the indirect APE: 1) east of Haynes Inlet (MP 5.5R); 2) west side of Kentuck Slough (MP 6.3R); 3) 13674 Sitkum Lane, Myrtle Point (MP 29.5); 4) near Dora Cemetery (MP 29.5): and 5) 2378 Upper Camas Road, Camas Valley (MP 49.5). Aboveground facilities that have not yet been surveyed are MLV #2, MLV #9, and the Harness Mountain Communication Tower. Where access has been denied, Pacific Connector would need a Certificate from the Commission in order to use eminent domain to conduct remaining surveys and other investigations. Additional deep testing remains to be conducted at the pipeline crossings of the Coos River, South Umpqua/I-5, and Rogue River.

Fifty-four unevaluated sites along the Pacific Connector Project pipeline route were recommended for additional work, either survey and/or testing, prior to our being able to determine their eligibility for the NRHP (see table L-12 in appendix L). We and the SHPO agree that 20 sites along the pipeline route are eligible for the NRHP and require treatment because they cannot be avoided (see table L-12 in appendix L).

To resolve adverse effects at affected historic properties, the FERC staff is producing a MOA for the current undertaking, to be circulated among the consulting parties. The MOA will stipulate that the treatment plans should be implemented, with the written permission of the FERC and federal land-managing agencies, as applicable. It will also allow for phased surveys and testing investigations.

To ensure that the Commission's responsibilities under the NHPA and its implementing regulations are met, **we recommend that:**

Jordan Cove and Pacific Connector should not begin construction of facilities and/or use any staging, storage, or temporary work areas and new or to-be-improved access roads until:

a. **Jordan Cove and Pacific Connector each file with the Secretary:**

   1. **remaining cultural resources inventory reports for areas not previously surveyed;**
   2. **site evaluations and monitoring reports, as necessary;**
   3. **a revised Ethnographic Study Report that addresses the items outlined in staff's May 4 and October 23, 2018 environmental information requests;**
   4. **final HPMPs for both Projects with avoidance plans;**
   5. **final UDP; and**
   6. **comments on the cultural resources reports, studies, and plans from the SHPO, applicable federal land managing agencies, and interested Indian tribes.**

b. **FERC staff produces an MOA and affords the ACHP an opportunity to comment on the undertaking; and**

c. **FERC staff reviews and the Director of OEP approves all cultural resources reports, studies, and plans and notifies Jordan Cove and Pacific Connector in writing that treatment plans may be implemented and/or construction may proceed.**

All materials filed with the Commission containing location, character, and ownership information about cultural resources must have the cover and any relevant pages therein clearly labeled in bold lettering: "CUI//PRIV - DO NOT RELEASE."

4.11.6 Conclusion

We have not yet completed the process of complying with the NHPA. Additional cultural resource inventories, evaluations, and associated reports are to be completed, as well as a final ethnographic study, HPMP, and UDP. Consultations with tribes, SHPO, and applicable federal land-managing agencies have also not been concluded. Constructing and operating the Project would have adverse effects on historic properties under Section 106 of the NHPA. However, an MOA is being developed with the goal of resolving adverse effects on historic properties. The execution of an MOA and the implementation of associated treatment plans would take into account the effects of the undertaking and conclude the Section 106 process.

4.12 AIR QUALITY AND NOISE

4.12.1 Air Quality

Construction and operation of the proposed Project would affect local and regional air quality. The term "air quality" refers to relative concentrations of pollutants in the ambient air. The subsections below summarize applicable federal and state air quality regulations and describe well-established air quality concepts that are applied to characterize air quality and to determine the significance of increases in air pollution. This includes metrics for specific air pollutants known as ambient air quality standards (AAQS), regional designations to manage air quality known as Air Quality Control Regions (AQCRs), and efforts to monitor ambient air concentrations.

Air quality impacts are spatially dependent, and therefore, this section is divided into subsections as follows:

- Impacts in the Coos Bay area associated with the Jordan Cove LNG Project and marine vessels on the waterway are discussed in section 4.12.1.3.
- Impacts associated with the Pacific Connector pipeline—for which the key air pollution sources are emissions from construction and operation of the compressor station in Klamath County—are discussed in section 4.12.1.4.
- Environmental consequences on federal lands are summarized in section 4.12.1.5.

4.12.1.1 Regulatory Setting

Regulatory requirements for air quality—aside from the requirement that the overall project not contribute to a degradation in air quality that results in an exceedance of the NAAQS—depend upon the equipment that is proposed to be constructed and the associated emissions. Sources of air pollution at the Jordan Cove LNG Project and in the associated waterway include the following:

- five direct-drive combined cycle combustion turbines, each rated at 524.1 million Btu per hour (MMBtu/hr), to power refrigeration compressors;
- one thermal oxidizer, rated at 110 MMBtu/hr for the gas conditioning system;
- one auxiliary boiler rated at 296.2 MMBtu/hr;
- one enclosed marine flare rated at 0.74 MMBtu/hr;
- one multipoint ground flare rated at 2.13 MMBtu/hr;
- two diesel black-start engines each rated at 4,376 hp;
- two backup engines each rated at 1,073 hp;
- three fire water pump engines each rated at 700 hp;
- two 160,000 cubic meters (m3) capacity LNG storage tanks;
- fugitive emission sources (valves, flanges, and other equipment); and
- LNG carriers and support vessels.

Regulatory requirements for air quality applicable to the Pacific Connector Pipeline Project depend in part upon the equipment that is proposed to be installed at the compressor station and the associated emissions. Sources of air pollution at the compressor station would include:

- three General Electric PGT25/DLE 1.5 natural gas–fired combustion turbines, each with a maximum site rating of 28,290 hp, and a maximum heat input rate of 194.7 MMBtu/hr at 0°F (the air permit would limit operation to only two turbines at a time; the third is solely for reliability to maintain maximum throughput for the pipeline at times when one of the two operating units is offline for maintenance);

- one 6.28 MMBtu/hr gas-fired hot water boiler;
- one 1,090 kilowatt (kW) natural gas–fired spark-ignition standby generator, limited to no more than 100 hours per year of operation; and
- ancillary activities (fugitive venting, blowdowns, and condensate tank).

Air emission sources for the Jordan Cove LNG Project and the Pacific Connector Pipeline Project are regulated at the federal and state level. Applicable federal and state air quality regulations are summarized below.

Federal and International Air Quality Requirements

Applicable and potentially applicable federal air quality regulations include:

- New Source Review (NSR)/Prevention of Significant Deterioration (PSD) preconstruction permit requirements;
- General Conformity;
- Title V Operating Permit requirements;
- New Source Performance Standards;
- National Emissions Standards for Hazardous Air Pollutants (HAP);
- Chemical Accident Prevention; and
- Mobile Source Regulations.

NSR/PSD Preconstruction Permit Requirements

The federal NSR preconstruction permit program is administered by ODEQ under OAR 340-224 and includes two components: Nonattainment NSR (NNSR), which applies to "major" stationary sources located in nonattainment areas, and NSR/PSD, which applies to "major" stationary sources located in attainment or unclassifiable areas. Because existing air quality is classified as "attainment" or "unclassifiable" for all NAAQS pollutants, only NSR/PSD regulations are applicable to the Jordan Cove LNG Project. The Jordan Cove LNG Project as originally designed was considered a "major" PSD source, and a PSD permit application was submitted to ODEQ in March 2013. However, the current Project design no longer includes the previously proposed South Dunes Power Plant facility, and as a result it no longer qualifies as a major PSD source. A Type B state-only NSR application was submitted to ODEQ in September 2017 for the Jordan Cove LNG Project and in May 2015 for the Pacific Connector Pipeline Klamath Compressor Station.

Criteria pollutant emissions from the Pacific Connector Pipeline Project compressor station would be well below major source thresholds. Although GHGs are above previously identified major source thresholds, the Supreme Court made a ruling on June 23, 2014 (*Utility Air Regulatory Group [UARG] v. EPA [No. 12-1146])* that effectively disallowed the triggering of NSR/PSD based on the significance of GHG emissions alone. Therefore, the Pacific Connector Pipeline Project is not expected to trigger the federal reporting requirements of NSR/PSD.

TABLE 4.12.1.3-1

Estimated Emissions from Terminal Construction Activities, By Year (tons)

Year	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	HAP	GHG (as CO_2e)
Year 1	120	351	0.35	23	268	39	7.4	53,397
Year 2	184	404	0.43	32	310	100	11.0	66,708
Year 3	199	269	0.33	31	192	87	11.3	52,768
Year 4	81	43	0.08	10	18	17	3.7	13,615
Year 5 (plus commissioning emissions)	85	72	20.94	71	209	68	4.1	925,856
Total	**669**	**1,139**	**22.13**	**167**	**997**	**311**	**37.5**	**1,112,344**

To mitigate construction-related emissions, all construction equipment would be maintained in accordance with manufacturers' recommendations and engine idling time would be minimized. As required by federal regulations, construction equipment would combust diesel fuel with no more than 0.0015 percent sulfur, and vessels would combust fuel that complies with International Convention for the Prevention of Pollution from Ships and EPA standards for sulfur content. Additionally, Jordan Cove would implement the following measures to mitigate construction emissions from mobile and temporary stationary sources:

- reduce use, trips, and unnecessary idling of heavy equipment.
- maintain and tune engines per manufacturer's specifications to perform EPA certification levels, where applicable, and to perform at verified standards applicable to retrofit technologies. Employ periodic, unscheduled inspections to limit unnecessary idling and to ensure that construction equipment is properly maintained, tuned, and modified consistent with established specifications.
- prohibit any tampering with engines and require continuing adherence to manufacturer's recommendations.
- use construction equipment engines that incorporate modern pollution control technology. If practicable, lease new, clean equipment meeting the most stringent of applicable federal or state standards.

To mitigate fugitive dust emissions during construction, Jordan Cove would spray water or use dust suppressants on disturbed soil and access roads. The frequency and methodology of dust suppression would depend on the specific construction activities, terrain, soil conditions, and weather conditions. Additionally, Jordan Cove would implement the following measures to mitigate construction emissions due to fugitive dust:

- use of large off-road equipment for excavation and hauling operations to complete the work in the shortest time and least number of trips;
- stabilization of open storage piles and disturbed areas by covering and/or applying water or chemical/organic dust palliative where appropriate. This applies to both inactive and active sites, during workdays, weekends, holidays, and windy conditions. Installing wind fencing, and phase grading operations, where appropriate, and operate water trucks for stabilization of surfaces under windy conditions;
- pre-wetting of material before excavation in selected areas;
- use of wheel-washing stations to prevent track out of materials onto public roads;

- use of street sweepers to clean any materials inadvertently tracked onto public roads near the project site; and
- when hauling material and operating non-earthmoving equipment, prevent spillage by covering loads, limiting fill height in trucks, and training operators in the proper hauling and loading of material.

The effect of construction emissions on ambient air quality would vary with time due to the construction schedule, the mobility of the sources, and the variety of emission sources. Fugitive dust and other emissions due to construction activities generally do not pose a significant increase in regional pollutant levels; however, local pollutant levels would increase during the construction period. Based on the duration and scope of construction activities, we determine that construction of the Project would impact local air quality. However, construction emissions would not have a long-term, permanent effect on air quality in the area.

Operational Air Quality Impacts

Operational emissions from the Project include those from the Jordan Cove LNG Project sources, fugitive emissions from evaporative losses, and emissions from the LNG carriers and tugboats (including emissions in the waterway). These emissions are summarized in table 4.12.1.3-2 for routine operation. Commissioning emissions are included in year 5 of the construction emissions in table 4.12.1.3-2.

TABLE 4.12.1.3-2

Estimated Emissions During Operation of the Jordan Cove LNG Project (tons per year)

Source	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	HAP	GHG (as CO_2e)
Combustion Turbines	97.82	81.99	35.19	32.72	112.26	112.26	5.06	1,292,706
Combustion Turbines Startup/Shutdown	0.73	0.23	4.4E-03	0.10	0.11	0.11	6.2E-04	188
Thermal Oxidizer	38.50	63.25	19.84	1.08	3.85	3.85	0.96	622,154
Auxiliary Boiler	1.16	0.96	0.36	0.67	1.3	1.3	0.24	15,193
Firewater Pump Engines	0.80	1.59	2.1E-03	4.5E-02	9.0E-02	9.0E-02	3.6E-03	241
Backup Generator Engines	0.28	3.33	2.5E-03	0.04	0.04	0.04	4.1E-03	278
Black Start Generator Engines	0.21	1.49	8.8E-03	0.09	0.05	0.05	1.5E-02	1,002
Flares	3.90	0.86	3.9E-02	8.31	0.38	0.38	4.3E-02	2,177
Gas-Up	9.5	2.09	0.16	17.53	1.12	1.12	3.8E-02	4,351
Fugitive Emissions	0	0	0	7.98	0	0	1.77	13,116
Aggregate Insignificant Emissions	1.0	1.0	1.0	1.0	1.0	1.0	--	--
LNG Carriers a/	37.33	52.75	10.05	9.84	3.50	3.50	--	16,479
Tugs	17.68	9.51	2.6	1.00	0.32	0.32	--	3,736
Total	**208.91**	**219.05**	**69.26**	**80.41**	**124.02**	**124.02**	**8.13**	**1,971,621**

a/ Values are based on 120 vessel calls per year, assuming worst-case emissions (i.e., vessel type with the highest emissions) for each pollutant. Emissions estimated at the state seaward boundary (i.e. 3.0 nautical miles from the Oregon coastline).

Commissioning and Start-Up Emissions: Commissioning of the Jordan Cove LNG Project is planned to occur during year 5 of construction. Table 4.12.1.3-2 includes estimated commissioning and operating emissions from all of the terminal stationary sources in year 5, including compressor turbines and duct burners, startup/shutdown emissions, auxiliary boiler, thermal oxidizer, flares, emergency engines, and fugitive emissions.

TABLE 4.12.1.4-1

Estimated Emissions from Construction of the Klamath Compressor Station and Pacific Connector Pipeline (tons)

Source	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	HAP	GHG (as CO_2e)
Compressor Station – Fugitive Dust on Unpaved Roads	0	0	0	0	4.67	0.47	0	0
Compressor Station – Fugitive Dust from Materials Handling	0	0	0	0	2.04	2.04	0	0
Compressor Station – Construction Equipment Exhaust	1.48	1.52	0.07	0.29	0.21	0.20	0.22	378
Pipeline – Fugitive Dust from Materials Handling	0	0	0	0	146.32	146.32	0	0
Pipeline – Fugitive Dust from Roads	0	0	0	0	123.45	12.55	0	0
Timber Removal – Fugitive Dust from Roads	0	0	0	0	30.92	3.22	0	0
Pipeline (Spread 1) – Construction Equipment Exhaust	12.96	35.39	2.39	4.40	4.36	4.23	3.66	14,342
Pipeline (Spread 2) – Construction Equipment Exhaust	12.60	32.82	2.18	4.06	3.99	3.87	3.37	13,099
Pipeline (Spread 3) – Construction Equipment Exhaust	10.58	25.77	1.64	3.10	3.02	2.93	2.56	9,784
Pipeline (Spread 4) – Construction Equipment Exhaust	9.10	23.56	1.52	2.79	2.82	2.73	2.34	9,082
Pipeline (Spread 5) – Construction Equipment Exhaust	8.06	20.11	1.33	2.50	2.46	2.39	2.09	8,003
Total	**54.78**	**139.17**	**9.13**	**17.14**	**324.26**	**180.95**	**14.24**	**54,688**

Emissions from construction equipment have been reduced over time as a result of the federal regulations for mobile engines and fuels, and measures would be taken by Pacific Connector to minimize fugitive dust. The predominant source of PM is fugitive dust (for which emissions estimation procedures have typically largely over-predicted emissions compared to what is seen in ambient measurements) (Watson and Chow 2000; Countess Environmental 2001). Pacific Connector would implement the following measures to mitigate the air emissions during pipeline construction:

Fugitive Dust Source Controls:

- Limit drop heights of soil excavation activities.
- Water the right-of-way, laydown areas, and temporary roads at least daily in areas of active construction, if necessary.
- Control project-related traffic speeds on dirt access roads and on linear facility rights-of-way.
- Ensure that speeds on the construction right-of-way would not exceed 15 mph where fugitive dust can be generated.
- Water gravel or dirt access roads in areas of heavy traffic, as determined necessary to control fugitive dust.
- Decrease speed limits when excessive winds prevail and where sensitive areas such as public roads may be adjacent to access roads or the right-of-way.
- Maintain speed limit signs for the duration of the construction activities and place them where access roads intersect the construction right-of-way.
- Water temporarily stockpiled soils to create a semi-hard protective layer to minimize wind erosion, if necessary.

Operation Air Quality Impacts

Emissions of criteria pollutants from operation of the compressor station and pipeline are shown in table 4.12.1.4-2. Most of the emissions result from fuel combustion in the compressor station turbines, boiler, and standby generator. Fugitive emissions result from the normal leakage of small amounts of methane, VOC, and HAP compounds from valves, flanges, and other components in the compressor station piping, as well as meter stations or valve sites along the pipeline. Venting emissions result from infrequent process upsets and planned maintenance activities.

TABLE 4.12.1.4-2

Criteria Pollutant Emissions from Operation of Klamath Compressor Station and Pacific Connector Pipeline (tons per year)

Source	CO	NO_x	SO_2	VOC	PM_{10}	$PM_{2.5}$	HAPs	GHGs (as CO_2e)
Compressor Station Turbines a/	146.4	144.6	8.7	9.9	17.1	17.1	2.88	379,251
Compressor Station Fugitive Emissions	0	0	0	7.3	0	0	0.27	10,307
Boiler a/	2.7	1.6	0.02	0.18	0.25	0.25	0.06	3,912
Generator	0.6	0.3	0.00	0.2	0.01	0.00	0.04	88
Pipeline Fugitive and Venting Emissions	0	0	0	1.01	0	0	--	162
Total	**149.7**	**146.5**	**8.72**	**18.59**	**17.36**	**17.35**	**3.25**	**393,720**

a/ Based on maximum potential emissions for all three turbines and boiler operating continuously at their rated capacities, with the exception that turbine operation at temperatures below 0 degrees Fahrenheit is excluded. This value corresponds to the potential-to-emit (PTE) for the Project based on the permitted number of turbines.

Routine Operation: The following compressor station and pipeline sources are expected to operate continuously during routine operation:

- three combustion turbines for the compressor drives;
- one boiler;
- compressor station fugitive emission sources (condensate tank, valves, flanges, and other equipment); and
- pipeline fugitive emission sources (valves, flanges, and other equipment at three meter and regulator stations).

Intermittent Operation: The following sources or activities would only operate intermittently, during startup or shutdown events, planned maintenance, process upsets, readiness testing, or emergency situations:

- one standby generator engine; and
- periodic venting and blowdown events, estimated at three major blowdown events per year.

The compressor station would remain below PSD major source thresholds for emissions of all criteria pollutants, HAP, and GHG, but would be a Title V major source for emissions of NO_x and CO. Pacific Connector submitted a standard ACDP initial application to ODEQ in May 2015 and submitted a modification to its standard ACDP application in September 2017.

Potential emissions of HAP from the turbines, boiler, and generator are estimated to be just 1.3 TPY. Potential emissions of four pollutants at the Klamath Compressor Station (NO_x, CO, PM_{10}, and $PM_{2.5}$) exceed the Significant Emission Rate threshold at OAR 340-200-0020 and require a inspection criteria are required. This may include many different types of assessment tools that provide specific types of information about the condition of the pipeline.

The Klamath Compressor Station would also be equipped with automatic emergency detection and shut down systems. For example, the station would have hazardous gas and fire detection systems, and an emergency shutdown system. These safety and emergency systems would be tested routinely to ensure they are operating properly. The emergency shutdown system would be designed to shut down and isolate elements of the compressor station in the event of a fire, before the development of a flammable mixture of gas could occur. The system would include sensors for detecting natural gas concentrations as well as ultraviolet sensors for detecting flames. Additionally, the compressor station equipment would be designed to shut down automatically if a mechanical failure poses risk to the equipment or otherwise constitutes a hazard. The compressor station would be equipped with relief valves to protect the piping from over pressurization and would be equipped with a blowdown system that can safely and rapidly depressurize part or all of the compressor station to a safe location.

Personnel would be able to respond to a compressor station emergency in 60 minutes or less during non-scheduled work hours and within a few minutes if they are at the compressor station. Personnel would be on call at all times, 24 hours a day, 365 days a year to respond to emergencies. Emergencies while the compressor station is unattended would be monitored remotely via Pacific Connector's gas control facility. Personnel living within a 30-minute travel time of the compressor station would be dispatched by the gas control facility in the event of an emergency at the compressor station.

Personnel would be Operator Qualified per USDOT PHMSA requirements for operational and emergency situations at the station. Fire protection, first aid, and safety equipment would be maintained at the compressor station, and personnel would be trained in first aid and proper equipment use.

The Pacific Connector pipeline would cross areas subject to ongoing and future land management activities on federal lands managed by BLM, Forest Service, and Reclamation. Pacific Connector would be required to prepare a POD for activities on these federal lands that also addresses other safety and reliability measures requested by the BLM, Forest Service, and Reclamation. The BLM, Forest Service, and Reclamation would review and approve draft plans to ensure all safety concerns associated with construction and operation of the proposed Pacific Connector pipeline on federally managed lands are addressed.

Pipeline Standards to Minimize Fire Risk to Forest Lands

The Pacific Connector pipeline would be in areas where forest fires could occur. Pacific Connector proposes to meet or exceed USDOT pipeline burial depth requirements (found in 49 CFR Part 192) and would install the Pacific Connector pipeline with at least 36 inches of cover in Class I locations with normal soils and at least 24 inches of cover in consolidated rock areas.

Pursuant to 49 CFR §192.615, each pipeline operator must also develop an ERP that includes procedures to minimize the hazards in the event of a natural gas pipeline emergency. The key elements of the required plan include establishing and maintaining communications with local fire officials and coordinating emergency response, emergency shutdown of the system and safe restoration of service, making personnel, equipment, tools, and materials available at the scene of

Pipeline Operation

During pipeline operation Pacific Connector would comply with the USDOT pipeline safety standards as well as regular monitoring and testing of the pipeline. While pipeline failures are rare, the potential for pipeline systems to rupture and the risk to nearby residents is discussed below.

The serious incidents data summarized in table 4.13.2.3-1 include pipeline failures of all magnitudes with widely varying consequences. Table 4.13.2.3-1 presents the average annual injuries and fatalities that occurred on natural gas transmission lines in the 5-year period between 2013 and 2017.

TABLE 4.13.2.3-1

Injuries and Fatalities – Natural Gas Transmission Pipelines

Year	Injuries	Fatalities
2013	2	0
2014	1	1
2015	16	6
2016	3	3
2017	3	3

The majority of fatalities from pipelines are due to local distribution pipelines not regulated by the FERC. These are natural gas pipelines that distribute natural gas to homes and businesses after transportation through interstate natural gas transmission pipelines. In general, these distribution lines are smaller diameter pipes and/or plastic pipes which are more susceptible to damage. Local distribution systems do not have large rights-of-way and pipeline markers common to the FERC-regulated natural gas transmission pipelines.

The nationwide totals of accidental fatalities from various anthropogenic and natural hazards are listed in table 4.13.2.3-2 to provide a relative measure of the industry-wide safety of natural gas transmission pipelines. Direct comparisons between accident categories should be made cautiously, however, because individual exposures to hazards are not uniform among all categories. The data nonetheless indicate a low risk of death due to incidents involving natural gas transmission pipelines compared to the other categories. Furthermore, the fatality rate is much lower than the fatalities from natural hazards such as lightning, tornados, or floods.

finally to connecting the towlines and de-berthing. Based on our air quality analysis, operational cumulative impacts associated with the Jordan Cove LNG Project are expected to be minor.

Operation of the Pacific Connector Pipeline Project would have long-term effects on air quality due to emissions from the Klamath Compressor Station. The compressor station would be located in an attainment area for the NAAQS. The compressor station emissions would be below the General Conformity *de minimis* thresholds; therefore, the compressor station would not significantly impact nonattainment or maintenance areas.

Pacific Connector would require an Air Contaminant Discharge Permit from the ODEQ to construct the Klamath Compressor Station and a Title V Operating Permit to operate the compressor station. The permits for this facility would include mitigation measures and operational requirements to ensure that air emissions do not exceed the permit requirements and that the facilities would be operated in compliance with applicable air quality regulations.

Pacific Connector completed air quality modeling for the operational emissions of the Klamath Compressor Station. The results of the air quality modeling are summarized in section 4.12 and provide the estimated facility air quality impacts combined with background air quality concentrations for NO_2, CO_2, PM_{10}, $PM_{2.5}$, and SO_2, and include existing operating air emission sources. Based on this analysis, the operation of Klamath Compressor Station would not result in an exceedance of any of the NAAQS. No projects were identified within the geographic scope of the Klamath Compressor Station that would result in operational air quality impacts. Therefore, the Project would not result in cumulative impacts on air quality from the operation of the Pacific Connector Pipeline Project.

Climate Change and Greenhouse Gas Emissions

Climate change is the variation in climate (including temperature, precipitation, humidity, wind, and other meteorological variables) over time, whether due to natural variability, human activities, or a combination of both, and cannot be characterized by an individual event or anomalous weather pattern. For example, a severe drought or abnormally hot summer in a particular region is not a certain indication of climate change. However, a series of severe droughts or hot summers that statistically alter the trend in average precipitation or temperature over decades may indicate climate change. Recent research has begun to attribute certain extreme weather events to climate change (USGCRP 2018).

The leading U.S. scientific body on climate change is the U.S. Global Change Research Program (USGCRP), composed of representatives from thirteen federal departments and agencies.[278] The Global Change Research Act of 1990 requires the USGCRP to submit a report to the President and Congress no less than every four years that “1) integrates, evaluates, and interprets the findings of the Program; 2) analyzes the effects of global change on the natural environment, agriculture, energy production and use, land and water resources, transportation, human health and welfare, human social systems, and biological diversity; and 3) analyzes current trends in global change,

[278] The USGCRP member agencies are: Department of Agriculture, Department of Commerce, Department of Defense, Department of Energy, Department of Health and Human Services, Department of the Interior, Department of State, Department of Transportation, Environmental Protection Agency, National Aeronautics and Space Administration, National Science Foundation, Smithsonian Institution, and U.S. Agency for International Development.

both human induced and natural, and projects major trends for the subsequent 25 to 100 years." These reports describe the state of the science relating to climate change and the effects of climate change on different regions of the U.S. and on various societal and environmental sectors, such as water resources, agriculture, energy use, and human health.

In 2017 and 2018, the USGCRP issued its *Climate Science Special Report: Fourth National Climate Assessment*, Volumes I and II (Fourth Assessment Report) (USGCRP, 2017; and USGCRP, 2018, respectively). The Fourth Assessment Report states that climate change has resulted in a wide range of impacts across every region of the country. Those impacts extend beyond atmospheric climate change alone and include changes to water resources, transportation, agriculture, ecosystems, and human health. The U.S. and the world are warming; global sea level is rising and acidifying; and certain weather events are becoming more frequent and more severe. These changes are driven by accumulation of GHG in the atmosphere through combustion of fossil fuels (coal, petroleum, and natural gas), combined with agriculture, clearing of forests, and other natural sources. These impacts have accelerated throughout the end 20th and into the 21st century (USGCRP 2018).

GHGs were identified by the EPA as pollutants in the context of climate change. GHG emission do not cause local impacts, it is the combined concentration in the atmosphere that causes global climate and these are fundamentally global impacts that feedback to localized climate change impacts. Thus, the geographic scope for cumulative analysis of GHG emissions is global rather than local or regional. For example, a project 1 mile away emitting 1 ton of GHGs would contribute to climate change in a similar manner as a project 2,000 miles distant also emitting 1 ton of GHGs.

