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VIA E-MAIL

Oregon Department of Energy – Energy Facility Siting Council
550 Capitol St NE
Salem, OR 97301
Attn: Sean Mole

RE: Jordan Cove Site Certificate Exemption Application
Response to Requests for Additional Information

Date: July 25, 2018

Dear Mr. Mole:

We are in receipt of the Oregon Department of Energy's ("ODOE") July 9, 2018 letter and Requests for Additional Information ("RAI") on Jordan Cove Energy Project, LP's ("JCEP") application for an exemption from a site certificate that was submitted to ODOE on June 14, 2018.

Attached are JCEP's responses to the RAIs. We have also attached a revised application (without the appendices) and a redlined version showing the edits to address ODOE's requests. As demonstrated in the revised application, JCEP's proposed Liquefied Natural Gas ("LNG") Terminal in Coos Bay, Oregon meets the *high efficiency cogeneration facility* exemption definitions and criteria set forth in OAR 345-015-0360(5). We understand that ODOE will review the additional information and revised application and either determine the application is complete or may request additional information from JCEP.

JCEP's revised application and the redlined version includes trade secret information as defined under ORS 192.345. For ODOE's convenience, JCEP is submitting a public version of the revised application with the trade secret information redacted. JCEP requests that ODOE and EFSC maintain as confidential and not disclose the version (including the redline) that contains the trade secret information. JCEP has marked those versions as:

Confidential Business Information
Exempt From Public Disclosure

JCEP appreciates ODOE's review of the attached and respectfully requests that ODOE determine that the application is complete and issue the notice per OAR 345-015-0350.

Sincerely,

Tony Diocee
VP of LNG Projects
Jordan Cove Energy Project, LP

59892-0013/140670215.2

1. Application for Exemption – Request for Additional Information

Request Number	Application Page	RAI	Comments
A-1	Application p. 6 Appendix A p. 6 (2.5.1.3), 22 (3.2)	Describe the total fuel gas system input (MMBtu/hr)	Appendix A page 6 describes fuel requirements of 20,642,940*10^6 Btu /yr. Additional inputs account for a further 653,470*10^6 Btu/yr, for a cumulative total of 21,296,410*10^6 Btu/yr. Appendix A p. 22 describes total system requirements as 23,835,960*10^6 Btu/yr. Please clarify this discrepancy. **JCEP's Response:** There is no discrepancy between the two fuel values. –Appendix A Page 6 describes fuel gas to the gas turbine drivers only and does not including fuel gas for the duct burners, aux. boiler, flare pilots or thermal oxidizer. The anticipated fuel gas use to the gas turbine drivers is 471.3 MMBtu/hr to produce 54.8 MW (for each gas turbine as shown on Table 2.5-1) for a total of 5 x 471.3 MMBtu/hr x 24 x 365 = 20,642,940 MMBtu/yr as stated in the application. 497 MMBtu/hr corresponds to a potential maximum output of 55.46 MW (per gas turbine) or a total of 5 x 497 MMBtu/hr x 24 x 365 = 21,768,600 MMBtu/yr. The fuel gas usage in Appendix A Page 22 on Table 3.2-2 includes the 471.3 MMBtu/hr and 497 MMbtu/hr for the gas turbine drivers and includes an additional 111.5 MMBtu/hr (for Thermal Oxidizer) and 4.4 MMBtu/hr (for flare pilots). This provides a total of 2,600.9 (~2,601) MMBtu/hr x 24 x 365 = 22,873,884 MMBtu/yr. The "Maximum Design" in the Table in Section 3.2.1.3 of 2,602 MMBtu/hr is very close to the above 2,601 MMBtu/hr. The difference is due to rounding. Values called out as NNF (Expected) are not included in the Max Design value of 2,602 MMBtu/hr since they are not expected to be continuous flows. For purposes of demonstrating that the facility qualifies for the high-efficiency co-generation exemption, the only fuel gas chargeable to power generation and thermal energy (steam) production at the facility are to the duct burners and auxiliary

			boiler which combines for an annual expected fuel input of 653,470 MMBtu/yr as described in the application and referenced in the ODOE comment above. The fuel gas values should not include fuel gas to the refrigeration gas turbine drivers because this fuel gas is not chargeable to the net heat rate of electric power production since it produces mechanical power for the refrigeration compressors and not electrical power. Similarly, the fuel gas should not include fuel gas for operations like the thermal oxidizer and flares which have no part in power generation or thermal energy (steam) production. However, as noted in the response to request A-7, JCEP will add to the fuel gas values a portion of the fuel gas to the refrigeration gas turbine drivers. Updated values and the calculation are shown on pages 5, 6 and 7 of the application.
A-2	Application p. 6 Appendix A p. 23 (3.3.1)	Describe HP steam requirements of electrical generators (STGs)	Application page 6 describes process HP steam requirement as 70,300 lbs/hr. Appendix A page 23 describes HP steam requirements as 167,000 lbs/hr per STG (holding). Please clarify this discrepancy. **JCEP's Response:** There is no discrepancy. The 70,300 lb/hr of high-pressure steam is the steam required by the LNG Process for regeneration of molecular sieve units. The 167,000 lbs/hr per STG is the steam required by the STGs for electrical power generation.
A-3	Application p. 6,7	Provide specifications for boiler capable of meeting steam requirements as determined for request A-1	Application page 6 "alternate source' is assumed to be a package boiler…" Application page 7 "Assuming a pair of boilers of similar heat rate…" Please rectify this discrepancy. **JCEP's Response:** The first paragraph of page 7 of the application has been revised to reflect that a single boiler will meet the high-pressure steam requirements for the process.