Climate change is a global phenomenon; however, for this analysis, we will focus on the existing and potential cumulative climate change impacts in the Project area. The USGCRP's Fourth Assessment Report notes the following observations of environmental impacts are attributed to climate change in the Northwest region (USGCRP, 2017; USGCRP, 2018):

- the region has warmed nearly 2°F since 1900;
- warmer winters have led to reductions in mountain snowpack, resulting in drought, water scarcity, and large wildfires;
- declines in dissolved oxygen in streams and lakes have caused fish kills and loss of aquatic species diversity; and
- moderate to severe spring and summer drought areas have increased 12 percent to 14 percent.

The USGCRP's Fourth Assessment Report notes the following projections of climate change impacts in the Project region with a high or very high level of confidence[279] (USGCRP, 2018):

[279] The report authors assessed current scientific understanding of climate change based on available scientific literature. Each "Key Finding" listed in the report is accompanied by a confidence statement indicating the consistency of evidence or the consistency of model projections. A high level of confidence results from "moderate evidence (several sources, some consistency, methods vary and/or documentation limited, etc.), medium consensus." A *very* high level of confidence results from "strong evidence (established theory, multiple sources, consistent results, well documented and accepted methods, etc.), high consensus." https://science2017.globalchange.gov/chapter/front-matter-guide/

- increases in stream temperature indicate a 22 percent reduction in salmon habitat by the late 20th century;
- more frequent severe winter storms, which may contribute to storm surge, large waves, coastal erosion, and flooding in low-lying coastal areas;
- the warming trend is projected to be accentuated in certain mountain areas in the Northwest in late winter and spring, further exacerbating snowpack loss and increasing the risk for insect infestations and wildfires;
- longer periods of time between rainfall events may lead to declines in recharge of groundwater and decreased water availability, and responses to decreased water availability, such as increased groundwater pumping, may lead to stress or depletion of aquifers and strain on surface water sources; and
- increases in evaporation and plant water loss rates may alter the balance of runoff and groundwater recharge, which would likely to lead to saltwater intrusion into shallow aquifers.

It should be noted that while the impacts described above taken individually may be manageable for certain communities, the impacts of compound extreme events (such as simultaneous heat and drought, wildfires associated with hot and dry conditions, or flooding associated with high precipitation on top of saturated soils) can be greater than the sum of the parts (USGCRP 2018).

The GHG emissions associated with construction and operation of the Project are identified in section 4.12.1.1 for the Jordan Cove LNG Project and section 4.12.1.2 for the Pacific Connector Klamath Compressor Station and pipeline. Both the Jordan Cove LNG Project and the Pacific Connector Klamath Compressor Station and pipeline would remain below PSD major source thresholds and are therefore not required to conduct a Best Available Control Technology analysis for mitigating GHG emissions. The construction and operation of the Project would increase the atmospheric concentration of GHGs, in combination with past, current, and future emissions from all other sources globally and contribute incrementally to future climate change impacts. Project emissions would contribute incrementally to future climate change impacts.

Currently, there is no universally accepted methodology to attribute discrete, quantifiable, physical effects on the environment to the Project's incremental contribution to GHGs. We have looked at atmospheric modeling used by the EPA, National Aeronautics and Space Administration, the Intergovernmental Panel on Climate Change, and others and we found that these models are not reasonable for project-level analysis for a number of reasons. For example, these global models are not suited to determine the incremental impact of individual projects, due to both scale and overwhelming complexity. We also reviewed simpler models and mathematical techniques to determine global physical effects caused by GHG emissions, such as increases in global atmospheric CO_2 concentrations, atmospheric forcing, or ocean CO_2 absorption. We could not identify a reliable, less complex model for this task and we are not aware of a tool to meaningfully attribute specific increases in global CO_2 concentrations, heat forcing, or similar global impacts on project-specific GHG emissions. Similarly, it is not currently possible to determine localized or regional impacts from GHG emissions from the Project. Absent such a method for relating GHG emissions to specific resource impacts, we are not able to assess potential GHG-related impacts attributable to this Project. Without the ability to determine discrete resource impacts, we are unable to determine the significance of the Project's contribution to climate change.

We have not been able to find any GHG emission reduction goals established at the federal level.[280] The State of Oregon has set GHG reduction goals with a state-wide target of 51 million metric tons of CO_2e by 2020 (a 10 percent reduction from 1990 levels), and 14 million metric tons of CO_2e by 2050 (a 75 percent reduction from 1990 levels) (Oregon Global Warming Commission 2017). The Oregon Global Warming Commission projects that Oregon will fall short of these goals without additional legislative action. Direct emissions from the Jordan Cove LNG and Pacific Connector Pipeline Projects would result in annual CO_2e emissions of about 2.14 million metric tons of CO_2e, which would represent 4.2 percent and 15.3 percent of Oregon's 2020 and 2050 GHG goals, respectively.

Noise

The Project would involve various types of equipment and activities, including pile driving, dredging, and drilling. In the Coos Bay area, these activities would temporarily and significantly increase noise levels. Projects listed in table 4.14-2 that are located within the geographic scope that could contribute to a cumulative noise impact include non-jurisdictional Project facilities, COE Coos Bay Federal Navigation Channel Maintenance Dredging, the Coos Bay, Oregon Section 408/204(f) Channel Modification (which may include blasting), the COE's North Jetty Major Maintenance, Southwest Oregon Regional Airport Expansion, McCullough Bridge Painting Project, various BLM and Forest Service vegetation maintenance projects, and the Klamath Dam Removal. Based on the schedule and proximity of the other projects, there may be some cumulative construction noise impacts. The Coos Bay, Oregon Section 408/204(f) Channel Modification could conduct dredging activities 24 hours per day over a three-year period with most work occurring overnight. The exact schedules of work and levels of noise that would occur from the projects identified in table 4.14-2 is not known. However, because noise impacts resulting from pile-driving activities at the terminal site would be significant in the Coos Bay area, we conclude that the impacts on noise resulting from construction the Project when added to the noise impacts of other projects would result in a temporary, but significant cumulative noise impact in Coos Bay. To reduce the impact of the pile-driving activities and the related cumulative impact, we are recommending additional noise minimization measures be implemented; see section 4.12.

Construction noise along the pipeline would primarily last for short periods and would vary as the equipment moves along the construction spread. The exception would be where the pipeline would be installed by HDD or DP, which would require equipment operating for up to several weeks at the HDD/DP entry and exit locations. To reduce the Project's contribution to a cumulative impact along the pipeline route, Jordan Cove would implement mitigation measures for several activities including selecting low-noise alternative equipment, restricting time of day for construction, installing temporary noise barriers, enclosing equipment, and preparing site-specific noise management plans. The HDD or DP crossing method would be used to cross under six waterbodies and a powerline/steep slope location along the BPA Powerline Corridor. Per our recommendation in section 4.12.2, Pacific Connector would be required to ensure that noise attributable to drilling operations does not exceed an 55 L_{dn} dBA.

Operation of the Jordan Cove LNG Project and Pacific Connector's Klamath Compressor Station would result in long-term increases in noise levels in the vicinity of these aboveground facilities. Noise at the Jordan Cove LNG Project would be associated with refrigerant gas

[280] The EPA's Clean Power Plan which provided national emissions reduction targets were repealed in June 2019.

5.0 CONCLUSIONS AND RECOMMENDATIONS

5.1 CONCLUSIONS OF THE ENVIRONMENTAL ANALYSIS

The conclusions and recommendations presented below are those of the FERC's environmental staff. They were prepared in cooperation with the BLM, Forest Service, Reclamation, DOE, COE, EPA, FWS, NOAA, Coast Guard, USDOT, and Coquille Tribe. However, these agencies may present their own conclusions and recommendations in their respective and applicable records of decision. The cooperating agencies can adopt this final EIS consistent with 40 CFR §1501.3 if, after an independent review of the document, they conclude that their requirements have been satisfied. Otherwise, they may elect to conduct their own supplemental environmental analyses.

Based on our review as described in the preceding sections, we conclude that constructing and operating the Project would result in temporary, long-term, and permanent impacts on the environment and a number of significant environmental impacts; however, a majority of impacts would be less than significant due to the implementation of proposed and recommended impact avoidance, minimization, and mitigation measures. As part of our review we developed measures that would appropriately and reasonably further avoid, reduce, or mitigate environmental impacts resulting from construction and operation of the Project (see section 5.2). Therefore, we recommend that these measures be attached as conditions to any authorizations issued by the Commission.

5.1.1 Geology

The LNG terminal would be located in Coos Bay within the seismically active CSZ. Numerous comments were received by the Commission about the potential affects to the LNG terminal from a tsunami. Recognizing the concern, and as described in the LNG safety and reliability section, Jordan Cove designed the terminal facilities consistent with maximum tsunami run-up elevations and considered tsunami wave heights and inundation elevations; therefore, FERC staff agrees that the equipment elevations that Jordan Cove provided are suitable for the proposed LNG terminal site. We also conclude that the LNG terminal would be able to withstand without damage a storm surge during a 500-year storm event. Although much of the pipeline would be located in the CSZ, we conclude, based on a review of potential impacts, historical data, seismic hazard mapping, peak horizontal ground acceleration values, pipeline tolerances, and Pacific Connector's proposed impact avoidance and minimization measures, that construction and operation of the pipeline facility would not be significantly affected by potential geological hazards including ground shaking, surface ruptures, soil liquefaction and lateral spreading, landslides, and slope failures. Additionally, the pipeline would cross steep slopes and mountain ranges which increases concerns for erosion, landslides, and slope failures. However, we conclude, based on our evaluation of the pipeline facility and Pacific Connector's proposed construction methods including its implementation of erosion control devices and other impact avoidance and minimization measures, that construction and operation of the pipeline would not be significantly affected. To ensure the risk of landslides in five moderate risk areas is further reduced, we are recommending that Pacific Connector file final monitoring protocols and mitigation measures. To ensure areas of potential moderate to high-risk landslides have been fully addressed, we are also recommending that Pacific Connector conduct an additional review of the most recent LiDAR data available from DOGAMI. Furthermore, due to the absence of mining and other mineral extraction activities along the pipeline route, we conclude that these activities would also not be affected.

minimization measures (including implementation of erosion controls, water management plans, hazardous substance management procedure, and construction timing), we conclude that the Project would not result in significant impacts on surface water resources.

5.1.3.3 Wetlands

Constructing and operating the LNG terminal would affect about 86.1 acres of wetlands and result in the loss of about 22.3 acres of wetlands. Constructing and operating the pipeline would temporarily affect about 114.1 acres of wetlands and result in long-term impacts on about 4.9 acres of wetlands.

Jordan Cove and Pacific Connector developed a *Compensatory Wetland Mitigation Plan* to address the COE's regulations and requirements to mitigate unavoidable impacts on wetlands. Impacts on freshwater wetland resources would be mitigated via the Kentuck project site, and impacts on estuarine wetland resources would be mitigated via the Eelgrass Mitigation site and Kentuck project site (see Jordan Cove and Pacific Connector's *Compensatory Wetland Mitigation Plan*). These mitigation plans are still being reviewed by the COE, ODSL, and applicable federal and state agencies. Approval of these mitigation plans by these agencies would be required prior to the issuance of federal and state wetland permits.

Based on our review of the Project and Jordan Cove and Pacific Connector's implementation of measures to reduce impacts on wetlands, we conclude that constructing and operating the Project would not significantly affect wetlands.

5.1.4 Vegetation

Constructing and operating the Project would affect over 4,600 acres of vegetation. Over 2,850 acres of forested vegetation including about 782 acres of LSOG forest would be cleared and experience long-term and permanent impacts. However, with the exception of LSOG forest, most of the vegetation types affected by the Project are common and widespread in the region. The temporary and permanent clearing of vegetation would affect soils, wildlife, and water resources; would result in the creation of forest "edges"; and could increase the introduction and spread of exotic and invasive species. To reduce the impacts of clearing vegetation along the pipeline route, Pacific Connector would implement erosion control and numerous other measures as described in its ECRP, *Fire Prevention and Suppression Plan,* and its *Integrated Pest Management Plan.* Based on the types and amounts of vegetation that would be affected by the Project, the measures that would be implemented to avoid, reduce, and mitigate the resulting impacts, our recommendation for Pacific Connector to develop a final *Integrated Pest Management Plan*, and the abundance of similar vegetation in the affected watersheds, we conclude that constructing and operating the Project would have permanent but not significant impacts on vegetation.

5.1.5 Wildlife and Aquatic Resources

Over 600 species of terrestrial and aquatic wildlife including amphibians, reptiles, birds, fish, and mammals occur in the Project area. Constructing and operating the Project would temporarily and permanently affect these species. Wildlife would avoid and be displaced by construction activities and changes to habitat caused by the Project. Avoidance, displacement, and impacts on other behaviors as well as the loss of habitat would increase the rates of stress, injury, and mortality experienced by wildlife. Furthermore, pile-driving noise resulting from construction of the terminal facilities may adversely affect wildlife depending on their proximity to the terminal and

5.1.11 Cultural Resources

Cultural resource investigations for the Project are currently incomplete. Surveys that have been completed have identified sites in the vicinity that require monitoring during construction or other mitigation prior to construction. Additionally, further survey and/or testing has been recommended for some sites if avoidance cannot be achieved or confirmed by the Project.

The FERC staff and the Applicants have contacted Indian tribes that may attach religious or cultural importance to sites in the APE. We received comments from the CTCLUSI, Coquille, Cow Creek, Grand Ronde, Karuk, Klamath, Tolowa Dee-ni' Nation, Ute Indian Tribe, and Yurok Tribe. The Coquille Tribe is a cooperating agency, while the others have filed motions to intervene. A finalized ethnographic study is in the process of being completed by the Applicants.

We have not yet completed the process of complying with Sections 101 and 106 of the NHPA. Additional cultural resource inventories, evaluations, and associated reports are yet to be completed. Consultations with tribes, SHPO, and applicable federal land-managing agencies have also not been concluded and are ongoing. We are recommending that Jordan Cove and Pacific Connector not construct or use any of their proposed facilities, including related ancillary areas for staging, storage, temporary work areas, and new or to-be-improved access roads, until all studies and consultations necessary to complete compliance with the NHPA have been completed. Constructing and operating the Project would have adverse effects on historic properties under Section 106 of the NHPA. However, an MOA would be developed with the goal of resolving adverse effects on historic properties. Execution of an MOA and the implementation of associated treatment plans would take into account the effects of the undertaking and conclude the Section 106 process.

5.1.12 Air Quality and Noise

5.1.12.1 Air Quality

Air pollutants would be emitted as a result of both construction and operation of LNG marine traffic, the LNG terminal, the Pacific Connector pipeline, and aboveground facilities. During construction, a temporary reduction in ambient air quality may result from emissions and fugitive dust generated by construction equipment. Emissions from construction equipment would be temporary and would not result in a significant impact on regional air quality or result in any exceedance of applicable ambient air quality standards.

The Jordan Cove LNG Project is located in an air attainment area for federal air quality standards. In September 2017, Jordan Cove submitted an air quality permit application to the ODEQ. The Project's Type B state-only NSR permit application demonstrates that applicable requirements have been met. For all pollutants, the impacts at the points of highest concentration during operation of the Jordan Cove facilities are well below the applicable NAAQS and the PSD increments when combined with ambient air quality concentrations.

The Klamath Compressor Station and most of the pipeline route would be located in areas designated as attainment for all federal air quality standards, except for approximately 325 feet of pipeline route that would be located within the Klamath Falls PM_{10} maintenance area. Pacific Connector submitted a standard ACDP initial application to the ODEQ in May 2015, and submitted a revised application in September 2017. For all pollutants, the combined impacts at

Oregon State Agency Comments
Jordan Cove Energy and Pacific Connector Gas Pipeline Project
Draft Environmental Impact Statement
(Docket # CP17-494-000 and CP17-495-000)
December 23, 2019

Introduction

The State of Oregon is currently reviewing the final Environmental Impact Statement ("final EIS" or "FEIS") to ensure it provides a full and fair disclosure of the significant environmental impacts that may result from the siting and operation of the Jordan Cove LNG export terminal facility and the Pacific Connector Pipeline project (hereinafter collectively referred to as, the "Project") as well as the comparative impacts resulting from a reasonable range of alternatives to the proposed action. *See* 40 C.F.R. § 1502.1; *see also* 40 C.F.R. § 1502.1 ("An environmental impact statement is more than a disclosure document. It shall be used by federal officials in conjunction with other relevant material to plan actions and make decisions.").

The State provides these consolidated comments on the behalf of certain agencies that filed comments on the Draft Environmental Impact Statement ("DEIS"). Because the State's review is ongoing, either these agencies, or other agencies who commented on the DEIS but are not included in these consolidated comments on the FEIS, may have additional comments at a later date.

If a State agency has determined that the FEIS adequately addresses a specific DEIS comment made by that agency, the agency will note that in the comments that follow. Otherwise, the State's position is that its consolidated comments on the DEIS, dated July 3, 2019, were either not addressed or inadequately addressed in the FEIS. The State therefore reiterates its consolidated comments on the DEIS except as specifically noted below.

Oregon Department of Fish and Wildlife

Contact: Sarah Reif, Energy Coordinator
Wildlife Division
Sarah.j.reif@state.or.us
503-947-6082

The Oregon Department of Fish and Wildlife (ODFW) submits the following comments on the FERC Final Environmental Impact Statement (FEIS) for the Jordan Cove Energy Project (JCEP) and the Pacific Connector Gas Pipeline (PCGP).

ODFW is statutorily charged with the management of the State of Oregon's fish and wildlife resources (ORS 496.012, ORS 506.109, ORS 509.140, and ORS 509.580 through 509.910). ODFW has an interest in federal actions affecting these resources.

Upon review of the FEIS and the various elements of the associated Comprehensive Mitigation Plan (September 2019). ODFW finds the proposed federal action insufficient in the following ways:

- Inconsistency with ODFW Fish and Wildlife Habitat Mitigation Policy (ORS 496.012 and ORS 506.109; OAR 635-415-0000 to -0025):
    - Proposed impacts to nesting habitats for marbled murrelet and northern spotted owls cannot be mitigated. The plans are inconsistent with the Category 1 mitigation standards of the policy.
    - Documents provide insufficient detail with regard to proposed mitigation actions. Since the project's inception, ODFW has recommended FERC and the federal land management agencies crosswalk the federal land compensatory mitigation plans with the standards in the ODFW mitigation policy to ultimately ensure that fish and wildlife impacts are avoided, minimized, and mitigated. As of the date of this letter, this crosswalk has not been included in the FEIS, and therefore ODFW does not have the information it needs to ensure the project's impacts will be offset to State of Oregon standards.
    - Where information has been provided, ODFW finds the proposed compensatory mitigation for impacts to estuarine environments, wetlands and waterbodies, and uplands does not fully meet the state's standards for offsetting the proposed pipeline's impacts to fish, wildlife, and their habitats.
- Incomplete or missing Fish Passage Plans (ORS 509.580 through 509.910; OAR 635-412-0005 through -0040).
    - At this time, ODFW has received Fish Passage Plans for the portion of the project located in the Coastal Zone Management Area (CZMA), however ODFW has requested additional information from the Applicant in order to finalize those approvals.
    - ODFW has not received fish passge design plans for the rest of the proposed pipeline and its associated infrastructure.
- In-Water Blasting Permit applications (ORS 509.140) have not been submitted to ODFW despite their mention in the FEIS.
- The FERC selection of the Blue Ridge Variation as its Preferred Alternative is inconsistent with the Biological Assessment, which analyzes the Applicant's preferred route. Furthermore, FERC has not obtained Section 7 Consultation from the US Fish and Wildlife Service or National Oceanographic and Atmospheric Adminsitration's (NOAA) Endangered Species Act Section 7 Consultations for the Blue Ridge Variation.

ODFW stands by its original comments on the FERC Draft EIS, which provide greater detail supporting the points raised above. Please continue to refer to the *Oregon State Agency Comments on FERC's Draft Environmental Impact Statement for Docket Nos. CP-17-494-000 and CP17-495-000 dated July 3, 2019*.

ODFW also requests FERC give equal consideration to the comments and recommendations ODFW provided to the BLM on December 20, 2019 in *Oregon Department of Fish and Wildlife Protest of the Bureau of Land Management Proposed Resource Management Plan Amendments: Jordan Cove Natural Gas Liquefaction Terminal and Pacific Connector Gas Pipeline Plan (DOI-ORWA-M000-2017-0007-EIS).*

Please be advised that ODFW intends to submit supplemental comments on this FEIS in the coming weeks. Should you have any questions or require additional information, I am your primary contact for this project and my contact information is provided above.

Oregon Department of Energy

Siting Division

Contact: Sean Mole
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503-934-4005

The FEIS addresses Oregon Department of Energy comments regarding State jurisdictional components of the LNG terminal by asserting that none are proposed. This is factually inaccurate. The applicant still proposes to construct a thermal energy production facility with the capacity to generate more than 25 MW. As proposed, the applicant would still utilize 3 STG's capable of producing 30 MW each. While the updated RR 13 and now FEIS assert that the applicant will purchase power from "the grid" reducing their need for on-site power production, this does not change the jurisdictional nature of the facility which is defined by its **generating capacity** (ORS 469.300(27)). Barring final engineering which describes how the facility will be incapable of generating more than 25 MW, or a fully executed agreement between the applicant and the State establishing that this is the case, Jordan Cove will still require approval from Oregon's Energy Facility Siting Council and will be responsible for meeting Oregon siting standards found in Oregon Revised Statute and Administrative Rules. In addition to other standards, these include Oregon's CO2 emissions standards, the provision of a legally enforceable retirement bond for the project, and a comprehensive discussion of, and preparation for, emergency situations that could endanger humans and the environment from construction and operation activities.

Emergency Preparedness

Contact: Deanna Henry
deanna.henry@oregon.gov
503-032-4429

The Oregon Department of Energy anticipates submitting comments on safety and security issues in the FEIS in the near future. In the interim, the Oregon Department of Energy reiterates the safety and security comments it provided on the DEIS.

Deb Evans, Ron Schaaf, Bill Gow and Evans Schaaf Family, LLC
affected landowners
Comments on Certificate Policy Economic Benefits Test does not meet U.S. Public Interest
CORRECTED COPY with Additional Information and EXHIBITS, particularly pertaining to Point 4
FERC Docket CP17-494-000 and CP17-495-000

January 30, 2020

EFILED: January 30, 2020
Ms. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street N.E.
Washington, D.C. 20426
Re: Pacific Connector Gas Pipeline L.P. Docket No. CP17-494-000
Jordan Cove Energy Project L.P. Docket No. CP17-495-000

Ms. Bose and Federal Energy Regulatory Commissioners,

We are writing to share with you some recent developments that we believe have bearing on the outcome of the economic benefits test and FERC's determination of whether the Jordan Cove LNG terminal (CP17-495-000) and Pacific Connector Gas Pipeline (CP17-494-000) applications should be granted. These comments contain new evidence and are supplemental to our previously submitted comments[1] and pertain to FERC's careful weighing of whether the economics benefit test rises to a declaration that this project is in the public interest. We believe it does not. Additionally, approval of this project would be a direct violation of our constitutional rights as evidenced by new information provided here.

We, Ron Schaaf, Deb Evans, Bill Gow and Evans Schaaf Family, LLC, as directly affected landowner interveners, respectfully ask FERC Commissioners to determine after a public review of the facts, whether a foreign government (Canada) has a "partnership" relationship with Pembina Pipeline Corporation (Pembina), the 100% parent owner of Jordan Cove Energy Project (JCEP) and Pacific Connector Gas Pipeline (PCGP) and other gas producers in Canada regarding the Jordan Cove FERC proceedings. This partnership, reflected in multiple actions including the Aug 29th, 2019 signing of Memorandum of Understanding between the Governments of BC and Canada[2], convey this foreign government's allocation of federal and provincial tax dollars, loans and grants to the private sector directly financially supporting Pembina and gas producers, while their application for public convenience and necessity is being decided by the commission. Landowners assert that this wholly unique set of circumstances, whereby the foreign government is in essence an "applicant" along with Pembina for the conveyance of the use of eminent domain authority over USA sovereign citizens, is unlawful. Landowners further assert that landowners do not have constitutional due process rights in Canada and have no voice in that country's sovereign affairs. We therefore ask FERC commissioners to determine, **prior to** applying the balancing test weighing public benefit versus adverse effects of a FERC decision, the constitutional question as to whether we are being deprived of Life, Liberty and Property with a public convenience and necessity approval.

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[1] Previous comments we've submitted to FERC:
10-3-2017 Landowner Filing - http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20171003-5105
11-7-2017 Landowner Filing - http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20171107-5040
6-1-2018 Landowner Filing - http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20180601-5038
7-5-2019 Landowner Filing - http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20190705-5198

[2] *Memorandum of Understanding between the Government of Canada and the Government of British Columbia on the electrification of the natural gas sector.* August 29, 2019.
https://pm.gc.ca/en/news/backgrounders/2019/08/29/memorandum-understanding-between-government-canada-and-government. [EXHIBIT 1]

when one of the problems Canada is facing is getting permission from indigenous communities and landowners in BC to access their own coast.

According to our records based on recorded easements in each of the four counties, as of January 9, 2020, PCGP has recorded 172 easements out of 268 total unique private and timber company landowners on the FEIS selected Blue Ridge Variation Route, which comes to 64% of the total unique landowners. PCGP has recorded 164 easements out of 248 total unique private and timber company landowners on the Blue Ridge Route, which is 66% of all total unique landowners. This leaves between 84-96 unique landowners, (one third of the total), that do not have a signed and recorded easement agreement with PCGP.

As landowners who understand and agree with the use of eminent domain for roads, schools, etc. that are for a **public use**, we are utterly failing to see how an approval of this project, granting permission for Canada to benefit at the expense of our fellow landowners and fellow citizens, is not a blatant violation of our rights.

Point 4 – When doing the economic benefits there is one more category of "existing customers" that stands to be harmed—Pacific Northwest and California natural gas ratepayers.

The three pillars of FERC's policy statement include making sure new pipelines are not subsidized by existing ratepayers, that they do not unduly harm existing pipelines serving the same market and that they take into account the adverse effects to landowners and communities. This project, as explained previously, is a new pipeline without existing customers. However, the pipelines upstream of Malin, namely the Gas Transmission Northwest (GTN) pipeline on which the gas from Canada would need to travel, could well harm the current customers of that pipeline in Idaho, Washington, Oregon and California as the Western Export Group (WEG)[36], which included many U.S. gas suppliers, argued up in Canada during 2017 and 2018 when the North Montney Mainline expansion was being discussed at Canada's National Energy Board (NEB). The worry was that this new 1.485 Bcfd of capacity that 11 Canadian gas producers were asking for, did not have a final destination after Petronas dropped their proposed Pacific Northwest LNG project, leaving open the possibility that they were planning to send it south to Jordan Cove or other markets.[37] WEG was arguing that existing longtime shippers should not be held responsible for the cost of pipeline expansion that would be needed to move this new volume of gas, and the cost burden should fall to those shippers asking for the needed expansion, especially since there was no certainty provided of a market. NEB agreed.

> When it comes to adding new capacity, it is difficult to achieve consensus on solutions due to competing cost and revenue models. Shippers with market diversification and sufficient (often excess) firm capacity do not need additional capacity and oppose paying for something they do not need. Legacy producers are already cost-challenged and are resistant to paying for service additions

[36] The Western Export Group (WEG) was mentioned in our earlier comments. They are a consortium of US gas suppliers that engaged Canada's National Energy Board (NEB) in 2017 and 2018 over the North Montney Mainline ask by 11 Canadian Gas Producers to ship 1.485 Bcfd of gas potentially south into the United States. The WEG group, which included PGE, Avista and others, was concerned that this approval should not include increased cost to the current firm transportation shippers buying Canadian gas for the US market and instead the new gas producer shippers should have to foot the bill for any expansion needed on the NGTL TC Energy pipelines in Canada. NEB agreed and asked the Canadian producers for a different pay schedule for any expansions required.

[37] North Montney Mainline Project Application for a Variance. March 20, 2017. At Page 11. https://docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90464/90550/554112/915551/1060220/2982347/3338452/3210868/A82147-1_NMML_Variance_Application_-_A5J5W6.pdf?nodeid=3210303&vernum=-2

Oregon

Kate Brown., Governor

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February 5, 2020

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street NE, Room 1A
Washington, D.C. 50426

RE: Oregon Department of Fish and Wildlife Supplemental Comments on FERC's Final Environmental Impact Statement for Docket Nos. 17-494-000 and CP 17-495-000 (Jordan Cove Energy Project LP and Pacific Connector Gas Pipeline LP)

Dear Ms. Bose:

The Oregon Department of Fish and Wildlife (ODFW) submits the following comments as a supplement to its December 23, 2019 letter[1] to the Federal Energy Regulatory Commission (FERC) on the Jordan Cove Energy Project (JCEP) and Pacific Connector Gas Pipeline Project (PCGP) Final Environmental Impact Statement (FEIS; Docket Nos. CP-17-494-000 and CP-17-495-000).

In addition to the comments ODFW provided in its December 23, 2019 letter and herein, ODFW recommends its July 3, 2019[2] comments to FERC regarding the Draft Environmental Impact Statement (DEIS) be considered still relevant and in need of remedy to sufficiently avoid, minimize, and mitigate impacts to the State of Oregon's fish and wildlife resources. Furthermore, ODFW recommends FERC give equal consideration to the comments and recommendations ODFW provided to the Bureau of Land Management on December 20, 2019[3] and to the U.S. Forest Service on January 6, 2020[4].

ODFW is statutorily charged with the management of the State of Oregon's fish and wildlife resources (ORS 496.012, ORS 506.109, ORS 509.140, and ORS 509.580 through 509.910). ODFW has an interest in federal actions affecting these resources. The manner in which the State of Oregon's fish and wildlife resources would be affected by the JCEP/PCGP projects is described in the aforementioned letters, and is discussed in further detail below.

These supplemental comments are focused on the following fish and wildlife resource issues:

[1] *Oregon State Agency Comments on FERC's Jordan Cove Energy and Pacific Connector Gas Pipeline Project Final Environmental Impact Statement (Docket # CP17-494-000 and CP17-495-000) December 23, 2019.*
[2] *Oregon State Agency Comments on FERC's Draft Environmental Impact Statement for Docket Nos. CP-17-494-000 and CP17-495-000 dated July 3, 2019*
[3] *Oregon Department of Fish and Wildlife December 20, 2019 Protest of the Bureau of Land Management Proposed Resource Management Plan Amendments: Jordan Cove Natural Gas Liquefaction Terminal and Pacific Connector Gas Pipeline Plan (DOI-ORWA-M000-2017-0007-EIS).*
[4] *Oregon Department of Fish and Wildlife January 6, 2020 Protest of the United States Forest Service's Proposed Forest Plan Amendments (#28132) to the Umpqua, Rogue River-Siskiyou, and Fremont-Winema National Forests Jordan Cove Natural Gas Liquefaction Terminal and Pacific Connector Gas Pipeline Projects.*

- Incomplete fish passage plans (ORS 509.580-.910 and OAR 635 Division 412)
- Inconsistent information regarding the need for- and location of in-water blasting (ORS 509.140)
- Inadequate avoidance, minimization, and mitigation of impacts to fish and wildlife (ORS 496.012, OAR 635-415-0000 to -0025), particularly as it relates to:
    - JCEP Terminal Impacts
        - Estuarine:
            - Impacts associated with dredging and construction of the terminal
            - Eelgrass mitigation plan insufficiencies
        - Upland:
            - Impacts associated with the terminal facilities
            - Upland habitat mitigation plan insufficiencies
            - Kentuck Slough wetland mitigation plan insufficiencies
    - PCGP Pipeline Impacts
        - Upland habitat mitigation insufficiencies
        - Forest habitat loss and mitigation for marbled murrelet and northern spotted owl
        - Horizontal directional drilling risks
        - Wetland/waterway impacts and mitigation
        - Water quality and quantity impacts.

Each of the bulleted items are discussed more fully below.

Fish Passage

It is the policy in the State of Oregon to provide upstream and downstream passage for native migratory fish (see ORS 509.580 through 509.910 and corresponding Administrative Rules OAR 635-412-005 through 0040). Fish passage is required in all waters of Oregon in which native migratory fish are currently or were historically present. With some exceptions defined in ORS 509.585, a person owning or operating an artificial obstruction may not construct or maintain any artificial obstruction across any waters of this state that are inhabited, or historically inhabited, by native migratory fish without providing passage for these fish. Projects that construct, install, replace, extend, repair or maintain, and remove or abandon dams, dikes, levees, culverts, roads, water diversion structures, bridges, tide gates or other hydraulic facilities can be “triggers” to Oregon’s fish passage rules and regulations.

ODFW has received fish passage plan submittals for project components within the Oregon Coastal Zone Management Area (CZMA) and has met with the Jordan Cove Energy Project, L.P. and Pacific Connector Gas Pipeline Project L.P. (hereafter, the applicant) on multiple occasions to address insufficiencies in their applications. ODFW has received sufficient information for the Kentuck and APCO Mitigation actions within the CZMA. These actions include the East Bay Drive Bridge, Golf Course Lane Culvert, Kentuck Tide Gate, Kentuck Creek Restoration and the APCO Bridge. The information we have received for these sites is adequate for our review and approval and ODFW is working on the final fish passage authorizations for these restoration actions.

However, the following CZMA fish passage plan items need to be updated and re-submitted to ODFW for final review and determinations on fish passage and compliance with the state's rules and regulations. These items include:

a. Updated Appendix 3 of the applicant's fish passage application (Horizontal Directional Drill Plans – CZMA) to understand current drilling strategies, potential impacts, and appropriate In-Water Work Windows, and
b. Updated Appendix 6 of the applicant's fish passage application (Stream Crossing Risk Assessment - CZMA) – Stream Restoration actions. This information is critical in the development of site specific stream crossing restoration plans.

These two appendices are necessary for ODFW's final review, evaluation and determination of fish passage authorizations for the project components within the CZMA authority and where the state has fish passage authority (ORS 509.585).

ODFW has not received fish passage plan information on project components situated outside of the CZMA authority. ODFW is unable to proceed forward with our review, evaluation, and fish passage authorization for these project components. These project components include:

a. the proposed new LNG Pipeline and the associated fish bearing waterway crossings subject to the state's fish passage authorities, as per ORS 509.585, and
b. the transportation road infrastructure to access, install, maintain and monitor the project where these actions will cross fish bearing waterways subject to the state's fish passage authorities, as per ORS 509.585, and
c. associated plans for fish salvage and release.

<u>In-Water Blasting</u>

The PCGP Blasting Plan (FEIS Appendix F.10 Part C) states that in-water blasting is not anticipated during construction of the pipeline project, but that blasting may occur near waterbodies or within dry stream beds. ODFW in-water blasting permits will be required for blasting activities that occur in or adjacent to the bed of a fish-bearing stream regardless of whether it is dry or not (ORS 509.140 and OAR 635 Division 425). At this time, the applicant has not coordinated with ODFW on in-water blasting permits and the applicant's planning documents do not suggest any intent to do so.

The purpose of the in-water blasting permit is to further the State of Oregon's Wildlife Policy (ORS 496.012 and 496.138) and the Food Fish Management Policy contained in ORS 506.109 by applying consistent standards for reviewing and issuing in-water blasting permits as required by ORS 509.140. These rules establish procedures that ODFW will use to review and make decisions on applications for in-water blasting activities, including any permit conditions necessary to prevent injury to fish, wildlife, and their habitat.

Per OAR 635-425-0010 (7), 'in-water blasting' means the use of explosives on, under or in waters of this state, or in any location adjacent to the waters of this state where blasting would have an impact on fish and wildlife or their habitat. The PCGP Blasting Plan discusses blasting adjacent to waters of this state, and therefore triggers the ODFW in-water blasting rules. Additionally, the applicant discusses blasting within dry stream beds. However, the plan is not clear which stream beds or when blasting would occur. Some dry stream beds are fish-bearing in the wet season and may also trigger state fish passage requirements (see the section above, regarding fish passage, within this letter). Diversion of water around a blasting site to make a streambed dry still requires an in-water blasting permit. It will also require maintenance of fish passage consistent with ODFW fish passage criteria (see above), and a mitigation plan to address potential direct and indirect impacts to terrestrial and aquatic habitat consistent with the ODFW Fish and Wildlife Habitat Mitigation Policy (OAR 635 Division 415). Manipulation of a stream to divert water around a work site will also require a removal-fill permit from Department of State Lands.

The Blasting Plan discusses using 25-foot setbacks of 2-pound charges in bedrock to avoid hydrostatic pressure exceeding 7.3 psi from reaching known wet areas containing listed salmonids. The Blasting Plan cites research and guidelines from Alaska Game and Fish in its justification for using this minimization strategy. ODFW acknowledges this minimization measure may be appropriate for some blasting activities in proximity to waters of this state. However, this may not be adequate in all cases. ODFW will require that additional site-specific information be provided to ensure consistency with state statute and rule. For example, ODFW will require documentation of fish presence or absence and specific geology for any waters crossed or adjacent to blasting areas.

In one particular case, the Blasting Plan specifically discusses the diverted open-cut stream crossing at the South Umpqua River. The document states (pg. 8) "*as the trench proceeds across the stream bed, the trench blasting will approach the diverted portion of the stream crossing. This will likely result in blasting right up to the bladder dam edge which is used to divert the stream flow. If instantaneous hydrostatic pressure differentials cannot be maintained at acceptable levels during construction in critical habitat locations, additional mitigation measures, such as modified blast design or bubble curtains may be employed. Bubble curtain mitigation involves the use of bubblers placed within the waterbody between the source and receptor to help attenuate pressure changes. Additionally, where blasting may need to occur within stream beds, mitigation measures to minimize impacts to aquatic species are provided in the Fish Salvage Plan included as Appendix L to the POD*". This example most certainly would trigger both ODFW's in-water blasting permit rules and fish passage rules, and DSL's removal-fill rules. The application will need to address impacts to any fish and wildlife of concern along this section of the South Umpqua River. It is also not clear whether there are other examples of proposed crossings similar to the one described for the South Umpqua River.

Avoidance, Minimization, and Mitigation of Impacts to Fish, Wildlife, and their Habitats

One of ODFW's consistent comments to FERC throughout this environmental analysis is that the JCEP/PCGP projects could have significant impacts to fish and wildlife and their habitats, and that the applicant's plans for avoidance, minimization, and mitigation were not meeting the standards set forth by the Oregon Fish and Wildlife Commission in the OAR 635 Division 415 Rules. This insufficiency has not been rectified in the FEIS.

ODFW acknowledges FERC's response to ODFW comments in the FEIS Appendix R Part 2, and appreciates FERC's response to ODFW's recommended technical corrections throughout. However, whenever ODFW DEIS comments would identify mitigation insufficiencies in meeting state regulatory standards, FERC repeated the following response "*It is not the role or scope of the federal EIS to assess the Project's compliance with State regulations. We assume* *that the State would determine if the Project is in compliance with the State requirements during their review of the Applicant's State permit applications. As disclosed in Section 5 of the EIS, any authorization from the Commission would be conditional on the Applicant acquiring all applicable federal and federally designated permits."*

Notwithstanding FERC's response, the Oregon Fish and Wildlife Commission directs ODFW to recommend avoidance, minimization, and/or mitigation for any impacts to fish and wildlife and their habitats in accordance with the Wildlife Policy (ORS 496.012) and to the standards set forth in the ODFW Fish and Wildlife Habitat Mitigation Policy (OAR 635-415). Given that mitigation plans for this project do not fully meet state standards (as outlined in multiple sections below), ODFW is obligated to continue to raise these issues for FERC's attention as well as the attention of other federal and state regulatory agencies, and for the citizens of Oregon for whom ODFW manages fish and wildlife in the public trust.

JCEP Terminal Aquatic Impacts and Mitigation

General Comments

The FERC FEIS (November 2019) does not include sufficient detail about the proposed mitigation measures designed to offset the environmental impacts of the JCEP terminal project. The proposed Compensatory Wetland Mitigation Plan (CWMP) for impacts to estuarine environments, wetlands and waterbodies does not include sufficient information required to fully meet the state's standards for offsetting the impacts to fish, wildlife, and their habitats.

The FERC FEIS concludes that "*constructing and operating the project would result in temporary, long-term, and permanent impacts on the environment. Many of these impacts would not be significant or would be reduced to less than significant levels with the implementation of proposed and/or recommended impact avoidance, minimization, and mitigation measures. However, some of these impacts would be adverse and significant*" (FERC FEIS; Executive Summary, ES-6). The conclusion reached by FERC is premature, because specific mitigation measures have not been presented in sufficient detail in the FEIS to convey the level of confidence required to support the FERC finding of no significant impact.

More specifically, the FERC FEIS states that "*the applicants' Compensatory Wetland Mitigation Plan would satisfy the COE's regulatory requirements to mitigate unavoidable impacts on wetlands and waters of the U.S.*" This statement is also premature at this time, because several essential components and details of the CWMP have not yet been finalized and are not presented in the FEIS. Consequently, it is not possible to fully evaluate the adequacy of the proposed CWMP and its capacity to satisfy federal or state regulatory requirements, particularly when the specific mitigation measures and habitat accounting details have not yet been developed, identified, or presented in the FEIS.

Several acres of intertidal and shallow subtidal habitats will be lost or converted to deeper water habitats in association with the proposed dredging, construction, and maintenance of the Navigation Channel, access channel, LNG Terminal and berth, and related LNG infrastructure. It is not clear that the proposed CWMP provides sufficient in-kind mitigation measures required to offset losses of the high-value (ODFW Fish and Wildlife Habitat Mitigation Policy / Category 2 and 3) estuarine habitats, or that the proposed mitigation measures can be implemented or maintained in a manner that does not create new impacts to existing intertidal and subtidal habitats at the proposed mitigation sites.

The FERC FEIS states that "*we recommend that the Project-specific impact avoidance, minimization, and mitigation measures that we have developed (included in this EIS as recommendations) be attached as conditions to any Authorization and Certificate of Public Convenience and Necessity issued by the Commission for the Project* (FERC FEIS; Executive Summary, ES-7). While many of the measures identified in the EIS are essential in offsetting impacts, many are not sufficiently detailed or supported by adequate contingency planning at this time to support the FERC conclusion of no significant impact. The details supporting this concern are provided more fully below.

Impacts to the Coos Bay Estuary
Construction and operation of the proposed JCEP project will result in a complex combination of temporary, long-term, and permanent impacts to the estuarine environment of Coos Bay. The FEIS identifies that some of the impacts would be "*adverse and significant*" (FERC FEIS; Executive Summary, ES-6). The unique landform of North Spit and the Coos estuary tidal basin provide a semi-protected aquatic and coastal environment that is inhabited by diverse communities of fish and wildlife. Coos Bay is the largest estuary located entirely in Oregon and currently supports populations of fish and shellfish that contribute to economically and culturally significant commercial and recreational fisheries. In addition, the aquatic and upland habitats encompassed by the JCEP Terminal and associated facilities have been subjected to a long legacy of a number of landscape and waterway alterations including: dredging, rip- rap installation, leveling, and removal of native coastal pine forest, filling of wetlands, and other development related impacts. These habitats historically would have been primarily characterized as ODFW Category 2 or 3 habitats, (providing essential, important, and/or limited habitat function for fish and wildlife) under the ODFW Fish and Wildlife Habitat Mitigation Policy. Although negatively impacted historically, much of the tidal, subtidal, and upland habitats at the proposed Project site have received only minimal disturbance over the past two decades, and substantial recovery of ecological function has occurred.

The subtidal, tidal, intertidal, and shoreline features of the Coos Bay estuary tidal basin provide critical habitat for numerous culturally and economically important game and non-game species including, but not limited to: Dungeness crab (*Metacarcinus magister*), red rock crab *(Cancer productus*), cockles (*Clinocardium nuttallii*), gaper clams (*Tresus capax)*, butter clams (*Saxidomus giganteus)*, littleneck clams (*Protothaca staminea*), rockfish (*Sebastes spp.*), lingcod (*Ophiodon elongates*), greenling (*Hexagrammos decagrammus*), California halibut (*Paralichthys californicus*), English sole (*Parophrys vetulus*), Pacific sand dabs (*Citharichthys sordidus*), ghost shrimp (*Neotrypaea californiensis*), mud shrimp (*Upogebia pugettensis*), starry flounder *(Platichthys stellatus)*, smelts (Osmeridae family), (Engraulidae family), sardines (Clupeidae family), fall run Chinook salmon *(Oncorhynchus tshawytscha)*, green sturgeon *(Acipenser medirostris)*, white sturgeon *(A. transmontanus)*, (OC) ESA threatened coho salmon *(O. kisutch)*, and possibly Pacific lamprey (*Entosphenus tridentata*). The Coos Bay estuary is designated as Essential Fish Habitat (EFH) for all groundfish and salmon species included in the Pacific Fisheries Management Council's Pacific Coast Groundfish Fishery Management Plan (FMP) and the Salmon FMP, respectively (PFMC 2019, PFMC 2014). Under the EFH provision of the MSA, estuaries such as Coos Bay are further considered as Habitat Areas of Particular Concern

(HAPC) in recognition of their inherently high habitat value for breeding, rearing, foraging and shelter for fish and widlife. There is some potential that Pacific smelt (eulachon) (*Thaleichthys pacificus)* may also occur in the JCLNG area of Coos Bay. Additionally, the tideflats and subtidal regions of the lower Coos estuary are also sites for the commercial harvest of bay clams (gaper clams, butter clams, cockles) and mudflats in the JCLNG area support a commercial fishery for ghost shrimp (*Neotrypaea californiensis*).

Scattered populations of the native Olympia oyster (*Ostrea lurida*) have recently become re-established within the marine and polyhaline regions of the Coos Bay estuary where they typically occur as individuals or small clusters attached to rip-rap, rock, shell, or other hard substrata. The recovering populations of *O. lurida* are considered as a Strategy Species by the Oregon Nearshore Conservation Strategy. These at-risk populations of Olympia oysters are particularly sensitive to smothering and burial by silt and other suspended materials, and it is likely that they will be exposed to heavy loads of suspended sediment and excessive siltation during dredging activities associated with excavation of the new JCEP terminal.

The proposed JCEP terminal will create a new deep-water backwater basin for the LNG vessels that will likely result in several localized but significant biological effects (e.g., conversion of terrestrial habitat to aquatic habitat, conversion of intertidal habitat to subtidal habitat, change to estuarine tidal water flow patterns, alteration of salinity regime, elevated turbidity associated with initial dredging and subsequent maintenance dredging, loss of eelgrass and infaunal invertebrate communities from the intertidal and shallow subtidal zones, etc.). New numerical hydrodynamic models constructed for the Coos Bay estuary tidal basin provide technical forecasts regarding the predicted physical changes that are expected to occur throughout the estuarine tidal basin (see the modeling work by D. Sutherland at the University of Michigan, funded by the National Estuarine Research Reserve System). Comparable effort should be expended by JCEP to develop empirical data and model forecasts regarding the biological changes and ecological impacts that are expected to occur in association with the JCEP construction and operation activities. Without the generation of new empirical data and advanced modeling simulations, it is not currently possible to accurately identify the suite of direct and indirect impacts that are likely to occur, nor the spatial scale over which the impacts are likely to be significant or substantial.

Dredging Impacts to Estuarine Habitats and Communities

The FEIS describes the location and extent of dredging and removal of unconsolidated sediment from the intertidal and subtidal zones of the Coos Bay estuary, but only superficially considers the potential effects of dredging on aquatic habitat and species that are expected to occur in response to construction of the different components of the JCEP Terminal (Section 4.5.2.2). Direct impacts to estuarine habitats associated with construction of the vessel slip, access channel, temporary material barge berth, the material offloading facility, and rock pile apron (Table 4.5.2.2-2) are expected to be long-lasting and substantial. In particular, the estuarine portion of the JCEP LNG facilities would include direct impacts to about 37 acres of estuarine habitat, including 2 acres of eelgrass habitat, 13 acres of intertidal un-vegetated habitat, 4 acres of shallow subtidal habitat, and 18 acres of deep subtidal habitat. The JCEP also includes dredging and excavation of four submerged areas of the sub-tidal zone in Coos Bay (total 40 acres) along the Federal Navigational Channel and vessel access route to improve navigation reliability for the LNG carriers.

Unconsolidated soft-sediment habitat is widespread in the Coos Bay estuary tidal basin where it occurs extensively throughout the intertidal zone and sub-tidal zone along the bottoms, sides, and margins of primary and secondary tidal channels (Cortright *et al*., 1987; Rumrill, 2003). Soft-sediment habitats provide a series of diverse, productive, and dynamic ecological functions in the estuary, including provision of habitat and forage areas for invertebrates, fish, birds, and marine mammals, as well as serving as an important source of detritus. Soft-sediments also play an important role in the microbial and biogeochemical transformations of organic materials and nutrient cycling, and they typically serve as a sink or reservoir for the deposition of water-borne particles. Diverse communities of motile, epifaunal, and infaunal invertebrates inhabit the soft-sediments, and the communities of crabs, shrimp, amphipods, polychaete worms, copepods, hydroids, anemones, clams, and other invertebrates are specifically adapted to survive, feed, grow, and reproduce themselves in the unconsolidated sediments (Simenstad 1983; Emmett *et al*., 2000). Microbial activity and deposition of organic matter associated with fine-grained sediments together support a complex food web that includes multiple resident (infaunal, epifaunal, motile) and transitory (seasonal, migratory) species.

Mixed communities of shellfish, such as Dungeness crab, red rock crab, bay shrimp, gaper clams, butter clams, littleneck clams, softshell clams, cockles, and many other species are year-round residents of the intertidal and sub-tidal areas of the Coos estuary. Some of these shellfish are motile (*i.e.*, crabs and shrimp) and periodically move to different locations or migrate through the intertidal and sub-tidal zones, while others are stationary (*i.e.*, bivalves) and remain largely in place over the duration of their adult lives. The mixed communities of living bivalves and the beds of their non-living shells (*e.g.*, shell rubble or shell hash) are particularly important, because they function to stabilize unconsolidated sediments and provide heterogeneous habitat for numerous species of adult and juvenile fishes, crabs, shrimp, amphipods, worms, and other estuarine organisms. Moreover, filter-feeding by dense populations of living clams can sometimes play an important role in the removal of phytoplankton and smaller particulate materials, thereby decreasing turbidity and increasing light penetration through the estuarine water column. Consequently, maintenance of suitable soft-sediment habitat is essential for survival of the moderately long-lived (life-span 10-15 years or longer) gaper, butter, and cockle clams, particularly in the sub-tidal zone. When soft-sediment habitat is chronically disturbed and altered by dredging of the subtidal zone, there may be a permanent loss and impact to benthic invertebrate populations and a decline in the biodiversity of benthic communities. Loss of some or all of these sub-tidal populations of bay clams has implications for both the ecological functioning of sub-tidal habitats and the ability of the bay clams to serve as broodstock to support the recreational and commercial shellfish fisheries in Coos Bay (D'Andrea 2012).

Dredging and removal of the soft-sediments will likely have substantial and immediate local impacts on the sub-tidal populations of benthic invertebrates and shellfish, such as gaper clams, butter clams, and cockles. This may include the physical removal of the clams and their surrounding sediments, as well as a disruption of the mixed ecological communities of shellfish, mobile and infaunal invertebrates, and fish that make use of the sub-tidal habitats. The FEIS states that dredging would directly remove benthic organisms (e.g., worms, clams, benthic shrimp, starfish, and vegetation) from the bay bottom within the access channel and navigation channel modifications. Mobile organisms such as crabs, many shrimp, and fish could move away from the region during the process, although some will be entrained during dredging so that direct mortally or injury could occur (FEIS Section 4.5.2).

The JCEP FEIS acknowledges that dredging, removal, and disturbance of the soft-sediment habitats will directly remove benthic organisms from the bay bottom, and that it is likely that recovery would occur in about one year for benthic resources particularly in the area of navigation channel modifications. This estimate of the rapid rate of community recovery is problematic, however, because the technical references cited by the JCEP FEIS (Section 4.5.2) are drawn from earlier investigations of dredging impacts that generally studied a group of small-bodied, rapidly-growing invertebrates (including amphipods, polychaete worms, small bivalves, etc. that have life-spans on the scale of months to a few years) as the focal species to provide metrics for the estimates of species and habitat recovery. These small opportunistic species are not representative of the large-bodied, long-lived bay clams that typically exhibit episodic recruitment and have life-spans on the scale of 10-20 years in the Oregon estuaries. Moreover, large-scale dredging modifications that include subsequent maintenance dredging every 5-10 years may not provide the opportunity for bay clams and other shellfish to recruit successfully and fully re-colonize after the repeated disturbance events. It is also likely that benthic food resources may also be impaired or lost for other estuarine species (*i.e.*, forage fish, salmonids, crab) as a result of dredging actions. Consequently, dredging activities that significantly disturb and/or remove the mixed communities of long-lived bay clams from soft-sediment habitat in the sub-tidal zones of Coos Bay are expected to have longer-term impacts that extend well beyond a time period of many years.

Despite notification by ODFW during the DEIS review process, the JCEP FEIS still incorrectly illustrates the major known oyster and shrimp habitat and clamming and crabbing areas in the bay relative to the Project activities (Figure 4.5-2). In particular, mixed communities of bay clams (*i.e.*, gaper clams, butter clams, cockles, and other species) are known to occur throughout the intertidal zone in the area immediately west and north-west of the airport runway (ODFW 2009; area AP). These areas are illustrated only as “Shrimp Habitat” and “Oyster Habitat” in FEIS Figure 4.5-2. It is not clear why the known clam beds located nearest the JCEP project area were omitted from Figure 4.5-2 when the map incorporates spatial information about the other clam beds throughout the intertidal zone of the Coos estuary tidal basin further distances away from the JCEP project area. The known clam beds within ODFW area AP (Airport Runway) are located within 50 m of the Temporary Dredge Line for the Federal Navigation Channel and within about 500 m of the proposed JCEP Access Channel, as illustrated in Figure 4.5-3 of the JCEP FEIS. In addition, it is also unclear what species of oyster is intended to be represented by the broad polygon that extends throughout the intertidal zone as “Oyster Habitat” in Figure 4.5-2. Commercial mariculture of Pacific oysters (*Crassostrea gigas*) does not occur anywhere in the intertidal zone near the airport runway, and patchy clusters of Olympia oysters (*Ostrea lurida*) only occur on the rocky rip-rap that extends around the periphery of the airport runway. The spatial distribution for major clam beds and shrimp beds should be corrected and updated with relevant information generated by ODFW for Coos Bay (2009).

As proposed, the JCEP also includes extensive dredging and excavation of four submerged areas of the sub-tidal zone in Coos Bay along the Federal Navigational Channel and vessel access route to improve navigation reliability for the LNG carriers. These actions include dredging of 27 acres of deep subtidal habitat at bend areas along the Federal Navigation Channel, and the dredge lines for this additional activity would include disturbance and modification of another 13 acres of mostly deep subtidal habitat. The JCEP FEIS points out that these additional dredging activities and follow-up maintenance dredging would disturb the 40 acres of subtidal habitat and result in a short-term reduction in the ecological function of these areas by disturbance of the benthic and epibenthic organisms.