A-4		Provide a licensed engineer's report or statement regarding the application for exemption.	Please provide some form of documentation that this application has been reviewed/prepared by a licensed engineer. OAR 345-015-0360(5)(c) requires "A detailed engineering assessment of fuel efficiency…" **JCEP's Response:** The revised application has been stamped by a licensed professional engineer.
A-5	Application p. 7	Provide clarifications on why the LNG Expander and MR Expanders have been included in the cogeneration plant total MW capacity.	The LNG Expander (1.86 MW) and MR Expanders (3.36 MW) are included in the total generating capacity and "Power" in the fuel chargeable to power heat rate calculations. It is not clear that these are actually part of the cogeneration process in the facility, and could be considered as unrelated to the specific proposed cogeneration facility. Please provide justification for including these. **JCEP Response:** The power generation from the LNG and MR Expanders have been removed from consideration in determination of fuel chargeable to power heat rate. Updated values and the calculation are shown on pages 5, 6 and 7 of the application.
A-6	Various	Please provide clarifications regarding the operating parameters used in the calculations and whether they represent a "maximum", "normal operating condition", or other scenario. There appears to be some discrepancy in the report.	It appears that some variables consider normal operating conditions (for example, 3 x steam turbine generators at 18.5 MW each, instead of using 30 MW nameplate capacity), and some variables assume maximum usage (such as high pressure and low pressure steam consumers on page 23 of Appendix A). Additionally, there seems to be some discrepancy between the statement on page 3 of application that "STGs are normally operated at 18.5 MW each, which requires 224,000 lb/hr," and page 23 of Appendix A which lists 224,000 lb/hr as the "maximum usage" and 183,700 lb/hr as "normal usage." Please verify and explain for key variables that consistent conditions are being used. **JCEP Response:** The JCEP Facility operates in two modes: a "Loading Mode" for the times when an LNG carrier is at the LNG Terminal and

			being loaded with LNG and a "Holding Mode" during all other times. The time that the facility is in Loading Mode is approximately 20% of the time and the remaining time (80%) is Holding Mode. Both modes are considered "Normal" modes of operation. During Loading Mode, there is a significantly greater electrical demand. The expected electrical demand during Loading Mode is 49.5 MW and is 39.2 MW during Holding Mode, but margin is included to cover non-ideal operating cases. The nameplate capacity of 30 MW for each STG is so that the facility can operate just two STGs in the event one STG trips. The values in the application were selected to illustrate the "Loading Mode" or maximum worst-case, thus the higher power generated and maximum process steam loads. If the lower electrical and process energy demand in the "Holding Mode" was used, the fuel input and electric power generation values would decrease but would still meet the high efficiency co-generation exemption.
A-7	Application p. 5	Fuel input to the cogeneration facility only includes the HRSG duct burners and the auxiliary boiler. Please explain why an applicable portion of either the fuel input to the refrigeration compressors or the gas turbine exhaust energy has not been included as a fuel input to the cogeneration process.	**JCEP Response:** The fuel input to the gas turbines would be the same regardless of the electrical power system design and cogeneration/waste heat configuration of the facility as it is required to mechanically drive the refrigerant compressors. This process will generate substantial exhaust heat which can be efficiently used to produce useful thermal energy (steam) with no additional fuel input to the base process. As described in response to request A-1, the fuel gas values should not include fuel gas to the refrigeration gas turbine drivers because this fuel gas is not chargeable to the net heat rate of electric power production since it produces mechanical power for the refrigeration compressors and not electrical power. JCEP recognizes that a portion of the gas turbine fuel input may not be converted to mechanical energy and that portion could be used in the fuel chargeable calculation. Per JCEP's response to A-1, the potential maximum mechanical power output of each gas turbine to the refrigerant compressor is 55.46 MW with 497 MMBtu/hr of fuel input. But

			55.46 MW equates to just 189.2 MMBtu/hr, the remaining fuel input is used to mechanically drive the air compressor portion of the gas turbine at approximately 65.2 MW (222.5 MMBtu/hr) or is heat exhaust due to efficiency losses (remaining 85.3 MMBtu/hr). These efficiency losses could be considered part of the cogeneration system as the rest is mechanical drive power with no impact to the net electrical power or thermal energy output of the facility. So 5 x 85.3 MMBtu/hr x 24 x 365 = 3,734,791 MMBtu/year of fuel not involved in the mechanical drive process. Adding this value to the duct burner and auxiliary boiler inputs presented in the application gives a total fuel input of 4,388,261 MMBtu/year. The fuel displaced and power output values are still the same as presented in the application based on the steam and electrical power requirements (minus the expanders) [3,823,816 MMBtu/year and 486,180,000 kW-hr, respectively]. Thus, the fuel chargeable to power heat rate would be as follows, and is well below the exemption threshold even with these conservative assumptions: (4,388,261 MMBtu – 3,823,816 MMBtu)*10^6 ÷ 486,180,000 kW-hr = **1,161 Btu/kW-hr** This change has been red-lined on pages 5, 6 and 7 of the application.