Ecological Importance and Impacts to Eelgrass

Beds of native eelgrass (*Zostera marina*) occur at several locations throughout the Coos estuary tidal basin where they provide numerous beneficial ecological functions, including heterogeneous habitat for a number of fish and wildlife species, nursery habitat for invertebrates and fish, forage areas for shorebirds and waterfowl, primary production and a source of organic-rich detritus, stabilization of unconsolidated sediments, trapping of suspended sediments, and contribute to improvements to estuarine water quality (Thom et al. 2003; Kentula and DeWitt 2003). In particular, the emergent canopy, blades and rhizomes of eelgrass beds provide complex and heterogeneous multi-dimensional habitat within the unconsolidated soft-sediments in the intertidal and shallow subtidal zones. In many cases, the abundance and species composition of macroinvertebrate, shellfish, and fish communities differ within eelgrass beds in comparison with un-vegetated areas where eelgrass is absent. Eelgrass beds are known to provide habitat for numerous species of invertebrates, including polychaete worms, cockles, gaper clams, butter clams, littleneck clams, Dungeness crab, grass shrimp and epibenthic invertebrates such as harpacticoid copepods, isopods, and gammarid amphipods. In addition, eelgrass beds also provide habitat for a diverse community of fishes, including juvenile salmonids, sculpin, English sole, shiner perch, lingcod, rockfish, pipefish, and herring. Native eelgrass is designated as Essential Fish Habitat (EFH) for all groundfish and salmon species managed under the PFMC Groundfish Fishery Management Plan and the PFMC Salmon Fishery Management Plan. Eelgrass beds are further designated as Habitat Areas of Particular Concern for groundfish and salmon due to their particular importance to ecosystem function and intrinsic habitat value for rearing, foraging and shelter.

Long-term efforts to remove root wads, large woody debris, and other natural structures embedded in the un-vegetated soft sediment of Coos Bay in order to facilitate commercial shipping and recreational boating have greatly exacerbated the lack of structural complexity along the shoreline and further increase the ecological importance of existing eelgrass beds. The heterogeneous canopies of eelgrass beds provide both primary complexity and an ecological edge-effect that presents an important biophysical transition zone for fish and invertebrates that forage in adjacent un-vegetated habitats.

The JCEP project includes dredging and construction of a new access channel to connect the terminal to the Federal Navigation Channel at about RM 7.3 (FEIS Section 2.1.1.7; Figure 2.1-7). The access channel will be about 700 feet in length, and about 2,200 feet wide at confluence with the Navigation Channel and about 780 feet wide at the Terminal. The access channel would be approximately 45 feet deep and would cover about 22 acres below the highest measured tide elevation of 10.3 feet (NAVD88). The proposed JCEP dredging activities will permanently destroy about 2 acres of established native eelgrass located in the intertidal and shallow subtidal zones of the project area. Dredging in the intertidal and shallow subtidal zones within the JCEP area is expected to have significant deleterious effects on native eelgrass habitats and the species found therein.

In addition to the direct removal of eelgrass at the JCEP dredging sites, it is likely that dredging operations carried out to implement the JCEP may also result in indirect impacts to adjacent eelgrass beds located in the vicinity of the JCEP area. For example, nearby eelgrass beds will likely experience periods of increased turbidity, sedimentation, and attenuated light levels resulting from dredging during construction and during subsequent periods of maintenance dredging. In this regard, the indirect effects of the JCEP to adjacent eelgrass beds have not been adequately addressed by the FEIS or Comprehensive Wetland Mitigation Plan.

Native eelgrass is recognized by ODFW as a Category 2 Habitat. The ODFW goal is no net-loss of either habitat quantity or quality and to provide a net benefit of habitat quantity or quality (OAR 635-415-0025). To achieve the mitigation goal, ODFW recommends avoidance of the impacts through alternatives to the proposed development action, or effective mitigation of the impacts (if unavoidable) through reliable in-kind, in-proximity habitat mitigation to achieve no net loss of either pre-development habitat quantity or quality.

The proposed eelgrass mitigation plan within the CWMP does not give adequate consideration to the difference in habitat quality that is anticipated between the eelgrass impact area and the eelgrass mitigation site. The plan proposes to excavate about 9 acres of existing algae/mud-sand algae habitat located in the intertidal zone near the North Bend Airport to an elevation of -2.00 ft NAVD, and to convert the algae/mud-sand habitat into about 6 acres of eelgrass. The proposed conversion of algae/mud-sand habitat to eelgrass habitat is problematic, because algae-mud-sand is also recognized as Category-2 value habitat under ODFW Fish and Wildlife Mitigation Policy. Eelgrass habitat and algae/mud-sand are both considered as Category-2 habitat, but they provide different habitat functions and values for aquatic organisms. Accordingly, diminishing the quantity and quality of algae/mud-sand habitat in order to offset the loss of eelgrass habitat is not ‘in kind’ and does not create a ‘net benefit’, and therefore does not meet the ODFW Fish and Wildlife Mitigation Policy goals for Category 2 habitat.

In order to offset the loss of 2 acres of eelgrass the JCEP includes a proposed eelgrass mitigation plan that relies on the “best case scenario” for full success by creating 6 ac of eelgrass (3:1 ratio) within a 9 acre site in the intertidal zone near the impact area.

ODFW has noted several potential problematic issues associated with the proposed JCEP eelgrass mitigation plan that have not been fully considered and addressed by the applicant. In particular, ODFW previously raised the concern that the excavated JCEP mitigation basin may refill with sediment, and that the rate of sedimentation may not be conducive to survival, growth, and propagation of the planted eelgrass plants. For example, Mills and Fonseca (2003) conducted a series of field experiments to determine the susceptibility of eelgrass to burial by estuarine sediments. Results from the study demonstrate that eelgrass plants experience an increased likelihood of mortality and decreased productivity under burial conditions, and that the threshold level of burial tolerance for *Z. marina* is extremely low. Burial of eelgrass to depths as low as 25% of the aboveground plant height (4 cm) substantially increase mortality of eelgrass, causing death of >75% of the plants. Moreover, the probability of eelgrass mortality reached 100% for burial depths of 50% (8 cm) to 75% (12 cm) of plant height, depending on the types of sediment (e.g., sand, silt, combined) in which the plants were buried. These empirical observations indicate that eelgrass can only tolerate rapid sedimentation events that cover less than half of its photosynthetic surfaces, and that small levels of rapid sedimentation are detrimental to survival of *Z. marina*.

Earlier research (Thom et al. 2018) has shown that eelgrass beds are typically limited by the availability of proper substrata, light, heat stress, and desiccation. Survival of the transplanted eelgrass within the excavated mitigation site will be dependent upon several ecological factors, including characteristics of the excavated sediment, sedimentation rate, erosion, light availability, nutrient availability, grazing upon seeds, seedlings, and blades, and a suite of inherent physical factors (*i.e.*, current velocities, wind fetch, slope, depth, seawater temperature, air temperature, humidity, desiccation, etc.). The proposed mitigation actions for eelgrass should be designed to retain the full array of ecosystem services provided by eelgrass beds in the JCEP area, and to achieve no-net loss of eelgrass over the entire lifespan of the JCEP operation in Coos Bay. In this regard, the planned mitigation activities should follow established in-kind, in-proximity standards established by the state of Oregon, and require long-term monitoring and remedial replanting of eelgrass as needed to compensate for losses that may occur over the entire lifespan of the Project.

The JCEP proposes to remove existing eelgrass in the Project area, and to offset the loss of eelgrass habitat by excavation of an eelgrass mitigation area coupled with replanting of eelgrass taken from a nearby donor bed. The JCEP proposes to monitor the effectiveness of the replanting effort for a period of only five years. It is important to note that failure of eelgrass replanting efforts is common in the Pacific northwest region (Thom et al., 2008), and that five years is an insufficiently short time period to adequately evaluate long-term mitigation success.

The CWMP does not adequately demonstrate that all efforts were made to identify optimal eelgrass transplant sites. The CWMP does not describe the alternative sites that were considered, characterize the location, species composition, and abundance of the eelgrass and other submerged aquatic vegetation at the alternative sites, and provide a more detailed rationale for rejection of the alternative sites and acceptance of the proposed site. The applicant has shared technical memoranda with ODFW describing some of the alternative sites considered in Coos Bay. However ODFW is aware of other potential sites that were not considered by the applicant. Furthermore, ODFW has not seen a revised version of the CWMP that incorporates the analysis shared in the technical memo.

Earlier attempts to mitigate for the damage or loss of eelgrass beds have met with limited success in Pacific Northwest estuaries. For example, Thom et al. (2008) conducted a review of 14 eelgrass mitigation and transplant projects, and they concluded that it is sometimes possible to restore eelgrass under favorable site conditions and when the reason for the initial loss of eelgrass is understood and corrected. The authors also noted, however, that eelgrass restoration science is hampered by knowledge gaps which reduce restoration success. The underlying mechanisms for recent eelgrass loss in the Pacific Northwest region are not obvious, which suggests that the scientific understanding of eelgrass biology and ecosystem conditions is currently inadequate to fully support environmental management actions (Thom et al. 2008).

Local complexities in hydrologic flow regimes are known to affect potential for success in eelgrass restoration efforts. These local complexities include considerations of the following:

- Habitat conditions created through excavation or filling are often ephemeral and subject to

subsequent deposition/erosion that results in movement of conditions outside of the range of preferred variability for eelgrass.
- Flow regimes including severity of wave action and current speed contribute to the potential success of a site for eelgrass establishment and growth. Sites that are created through excavation or fill are an artificial modification of conditions that have formed through the geomorphological features that drive flow regimes. Factors such as water depth reflect deposition/erosion rates from water transported sediments. Excavation or filling to a specific elevation is attempting to alter the natural elevation conditions in relation to hydrologic conditions for many sites that might serve as potential mitigation. Consequently, the potential for success is limited for projects that modify water depth/elevation of the substrates for creating conditions appropriate for eelgrass mitigation unless the site chosen has substrate elevation that has been artificially created from previous disturbance or the conditions are dominated by factors other than hydrology.
- Use of eelgrass sites immediately adjacent to or within the mitigation area for obtaining plants/shoots results in impacts to these locations, potentially weakening the vigor of eelgrass at these locations which is counter to goals.
- Excavation of locations adjacent to existing eelgrass beds can result in hydrologic changes such as erosion of surrounding substrates resulting in impacts to currently productive stands.
- The monitoring plan should be amended to include more robust methods such as diver or low tide visual count surveys with established known planting densities at time-0 and subsequent measurable surveys with quantifiable methods.
- Due to the potential for minimal success the eelgrass mitigation ratio is likely insufficient to offset impacts at the JCEP project impact location.

For all of the reasons listed in the discussion above, ODFW recommends the eelgrass mitigation strategies be re-evaluated to favor avoidance.

Dredging of the Navigation Channel and Impacts to Adjacent Estuarine Habitats
The FEIS also includes a description of excavation activities for four submerged areas (NRI Areas 1-4; removing about 700,000 cubic yards of material) that are located adjacent to the existing federally-authorized Coos Bay Navigation Channel. In particular, the JCEP will include dredging of four submerged areas that directly abut the current boundary of the Navigation Channel between RM 2 to RM 7 (FEIS Figure 2.1-1). These dredging activities will modify and alter the physical morphology of the Navigation Channel by widening four turns to allow for more efficient transit of LNG carriers.

It is likely that dredging of the four submerged areas (NRI Areas 1-4) will have indirect impacts to side slopes and soft sediment habitats located adjacent and in close proximity to the dredged areas. For example, the JCEP will include significant dredging and removal of unconsolidated sediment from NRI Area 2 (RM 4.5), NRI Area 3 (RM 6), and NRI Area 4 (RM 7), coupled with erosion of sediment from the adjacent subtidal and intertidal areas. The FEIS states that while the banks of the dredged areas are intended to be stable, some insignificant side slope equilibration may occur over about a 6-year period (see FEIS section 4.5.2). Loss of sediment from these immediately adjacent areas, however, will likely be substantial (*i.e.*, loss of 1-2 ft (30-60 cm) in depth over the first 3 years). Loss of the upper 30-60 cm of sediment from the side slopes located adjacent to the NRI dredged areas during the equilibration process is certainly not insignificant, and may result in further impacts and loss of eelgrass, infaunal invertebrates, and degradation of the habitat for shellfish and fish. Loss of the upper 30-60 cm of sediment from the side slope of NRI Area 4 is particularly alarming, because this side slope is located in the immediate vicinity of the important eelgrass donor bed and eelgrass reference bed identified as essential components of the proposed JCEP eelgrass mitigation activities.

Potential loss or disturbance of the eelgrass donor bed and eelgrass reference area in the vicinity of NRI Area 4 puts the proposed JCEP eelgrass mitigation plan in jeopardy. The FEIS is deficient, because it does not adequately address the potential for loss of sediment adjacent to NRI Areas 2-4, and because it does not give adequate consideration to loss or disturbance of the important eelgrass donor bed and reference bed located adjacent to NRI Area 4.

Impacts of Maintenance Dredging

It is likely that marked changes will occur to the species composition, abundance, and productivity of benthic invertebrate communities that inhabit soft-sediments in the dredged areas of the Coos Bay tidal channel, and little recovery is expected over time due to the continual need for maintenance dredging. The JCEP proposes to conduct maintenance dredging about every 3 years, including removal of about 115,000 cy of material per dredging interval for the first 10 years of operation. Subsequent maintenance dredging will be carried out about every 5 years with removal of up to 160,000 cy of materials during each dredging event. For the marine waterway modification projects within the channel, maintenance dredging would also be conducted about every 3 years with about 27,900 cy of materials removed during each dredging event. It is likely that maintenance dredging operations of this magnitude will result in a continually disturbed condition for the soft-sediment habitat, preventing recruitment, growth, and survival of long-lived bay clams and other shellfish, and curtailing recovery of fish and invertebrate communities in the affected areas.

JCEP Terminal Freshwater/Estuarine Wetland Impacts and the Kentuck Slough Habitat Mitigation Plan

The JCEP terminal at Ingram Yard and South Dunes workforce housing/staging area will impact a number of habitats that provide critical function for fish and wildlife (see Jordan Cove CMP Attachment 3 Terminal Upland Mitigation Plan, Table 3). There is a total of 27.34 acres of permanent impact to estuarine and freshwater wetland associated with the terminal (7.32 acres freshwater).

The Kentuck Project is part of the JCEP/PCGP Compensatory Wetland Mitigation Plan (CWMP), and is the applicant's proposed mitigation offset for estuarine and freshwater wetland impacts of the JCEP/PCGP projects. ODFW has reviewed the Kentuck Project both in terms of its consistency with the ODFW Fish and Wildlife Habitat Mitigation Policy and its consistency with Fish Passage Rules, and provided substantive input to the applicant since concept inception. ODFW finds that the Kentuck Slough Mitigation Plan is missing some final key pieces of information in order to be consistent with state habitat mitigation standards.

ODFW reviewed the CWMP that the applicant included in its Comprehensive Mitigation Plan (CMP; submitted to the FERC Docket Numbers C17-494-000 and C17-495-000 in September 2019). ODFW also compared the impacts of the terminal to the offsets at Kentuck using Tables 1 and 2, and Appendix A-1, and sheet C-151 from the CMP, Resource Report 3 documents, and a David Evans and Associates JCEP project memo from 2013. The purpose of this comparison was to ensure that the Kentuck Project would provide mitigation sufficient to meet the state standards outlined in OAR 635-415.

ODFW has determined the Kentuck Project will serve as in-proximity habitat mitigation at the HUC 4 scale for the wetland impacts of the JCEP terminal. The Kentuck Mitigation site has geomorphology, elevational, and hydrological ability to produce in-kind habitat features as defined under OAR 635-415. The historical actions at the site have altered its functional value from a Category-2 habitat of primarily algae-mud-sand and saltmarsh habitats to a minimally-functional freshwater wetland that is considered Category-5, which demonstrates sufficient restoration potential. The estuarine habitats altered/degraded by the JCEP as categorized under OAR 635-415 are able to be functionally reproduced through the design features of the Kentuck Project. There is sufficient land area to reproduce the habitat features impacted to offset affected Category-2-4 estuarine habitats.

However, the remaining issue is that ODFW has requested, but has not yet received, a long-term management plan for the Kentuck mitigation site, including:

- Long-term protection and stewardship strategies to ensure the mitigation site will be durable for the life of the project's impacts
- Long-term water management strategies for the Kentuck Creek water control structure.

Without this information, ODFW does not consider the Compensatory Wetland Mitigation Plan complete, in accordance with the ODFW Fish and Wildlife Habitat Mitigation Policy.

The applicant has verbally committed to redesigning the Kentuck mitigation elevation plan to develop additional acreage that will be below elevation +5.5 NAVDD88 *(*the elevation threshold for saltmarsh development) on the site. This will offset loss of Category-2 Algae/Mud/Sand habitats that will be dredged and regraded at the eelgrass mitigation site south of the North Bend Airport runway. The exact acreage (6.81 acres + slope area) of grading/dredging at the eelgrass location has of yet not been finalized. ODFW will need design plans and associated written information the final eelgrass site dredging/grading plan and the mitigation designs for the Kentuck site in order to determine if the loss of the Category-2 Algae/Mud/Sand will be offset. The expectation is the information would be in a revised Compensatory Wetland Mitigation Plan, but would be essential for ODFW to determine sufficiency and likely essential in the Oregon Department of State Land removal-fill permit as well.

The Kentuck site is slated for disposal of 300,000 cubic-yards of dredge spoils from development of the JCEP access channel. The applicant has not updated plans to describe where fill proposed to be disposed of at Kentuck will be relocated in order to allow the Kentuck grading plan to produce the additional acres below elevation +5.5ft. There would also be a need to update the grading and erosion control plans for both the eelgrass mitigation site and Kentuck Mitigation site, which may have additional or different impacts to fish and wildlife. These types of significant alterations to project plans are not addressed in the FEIS.

With regard to fish passage requirements at Kentuck, ODFW has received sufficient information for the Kentuck fish passage applications. These actions include the East Bay Drive Bridge, Golf Course Lane Culvert, Kentuck Tide Gate, and Kentuck Creek Restoration. The information we have received for these sites is adequate for our review and approval and ODFW is working on the final fish passage authorizations for these restoration actions.

JCEP Terminal Upland Impacts and Mitigation
The construction of the JCEP slip, terminal, LNG storage tanks, workforce housing area, and staging areas are expected to degrade or remove 345.8 acres of wildlife habitat on the North Spit, Coos Bay (Jordan Cove LNG Comprehensive Mitigation Plan – Terminal Upland Mitigation Plan, Table 2). ODFW concurs with the habitat categorization provided in Table 2 of the CMP Terminal Upland Mitigation Plan, and finds it consistent with the ODFW Fish and Wildlife Habitat Mitigation Policy, except for the habitat categorization of coastal dune forest.

A total of 125.8 acres of Category 2 coastal dune forest will be impacted by construction of the JCEP Terminal and South Dunes workforce housing. In 2017, ODFW conveyed to JCEP that coastal dune forest is considered Category 2 habitat given its function and value for the coastal marten *(Martes caurina).* Coastal marten are an Oregon State Sensitive Species (OAR 635-100-0040), because they have low survival rates in fragmented forests, they occupy a significantly small area relative to their historic range, and because significant information gaps exist for the species. Coastal marten select for and show higher survival rates within multi-aged, multi-storied coastal dune forests with a higher percentage of older trees (Slauson et al. 2019). The portion of coastal dune forest west of Highway 101 and in the JCEP project area near Tenmile Creek is unique relative to other coastal dune forest in Oregon because of the presence of shore pine (*Pinus contorta*), approximates the multi-aged description above, and it is an area with known marten detections (ODFW District Wildlife Biologist, Stuart Love, Pers. Comm.). These coastal dune forests and the mixed understory vegetative dynamics are considered as essential and limited Category 2 habitat for the coastal marten in Oregon. Therefore, ODFW recommends no net loss plus a net benefit of habitat quantity or quality through reliable in-kind, in-proximity mitigation. Despite the Category 2 recommendation from ODFW, the applicant did not update its plans. Table 2, Table 4, and Table 5 of the Terminal Upland Mitigation Plan incorrectly identify coastal dune forest as Category 3. JCEP's proposed mitigation for these impacts is insufficient to meet the standards in ODFW's Fish and Wildlife Habitat Mitigation Policy (OAR 635-415).

Additionally, 1.6 acres of riparian forest and 7.6 acres of un-vegetated sand (Category 3 habitat; see Tables 4 and 5) will be impacted by the project. Riparian habitats are relevant for amphibians, neo-tropical migrant birds, and raptors. Un-vegetated sands are used by many species of shorebirds, small mammals, mesocarnivores, and raptors. The mitigation goal for unavoidable impacts to Category 3 habitats is reliable in-kind and in-proximity mitigation to achieve no net loss in habitat quantity or quality.

The remaining habitats that will be impacted at the JCEP terminal site are Cateogory4; shrub (9.3 acres), herbaceous shrub (63.5 acres), herbaceous (126.5 acres), and unvegetated sand that has been somewhat degraded from past impacts (4 acres). These Category-4 habitats are considered "important" for fish and wildlife species. The mitigation policy for unavoidable impacts to Category 4 habitat is no net loss.

From 2010 through 2016, ODFW staff worked with the JCEP consultant, David Evans and Associates to categorize JCEP terminal habitats according to their function and importance for fish and wildlife under OAR 635-415. This information was captured initially in the David

Evans and Associates *ODFW Habitat Categorization, Jordan Cove Energy Project Memo,* September 9th 2013; and is reiterated in the CMP Main Body and CMP Attachments (Supplemental info Attachment A Figures). ODFW has determined that implementation of the JCEP terminal project will eliminate/degrade upland habitats and their function for production of fish/wildlife, and that mitigation is necessary to offset losses.

During this same period, ODFW coordinated with David Evans and Associates in an effort to identify appropriate mitigation lands/actions in alignment with OAR 635-415. There were three primary mitigation projects discussed: 1) Panhandle Site, 2) North Bank Lane Parcel S, and 3) Access management within the Dunes National Recreation Area (Dunes NRA) or vicinity. The purpose of the third project was to manage all-terrain vehicle (ATV) activity to reduce disturbance to coastal marten and other species that use coastal dune forest as habitat.

Ultimately, David Evans and Associates informed ODFW that after extensive investigations and landowner contacts, the options to replace terminal upland habitats with in-kind and in-proximity habitat were very limited.

The current mitigation proposal in the JCEP CMP Terminal Upland Mitigation Plan identifies three sites with associated actions:

1). Panhandle Site 59.3 acres: Acquisition/conservation and uplift actions including management of non-native invasive plants, primarily Scotch broom. Local ODFW staff coordinated extensively concerning the identification of the Panhandle site for mitigation and have been on the property on several occasions to assess the proposed habitat improvements. Invasive Scotch broom currently dominates the site and reduces habitat quality and function for native fish and wildlife. The site is considered in-proximity and the treatments are partially considered in-kind as noted in Figure 2 (CMP; Terminal Upland Habitat Mitigation Plan). ODFW is generally in agreement with the details specified in Figure 2. Conservation of this parcel and preventing future development and current access by ATV's would be considered beneficial for coastal dune forest function on the properties.

2). North Bank Parcel S site 156 acres: Acquisition/conservation; provides middle-age timber stands on lands that are several miles east of coastal dune forest habitats. Mitigation actions would include conservation of land, forest management to promote late seral habitats, removal of gorse and Scotch broom, and seeding with wildlife seeding mixtures.

As stated above, the JCEP project will impact 125.8 acres of coastal dune forest (Table 4; CMP Terminal Upland Habitat Mitigation Plan), which are classified by ODFW as Category 2 according to the Fish and Wildlife Habitat Mitigation Policy.

The North Bank Parcel S is 17.1 acres of Category 2 shrub/scrub wetland, 133.8 Category 2 managed coastal dune forest dominated by Douglas fir (*Pseudotsuga menzeisii*), and 5.2 acres of riparian forest. This parcel is east of- and outside of - the largely unmanaged, coastal dune forest dominated by shore pine that is currently occupied by coastal marten. The mitigation site has an even-aged, evenly-spaced, mid-seral forest condition whereas the impacted forest has greater diversity and maturity in forest structure.

North Bank Lane mitigation actions (wildlife forage planting, control of gorse, and stand management) have been determined by ODFW to have potential to provide uplift benefits for coastal marten, their sciurid prey base, and other wildlife using coastal dune forest. The seeding with wildlife forage will offset loss of the Ingram Yard site for small mammals, deer, and perhaps foraging raptors. If timber management of stands at the North Bank site create forest attributes more similar to late-seral stand features, this will trend the 92.7 acres of coastal forest toward Category 2 function.

While the North Bank site may trend toward providing coastal dune habitat useful to coastal martens and other species, the mitigation ratio of impact to offset does not meet the ODFW Fish and Wildlife Habitat Mitigation Policy goal of no net loss in quantity. The 92.7 acres of incremental improvement at North Bank is not equivalent to loss of function of 125.8 acres at the JCEP site.

ODFW recommends additional consultation to more adequately address coastal dune forest habitat loss not offset by the North Bank Parcel S. One potential for uplift discussed previously that would be considered sufficient would be restriction of ATV access on 50-70 acres of coastal dune forest from Hwy 101 west to the beach and from the JCEP project area to Tenmile Creek. This would reduce disturbance on these additional acres, and improve habitat function for coastal marten.

3). Lagoon Site 41.2 acres: Acquisition/conservation or easement of the old Weyerhaeuser Paperboard Plant wastewater treatment ponds. Associated uplift actions include a) burying of power lines that are a bird strike risk, and b) long-term assurance of management control of the property in order to manage for fish and wildlife.

The Lagoon Site properties (Figure 4; CMP Terminal Upland Habitat Mitigation Plan) are ponds that were utilized historically for processing of the Weyerhaeuser Paperboard facility that was located at the South Dunes site wastewater. The lagoons have undergone healing since the closing of the paperboard facility in the 1990's. Willow, alder, and vegetative plants are now present. The Lagoon site is currently degraded, but recovering wetland functions. The proposed mitigation uplift actions are burying an above-ground powerline, which would eliminate bird strikes.

ODFW acknowledges that bird strikes do occur with the presence of overhead powerlines. The Lagoon site has high levels of waterfowl use and placement of the powerline underground will eliminate this loss. Placing powerlines underground would provide direct in-kind mitigation for the extensive powerlines that will be constructed to serve the JCEP LNG terminal. However, it is unknown if heavy metals remain in the soils at the site. ODFW recommends a toxicity survey prior to considering this site fully as a mitigation area.

In-perpetuity stewardship of the parcel is considered highly valuable for preventing development impacts that potentially might occur. However, the parcel offers no immediate offset for the impacts at the JCEP site and does not result in added benefit ecologically for degraded function. ODFW does consider re-seeding beneficial, however, this will only involve a small portion of the property. It is unclear if a brownfield survey needs to be completed to ascertain if there could be improvement of the site through removal of toxic chemical compounds. ODFW previously recommended a number of actions that could provide uplift at the site including planting of waterfowl desirable plant species (e.g. wapato, wild rice, American sloughgrass), which would in part replace lost function for disturbance impacts to waterfowl in Henderson Marsh adjacent to the JCEP Terminal that will be degraded/eliminated. Function of the site for fish and wildlife could improve with several actions that are not proposed such as: 1) planting of Sitka spruce *(Picea sitkensis)* at appropriate elevations; 2) management of non-native beach grass combined with planting of native species; and 3) in-perpetuity control of non-native plants 4) placement of wood-duck nest boxes. If public access were allowed in perpetuity, ODFW recognizes the highly valuable benefits for recreational resources that the Lagoon Site could provide.

Overall, ODFW appreciates the JCEP project numerical accounting of upland impact quantity the long-term coordination through time with David Evans and Associates, and other consultants, to develop habitat categorization (Tables 4 and 5) in accordance with the ODFW Fish and Wildlife Mitigation Policy, as well as extensive efforts to locate appropriate mitigation. There are, however, discrepancies in the acreages between the Terminal Upland Habitat Mitigation Plan and Resource Report 3 (Table 1 in Appendix A; RR-3 Table 3.3.2). Resource Report 3 indicates 194.1 acres of habitats will be permanently impacted and another 227.4 acres will be temporarily impacted for construction staging for a total of 427.9 acres. In the body of the CMP the impacts (Tables 4 and 5) are listed as 345.8 acres of impact. It is also unclear if the accounting tables include impacts at the South Dunes site where workforce housing will be located and construction staging for the LNG terminal will be partially based.

PCGP Pipeline Impacts and Mitigation

General Comments

The PCGP (pipeline) portion of the project proposes construction of a 36” steel gas pipeline from the North Spit of Coos Bay, Oregon (229 miles) to Malin, OR in order to connect the JCEP export facility to the Ruby Pipeline carrying gas primarily from the Rocky Mountain region. The pipeline will cause significant direct and indirect impacts to fish and wildlife habitat, as well as the indirect impacts to water quality associated with an increase in watershed runoff caused by this project, particularly in areas where the pipeline is proposed on slopes exceeding 50%, and where vegetation will be removed from riparian corridors. Impacts are likely within the Coos, Coquille, South Umpqua, Upper Rogue, Upper Klamath, and Lost River watersheds.

ODFW remains concerned that mitigation planning for the pipeline has not adequately addressed impacts to state standards. Again, please see the ODFW letters referenced on Page 1 of this letter for a more thorough articulation of the impacts and mitigation insufficiencies.

While the applicant and federal agencies have attempted to address habitat mitigation needs for the marbled murrelet, northern spotted owl, and for wetlands and waterways, there is still no habitat mitigation planning for the other upland wildlife habitats impacted by the proposed pipeline. For example, in addition to conifer forests, the pipeline also passes through sagebrush shrub-steppe, juniper woodland, and oak woodland habitats. These habitats are important for a number of Oregon Conservation Strategy Species and as winter range for big game species. It is anticipated that the pipeline would have both temporary and permanent impacts to habitat quantity and quality in these vegetation communities, and yet offsets have not been proposed to meet state standards. This is a significant deficiency in the project proposal, both within- and outside of – the Coastal Zone Management Area.

Please refer to the sections below for a more detailed discussion of pipeline impacts and mitigation insufficiencies.

Pipeline Impacts to Water Quality and Quantity
It is the policy of the State of Oregon to maintain all species of fish and wildlife at optimum levels and prevent serious depletion (ORS 496.012, ORS 506.109). Water quality and quantity is an important need for all Oregon's fish and wildlife.

In many Oregon statutes and rules, ODFW is directed to provide comments to Oregon Water Resources Department (OWRD) regarding water use applications, permit extensions, or transfers of use (OAR 690-033, especially sections 120-140, 230, and 330) for new water applications; OAR 690-315 for extensions, and OAR 690-380 for transfers). As the state agency with fish and wildlife expertise, ODFW provides technical assistance to OWRD to ensure water use applications adequately protect fish and wildlife. ODFW also provides technical assistance to Oregon Department of Environmental Quality (ODEQ) related to water quality standards and Total Maximum Daily Loads (TMDLs) for their 401 Water Quality Certification permit program (ORS 468 and 468B; OAR 340-048; OAR 340-041). Many ODFW rules come into play in the development of this technical assistance, but the ODFW Fish and Wildlife Habitat Mitigation Policy (OAR 635-415) provides the overarching framework and is used as the implementing rule for ORS 496.012 and 506.109.

It is ODFW's understanding that the JCEP/PCGP applicants will be applying for OWRD applications after FERC's decision and prior to construction. It is also ODFW's understanding that the JCEP/PCGP applicants have not yet submitted their ODEQ 401 Water Quality Application. While ODFW does not have a comment on the sequencing of permit applications per se, FERC should be aware that some of the approaches outlined in the FEIS do not currently align with state standards. ODFW provides the following comments to FERC in an effort to address the expected impacts to water quality and quantity in the project area, and to highlight for you the insufficiencies in the project's current plans.

In order to review the potential impacts to water quality and quantity, ODFW reviewed the applicant's response to ODFW's DEIS comments, the FEIS (Part 1 – 3), FEIS Appendix R Part 2, the Jordan Cove Comprehensive Mitigation Plan (CMP) Main Document, and CMP attachments 5 (Conservation Measures), 12 (Groundwater Monitoring and Mitigation Plan), and 21 (PCGP Hydrostatic Testing Plan). ODFW's comments herein largely pertain to water withdrawals for the hydrostatic testing and dust control measures.

Water availability: In FERC's response (comment # SA2-225; Appendix R part 2) to ODFW DEIS comments, and elsewhere in the FEIS, FERC states "*We have included a limitation on water withdrawal to no more than 10 percent of the flow at the time of withdrawal. This flow reduction even in low flow would be adequate to protect resources. The flow restrictions process is handled through the State permitting. The State through this process can implement requirements deemed necessary to meet the State's permit requirements*". Again on page 79 of the CMP, the applicant states "overall change in any specific reduction in streamflow from [dust abatement] would likely be unsubstantial". ODFW does not find this response adequately addresses state standards. There are specific periods of time each year that instream flow targets in Project area streams are unmet. When instream flow targets are not met, a further reduction of 10% of the flow will impair or be detrimental to aquatic life. The response does not describe a contingency plan for when the State (through OWRD) determines water is not available or would harm aquatic life (through comments from ODFW or ODEQ). If a State permit is denied, water should not be withdrawn, even if limited to 10% of flow. Mitigation may also be required by OWRD, and the applicant should contact OWRD for more information.

Identification of instream water rights: When instream flow targets are not met, a further reduction of any flow will impair aquatic life, and OWRD may deny an application or require mitigation for new water use. Oregon statute requires transfers that injure an instream water right to provide a net benefit to the resource. Mitigation for a reduction of flow and impacts to fish and wildlife can be expensive and difficult to obtain. In FERC's response to ODFW DEIS comments, FERC states "*We assume that the State would determine if the Project is in compliance with the State requirements and OARS during their review of the Applicant's State permit applications. The State can include the requested information and mitigation as part of their State Permit requirements*". FERC is correct that it is the State's authority to determine compliance. However the applicant should be aware that a denial from OWRD could impact their construction timing. Preliminary identification of mitigation options in the project plans would lessen this risk.

Hydrostatic Testing and Dust Abatement: ODFW identified a number of issues associated with the PCGP's plans for hydrostatic testing and dust abatement. Those are outlined below.

The CMP (p. 15) states an intent to "*[include] screening intake hoses to prevent the entrainment of fish and other aquatic organisms, meeting NMFS screening criteria, and regulating the rate of withdrawal to avoid adverse impact on aquatic resources or downstream flows*". ODFW acknowledges the intent to meet screening criteria. However, regulating the rate of withdrawal should comply with OWRD permitting requirements, which may determine that withdrawal is not allowable. Contingency plans for any denials from OWRD have not been provided in the project's plans.

The CMP – Attachment 5 Conservation Measures states (p. 5; and again in the PCGP Hydrostatic Testing Plan) that all hydrostatic test water will be obtained from commercial or municipal sources, private supply wells, or surface water sources permitted through OWRD. The PCGP applicant should check with OWRD to ensure hydrostatic testing is a permitted use of targeted water rights. Oregon statute requires transfers that injure an instream water right to provide a mitigation net benefit to the resource. If mitigation cannot be obtained, OWRD may deny the application.

ODFW understands PCGP will release water within the same basin from which it was withdrawn, or will use pump screening to prevent invasive species transmission. ODFW believes consideration should also be given to the reduction in water quantity from the out-of-basin transfer of water.

The CMP – Attachment 12 Groundwater Monitoring and Mitigation Plan does not cover impacts to habitat from the diminishment of the quality or quantity of seeps and springs, only to water right holders. Seeps and springs play a crucial role for aquatic life in the State of Oregon.

Risks of Horizontal Directional Drilling

ODFW does not find that the risks of the pipeline's proposed horizontal directional drilling (HDD) under Oregon's waterways have been adequately assessed, nor that plans have adequately demonstrated that impacts to fish and wildlife would be avoided, minimized, or mitigated according to state regulatory standards (OAR 635-415; ORS 496.012; ORS 506.109).

While HDD can be less impactful than open-cut methods of crossing waterways, there are still risks for aquatic habitats associated with HDD including: 1) potential frac-out (the unintentional leak of drilling fluids through fractured rock) and subsequent drilling fluid "mud" delivery to the water column; 2) drill bore site soil rutting/denigration and soil erosion to the waterway; 3) drill bore site impacts to wetlands and riparian habitats. Release of drilling fluid ("mud") into waterways can result in heavy sediment plumes that potentially embed in fish spawning gravels, reduce fish ability to pursue food items due to poor visibility, and impact fish respiration by covering gill filaments.

ODFW's experience with other pipeline HDD projects in southwestern Oregon has shown that frac-outs can and do occur, as was the case on the 2003 Coos County Gas Pipeline HDD which had multiple frac-outs that spilled harmful chemicals and drilling mud into fish-bearing streams.

To address this risk, ODFW recommends that monetary bonds be retained at all the HDD sites on this project to cover mitigation costs associated with a frac-out event and the resulting fish/wildlife losses and habitat damages. The ODFW Fish and Wildlife Habitat Mitigation Policy states "the Department may recommend or require the posting of a bond, or other financial instrument acceptable to the Department, to cover the cost of mitigation actions based on the nature, extent, and duration of the impact and/or the risk of the mitigation plan not achieving mitigation goals" (OAR 635-415-0020(6)).

HDD in Coos Bay: In a meeting between the applicant and ODFW on January 3, 2020, the applicant noted that they will be revising the Coos Bay HDD plan to include: 1) that there will not be a need for dredging of equipment access channels to the drill bore site; 2) that the language will be adjusted in the HDD plan for the dual HDD with tie-in option. This revised written plan is necessary for ODFW to determine if the plan will sufficiently address concerns.

In the applicant's HDD plans, ODFW notes a limited number of geotechnical borings along the two-mile HDD line under Coos Bay. ODFW remains concerned that the frac-out risk may not have been adequately analyzed. This concern needs to be resolved prior to ODFW having sufficient information to determine if the proposed crossing strategy is considered a "reliable" method under OAR 635-415.

ODFW and the applicant are currently in discussions concerning the IWWW timing for the Coos Bay HDD. ODFW recommends the standard October 1 to February 15 IWWW for drilling. In addition, ODFW has strongly encouraged the applicant to construct the preparatory bore site pads during drier months, and to include access construction with rock base to prevent site rutting and sediment transport during wetter months. ODFW needs resolution of Coos Bay HDD construction timing prior to full assessment of the ability to meet the standards of the ODFW Fish and Wildlife Habitat Mitigation Policy.

Rogue River HDD Crossing: ODFW is highly concerned with the potential for frac-out risk at the Rogue River HDD site. The project engineering/design plans identify the pipeline crossing for the Rogue River is at milepost 122.6. The geotech survey indicates the pipe will be 56ft below the surface of the lowest thalweg location of the Rogue River, which may provide substantive overburden protection. However, a release of drilling fluid through the riverine and streambank portions of the 4,200+ft HDD would deliver drilling fluids directly to active Rogue River flow.

This reach of the Rogue River is just downstream from Trail Creek, and provides critical spawning habitat for endemic Rogue Basin spring Chinook *(Oncorhynchus tshawytscha).* Construction of William Jess Dam/Lost Creek Reservoir reduced the amount of spawning habitat available for spring Chinook salmon on the Rogue River. Spring Chinook spawning habitat is now limited to approximately 30 miles of the river just downstream of a barrier dam at Cole Rivers Fish Hatchery. Spring fed Big Butte Creek is the only tributary of the Rogue that is used by spawning spring Chinook on an annual basis. Because of dam construction, habitat volume is considered a limiting factor for the population in the Rogue Spring Chinook Salmon Conservation Plan (ODFW 2007).

Surveys conducted by ODFW during 2016-2018 found that, unlike some other rivers on the west coast, the Rogue spring Chinook population maintains a strong component of fish that are homozygous for the allele(s) that determine spring migration. Introgression with fall chinook genetic material is limited. Therefore, despite the limited habitat volume described above, the Rogue River maintains a genetically healthy population of spring Chinook. This knowledge has further increased the need to protect the ecological function of habitat that remains for this important population. A mistake here could have profound consequences.

Coos, Umpqua, Rogue, and Klamath Rivers HDD Work Timing: In addition to the monetary bonding recommended above to cover fish/wildlife population or habitat mitigation costs in the event of a frac-out, ODFW recommends the following as it pertains to ODFW In-Water Work Windows (*see ODFW 2008 "Oregon Guidelines for Timing of In-Water Work to Protect Fish and Wildlife Resources*).

- Coos HDD: The applicant has proposed performing the Coos River HDD during the October 1 to February 15th In-Water Work window (BA, Appendix M pdf pg 3). The PCGP proposed crossing at Lillian Creek of the Coos River is 2.3 miles downstream from the location where the prescribed ODFW In-Water Work window is July 1 to September 15th. ODFW considers the risks associated with equipment/drill bore soil disturbance during wet weather as the greater habitat function risk for this site and recommends the July 1 to September 15th In-Water Work window period for this HDD.
- Umpqua #1 Direct Pipe: The applicant has proposed the South Umpqua River Direct Pipe installation for July 1 to August 31st, (BA, Appendix M pdf pg 25), which is the standard In-Water Work window for this reach of river. ODFW concurs with use of this window for the Umpqua Direct Pipe.

- Rogue HDD: The applicant has proposed the Rogue HDD for June 15th to August 31st, (BA, Appendix M pdf pg 40), which is the standard ODFW In-Water Work window for this location. ODFW concurs with use of the proposed In-Water Window for the Rogue HDD crossing.
- Klamath River HDD: The applicant is proposing to implement this HDD during the July 1 to January 31st period (BA, Appendix M pdf pg 55). ODFW concurs with use of the proposed In-Water Window for the HDD crossing.

Pipeline Impacts to Forest Habitats in the Coast and Cascade Ranges

The comments in this section address the following impacts of the proposed pipeline to terrestrial wildlife that would be authorized by federal decisions from FERC, BLM, and USFS:

- Incomplete analysis of the Blue Ridge Variation
- Marbled murrelet habitat impacts and mitigation
- Northern spotted owl habitat impacts and mitigation
- Sufficiency of proposed mitigation in offsetting habitat loss for marbled murrelet, northern spotted owl, and other wildlife.

Incomplete Analysis of Blue Ridge Variation

In order to assess the impacts of this project on fish and wildlife, ODFW reviewed a number of sections within the FEIS. To the extent ODFW was able to review the tremendous volume of information, and the various versions of documents that have been submitted to the FERC docket, ODFW reviewed FEIS Sections 2.1.3, 2.1.4, 2.1.5, 2.6.3, 4.6, FEIS Appendices F.1 through F.12, and the Comprehensive Mitigation Plan provided by the Applicant to FERC and Cooperating Agencies in September 2019. ODFW also reviewed the FERC Biological Assessment (filed July 29, 2019, and included as part of Appendix I of the FEIS).

The FEIS Section 2.1.3 discusses impacts of the PCGP pipeline on Late Successional Reserve (LSR) and wildlife habitat in terms of acres, miles, and extent. However, it is not clear in every case that the numerical estimates represent the original proposed action in the DEIS or the newly-recommend Blue Ridge Variation. In some cases, for example in the BLM's summary of impacts (Section 2.1.4 and Section 4.6), the impact of the Blue Ridge Variation on total acres of impact for marbled murrelet suitable habitat and total acres of impact for the northern spotted owl are not provided. An acreage summary is only provided for those portions of the LSR crossed by the PCGP project where NSO and marbled murrelet habitats overlap. In this case, ODFW is unable to accurately assess habitat loss and address that loss in its comments.

ODFW also observed that the Biological Assessment in the FEIS, which was recently analyzed by the USFWS and NOAA, does not include the Blue Ridge Variation (NOAA Biological Opinion and Magnuson-Stevens Fishery Conservation and Management Act Essential Fish Habitat Response issued January 10, 2020; USFWS Biological and Conference Opinion issued by USFWS on January 17, 2020).

Without complete information quantifying the wildlife impacts of the Blue Ridge Variation, ODFW cannot fully assess the impacts and compare the consistency of the proposed mitigation with state standards.

Marbled Murrelet Habitat Impacts and Mitigation

The PCGP pipeline would cross occupied suitable habitat for the marbled murrelet. Marbled murrelet occupied suitable habitat would be impacted by both route variations under consideration, including the originally-proposed route analyzed in the DEIS and the new Blue Ridge Variation.

Marbled murrelets in Washington, Oregon, and California were listed as threatened under the federal Endangered Species Act in 1992, and were subsequently listed as state-threatened in Oregon under the Oregon Endangered Species Act in 1995. The species is listed as state-endangered in both Washington and California.

Nesting habitat loss and degradation is one of the primary threats to sustaining populations of the marbled murrelet. There is strong evidence of large-scale loss of older forests since European settlement within the marbled murrelet range in the Pacific Northwest and northwestern California (e.g., Booth 1991, Teensma et al. 1991, Bolsinger and Waddell 1993, Ripple 1994, Perry 1995, USFWS 1997, Wimberly et al. 2000, McShane et al. 2004, Strittholt et al. 2006, Ohmann et al. 2007, Davis et al. 2015). In the Oregon Coast Range, Wimberly and Ohmann (2004) estimated that large-conifer forests declined by 58% between 1936 and 1996, with corresponding increases in small-conifer forests during this period. Habitat loss and degradation were primary factors in the initial federal and state listings of the marbled murrelet in the 1990s (CDFG 1994, ODFW 1995, Desimone 2016, USFWS 1997, 57 FR 45328). Since the 1990s, further habitat losses have occurred, mainly due to timber harvest on non-federal lands and wildfire on federal lands (Raphael et al. 2016a).

Past habitat removal has created large gaps that fragment population distribution within the core of the marbled murrelet range (Ralph et al. 1995a, USFWS 1997, RIT 2012). In Oregon, large habitat gaps occur in the northwest portion of the state as well as the coastal strip between Reedsport and the Siskiyou Mountains (RIT 2012; Fig. 2 in ODFW 2018). Most remaining nesting habitat persists on federal lands in Oregon, including the Siuslaw and Rogue River-Siskiyou National Forests, forests owned by the Bureau of Land Management, and the state-owned and managed Tillamook, Clatsop, and Elliott State Forests (Raphael et al. 2016a; Fig. 2 in ODFW 2018). The full extent of occupied habitat on private lands is unknown since state regulations for forest practices do not require pre-project wildlife surveys by private landowners (Tucker and Weikel 2017a). However, marbled murrelet nesting habitat is generally assumed to be low on private lands given available forest stand inventory and harvest data (Greber et al. 1990, Ohmann et al. 2007) and ODFW's examination of the 2012 habitat suitability data produced by Raphael et al. (2016a) for Oregon (see ODFW 2018 for details).

Other environmental impacts such as adverse oceanic conditions, climate change, effects of oil spills, and other large-scale disturbances such as catastrophic fire, are also serious additive threats to the species' survival and recovery (ODFW 2018).

The Northwest Forest Plan, created in 1994, established a system of late-successional reserves (LSR) across the range of the marbled murrelet on both USFS and BLM lands. LSRs provide suitable nesting habitat over the long term for both murrelets, northern spotted owls, and other late successional dependent species (USDA FS and USDI BLM 1994).

Category 1 Habitat Issues for Marbled Murrelet: ODFW considers occupied suitable habitat for the marbled murrelet to be Category 1 habitat according to the ODFW Fish and Wildlife Habitat Mitigation Policy (OAR 635-415). Category 1 habitat is essential, limited, and irreplaceable within a reasonable time frame. The components of this determination are detailed below:

- "Occupied suitable habitat" (USFWS 2014) is defined the following manner:
    - Suitable Habitat: generally, includes old-growth forests within 50 miles of the coast and characterized by large trees, multi-storied stands, and moderate-to-high canopy coverage. Nest trees can be remnant old-growth trees in a stand of younger forest, but nest trees must have large branches or deformities such as high, moss-covered branches or branches with growths of dwarf mistletoe, which serve as nest platforms.
    - Occupied Suitable Habitat: Habitat in the vicinity of the proposed project that meets any of the following criteria:
        - Occupied Stand: is a stand that has been surveyed by the applicant, landowner, or manager, or others following the Pacific Seabird Group (PSG) protocol (Mack et al. 2003) and that encompasses an "occupied site"
        - Historically Occupied Stand: is a stand that was at any time known to be occupied by marbled murrelet. This includes stands where more recent surveys may have indicated that the status is not currently "occupied"
        - Unsurveyed Suitable Habitat (=Presumed Occupied): is an area or forested stand identified as potential nesting habitat that has not been ground-truthed for suitable nesting structures or surveyed following the PSG protocol, including areas with incomplete survey data (*e.g.*, where only one year of marbled murrelet surveys have been completed).

- The occupied suitable habitat in Oregon is "Essential" for the marbled murrelet because it supports reproduction for the species, which is a critical life history function. It is well-established that the decline in nesting habitat quantity and quality is the primary threat to marbled murrelet populations, and any further reduction would have significant impact to the population (see sources cited within ODFW 2018). The loss of this essential habitat depleted the murrelet population sufficiently to warrant listing under the federal and state Endangered Species Acts in the 1990s.

- The occupied suitable habitat in Oregon is also "Limited" for the marbled murrelet because they are tied to mature, late successional, old growth forest. As described above, an estimated 58% decline in late successional forests occurred between 1936 and 1996, and an estimated 9.2% further decline was documented between 1993 and 2012. What remains is highly fragmented, and at risk to fire, insect infestation, and disease.

- And finally, the occupied suitable habitat in Oregon is "Irreplaceable" because of the unreasonable time frame necessary to re-create late successional, old growth forests. While trees can be replanted and forests can be managed toward old growth condition, the time it takes to create the functions and values selected for by nesting murrelets (80-year old trees, multi-storied canopy, wide platform branches) interrupts nesting opportunity for at least 5 generations. This is not a reasonable mitigation time frame to allow for mitigation to replace the lost functions and values.

The extent of occupied suitable habitat follows the ‘continuous habitat’ descriptions in Mack et al. (2003), meaning the delineation of Category 1 habitat should include all of the sub-canopy detection area plus all of the area extending out from the sub-canopy detection until natural breaks in habitat 100 meters or larger are encountered. Therefore, a project that proposes to impact the edge of occupied suitable habitat is still impacting Category 1 habitat.

As per the ODFW Fish and Wildlife Habitat Mitigation Policy (OAR 635-415), the mitigation goal for Category 1 habitat is no loss of either habitat quantity or quality. The Oregon Fish and Wildlife Commission directs ODFW to protect Category 1 habitats by recommending (a) avoidance of impacts through alternatives to the proposed development action, or (b) no authorization of the proposed development action if impacts cannot be avoided.

Table 1 below provides a summary of ODFW’s understanding of the PCGP pipeline’s impacts to Category 1 habitat for the marbled murrelet. Sources used to generate these numbers include the FEIS Section 4.6 and the Effects Determination Section of the Biological Assessment (Appendix I of the FEIS). Given the volume and complexity and sometimes discrepancies among the information provided in the various planning documents for this project, ODFW seeks confirmation from the federal agencies that these estimates are in fact correct. Of note, these acreages are for the originally-proposed route as described in the current Biological Assessment. Similar summaries were not readily available for the Blue Ridge Variation.

Table 1. Summary of PCGP Pipeline Impacts to Marbled Murrelet Category 1 Habitat as Defined by the ODFW Fish and Wildlife Habitat Mitigation Policy (OAR 635 Division 415). Source for the acreages is the Jordan Cove/PCGP Biological Assessment dated July 2019.

Marbled Murrelet Known/Presumed-Occupied Suitable habitat that will potentially be….	Acres
Removed by the Right-of-Way or Temporary Work Areas (TEWAs)	78 (Approximately 71 federal, 7 private land)
Disrupted indirectly from construction noise and road noise (extending 0.25 mi from ROW)	7,145
Degraded from the indirect effects of increased edge, fragmentation, and increased predation	656

ODFW acknowledges the condition recommended by FERC, BLM, and USFS to avoid tree removal during the marbled murrelet breeding season. This is an important avoidance strategy; however, it does not offset the habitat loss associated with the permanent ROW and the TEWAs or the indirect effects of increasing forest that may degrade habitat quality over time.

ODFW does not find this level of impact to marbled murrelet Category 1 habitat consistent with the ODFW Fish and Wildlife Habitat Mitigation Policy, and therefore it is also not consistent with the State of Oregon's Wildlife Policy. ODFW recommends FERC consider alternative siting of the ROW that avoids impacts to Category 1 habitat for marbled murrelet.

Northern Spotted Owl Habitat Impacts and Mitigation

The PCGP pipeline would cross northern spotted owl (NSO) nesting, roosting, and foraging habitat. NSO habitat would be impacted by both route variations under consideration, including the originally-proposed route analyzed in the DEIS and the new Blue Ridge Variation.

Northern spotted owls are protected in Oregon by the state (listed in 1987) and federal (listed in 1990) Endangered Species Acts, where they are listed as threatened. The species also receives protections through the Oregon Forest Practices Act (FPA; OAR 629-665-0210).

NSO populations appear to have declined annually since 1985 when many studies began, and are currently declining at an average rate of 3.8 percent range-wide each year (Dugger et al. 2015). Loss and adverse modification of nesting, roosting, and foraging habitat due to timber harvesting and natural disturbances such as fire and windstorms, and competition with encroaching barred owls (*Strix varia*) have led to a decline of NSOs throughout much of their historic range (Davis et al. 2011, Dugger et al. 2015, Davis et. 2016). Wildfire has been the major cause of habitat loss on federal lands (e.g., National Forests and National Parks), where most NSO habitat is protected from timber harvesting by protective land management plans (Davis et. 2016). Timber harvest continues to be the primary cause of habitat loss on non-federal lands. Over the past decade it has become apparent that competition from the barred owl now poses a significant threat to the NSO (Dugger et al. 2015). Barred owls compete directly with NSOs for habitat and resources for nesting, roosting, and foraging.

Recovery efforts for the NSO are helping to reduce habitat loss on federal lands. Although the need for timber necessitates continued harvesting, current forest management practices stress more limited harvesting in older-age forests and suggest alternate areas for harvest which are less preferred by spotted owls. Careful planning of timber sales and forest conservation are necessary to halt the decline of the NSO. Large, continuous blocks of late-successional forest have been an element of NSO conservation strategies for over two decades.

Current management of federal forest lands in Oregon includes established network of lands reserved from logging. The Northwest Forest Plan, created in 1994, established a system of late-successional reserves (LSR) across the range of the spotted owl on USFS and BLM lands to provide suitable nesting habitat over the long term (USDA and USDI 1994). The federal forest lands outside these reserves are managed to allow dispersal between the LSRs through riparian reserves and other land allocations. In 2011, the USFWS issued a Revised Recovery Plan for the NSO that contains a wide array of recommendations, including protecting high-quality and occupied spotted owl habitat, actively managing forests to restore their health, and managing competition from the encroaching barred owl (USFWS 2011). The USFWS is currently conducting an experimental removal of barred owls from spotted owl habitat to assess the effect on NSOs. A new final rule designating critical habitat was published by the USFWS in December 2012. In 2016, the BLM replaced the Northwest Forest Plan for the management of

BLM-administered lands in western Oregon with an updated conservation strategy to maintain large, continuous blocks of late-successional forest because of new scientific information and policies related to the NSO (USDI BLM 2016a, 2016b).

Forest management operations on State and private lands in Oregon are governed by rules promulgated under the Oregon Forest Practices Act. The Act requires the Board of Forestry to adopt rules to protect Federal- and State-listed wildlife species. The Board of Forestry created NSO protection rules in 1991. The Oregon Forest Practices Act provides for protection of 70-acre owl core area around known nest sites on State and private lands. This rule is intended to protect the size of areas used by juvenile NSO prior to dispersal, which is about 70 acres (Miller 1989).

The existing science clearly establishes the importance of older more structurally-complex multi-layered conifer forests as NSO (Thomas et al. 1990, Courtney et. 2004). The NSO recovery plan recommends the maintenance of older and more structurally-complex multi-layered conifer forests (USFWS 2011). The results of previous analyses demonstrate that maintaining older and more structurally-complex multi-layered conifer forests would contribute to meeting the needs of the NSO (Davis et al. 2011, Dugger et al. 2015, Davis et. 2016). Therefore, maintaining older and more structurally-complex multi-layered conifer forest is a necessary part of the purpose of contributing to the conservation and recovery of the NSO.

Category 1 Habitat Issues for Northern Spotted Owl: While protection and enhancement of all NSO nesting, roosting, and foraging habitat (as defined in the USFWS 2014 Conservation Framework) is important for recovery of the northern spotted owl, ODFW is particularly concerned about impacts to habitat in the immediate vicinity of known nests and/or activity centers (referred to as a ‘resource site’ in the Oregon Forest Practices Act).

Consistent with the definitions in the Oregon Forest Practices Act (OAR 629-665-0210), ODFW uses the following definitions for terms used herein:

- ‘Resource sites’ consist of a 70-acre “core area” surrounding a NSO nest site or activity center of a pair of owls. The shape of the 70-acre core area depends on the characteristics of the forest, it must encompass the activity center or nest tree and consist of forest stands with structural characteristics known to represent nesting habitat for NSOs.
- On federal lands, ODFW considers known-occupied (surveyed according to protocol), historical, and presumed-occupied (unsurveyed but with relevant structural characteristics and/or designated by the federal land management agency) as NSO resource sites.

ODFW considers known/presumed-occupied resources sites for the NSO to be Category 1, meaning it is essential, limited, and irreplaceable within a reasonable time frame. The components of this determination are detailed below:

- The nesting resource site is “Essential” for the NSO because it supports reproduction for the species, which is a critical life history function. It is well-established that the decline in nesting habitat quantity and quality is one of the primary threats to NSO, and any further reduction would have significant impact to the population (as described and cited above). The loss of this essential habitat depleted the NSO population sufficiently to warrant listing under the federal and state Endangered Species Acts in the late 1980s and early 1990s respectively.

- NSO nesting resource sites in Oregon are also “Limited” because they are tied to mature, late successional, old growth forest. As described above, an estimated 58% decline in late successional forests occurred between 1936 and 1996, and an estimated 9.2% further decline was documented between 1993 and 2012. What remains is highly fragmented, and at risk to fire, infestation, and disease.

- And finally, the NSO nesting resource sites in Oregon are “Irreplaceable” because of the extended time frame necessary to re-create late successional, old growth forests. While trees can be replanted and forests can be managed toward old growth condition, the time it takes to create the functions and values selected for by nesting NSOs (mature forest stands with multi-layered and multi-species canopy, dense canopy closure [>60%], forest with large standing and fallen dead trees, and many trees with cavities and broken tops) interrupts nesting opportunity for multiple generations. This is not a reasonable mitigation time frame to allow for mitigation to replace the lost functions and values.

As per the ODFW Fish and Wildlife Habitat Mitigation Policy, the mitigation goal for Category 1 habitat is no loss of either habitat quantity or quality. The Oregon Fish and Wildlife Commission directs ODFW to protect Category 1 habitats by recommending or requiring (a) avoidance of impacts through alternatives to the proposed development action, or (b) no authorization of the proposed development action if impacts cannot be avoided.

Based on information in the Biological Assessment (Appendix I), and the BLM and USFS Supporting Documentation (Appendix F), it does appear that some amount of Category 1 habitat for northern spotted owls will be impacted by the project. ODFW has met on a number of occasions with the project applicant to review maps of northern spotted owl resource nest sites relative to the proposed ROW and surrounding area. However, final acreages of impact to Category 1 have not been settled and would require additional time beyond what was provided by this public notice.

ODFW acknowledges the condition recommended by FERC, BLM, and USFS to avoid tree removal during the northern spotted owl breeding season. This is an important avoidance strategy. However, it does not offset the habitat loss associated with the permanent ROW and the TEWAs or the indirect effects of increasing forest that may degrade habitat quality over time.

It is clear, however, that some NSO Category 1 habitat will be impacted. ODFW does not find any level of impact to NSO Category 1 habitat consistent with the ODFW mitigation policy, and therefore, it is not consistent with the State of Oregon’s Wildlife Policy. Construction of the project would remove and modify high value nesting, roosting, foraging habitat, dispersal, and capable habitat within the home range of 97 NSOs, 58 of which are currently below sustainable threshold levels of suitable habitat for continued persistence in their home range and/or core area. As such, ODFW recommends the BLM and USFS consider alternative siting design of the ROW to avoid impacts to NSO Category 1 habitat.

Mitigation Sufficiency for Marbled Murrelet, Northern Spotted Owl Category 2 Habitats: Outside of Category 1 habitats for the marbled murrelet and northern spotted owl, ODFW assumes that impacts to wildlife habitat could be offset depending on the ecological benefit and reasonableness of the proposed mitigation.

ODFW assumes that unoccupied (surveyed according to protocol) suitable habitat for the marbled murrelet would meet the Category 2 definition within the ODFW Fish and Wildlife Habitat Mitigation Policy. ODFW also assumes that marbled murrelet recruitment and capable habitat, as defined in the Biological Assessment as well as by USFWS (2014 Conservation Framework), can meet the definitions of Category 3 or lower, but that determination would need to be made on a site-specific basis given patterns of forest alteration and the existing forested stand structure.

The FEIS and supporting documents report that at least 517 acres of NSO nesting, roosting, and foraging habitat will be directly impacted by the project. The nesting resource sites within that 517 acres would be Category 1 habitat and ODFW recommends avoidance. However, ODFW would consider the remainder to fall within definitions of Category 2 according to its mitigation policy. As such, those impacts beyond the nesting resource site would likely be mitigatable.

However, without a cross-comparison of habitat impacts to habitat mitigation offsets according to the ODFW mitigation policy, it is not possible for ODFW to assess the sufficiency of the proposed mitigation actions designed to address impacts to marbled murrelet and NSO habitat. That said, ODFW provides the following feedback on the mitigation proposed in the FEIS.

Offsite Mitigation Proposed on Federal Lands: Appendix F of the FEIS contains the BLM and Forest Service Supporting Documentation, including proposed mitigation offsets for impacts to marbled murrelet and NSO. To that end, ODFW evaluated the relative merits of the proposed BLM and USFS mitigation actions. Please see ODFW protests of the BLM and USFS plan amendments referenced on page 1 of this letter for a full analysis.

ODFW recognizes the efforts of the USFS and the applicant in finding mitigation projects with features that seek to address impacts across a large and diverse landscape. Of particular note is that on the Umpqua and Rogue River National Forests, more late-successional old growth (LSOG) would be re-allocated from Matrix to LSR than would be impacted by the PCGP ROW and temporary work areas (TEWAs) within current LSR. However the FEIS does not include sufficient descriptions of whether and how the LSOG contained within the re-allocated Matrix lands matches or exceeds the quality of the LSOG being impacted by the project. Some of the mitigation actions proposed not only offset impacts, but could generate a net benefit in both quantity and quality. For example, the road decommissioning activities would reduce human disturbance impacts not only to marbled murrelet, but to other sensitive wildlife as well.

There are substantial acreages proposed for fuels reduction and stand density management on both USFS and BLM lands, which are designed to reduce the risk of catastrophic wildfire but also to potentially accelerate development of LSOG forest conditions. If properly designed with wildlife habitat goals helping to drive silvicultural plans, these projects could serve to offset the loss and degradation of habitat associated with the pipeline's construction activities. ODFW noted in the FEIS that these potential fuels reduction projects have not yet been scoped or approved nor described in any great detail. For this reason, fuels reduction projects carry uncertainty as mitigation. In addition, planning and approvals for these fuel reduction projects would likely take considerable time and public process, so there likely would be a time lag between the PCGP project's impacts to wildlife habitat and the implementation of a fuels reduction mitigation offset. This time lag would also be inconsistent with the ODFW mitigation policy, which recommends that mitigation actions occur prior-to or concurrent with the development action.

Offsite Compensatory Mitigation: In addition to on-site mitigation measures and the proposed mitigation projects on BLM and USFS lands, the Jordan Cove Comprehensive Mitigation Plan (Main Document, Sections 2.3 and 3.3) describes voluntary compensatory mitigation for the NSO and marbled murrelet, as proposed by the applicant. Compensatory mitigation measures proposed include:

- "*PCGP has an option agreement to purchase a minimum of 1,787.6 acres (Table 3.3-1) from a private forest company in the Oregon Coast range to off-set removal of 517 acres of LSOG (equivalent to NRF) habitat and impacts to dispersal/recruitment and capable habitat. A total of 1,057.5 acres of LSOG would be acquired. Another 150.1 acres is in age class 60 to 80 years, 20 years of reaching the nominal 80-year age of LSOG. All lands would be preserved in perpetuity. In the absence of PCGP's acquisition and preservation, approximately 275 acres in age class 40 to 80 years would be harvested within 1 to 5 years. Absent preservation, all stands would be subject to harvest in the future to the full extent allowable under the Oregon Forest Practices Act*".
- *"In addition, Jordan Cove is committed to funding up to $197,400 (plus reasonable administrative overhead) to support the barred owl management program in a manner to be determined by the FWS".*
- *"PCGP is proposing to provide $350,000 (plus reasonable administrative overhead) to support a program, identified by the U.S. Fish and Wildlife Service, to reduce MAMU nest predation. The supported program(s) would be designed to reduce nest predation by corvids, generally through public outreach efforts (including seasonal interpretive rangers and materials) and control of anthropogenic food sources at Oregon State Parks that support or are adjacent to MAMU suitable habitat".*

It is possible that the applicant's proposed compensatory mitigation could offset impacts to Category 2 habitat for the marbled murrelet and NSO. The mitigation goal for Category 2 habitat impacts is no net loss of habitat quantity or quality and a net benefit of either habitat quantity or quality. The ODFW Fish and Wildlife Habitat Mitigation Policy further guides Category 2 habitat mitigation to be in-kind and in-proximity. The proposed predator management programs would likely provide valuable benefits to habitat <u>quality</u> for both the marbled murrelet and the NSO populations in Oregon, However, the CMP does not provide sufficient information for ODFW to determine if the proposed forest acquisition will achieve the goal of no net loss in habitat <u>quantity</u>. To make that determination, ODFW would need additional information regarding location, forest structure and presence of habitat features important to both species, species occupancy information, proposed habitat uplift actions for the mitigation site, and demonstrated durability of the mitigation area for the life of the PCGP project's impacts.

Mitigation for Other Forest Dwelling Species: At this time, mitigation impacts to habitat for coastal marten, fisher, and big game winter range is not fully described in the FEIS or the

Comprehensive Mitigation Plan. ODFW recommends these plans be more fully developed to the in-kind, and in-proximity standards of the ODFW mitigation policy so as to achieve no net loss of habitat.

Pipeline Impacts to Riparian Habitat and Fish-bearing Streams
The PCGP pipeline will remove a 75-foot wide swath of riparian forest at 155 fish-bearing stream crossings (PCGP Comprehensive Mitigation Plan pg ES-9) in the 229-mile route from Coos Bay to Malin. The PCGP route traverses through a number of ecoregions and stream habitats that are highly important for production of fish and wildlife linked to aquatic habitats including: Oregon Coast (OC) coho salmon (*Oncorhynchus kisutch*) (ESA threatened), fall and spring Chinook salmon (*O. tshawytscha*), Pacific lamprey *(Entosphenus tridentata),* Lost River sucker *(Catostomus luxatus/Deltistes luxatus)*, winter steelhead *(O. mykiss irrideus),* coastal cutthroat trout (*O. clarki clarki*), river otter *(Lutra canadensis*), mink *(Neovison vison),* American beaver (*Castor canadensis*), common merganser *(Mergus merganser*), and numerous others.

Although a large number of the proposed pipeline stream crossings are on private land, a notable smaller number are on BLM lands in the Coos Bay, Roseburg, Medford, and Klamath Falls districts. Additionally, there are proposed pipeline stream crossings on the USFS Winema and Rogue National Forests. Please see the aforementioned ODFW Protests of the BLM Resource Management Plan Amendments and USFS Forest Plan Amendments for a more detailed description of the potential stream impacts.

The potential negative effects to aquatic/stream habitats through implementation of the PCGP project will reduce the productive value of the habitats of native fish and amphibians that use these streams and waterways. ODFW has evaluated both the direct and indirect impacts the proposed PCGP project would have in relation to stream, river, and wetland habitats and the subsequent effects to productive capacity of these habitats for native fish and wildlife. ODFW recommends further development of avoidance and mitigation measures to address these concerns.

Upland Steep Slope and Pipeline Corridor Sediment Concerns
There are numerous critical concerns with the risk of placing the PCGP pipeline on steep slopes, especially when the pipeline is routed perpendicular to slopes. Coastal sandstone soils are highly susceptible to mass-wasting when undercut, deconsolidated, de-vegetated, and generally disturbed. The excavation of the pipeline trench and associated soil disturbance will unconsolidate soils removing the ionic bonds of the colloids resulting in a highly erosive condition. A secondary factor, the extensive access road network that will be created to access the pipeline installation and facilitate pipeline maintenance, will further create potential for mass-wasting slope failures and general sediment production over the current condition. Stream productive capacity for numerous anadromous fish streams in the Coos and Coquille River basins has been assessed as “poor” (scale: “very poor”; “poor; fair”; “good”; “excellent”) with similar stream health conditions in the South Umpqua River basin, and varying health of streams in the Rogue and Klamath basins. This “poor” condition rating is in many cases related to upland disturbance factors that have increased sediment loading and the loss of riparian forest and LWD since 1900. Sediment transport to streams is considered a substantial factor currently suppressing

recovery of OC coho salmon. Extensive research has documented the impacts of sediments to salmonids.

A number of miles of the pipeline will be constructed on slopes that are adjacent to slopes that exceed 50% or on slopes that are over 30%. Tyee sandstone geology in the Coos and Coquille River basins and the geology of the Rogue Basin to a lesser degree are highly prone to landslides if the supporting matrix is disturbed. Klamath basin streams are also vulnerable to impacts from erosion and sediment delivery. Chronic turbidity is a substantive force currently suppressing ecological productivity for salmonids in these watersheds. Mass wasting debris torrents and general erosion are considered a substantial threat to the function of stream habitats for ESA listed and non-ESA listed salmonids, and the wildlife that depend on these fish.

The PCGP will result in timber removal initially that is 95 feet in width. Within the logged corridor of the pipeline, the trenched area will include full excavation of the soil profile and adjacent ground disturbance from heavy equipment. In addition to the PCGP and the associated ROW, numerous access roads will be built to harvest timber and for pipeline construction. These activities will likely create conditions that produce new sources of both acute and chronic sedimentation.

ODFW continues to recommend interagency coordination to design measures of avoiding, minimizing, and mitigating the impacts of erosion and sediment transport of sediments into Oregon's stream networks. Management of erosion and transport of sediments to stream networks is foundationally critical for enhancing spawning and rearing habitat for fall Chinook salmon, OC coho salmon, Pacific lamprey, winter steelhead and coastal cutthroat trout as water quality is directly linked to hatch rates and food available for these species. Sediment loading above natural background levels contributes to embedding of substrates, which often results in reduced hatch rates for eggs in redds, inability of fry to emerge from redds, inhibited production of macroinvertebrates (invertebrates largely live in the interstitial spaces of gravels), and impacts on the ability of fish to obtain food due to the nature of salmonids to feed predominantly by using their sight (Burns 1970; Hall and Lanz 1969;Weiser and Wright 1988; Suttle et al. 2004; Tripp and Poulin 1992; Waters 1995). For these reasons, ODFW has repeatedly made recommendations to FERC and the Cooperating Agencies that there be interagency coordination in order to fully address these resource concerns.

Pipeline Aquatic Habitat Mitigation Sufficiency Review
Nearly all aquatic habitats that will be affected within the 229-mile PCGP corridor have a habitat categorization of 4 or higher, and ODFW recommends the impacts be offset to achieve a mitigation goal of no net loss (per OAR 635-415). However, habitat categorization was not included in the FEIS and is based on draft maps ODFW received from the project applicant. Please see the aforementioned ODFW Protests of the BLM Resource Management Plan Amendments and USFS Forest Plan Amendments for a more detailed description of the potential stream impacts.

Some of the proposed mitigation for aquatic impacts is not in-proximity. For example, in the Coos River basin where over 20 miles of pipeline impacts occur to stream/aquatic habitats, no mitigation projects proposed in that HUC 4 watershed were identified. A number of these stream and upland impacts will directly or indirectly impact estuarine wetlands and coho habitat that are considered essential and limited (category 2) according to state standards.

Stream Crossing/Riparian Mitigation: The BLM and USFS have been asked to develop a large number of mitigation projects to address PCGP impacts including stream crossing riparian forest removal.

- Temperature***:*** The applicant's modeling fails to address cumulative impacts that can occur within watersheds over a relatively short stream distance and temporal period. Although modeling suggested that 0.3˚F is likely to be the largest thermal impact to a stream segment through installation of the PCGP for an individual stream, this can be largely increased if other landscape projects (e. g. timber harvest, road building, home construction, fire, etc.) within a watershed are within the time period prior to recovery of the shade component at a particular impact location. The CMP identifies 44 projects on BLM lands (CMP pdf pg 30) designed to mitigate directly for aquatic impacts, and another 13 projects on USFS lands. These projects range from fish passage and sediment management to placement of LWD. However, the mitigation does not identify any projects that directly produce in-kind canopy mitigation for harvest of trees adjacent to the PCGP 155 stream crossings. The PCGP project has offered a single project designed to specifically develop riparian canopy on Spencer Creek in the Winema National Forest. However, local ODFW staff believe the likelihood this project would produce substantive ecological benefit is low, because degraded stream conditions downstream will nullify benefits. In order to address riparian forest impacts associated with the PCGP, ODFW's DEIS comments included recommendations for projects to align with the ODFW Fish and Wildlife Habitat Mitigation Policy mitigative actions that are "In-Kind." For example, projects that enhance stream buffers on private forest lands through long-term or in perpetuity easements would serve as direct ecological benefit for impacts. ODFW recommends that FERC revisit and adopt ODFW's DEIS comment recommendations to sufficiently mitigate for these impacts.

- Loss of future LWD potential***:*** The removal of the riparian forest from stream crossings to facilitate the PCGP will result in mostly permanent impacts. ODFW does recognize that over a long-term period there will be some encroachment into the access corridor by riparian forest up to the boundaries of the allowable ROW, which will provide limited recovery. However, there will be a habitat function gap in these segments through time. Large Woody Debris from the stream adjacent slopes and upslope to Stand Potential Tree height will not be allowed to grow and recruit to streams within the PCGP corridor. This zone will be managed for low stature ground cover vegetative species that will not replace lost function of the timber overstory. ODFW has calculated that the PCGP project has potential to remove up to 8,073+ trees (based on standard observed stocking rates in riparian habitats) in the PCGP stream crossing zones. If conservatively one-half of these trees through time are likely to fall towards and into the stream, then a total of 3,836 trees would be removed that would have potentially been available for creation of LWD instream complexity. The review of proposed mitigation on federal lands to offset impacts of the PCGP collectively identifies placement of 1,257 individual LWD pieces.

This results in a in a direct mitigation inequality of 2,597 trees. ODFW recommends that the federal cooperating agencies and applicant develop a coordination plan with ODFW for the overall goal of evaluating the lost functions of the PCGP impacts within the ODFW mitigation policy framework and corresponding mitigation actions.

ODFW recognizes that a notable quantity of soil stabilization projects will be implemented during construction of the PCGP. These BMP's are important for minimizing effects, but recovery of permanent ground cover vegetation to reach maximum effectiveness will likely take 5-8 years at some locations. After that time the pipeline corridor will be vulnerable long-term to greater soil erosion due to lack of overhead canopy that softens rainfall patterns. The proposed access road networks will likely have long-term chronic effects to fish and wildlife unless seeded, mulched, and closed. The pipeline corridor will have elevated sediment delivery for a number of years post-project despite BMP's. Additionally, there will be a greater potential for landslides to occur within the corridor due to the lack of timber following construction that currently provides hydrograph buffering through evapotranspiration processes that reduce overall water yield resulting in more modest forces on soils and stream morphology.

Comparison of Proposed BLM and USFS Mitigation and ODFW Mitigation Policy: ODFW reviewed the proposed PCGP riparian, wetland and waterbody mitigation projects (Jordan Cove CMP Attachment 28 PCGP Wetland Waterbody Riparian Mitigation Plan, Revised July 2018, and Attachment 11 Forest Service Proposed Amendments and CMP, March 2019). ODFW is unable to confirm that mitigation actions will meet the definitions and standards of the ODFW Fish and Wildlife Habitat Mitigation Policy because of:

1) Very limited location information
2) Little or no current condition information
3) A lack of information on the exact treatment that will provide offset/ecological uplift.

ODFW recommends further development of the mitigation proposals through interagency coordination. Some of the proposed BLM and USFS mitigation projects would be considered by ODFW to meet the threshold of in-kind because they would help to reduce sediment production/delivery to streams and waterways. However, not all projects would meet this threshold. The array of projects includes: road sediment abatement, road drainage, and replacement of failing culverts, which have potential to provide correlative benefit to offset the potential turbidity impacts of the PCGP project corridor and road construction ground disturbance. However, given the limited information available to ODFW at this time, it is not entirely clear how the proposed projects will achieve the mitigation goals of no net loss and net benefit in habitat quantity and quality.

In order to properly assess whether the sediment abatement projects meet the rigor of fully mitigating for impacts, ODFW recommends complete information on the proposed project actions including at a minimum:

1) GPS location and detailed current condition of habitat function(s) or lack thereof
2) Previous land management actions within the HUC 6 of the proposed project that are relevant to the proposed uplift
3) Fish passage status of upstream/downstream reaches from the project area
4) Future land management strategies proposed at the HUC 6 level that may affect performance of the project in the future

Concluding Remarks

ODFW requests FERC give full consideration to ODFW's concerns and recommendations provided herein, and the letters referenced on page 1. ODFW does not find the JCEP/PCGP plans contained within the FERC FEIS to be fully consistent with the State of Oregon's fish and wildlife protection statutes and rules. ODFW is open to working with the applicant and the federal and state regulatory agencies to try and resolve these remaining issues. Your primary point of contact continues to be Sarah Reif, Energy Coordinator, who can be reached at sarah.j.reif@state.or.us or 503-947-6082.

The analysis and comments in this letter were authored by the following ODFW staff:
Sarah Reif, Energy Coordinator, Wildlife Division
Christopher Claire, Habitat Protection Biologist, Charleston Field Office
Dr. Steve Rumrill, Shellfish Program Leader, Marine Resource Program
Greg Apke, Statewide Fish Passage Program Leader, Fish Division
Danette Faucera, Water Policy Coordinator, Fish Division

Thank you for your consideration of Oregon's fish and wildlife resources.

Sincerely,

Sarah Reif

Sarah Reif
Energy Coordinator

Oregon
Kate Brown, Governor

Department of Land Conservation and Development
Oregon Coastal Management Program
635 Capitol Street NE, Suite 150
Salem, Oregon 97301-2540
Phone: 503-373-0050
Fax: 503-378-6033
www.oregon.gov/LCD

February 19, 2020

Mike Koski
Jordan Cove Energy Project, LP
Pacific Connector Gas Pipeline, LP
Email: mkoski@pembina.com

Project:	*Jordan Cove Energy Project/Pacific Connector Gas Pipeline* US Army Corps Federal Permit No.: NWP-2017-41 FERC Docket Nos: CP17-495-000 and CP17-494-000
Applicants:	Jordan Cove Energy Project, LP and Pacific Connector Gas Pipeline, LP
Location:	Coos Bay, Oregon and Pipeline Route within Coastal Zone
Re:	**Federal Consistency Determination**

Dear Mr. Koski:

The Oregon Department of Land Conservation and Development (DLCD) has completed its review of the Joint Coastal Zone Management Act Certifications that Jordan Cove Energy Project and Pacific Connector Gas Pipeline (JCEP) submitted on April 12, 2019. JCEP certifies that the proposed project complies with, and will be conducted in a manner consistent with, the Oregon Coastal Management Program (OCMP). Pursuant to the section 307(c)(3)(A) of the Coastal Zone Management Act (CZMA), its regulation at 15 CFR § 930.63, and having fully considered the project information and public comments submitted, DLCD **objects** to your consistency certification on the basis that it has not established consistency with specific enforceable policies of the OCMP and that it is not supported by adequate information.

JCEP has applied for two major federal permits/licenses needed for the proposed project: the section 404 of the Clean Water Act/section 10 of the Rivers and Harbors Act permits managed by the US Army Corps of Engineers (Corps or USACE) and the Natural Gas Act section 3 Authorization and section 7 Certificate of Public Convenience and Necessity managed by the Federal Energy Regulatory Commission (FERC). The activity that JCEP proposes is to site, construct, and operate a natural gas liquefaction and liquefied natural gas (LNG) export facility on the bay side of the North Spit of Coos Bay, Oregon. To supply the LNG Export Terminal with natural gas, JCEP is proposing to construct and operate a new, approximately 229-mile-long natural gas transmission pipeline and compressor station from interconnections with the existing Ruby Pipeline LLC and Gas Transmission Northwest LLC systems to the LNG Export Terminal. After careful review of the proposed project, in conjunction with receiving extensive public comment, and coordination with coastal partners, **DLCD has determined that the coastal adverse effects from the project will be significant and undermine the vision set forth by the OCMP and its enforceable policies**. Coastal effects analyses show that the project will negatively impact Oregon's coastal scenic and aesthetic resources, a variety of endangered and threatened species, critical

Wildfire risk

Oregon faces great wildfire risk. The proposed activity could substantially increase wildfire risk from human and equipment activity in heavily timbered areas during PCGP pipeline construction and operation. The majority of the pipeline route is forested and vulnerable to wildfire. Pipeline construction would occur primarily during "fire season." Pipeline construction employs the use of feller-bunchers, chainsaws, bulldozers, track-hoes, rock saws, and other heavy equipment, as well as blasting. Pipeline rupture and explosion during operation is a risk. Areas of the project have extensive soil and seismic characteristics present. Evidence of numerous areas at risk of soil liquefaction and lateral spreading, and extensive landslide-prone conditions have already been identified across the 229-mile route. The Pipeline and Hazardous Materials Safety Administration (PHMSA) reported an increasing number of ruptures and explosions nationwide due to particularly weather-related landslides. PHMSA also issued two sets of protocols calling for renewed efforts to site, engineer, build, and monitor gas pipelines.[57] Landslides can be found along the pipeline route.

Flight Hazards

The proposed project would be situated less than 1.1 miles from the Southwest Oregon Regional Airport located in North Bend. The Federal Aviation Administration (FAA) issued four notices of presumed hazard for the two LNG tanks at the terminal and the two towers at the south dune power plant. These LNG infrastructure facilities violate the FAA Obstruction Standard. This geographical area is regularly consumed naturally by fog and visual impairment is regularly compromised imposing a potential air to surface collision and explosion hazard to the residents of Coos Bay and North Bend. FAA has issued 13 Notices of Presumed Hazard regarding the proximity of the local airport and flight paths to proposed LNG tanks.

Cumulative Effects

Cumulative adverse coastal effects have been defined as the effects of an activity when added to the baseline of other past, present, and future activities in the area of, and adjacent to, the coastal zone. Thus, an analysis of cumulative effects considers the adverse coastal effects of a project when added to the temporary or permanent effects associated with other activities that already are likely to occur. DLCD notes that there are many unmitigable impacts that the proposed activity would have on public health, safety, clean air, clean water, healthy forests, the local economy, and a stable climate.

Channel Modification

DLCD considers cumulative effects from additional large-scale projects in Coos Bay as part of this federal consistency review. This is particularly important related to a proposed Channel Modification project by the Port of Coos Bay. The JCEP terminal will dredge a combined total of 5.7 million cubic yards (CY) from North Spit and Coos Bay in order to create the slip for ships to load LNG and navigate along the Coos Bay

[57] PHMSA, "Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geologic Hazards," Federal Register, 5/2/2019.

April 10, 2020

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

Re: *Pacific Connector Gas Pipeline, LP* and *Jordan Cove Energy Project L.P.*
Docket Nos. CP17-494-000 and CP17-495-000
Acceptance of Order Granting Authorizations

Dear Ms. Bose:

By order dated March 19, 2020 in the above referenced dockets, the Federal Energy Regulatory Commission ("Commission") granted authorization pursuant to Section 3 of the Natural Gas Act ("NGA") for Jordan Cove Energy Project L.P. ("JCEP") to site, construct, and operate a proposed liquefied natural gas terminal and associated facilities.[1] The Order also granted a certificate of public convenience and necessity pursuant to Section 7(c) of the NGA to Pacific Connector Gas Pipeline, LP ("PCGP", and together with JCEP, "Applicants") to construct, install, own, and operate a new natural gas pipeline.[2]

Pursuant to Section 157.20(a) of the Commission's regulations and Ordering Paragraph (D)(2) of the Order, Applicants hereby accept the authorizations issued in the Order.[3] This acceptance is without prejudice to the statutory rights of Applicants pursuant to Section 19(a) of the NGA and the Commission's regulations, including the right to request rehearing and/or seek clarification of the Order.[4] Applicants appreciate the efforts of the Commission and its Staff in processing the applications in these proceedings and in issuing the Order.

Should you have any questions, please contact me at dowens@pembina.com or 832-255-3841.

Sincerely,

/s/ David Owens
David Owens
Jordan Cove Energy Project L.P.
Pacific Connector Gas Pipeline, LP

cc: All Parties (CP17-494-000 and CP17-495-000)

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[1] *Jordan Cove Energy Project L.P.* and *Pacific Connector Gas Pipeline, LP*, 170 FERC ¶ 61,202 (2020) ("Order").
[2] *Id*.
[3] 18 C.F.R. § 157.20(a) (2019).
[4] 17 U.S.C. § 717r(a) (2018).

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATOR COMMISSION

Jordan Cove Energy Project L.P.	)	Docket Nos. CP17-495-000
Pacific Connector Gas Pipeline L.P.	)	CP17-494-000

REQUEST FOR REHEARING BY THE
COW CREEK BAND OF UMPQUA TRIBE OF INDIANS

Pursuant to Section 19(a) of the Natural Gas Act ("NGA"), 15 U.S.C. § 717r(a), and Rule 713 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.713, the Cow Creek Band of Umpqua Tribe of Indians ("Tribe") hereby requests rehearing of the Order Granting Authorizations Under Sections 3 and 7 of the Natural Gas Act ("Order") issued on March 19, 2020, in the above captioned dockets.

As explained in detail below, the Commission should grant the Tribe's request for rehearing of the Order, because: (1) the Final Environmental Impact Statement ("FEIS") failed to take a "hard look" at cultural resource impacts of the Project; (2) the Order failed to require the completion of the National Historic Preservation Act ("NHPA") Section 106 process or improperly deferred the completion of the process; (3) the Commission has engaged in the development of NHPA Section 106 Memorandum of Agreement ("MOA") instead of a Programmatic Agreement ("PA"); and (4) the Order improperly conditioned the Commission's approval on a determination of consistency with the Coastal Zone Management Plan issued by the State of Oregon, as required by the Coastal Zone Management Act ("CZMA").

I. STATEMENT OF FACTS

On September 21, 2017, Jordan Cove Energy Project L.P. filed an application requesting authorization, pursuant to Section 3(a) of the NGA, to site, construct, and operate a new liquified

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Jordan Cove Energy Project L.P.	)	Docket Nos. CP17-495-000
Pacific Connector Gas Pipeline, L.P.	)	and CP 17-494-000
	)	

REQUEST FOR REHEARING OF NATURAL RESOURCES DEFENSE COUNCIL

Pursuant to Section 19(a) of the Natural Gas Act (NGA)[1] and Rule 713 of the Federal Energy Regulatory Commission's (Commission) Rules of Practice and Procedure,[2] Natural Resources Defense Council (NRDC), an intervenor in this proceeding,[3] respectfully requests rehearing of the Commission's March 19, 2020 "Order Granting Authorizations Under Sections 3 and 7 of the Natural Gas Act" (Certificate Order) authorizing the Jordan Cove LNG Terminal and the Pacific Connector Gas Pipeline (collectively, the Project).[4] This request is timely, having been filed within 30 days of the Commission's Certificate Order.[5]

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[1] 15 U.S.C. § 717r(a).

[2] 18 C.F.R. § 385.713.

[3] NRDC timely moved to intervene in this proceeding on July 5, 2019 on the basis of the draft Environmental Impact Statement. Accession No. 20190705-5164. As the Commission's regulations implementing NEPA state, "[a]ny person who files a motion to intervene on the basis of a draft environmental impact statement will be deemed to have filed a timely motion, in accordance with [18 C.F.R.] § 385.214, as long as the motion is filed within the comment period for the draft environmental impact statement." 18 C.F.R. § 380.10(a)(1). *See also Jordan Cove Energy Project L.P.*, 170 FERC ¶ 61,202 (2020), at P 22 & n.30 (hereinafter Certificate Order).

[4] NRDC also joins and fully supports the arguments outlined in Sierra Club *et al.*'s coalition request for rehearing and stay.

[5] The Commission issued the Certificate Order on Thursday, March 19, 2020. Under the NGA and the Commission's regulations, a request for rehearing is due 30 days after issuance of the Certificate Order. 15 U.S.C. § 717(a); 18 C.F.R. § 385.713. Thirty days from March 19, 2020 is Saturday, April 18,

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Jordan Cove Energy Project, L.P.	**)**	**Docket No. CP17-495-000**
Pacific Connector Gas Pipeline, L.P.	**)**	**Docket No. CP17-494-000**

REQUEST FOR REHEARING
OF OREGON DEPARTMENT OF ENERGY,
OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY,
OREGON DEPARTMENT OF FISH AND WILDLIFE,
AND OREGON DEPARTMENT OF LAND CONSERVATION AND DEVELOPMENT

Pursuant to the Natural Gas Act, 15 U.S.C. § 717r(a), and Rule 713 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") Rules of Practice and Procedure, 18 C.F.R. § 385.713 (2018), Intervenors the Oregon Department of Land Conservation and Development ("DLCD"), the Oregon Department of Energy ("ODOE"), the Oregon Department of Environmental Quality ("DEQ"), and the Oregon Department of Fish and Wildlife ("ODFW") (collectively, "State Intervenors") hereby request rehearing of the FERC's Order Granting Authorizations Under Sections 3 and 7 of the Natural Gas Act (March 19, 2020) ("March 19, 2020 Order" or "Order"). 170 FERC ¶ 61,202.

The Order approved applications for the construction and operation of the Jordan Cove Liquified Natural Gas Terminal under Section 3 of the Natural Gas Act ("NGA"), 15 U.S.C. § 717b ("Section 3"), and for the construction and operation of the Pacific Connector Pipeline under Section 7 of the NGA, 15 U.S.C. § 717f ("Section 7"), (collectively, the "Authorizations"). The

Department of Justice
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project. Despite having spent much time over the past year conferring with Oregon DEQ, Pacific Connector has not developed plans to show whether or how mitigation can occur at the locations and in the amounts required. In the absence of data showing that there are mitigation sites capable of accommodating the required planting, requirements that were established to protect salmonids including bull trout and Southern Oregon Northern California coho, the conclusion in the FEIS that such impacts are insignificant or can be mitigated is not supported in the record. Courts have concluded that a federal agency's unsupported conclusion that mitigation will be effective in light of known violations of water quality standards is arbitrary and capricious. *See Am. Rivers v. Fed. Energy Regulatory Comm'n*, 895 F.3d 32, 53–54 (D.C. Cir. 2018); *Save Our Cabinets v. United States Dep't of Agric.*, 254 F. Supp. 3d 1241, 1254–55 (D. Mont. 2017), *judgment entered*, No. CV 16-53-M-DWM, 2017 WL 2829681 (D. Mont. June 29, 2017), *dismissed sub nom. Save Our Cabinets v. United States Fish & Wildlife Serv.*, No. 17-35694, 2018 WL 1091533 (9th Cir. Feb. 23, 2018).

CONCLUSION

For the foregoing reasons, the State Intervenors respectfully request that FERC grant this request for rehearing, withdraw the Order, and issue a new order denying the Section 3 and Section 7 Authorizations.

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DATED this 20th day of April 2020.

Respectfully submitted,

Ellen F. Rosenblum
Attorney General

/s/ Jesse D. Ratcliffe
____

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/s/ Paul A. Garrahan
____

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

In the Matter of

JORDAN COVE ENERGY PROJECT, L.P.	CP17-495-000
PACIFIC CONNECTOR GAS PIPELINE, LP	CP17-494-000

REQUEST FOR REHEARING AND STAY OF ORDER 170 FERC ¶ 61,202, GRANTING AUTHORIZATIONS UNDER SECTIONS 3 AND 7 OF THE NATURAL GAS ACT

Pursuant to section 19(a) of the Natural Gas Act, 15 U.S.C. § 717r(a), and rule 713 of the Federal Energy Regulatory Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713, Sierra Club, the Niskanen Center (on behalf of affected landowners Bill Gow, Sharon Gow, Neal C. Brown Family LLC, Wilfred E. Brown, Elizabeth A. Hyde, Barbara L. Brown, Pamela Brown Ordway, Chet N. Brown, Evans Schaaf Family LLC, Deb Evans, Ron Schaaf, Stacey McLaughlin, Craig McLaughlin, Richard Brown, Twyla Brown, Clarence Adams, Stephany Adams, Will McKinley, Wendy McKinley, Frank Adams, Lorraine Spurlock, Toni Woolsey, Alisa Acosta, Gerrit Boshuizen, Cornelis Boshuizen, Robert Clarke, John Clarke, Carol Munch, Ron Munch, Mitzi Sulffridge, James Dahlman, and Joan Dahlman), the Western Environmental Law Center, Klamath Tribes, Center for Biological Diversity, Oregon Wild, Rogue Riverkeeper, Pacific Coast Federation of Fishermen's Associations (PCFFA), Institute for Fisheries Resources (IFR), Greater Good Oregon, Friends of Living Oregon Waters (FLOW), Surfrider Foundation, Oregon Women's Land Trust, Oregon Shores Conservation Coalition, League of Women Voters of Coos County, Umpqua Valley, Rogue Valley, and Klamath County, Rogue Climate, Umpqua Watersheds, Waterkeeper Alliance, Coast Range Forest Watch, Cascadia Wildlands, Oregon Physicians for Social Responsibility, Hair on Fire Oregon, and Citizens for Renewables/ Citizens Against LNG, Francis Eatherington, Janet Hodder, Michael Graybilland, and Natural Resources Defense Council (collectively, "Intervenors"), hereby request rehearing of FERC's "Order Granting Authorizations" ("Order") in the above-captioned matters, issued March 19, 2020. In addition, Intervenors request a stay of this order, pursuant to 5 U.S.C. § 705.

FERC granted the Intervenors' respective motions to intervene in these dockets, as affirmed in the Order P21. Thus, each Intervenor is a "party" to this proceeding, 18 C.F.R. § 385.214(c), with standing to file this request for rehearing. A list of addresses for communication regarding this request is provided starting on page 116 of this document.

We request that the Order and deficient final environmental impact statement ("FEIS") be withdrawn, and the environmental analysis, public convenience and necessity, and public interest analyses be redone in a manner that complies with the Commission's obligations under the Fifth Amendment, National Environmental Policy Act, 42 U.S.C. § 4321 *et seq*, Natural Gas Act, 15 U.S.C. § 717 *et seq.*, and other statutes.

I. Concise Statement of Alleged Errors

A. FERC's conclusion that the terminal and pipeline are in the public interest, as required by sections 3 and 7 of the Natural Gas Act, is arbitrary and capricious.

1. FERC's conclusion that the Pacific Connector Pipeline is needed or has market support is arbitrary. FERC's refusal to "look behind" the precedent agreement is arbitrary where there is only one purported buyer, the buyer is an affiliate, the project is speculative, and the agreement was quickly entered in response to FERC's 2016 denial of the prior application—all factors identified as undermining the value of precedent agreements in FERC's Certificate Policy Statement or other precedent. *Certification of New Interstate Nat. Gas Pipeline Facilities*, 88 FERC ¶ 61227, 61746 (Sept. 15, 1999); *Independence Pipeline Co.*, 89 FERC ¶ 61,283 (1999). There is no evidence indicating that Jordan Cove has market support; FERC can and must address this fact in FERC's section 7 review of the pipeline, and doing so does not intrude upon the Department of Energy's exclusive section 3 authority. *EarthReports, Inc. v. FERC*, 828 F.3d 949, 953 (D.C. Cir. 2016).

2. FERC failed to explain why it is lawful to credit export capacity towards an assessment of market demand for what they categorize as a pipeline carrying gas in "interstate commerce," when interstate commerce does not include foreign commerce under section 7 of the NGA. *City of Oberlin, Ohio v. FERC*, 937 F.3d 599 (D.C. Cir. 2019).

3. FERC has an obligation to ensure that a project satisfies the 5th Amendment's Takings Clause's "public use" or "public benefit" requirement in addition to being necessary for the public convenience and necessity. *City of Oberlin, Ohio v. FERC*, 937 F.3d 599 (D.C. Cir. 2019).

4. An export-only project does not provide public benefits pertinent to section 7 of the NGA or the 5th Amendment's takings clause even if the project has market

support. *City of Oberlin, Ohio v. FERC*, 937 F.3d 599 (D.C. Cir. 2019).

5. A project that will export only Canadian gas does not provide any public benefits under either section 7 or the 5th Amendment's public use requirement, and provides only private benefits to Pembina. *City of Oberlin, Ohio v. FERC*, 937 F.3d 599 (D.C. Cir. 2019); *Kelo v. City of New London, Conn.*, 545 U.S. 469 (2005).

6. FERC provided no explanation as to why the benefits of the project outweigh adverse impacts on landowners, communities, and the environment. *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

B. Issuance of a conditional certificate was unlawful.

1. Both the Clean Water Act and Coastal Zone Management Act apply, by their text, to FERC's issuance of the certificate, rather than commencement of construction. 33 U.S.C. § 1341(a)(1),16 U.S.C. § 1456(c)(3)(A). Issuance of a certificate conditioned on future Oregon approval under these authorities is unlawful, especially where Oregon has already explicitly denied such approval.

2. Approving the project prior to completion of cultural resource surveys and consultation with Tribes precludes FERC from full disclosing the impacts of the project, violating NEPA. 42 U.S.C. § 4332 *et seq.*

3. FERC violated the Endangered Species Act by issuing of certificate requiring the Blue Ridge Alternative without consulation with the Fish and Wildlife Service or National Marine Fisheries Service regarding that alternative. 16 U.S.C. § 1536(d).

4. Issuance of a certificate conditioned on future receipt of required permits violates the Fifth Amendment, as it permits the taking of property without a public benefit *Matter of National Fuel Gas Supply Corporation v. Schueckler*, 2018 N.Y. App. Div. LEXIS 7566 (4th Dept. 2018), appeal docketed December 7, 2018.

5. FERC's failure to prohibit quick take condemnation violates the Fifth Amendment, as it permits the taking of property prior to payment of just compensation. *Knick v. Scott Township*, --- U.S. ---, 139 S.Ct. 2162 (2019).

C. FERC's process in reviewing and approving the projects was unlawful.

1. The draft EIS was so incomplete as to preclude meaningful public participation. 40 C.F.R. § 1502.9(a).

2. FERC’s failure to ensure that all landowners received notice required by the Due Process Clause in a proceeding which may result in the taking of their property violated landowners’ due process rights, a violation exacerbated by FERC’s failure to release the lists of landowners to whom notice was allegedly provided by the Applicant. *Mullane v. Central Hanover Bank & Trust Co.*, 339 U.S. 306 (1950); *M.A.K. Inv. Grp., LLC v. City of Glendale*, 897 F.3d 1303 (10th Cir. 2018); *Brody v. Vill. of Port Chester*, 434 F.3d 121 (2d Cir. 2005).

3. FERC failed to clearly articulate adequate reasons for denying various motions for evidentiary hearing. *Gen. Motors Corp. v. Fed. Energy Regulatory Comm'n*, 656 F.2d 791, 798 (D.C. Cir. 1981)

D. FERC violated NEPA by failing to rigorously explore reasonable alternative terminal designs. 40 C.F.R. § 1502.14. The record does not support FERC’s stated reasons for rejecting alternative slip and berth designs. FERC entirely failed to consider alternatives that would reduce the use of electricity from the grid by making greater use of on-site waste heat.

E. FERC violated NEPA by failing to take a hard look at safety impacts. *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 350 (1989).

1. FERC entirely failed to consider the impact of the terminal’s thermal plume on aviation, despite Federal Aviation Administration identifying such plumes as potentially incompatible with safe airport operation. FERC provided an incomplete analysis of structural hazards to aviation.

2. FERC failed to take a hard look at how pipeline construction and operation will increase the risk of forest fire.

3. FERC violated the Endangered Species Act by relying on Biological Opinions that FERC has reason to know are flawed. *Ctr. for Biological Diversity v. U.S. Bureau of Land Mgmt.*, 698 F.3d 1101, 1118 (9th Cir. 2012).

F. FERC failed to take a hard look at the impact of greenhouse gas emissions.

1. FERC has the authority and obligation to consider greenhouse gas emissions in its NEPA and NGA analyses. *Sierra Club v. FERC*, 867 F.3d 1357, 1373 (D.C. Cir. 2017) (“*Sabal Trail*”).

2. FERC’s conclusion that it cannot determine the significance or importance of greenhouse gas emission is arbitrary, especially in light of Oregon’s legislatively-

adopted greenhouse gas emission reduction targets, OR. REV. STAT. § 468A.205, and "generally accepted" methods of using social cost to estimate the impact of greenhouse gas emissions. 40 C.F.R. § 1502.22(b)(4).

3. FERC's conclusion that it cannot evaluate the significance or severity of greenhouse gas emissions undermines FERC's conclusion that overall environmental impacts are, with few specific exceptions, insignificant, and prevents FERC from properly making the NGA public interest determination. *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43; *Sabal Trail*, 867 F.3d at 1373.

G. The Department of Energy's review of whether to authorize exports to non-Free Trade Agreement nations is a "connected action" that must be considered in the FEIS here. 40 C.F.R. § 1508.25(a)(1), Flanagan South, 803 F.3d at 50. The FEIS was therefore required to consider indirect impacts on gas production and use. 40 C.F.R. 1508.8(b).

H. FERC has failed to fully address impacts to landowners, and to ensure that they were adequately mitigated. *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332 (1989).

I. FERC failed to take a hard look at how the pipeline will violate applicable forest plans. The Forest Service's proposal to amend those forest plans violates the Forest Planning Rule, and FERC should not have approved the pipeline until these issues are resolved.

J. FERC violated NEPA by failing to take a hard look at pipeline and terminal impacts to surface and groundwater. *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 350 (1989).

II. Argument

A. FERC's Interpretation and Application of Section 7 of the Natural Gas Act Is Unlawful

1. No One Wants to Buy LNG from Jordan Cove, and FERC Cannot Ignore This Fact

In 2016, FERC correctly denied applications for the projects because the applicants had failed to identify even a single buyer for the proposed LNG exports. Four years later, there is still no evidence of any buyer. FERC's conclusion that it lacks authority to address this issue, Order

P34,[1] is legally incorrect, and FERC's refusal to address the consequences of this complete lack of actual market support is arbitrary.

FERC cannot approve a pipeline under section 7 of the Natural Gas Act, as FERC has done here, without engaging in a robust inquiry into whether the pipeline is required by the public convenience and necessity. A key part of that inquiry is whether the pipeline has market support. "Landowners should not be subject to eminent domain for projects that are not financially viable and therefore may not be viable in the marketplace." *Certification of New Interstate Nat. Gas Pipeline Facilities*, 88 FERC ¶ 61227, 61746 (Sept. 15, 1999). A pipeline that no one will actually use cannot be "required by . . . public convenience and necessity," 15 U.S.C. § 717f(e) and provides no benefit to the public.

Here, the record demonstrates that the pipeline, if built, will be unused. The pipeline exists to supply the terminal, and the pipeline will not be used unless someone is purchasing LNG from the terminal. As FERC extensively documented in its 2016 denial, the applicants had ample opportunity to provide evidence of such a buyer, and failed to do so. The Terminal *has no customers or any use for the gas*, and it has provided no evidence whatsoever that it ever will. Global gas markets, and LNG markets in particular, are saturated and are unlikely to prove more favorable to Jordan Cove in the future. *See Sierra Club et al. Protest, CP17-494 and CP17-495*;, *The Questionable Economics of Jordan Cove LNG Terminal*, McCullough Research (June 2019), annexed to July 5, 2019 Niskanen Center Comments as Exhibit 26; *Natural Gas Supplies for the Proposed Jordan Cove LNG Terminal*, McCullough Research (July 3, 2019), annexed to July 5, 2019 Niskanen Center Comments as Exhibit 18. FERC did not dispute any of the evidence Intervenors and other parties provided regarding Jordan Cove's present lack of customers and dismal prospects for acquiring customers in the future; FERC simply argued that this evidence was irrelevant. Order P34. This outright refusal to confront evidence before it, bearing on a

[1] "We find that these issues regarding global market support (*i.e.*, whether exports from Jordan Cove LNG Terminal are supported by global market conditions) are beyond the Commission's purview, as they relate to exportation of the commodity and not to construction and operation of the terminal."

EXECUTIVE ORDER NO. 20-04

DIRECTING STATE AGENCIES TO TAKE ACTIONS TO REDUCE AND REGULATE GREENHOUSE GAS EMISSIONS

WHEREAS, climate change and ocean acidification caused by greenhouse gas (GHG) emissions are having significant detrimental effects on public health and on Oregon's economic vitality, natural resources, and environment; and

WHEREAS, climate change has a disproportionate effect on the physical, mental, financial, and cultural wellbeing of impacted communities, such as Native American tribes, communities of color, rural communities, coastal communities, lower-income households, and other communities traditionally underrepresented in public processes, who typically have fewer resources for adapting to climate change and are therefore the most vulnerable to displacement, adverse health effects, job loss, property damage, and other effects of climate change; and

WHEREAS, climate change is contributing to an increase in the frequency and severity of wildfires in Oregon, endangering public health and safety and damaging rural economies; and

WHEREAS, the world's leading climate scientists, including those in the Oregon Climate Change Research Institute, predict that these serious impacts of climate change will worsen if prompt action is not taken to curb emissions; and

WHEREAS, the Intergovernmental Panel on Climate Change has identified limiting global warming to 2 degrees Celsius or less as necessary to avoid potentially catastrophic climate change impacts, and remaining below this threshold requires accelerated reductions in GHG emissions to levels at least 80 percent below 1990 levels by 2050; and

WHEREAS, Oregon, as a member of the U.S. Climate Alliance, has committed to implementing policies to advance the emissions reduction goals of the international Paris Agreement; and

WHEREAS, GHG emissions present a significant threat to Oregon's public health, economy, safety, and environment; and

WHEREAS, the transition from fossil fuels to cleaner energy resources can significantly reduce emissions and increase energy security and the resilience of Oregon communities in the face of climate change; and

WHEREAS, emissions from the transportation sector are the single largest source of GHG emissions in Oregon; and

WHEREAS, actions to reduce GHG emissions in Oregon's transportation sector will provide substantial public health co-benefits by reducing air pollutants from the combustion of gasoline and diesel fuel that are harmful to human health; and

WHEREAS, the rapid transition from internal combustion engines to zero-emission vehicles will play a key role in reducing emissions from the transportation sector and advancing the state's GHG emissions reduction goals; and

WHEREAS, zero-emission vehicles provide multiple benefits to Oregonians, including lower operating, maintenance, and fuel costs, and lower emissions of GHGs and other pollutants; and

WHEREAS, the Legislature established ambitious goals for the adoption of zero-emission vehicles in Senate Bill 1044 (2019); and

WHEREAS, rapid actions and investments by Oregon's utility sector to reduce GHG emissions and improve the resilience of the energy system in the face of climate change and wildfire risk can reduce risks for utility customers; and

WHEREAS, transitioning the traditional natural gas supply to renewable natural gas can significantly reduce GHG emissions; and

WHEREAS, energy efficiency standards in the built environment can reduce operating costs, save renters and homeowners money on their utility bills, improve the comfort and habitability of dwellings, and reduce GHG emissions; and

WHEREAS, product energy efficiency standards reduce costs for consumers, save energy, and reduce GHG emissions; and

WHEREAS, in the absence of effective federal engagement on these issues, it is the responsibility of individual states to take immediate actions to address climate change and ocean acidification; and

WHEREAS, after thorough hearings within the Oregon Legislature, a majority of both chambers support addressing climate change, and the failure of the Oregon Legislature to attain quorum has thwarted legislative action to achieve science-based GHG emissions reduction goals; and

WHEREAS, given the urgency and severity of the risks from climate change and ocean acidification, and the failure of the Legislature to address these immediate harms, the executive branch has a responsibility to the electorate, and a scientific, economic, and moral imperative to reduce GHG emissions and to reduce the worst risks of climate change and ocean acidification for future generations, to the greatest extent possible within existing laws; and

WHEREAS, existing laws grant authority to state agencies to take actions to regulate and encourage a reduction of GHG emissions in a variety of circumstances; and

WHEREAS, the Legislature through the Emergency Board took action on March 9, 2020, to provide permanent funding to the executive branch to pursue executive action on reducing GHG emissions; and

WHEREAS, considering climate change in agency planning and decision making will help inform decisions regarding climate change risks and avoid higher mitigation and adaptation costs in the future; and

WHEREAS, all agencies with jurisdiction over the sources of GHG emissions will need to continue to develop and implement programs that reduce emissions to reach the state's GHG goals; and

WHEREAS, all agencies with jurisdiction over natural and working landscapes in Oregon will need to prepare and plan for the impacts of climate change and take actions to encourage carbon sequestration and storage; and

WHEREAS, the Legislature previously established the goal of achieving GHG levels "at least 75 percent below 1990 levels" by 2050, and our State has an urgent, moral obligation to set and achieve more ambitious GHG reduction goals.

NOW, THEREFORE, IT IS HEREBY DIRECTED AND ORDERED:

1. **State Agencies**. The following state commissions and state agencies are subject to the directives set forth in this Executive Order:

A. Business Oregon;

B. Department of Administrative Services (DAS);

C. Department of Consumer and Business Services Building Codes Division (BCD);

D. Department of Land Conservation and Development (DLCD) and Land Conservation and Development Commission (LCDC);

E. Environmental Justice Task Force;

F. Environmental Quality Commission (EQC) and Department of Environmental Quality (DEQ);

G. Oregon Department of Agriculture (ODA);

H. Oregon Department of Energy (ODOE);

I. Oregon Department of Fish and Wildlife (ODFW);

J. Oregon Department of Forestry (ODF);

K. Oregon Department of Transportation (ODOT) and Oregon Transportation Commission (OTC);

L. Oregon Global Warming Commission;

M. Oregon Health Authority (OHA);

N. Oregon Water Resources Department (OWRD);

O. Oregon Watershed Enhancement Board (OWEB); and

P. Public Utility Commission of Oregon (PUC).

2. **<u>GHG Emissions Reduction Goals</u>**. Consistent with the minimum GHG reduction goals set forth in ORS 468A.205(1)(c), this Executive Order establishes science-based GHG emissions reduction goals, and calls for the State of Oregon to reduce its GHG emissions (1) at least 45 percent below 1990 emissions levels by 2035; and (2) at least 80 percent below 1990 emissions levels by 2050.

3. **<u>General Directives to State Agencies</u>**. From the date of this Executive Order, the state commissions and state agencies listed in paragraph 1 are directed to take the following actions:

   A. <u>GHG Reduction Goals</u>. Agencies shall exercise any and all authority and discretion vested in them by law to help facilitate Oregon's achievement of the GHG emissions reduction goals set forth in paragraph 2 of this Executive Order.

   B. <u>Expedited Agency Processes</u>. To the full extent allowed by law, agencies shall prioritize and expedite any processes and procedures, including but not limited to rulemaking processes and agency dockets, that could accelerate reductions in GHG emissions.

   C. <u>Agency Decisions</u>. To the full extent allowed by law, agencies shall consider and integrate climate change, climate change impacts, and the state's GHG emissions reduction goals into their planning, budgets, investments, and policy making decisions. While carrying out that directive, agencies are directed to:

      (1) Prioritize actions that reduce GHG emissions in a cost-effective manner;

      (2) Prioritize actions that will help vulnerable populations and impacted communities adapt to climate change impacts; and

      (3) Consult with the Environmental Justice Task Force when evaluating climate change mitigation and adaptation priorities and actions.

   D. <u>Report on Proposed Actions</u>. The following agencies are directed to report to the Governor by May 15, 2020, on proposed actions within their statutory authority to reduce GHG emissions and mitigate climate change impacts: DEQ, DLCD, ODA, ODOE, ODFW, ODF, ODOT, OWRD, OWEB, and PUC.

McCullough Research

ROBERT F. MCCULLOUGH, JR.
PRINCIPAL

Date: April 20, 2020

To: David Bookbinder

From: Robert McCullough

Subject: Supplement to July 3, 2019 report entitled "Natural Gas Supplies for the Proposed Jordan Cove LNG Terminal"

On March 19, 2020, FERC issued an order giving the Jordan Cove Energy Project ("JCEP") permission to proceed on a project unlikely ever to be operated and, currently, is unfinanceable.

The basic issue is economics. JCEP, at current prices, could not afford to buy, transport, process, and ship natural gas to Japan for anywhere near its costs. An updated version of our 2019 analysis indicates that JCEP's costs are U.S.$6.43 per mmbtu.[1] At that cost, the

	Jordan Cove	LNG Canada	Cheniere
Output (MTPA)	7.8	14	31.5
Pipeline ($ billions)	$ 2.46	$ 4.77	
Project ($ billions)	$ 7.30	$ 10.77	$ 30.00
Required Margin for FID ($ billions)	$ 0.98	$ 1.55	$ 3.00
Total ($ billions)	$ 10.74	$ 17.09	$ 33.00
Total Per MTPA ($ billions)	$ 1.38	$ 1.22	$ 1.05
Annualized/MTPA ($ billions)	$ 0.15	$ 0.13	$ 0.11
Annualized/MMBTU ($)	$ 2.96	$ 2.63	$ 2.26
O&M $ billions)	$ 0.04	$ 0.04	$ 0.02
O&M/MMBTU ($)	$ 0.84	$ 0.74	$ 0.32
Break Even ($/mmbtu)	$ 3.80	$ 3.37	$ 2.58
Transportation ($/mmbtu)	$ 0.87	$ 0.87	$ 1.50
Required Margin ($/mmbtu)	$ 4.67	$ 4.24	$ 4.08
AECO ($/mmbtu)	$ 1.75	$ 1.75	$ 1.75
Delivered Cost ($/mmbtu)	$ 6.43	$ 6.00	$ 5.83

[1]. "Break Even" represents the cost required to provide "tolling" a third party's natural gas into LNG. "Required Margin" is the margin above the cost of Alberta natural gas delivered to Japan. "Delivered Cost" is the total cost of LNG landed in Japan. https://www.mresearch.com/the-questionable-economics-of-jordan-cove-lng-terminal-revised/

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project could not turn a profit through to 2023 – the last date JKM prices are quoted on the appropriate Chicago Mercantile Exchange market.[2]

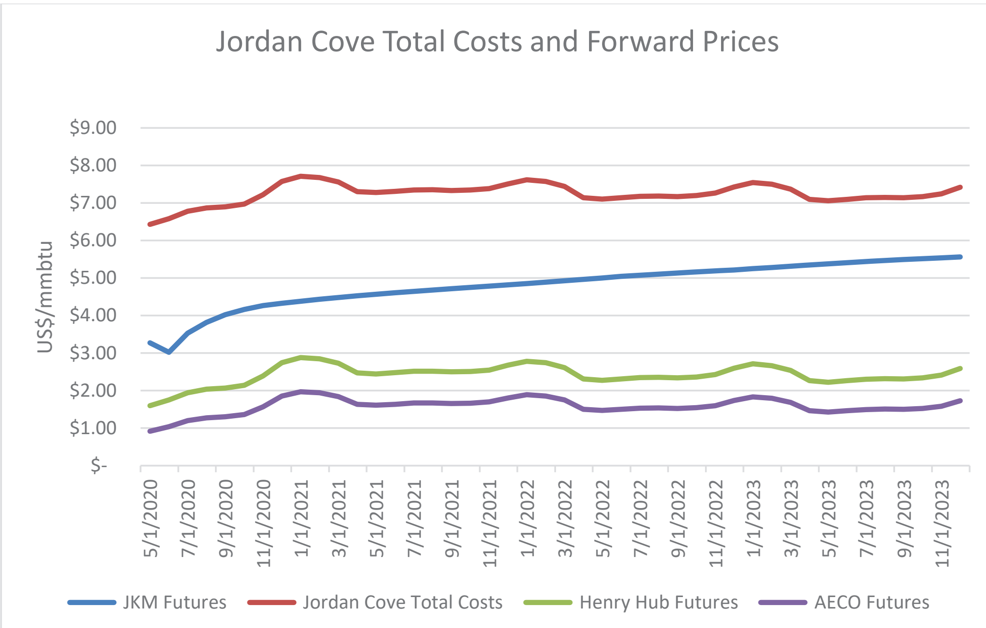

Figure 1 Jordan Cove Costs and Forward Prices

Any due diligence on the project would first review whether the project could afford to purchase natural gas and sell the LNG in Japan or Korea at a profit. For out as far as prices are quoted for the Japanese Korea Marker (JKM), this is not the case. The red line is the cost of Jordan Cove LNG delivered to Japan.

The approval of this project constitutes an unpaid option conferred on a foreign investor, while also imposing real costs on U.S. citizens. This enables Pembina to sell the project to a third party, while does not require them to actually build the pipeline, transport natural gas, or process the natural gas into LNG.

In its approval of the JCEP, FERC stated that:

[2] https://www.cmegroup.com/trading/energy/natural-gas/lng-japan-korea-marker-platts-swap_quotes_settlements_futures.html/

> Here are no proposed LNG export terminal proposals in the same geographic area and temporal scope as the Jordan Cove LNG Terminal, so that preparing a programmatic EIS would not assist in our decision making. Thus, we find a programmatic EIS is neither required nor useful under the circumstances here.[3]

This is a very odd comment. As the FERC commissioners should know, Jordan Cove is just one of more than twenty LNG projects that have been proposed for Oregon and British Columbia. Two of these projects, Jordan Cove and Oregon LNG, were subject to FERC's regulatory review. Another thirty projects have been given export permits by Canada's National Energy Board, although some of the projects have secured more than one permit.[4] At this point, none of the projects appear viable, although two of the Canadian projects have commenced construction.[5]

A central feature of the FERC order was the assumption that there are credible and committed customers for the proposed Pacific Connector pipeline from Malin, Oregon to Coos Bay, Oregon. Unfortunately, the only customers for the pipeline are affiliates of the owner of the project. No other purchasers are likely since contracting for space on the pipeline is required to carry natural gas that the project cannot afford and to process the natural gas in a project that the proponent cannot build. This would be a substantial gamble for a third party. Inter-affiliate transactions are not a gamble for the proponent, since the transaction can simply be cancelled at a later date.

Although the project could not currently pass any form of lender due diligence, I have updated the Monte Carlo study from our June 5 2019 report, cited in our July J, 2019 report.

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

[3] Order Granting Authorizations Under Sections 3 And 7 Of The Natural Gas Act, March 19, 2020, page 70.
[4] https://www.cer-rec.gc.ca/pplctnflng/mjrpp/lngxprtlcnc/index-eng.html
[5] Woodbine has contractor and financing challenges. LNG Canada's owners have recently reduced their work force by 50%.

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 2 below.

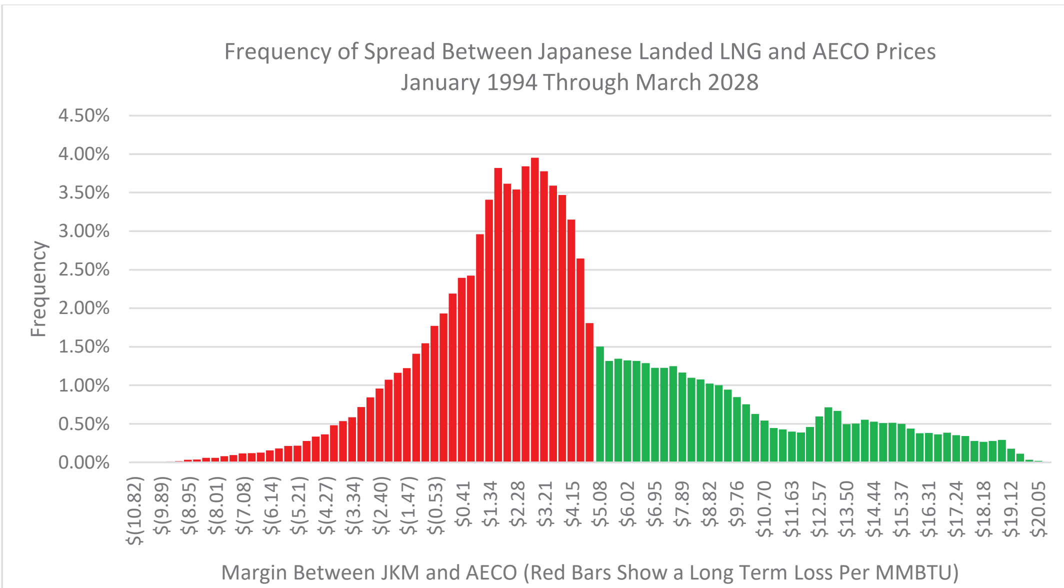

Figure 2: Monte Carlo Results

The Monte Carlo study complements the conclusions raised in Figure 1. Even assuming that the prices for landed LNG in Japan and Korea are incorrect, any prudent investor would investigate how often such a project could be profitable over market conditions since 1994. The answer is daunting – the project would only meet or exceed its costs 30% of the time.

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 JCEP, let alone earn any profits.

Robert McCullough
Portland, Oregon
April 20, 2020

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pacific Connector Gas Pipeline, L.P.	Docket No. CP17-494-000
Jordan Cove Energy Project, L.P.	Docket No. CP 17-495-000

REQUEST FOR REHEARING
of Jody McCaffree / Citizens for Renewables / Citizens Against LNG

Pursuant to Section 19(a) of the Natural Gas Act, 15 U.S.C. §717r(a), and Rule 713 of the Rules of Practice of the Federal Energy Regulatory Commission (FERC), 18 C.F.R. §385.713, the aggrieved parties, Jody McCaffree, individually and as the Executive Director of Citizens for Renewables /Citizens Against LNG (collectively "CFR Intervenors") hereby request rehearing of the Commission's "Order Granting Authorization Under Section 3 and 7 of the Natural Gas Act", 170 FERC ¶ 61.202, issued March 19, 2020 (Order) in the docketed matters; CP17-494-000 and CP17-495-000.

CFR Intervenors request that FERC withdraw, vacate, or modify its order and prepare a new Environmental Impact Statement (EIS) that considers the issues outlined in this petition. FERC granted CFR Intervenors intervention status and they submitted written comments and testimony opposing issuance of the approvals and certificates granted by FERC's order, thereby establishing their aggrievement.

STATEMENT OF ISSUES AND ERRORS

1. FERC's decision approving the siting of the proposed LNG terminal and associated pipelines under Section 7 violates both Sections 3 and 7 of the Natural Gas Act, because the proposed exportation of Canadian liquefied natural gas to overseas countries makes the pipeline an export pipeline and it is otherwise not consistent with the U.S. of America public interest, as the significant and substantial negative environmental impacts of the terminal and pipeline outweigh the purported but not adequately demonstrated need for the export of fossil fuels in the Pacific Northwest. 15 U.S.C. § 717b(a); *Certification of New Interstate Natural Gas Pipeline Facilities (Certificate Policy Statement)*, 88 FERC ¶ 61,227 (1999), and clarifying orders, 90 FERC ¶ 61,128 (2000) and 92 FERC ¶ 61,094 (2000) (collectively Certificate Policy). The PCGP is a defacto export pipeline and is not eligible for a section 7 certificate. In addition, having rejected Jordan Cove's reliance on its permits to export natural gas to demonstrate public

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Jordan Cove Energy Project L.P.	)	**Docket Nos.**	**CP17-495-000**
Pacific Connector Gas Pipeline, LP	)		**CP17-494-000**

CONFEDERATED TRIBES OF THE COOS, LOWER UMPQUA AND SIUSLAW INDIANS' REQUEST FOR REHEARING AND CLARIFICATION OF ORDER GRANTING AUTHORIZATIONS UNDER SECTIONS 3 AND 7 OF THE NATURAL GAS ACT

Pursuant to Section 19(a) of the Natural Gas Act ("NGA"), 15 U.S.C. § 717r(a), and Rule 713 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Rules of Practice and Procedure, 18 C.F.R. § 385.713, the Confederated Tribes of the Coos, Lower Umpqua and Siuslaw Indians ("CTCLUSI" or "Tribe") hereby request rehearing of the Commission's March 19, 2020 Order Granting Authorizations under Sections 3 and 7 of the Natural Gas Act[1] in the above titled matters. In addition, the Tribe seeks clarification of a portion of the Order. The grounds for these requests are specifically set forth below.

The Order approves Jordan Cove Energy's ("JCEP") proposal under NGA section 3 to site, construct, and operate the Jordan Cove LNG Terminal and approves Pacific Connector's proposal under NGA section 7(c) to site, construct, and operate the Pacific Connector Pipeline and grant the requested blanket certificate authorizations.[2]

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[1] Federal Energy Regulatory Commission, Order Granting Authorizations Under Sections 3 and 7 of the Natural Gas Act, FERC Docket Nos. CP17-494-000 and CP-495-000 (FERC Accession No. 20200319-3077) ("Order").
[2] These two proposals are collectively referred to as "the Project." JCEP and Pacific Connector are collectively referred to as "the Applicant."

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Pacific Connector Gas Pipeline, LP	)	**Docket No. CP17-494-001**
	)	
Jordan Cove Energy Project L.P.	)	**Docket No. CP17-495-001**
	)	

ANSWER TO MOTIONS FOR STAY AND
MOTION FOR LEAVE TO ANSWER AND
ANSWER OF PACIFIC CONNECTOR GAS PIPELINE, LP AND
JORDAN COVE ENERGY PROJECT L.P. TO
REQUESTS FOR REHEARING

determined the overall risk associated with thermal exhaust plumes in causing a disruption of flight is low."[1232] The FAA cautioned, however, that "thermal exhaust plumes in the vicinity of airports may pose a unique hazard to aircraft in critical phases of flight (particularly takeoff, landing and within the pattern) and therefore are incompatible with airport operations."[1233] Although thermal plumes are not part of the FAA's Determination of No Hazard ("DNH") analysis,[1234] the FAA "encourages airport sponsors and land use planning and permitting agencies to evaluate and take into account potential flight impacts from existing and planned development that produce plumes."[1235]

In anticipation of preparing the EIS, the Commission first evaluated thermal plume concerns in January of 2018.[1236] In response to the Commission's data request, JCEP provided the Commission with the results of its thermal plume analysis, where JCEP ultimately concluded that "no impacts are anticipated."[1237] After further consideration of available information, the Commission acknowledged that "thermal plumes emanating from the terminal could adversely affect takeoffs and landings" and reiterated the FAA's guidelines for airport sponsors, among other groups.[1238] In contrast to the requester's arguments, NEPA requires no more.[1239] As noted in the final EIS,[1240] JCEP previously indicated, and reaffirms its intention to, continue to coordinate with

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[1232] *Id.* at 2.
[1233] *Id.*
[1234] Aeronautical Study No. 2017-ANM-5386-OE (providing that "objections based on weather phenomena, thermal or steam plumes, [or] gas flare plumes… are not considered a factor for determining the extent of the aeronautical effect as defined by U.S. Law/Regulations").
[1235] Final EIS at 4-657.
[1236] January 3, 2018 Data Request of Pacific Connector Gas Pipeline, LP and Jordan Cove Energy Project L.P., Docket Nos. CP17-494-000, *et al.*, Accession No. 20180103-3051 at 12.
[1237] Response to January 3, 2018 Data Request of Pacific Connector Gas Pipeline, LP and Jordan Cove Energy Project L.P., Docket Nos. CP17-494-000, et al., Accession No. 20180126-5174 at 102 and Attachment FERC-JCEP-RR5-1 (filed Jan. 26, 2018).
[1238] Final EIS at 4-657.
[1239] *See* discussion of requirements for discussion of "significant" impacts *supra* Section II.C.3.c.
[1240] Final EIS at 4-657.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Jordan Cove Energy Project L.P.	Docket Nos. CP17-495-001
Pacific Connector Gas Pipeline, LP	CP17-494-001

ORDER GRANTING REHEARINGS FOR
FURTHER CONSIDERATION

(May 18, 2020)

Rehearings have been timely requested of the Commission’s order issued on March 19, 2020, in this proceeding. *Jordan Cove Energy Project L.P. and Pacific Connector Gas Pipeline*, *LP*, 170 FERC ¶ 61,202 (2020). In the absence of Commission action within 30 days from the date the rehearing requests were filed, the requests for rehearing (and any timely requests for rehearing filed subsequently)[1] would be deemed denied. 18 C.F.R. § 385.713 (2019).

In order to afford additional time for consideration of the matters raised or to be raised, rehearing of the Commission’s order is hereby granted for the limited purpose of further consideration, and timely-filed rehearing requests will not be deemed denied by operation of law. Rehearing requests of the above-cited order filed in this proceeding will be addressed in a future order. As provided in 18 C.F.R. § 385.713(d), no answers to the rehearing requests will be entertained.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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[1] *See San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services into Markets Operated by the California Independent System Operator and the California Power Exchange*, 95 FERC ¶ 61,173 (2001) (clarifying that a single tolling order applies to all rehearing requests that were timely filed).

Federal Aviation Administration

Memorandum

Date:	SEP 24 2015
To:	Regional Division Managers 610 Branch Managers 620 Branch Managers Airports District Office Managers
From:	Director, Office of Airport Planning and Programming, (APP-1) Director, Office of Airport Safety and Standards (AAS-1)
Subject:	Technical Guidance and Assessment Tool for Evaluation of Thermal Exhaust Plume Impact on Airport Operations

The Federal Aviation Administration (FAA) has received several inquiries and requests from state and local government and airport operators for guidance on the appropriate separation distance between power plants and airports where exhaust plumes from power plant smoke stacks and cooling towers may cause disruption to aircraft near Federally-obligated airports. The only related FAA regulations address the physical restrictions of the exhaust stack height. There are no FAA regulations protecting for plumes and other emissions from exhaust stacks.

In response, the FAA's Airport Obstruction Standards Committee (AOSC) was tasked to study the impact exhaust plumes may have on flight safety. The AOSC study evaluated the following:

1. How much turbulence is created by the exhaust plumes?
2. Is this turbulence great enough to cause loss of pilot control? If so, what size aircraft are impacted?
3. Is there a lack of oxygen (within a plume) causing loss of engine or danger to pilot/passengers?
4. Are there harmful health effects to the pilot or passengers from flying through the plume?

After thorough analysis, the FAA has determined the overall risk associated with thermal exhaust plumes in causing a disruption of flight is low. However, the FAA has determined that thermal exhaust plumes in the vicinity of airports may pose a unique hazard to aircraft in critical phases of flight (particularly takeoff, landing and within the pattern) and therefore are incompatible with airport operations.

Flight within the airport traffic pattern, approach and departure corridors, and existing or planned flight procedures may be adversely affected by thermal exhaust plumes[1]. The FAA-sponsored research indicates that the plume size and severity of impact on flight can vary greatly depending on several factors at a site such as:

- Stack size, number, and height; type of exhaust or effluent (e.g., coolant tower cloud, power plant smoke, etc.);
- Proximity of stacks to the airport flight paths;
- Temperature and vertical speed of the effluent;
- Size and speed of aircraft encountering exhaust plumes; and
- Local winds, ambient temperatures, stratification of the atmosphere at the plume site.

Airport sponsors and land use planning and permitting agencies around airports are encouraged to evaluate and take into account potential flight impacts from existing and planned development that produce plumes, (such as power plants or other land uses that employ smoke stacks, cooling towers or facilities that create thermal exhaust plumes).

To aid these reviews the FAA contracted MITRE Corporation to develop a model to predict plume size and severity of flight impact from a site of thermal exhaust plume(s). MITRE developed the "Exhaust-Plume-Analyzer" and it is available for no cost. Access can be found for licensing and downloading from MITRE at: http://www.mitre.org/research/technology-transfer/technology-licensing/exhaust-plume-analyzer.

The MITRE Exhaust-Plume-Analyzer can be an effective tool to assess the impact exhaust plumes may impose on flight operations at an existing or proposed site in the vicinity of an airport.

The FAA Advisory Circular (AC) 5190-4, A Model Zoning Ordinance to Limit the Height of Objects Around Airports (Airport Compatible Land Use Planning), is currently being updated to include comprehensive guidance to airport sponsors and local community planners on airport compatible land use issues, including evaluation of thermal exhaust plumes. The updated AC is expected to be issued in FY 2016.

[1] On July 24, 2014, the FAA issued a change to the Aeronautical Information Manual (AIM) to update terminology and provide more detail regarding the associated hazards of exhaust plumes. See the updated AIM flight instruction to pilots at Section 7-5-15, Avoid Flight in the Vicinity of Exhaust Plumes (Smoke Stacks, Cooling Towers) at http://www.faa.gov/air_traffic/publications/media/aim_chg1.pdfl.

In the interim, please provide this technical memorandum to airport sponsors to advise them of the availability of the Exhaust-Plume-Analyzer. Sponsors, state and local planning organizations, and permitting jurisdictions now have the opportunity to ensure that their planning and land use development decisions adequately evaluate the potential effects of thermal exhaust plumes on airport operations.

Should you have any questions concerning this memorandum please contact Rick Etter, Airport Planning and Environmental, (APP-400) at 202-267-8773 or by email at rick.etter@faa.gov.

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Aeronautical Study No.
2017-ANM-5386-OE

Issued Date: 12/23/2019

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**** DETERMINATION OF NO HAZARD TO AIR NAVIGATION ****

The Federal Aviation Administration has conducted an aeronautical study under the provisions of 49 U.S.C., Section 44718 and if applicable Title 14 of the Code of Federal Regulations, part 77, concerning:

Structure:	LNG Tank South
Location:	North Bend, OR
Latitude:	43-25-48.88N NAD 83
Longitude:	124-16-00.87W
Heights:	23 feet site elevation (SE)
	181 feet above ground level (AGL)
	204 feet above mean sea level (AMSL)

This aeronautical study revealed that the structure would have no substantial adverse effect on the safe and efficient utilization of the navigable airspace by aircraft or on the operation of air navigation facilities. Therefore, pursuant to the authority delegated to me, it is hereby determined that the structure would not be a hazard to air navigation provided the following condition(s) is(are) met:

As a condition to this Determination, the structure is to be marked/lighted in accordance with FAA Advisory circular 70/7460-1 L Change 2, Obstruction Marking and Lighting, a med-dual system - Chapters 4,8(M-Dual),&12.

Any failure or malfunction that lasts more than thirty (30) minutes and affects a top light or flashing obstruction light, regardless of its position, should be reported immediately to (877) 487-6867 so a Notice to Airmen (NOTAM) can be issued. As soon as the normal operation is restored, notify the same number.

It is required that FAA Form 7460-2, Notice of Actual Construction or Alteration, be e-filed any time the project is abandoned or:

_____ At least 10 days prior to start of construction (7460-2, Part 1)
__X__ Within 5 days after the construction reaches its greatest height (7460-2, Part 2)

See attachment for additional condition(s) or information.

This determination expires on 06/23/2021 unless:

3. EFFECT ON AERONAUTICAL OPERATIONS

a. The impact on arrival, departure, and en route procedures for aircraft operating under VFR: The proposed structures in this notice would exceed the OTH Part 77 Horizontal Surface by a maximum of 37 feet.

There are no effects on the VFR traffic pattern.

There are no effects on any existing or proposed arrival, departure, or en route IFR/VFR minimum flight altitudes.

b. The impact on arrival, departure, and en route procedures for aircraft operating under IFR: None.

c. The cumulative impact of the proposed structures, when combined with other proposed and existing structures, is not considered to be significant. Study did not disclose any significant adverse effect on existing or proposed public-use or military airports or navigational facilities, nor would the proposals affect the capacity of any known existing or planned public-use or military airport.

The OTH Airport Master Record can be viewed/downloaded https://adip.faa.gov/agis/public/#/airportData/OTH. It states there are 36 single-engine, 8 multi-engine, 1 jet, 0 glider, 5 military, 0 ultralight and 6 helicopter aircraft based there with 18,549 operations for the 12 months ending 31 December 2018 (latest information).

4. CIRCULATION AND COMMENTS RECEIVED

The five studies were circularized under ASN 2017-ANM-5386-OE on 3 September 2019 to all known aviation interests and to non-aeronautical interests that may be affected by the proposal. The public comment period closed on 10 October 2019. Five letters of objection were received by 10 October 2019.

Many of the comments received were objections based on safety reasons or other reasons that are outside the scope of studies conducted under Part 77. The basis for all determinations must be on the aeronautical study findings as to the extent of adverse physical or electromagnetic interference effect upon navigable airspace or air navigation facilities.

Objections based on weather phenomena, thermal or steam plumes, gas flare plumes and effects on wildlife are not considered a factor for determining the extent of the aeronautical effect as defined by U.S. Law/Regulations.
Objections were made regarding the potential for aircraft accident and fire hazard. Regulations contained within Part 77 are not, as some appear to believe, safety procedures or a reason to call a proposed structure a "hazard". The FAAs determination of whether a proposal would or would not be a hazard to air navigation is based on the findings of the completed aeronautical study and not simply whether or not they exceed the obstruction standards.

Comments were received questioning the location of the proposed LNG plant amine tower and flare tower. The amine contactor (ASN 2019-ANM-5196-OE) and amine regenerator (ASN 2019-ANM-5197-OE) were filed, accepted, studied, and were two of the five structures described in the public comment disclosure. The multipoint ground flare (ASN 2017-ANM-5397-OE) and LNG Marine Terminal Flare (ASN 2017-ANM-5390-OE) were filed and evaluated by the FAA for heights of 127 feet AMSL (85 feet AGL) and 142 feet AMSL (100 feet AGL), respectively. The two studies weren't part of the public comment set because the structures did not exceed a Part 77 obstruction surface. Only the physical structure of the aforementioned studies were evaluated as flares and steam plumes are outside the scope of Part 77.