PUGET SOUND ENERGY

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August 11, 2017

BY U.S. MAIL AND EMAIL

Mr. Ralph Munoz
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Re: Tacoma LNG June 21, 2017 Information Request Letter - Response to Questions 1, 5, 6, & 7

Dear Ralph:

Puget Sound Energy ("PSE") received your June 21, 2017 letter requesting additional information about the Tacoma LNG facility. We provided a response to the majority of your questions on June 30, 2017 and are providing answers to the remaining questions (1, 5, 6, and 7) in this letter.

Question 1: Provide additional information in permit application Table 1.

During recent telephone calls, you requested additional information about the equipment list provided in Table 1 of PSE's permit application. The additional information supplementing Table 1 is provided in Attachment A.

Question 5: Provide additional support for BACT analysis.

This response is based on further discussion with you and Carole Cenci during our June 28 meeting at PSCAA's offices. As requested, BACT guidance and clearinghouse data from California and Texas air agencies were reviewed. Relevant determinations were found in the California Air Resources Board (CARB), Texas Air Control Board (TACB) clearinghouse, Bay Area Air Quality Management District (BAAQMD) guidelines, San Joaquin Valley Air Pollution Control District, and South Coast Air Quality Management District (SCAQMD) clearinghouse. A summary of our clearinghouse findings is provided in the attached table for each for the proposed emission sources and pollutants under review. This summary includes BACT and LAER determinations for emission sources that are reasonably comparable to and representative of the equipment at the Tacoma LNG facility, and excludes any BACT emission limits for which compliance has not been demonstrated with source tests. Determinations that were submitted with the initial permit application are not repeated here.

No clearinghouse entries were found specifically for vaporizer heaters or enclosed ground flares at LNG production facilities, so we attempted to identify similar emission source types using the following approaches:

- Ground Flare – We began by looking at clearinghouse entries and BACT guidelines related to flares that were permitted in all types of facility. Because combustion processes and emissions differ significantly for ground flares that have enclosed flames vs. elevated flares that have open flames, we focused our review on clearinghouse entries for ground flares. Consistent with our May 22, 2017 application, ground flares in use at landfills were not included in the list of representative source types due to the significant difference in waste gas composition at landfills (i.e., primarily methane with many trace contaminants).

- Vaporizer – Likewise, combustion devices identical to a vaporizer were not found in the clearinghouses. Because the proposed vaporizer heater is structurally similar to a fire-tube type water heater, clearinghouse and BACT guidelines for natural gas boilers are used as a surrogate.

A more detailed summary of the results of our research is provided in Attachment B of this letter.

PSE's proposed BACT limits in our May 22, 2017 permit application are consistent with the most stringent limits found in this extended clearinghouse search except for NO_X and CO emissions from the ground flare when compared to the SCAQMD's Lowest Achievable Emission Rate (LAER) determinations.

VAPORIZER

PSE's proposed BACT for the vaporizer exhaust is consistent with the most restrictive determinations for boilers that we identified during this extended review (see Attachment B).

GROUND FLARE

Our review of California and Texas clearinghouses and guidelines identified one LAER determination by the SCAQMD for an enclosed ground flare that burns waste gases from an oil and gas production field's processing facility. The stated LAER technology for that ground flare is "clean enclosed burner".

Ground flares are typically custom-designed, based on a given facility's waste gas composition and flow rate; therefore, a direct comparison of BACT/LAER determinations for facility types that have different inlet gas composition and flow characteristics is not appropriate. Such comparisons must be made with careful analysis of the differences.

Based on a careful analysis of the SCAQMD LAER determination, it was determined that the oil and gas production flare technology/limit are not transferable to the LNG Facility due to significant differences in feedstock characteristics. Process gas at the SCAQMD oil and gas operation is mostly methane. This composition differs significantly from the LNG Facility's ground flare inlet gases that will contain significantly higher levels of heavier hydrocarbons such as butane, ethane, and propane. In addition, the process gas at the SCAQMD oil and gas operation typically has a consistent heat input and heating value. This is in marked contrast to the heat input of the LNG Facility waste gas which will vary from approximately 2.5 to 35.6 million British thermal units per hour (MMBtu/hr) and the LNG Facility heating value which will vary between 337 and 1,820 British thermal units per standard cubic feet (Btu/scf). This wide heating value range will cause flame temperature and emissions to vary. Also, the inlet temperature of process gas from an oil and gas operation has a smaller range than the LNG Facility. According to SCAQMD's LAER determination record, one emission test was performed to confirm emission compliance. During that test, the flare combusted process gas at a constant rate of 21.73 MMBtu/hr with a higher heating value of 913 Btu/scf. The LNG Facility's waste gas can range from very cold (e.g. cryogenic LNG vapors) or warm (liquefaction and pretreatment off gas). All of these factors influence the selection of burner technology for the LNG Facility's proposed ground flare. Four burner types are required to the address the wide flow, heat input and inlet temperature variation experienced by the LNG Facility. Because of the fundamental difference in feed gas characteristics that the LNG Facility flare must accommodate, the SCAQMD oil and gas production flare limits are not technically feasible.

While the RBLC search did not identify any examples demonstrating the use of low-NO_x technology for enclosed flares at comparable facilities, PSE is committed to reasonably minimize emissions from the ground flare, and will install low-NO_x technology on the flare burners where operational considerations do not preclude their use. At the recommendation of the ground flare manufacturer, PSE proposes the following 4-burner scenario to address the ground flare's wide operating ranges:

- A large low-NO_x burner will be used during periods when the inlet waste gas stream is warm and has a heat input rate greater than 8 MMBtu/hr,

- A small standard burner will be used during warm, low flow inlet gas cases that occur rarely during holding mode or facility turndown,

- A large low-NOx burner designed for cold inlet gases will be used during plant upset conditions (even though a cost-effectiveness case in favor of a standard burner could be made for this condition that will occur infrequently),

- A small cryogenic burner will be used to flare loading arm/hose purge gas after ship bunkering or truck loading.

Due to the size of the combustion chamber for the flare, it is not technically feasible to use low-NO_X technology for the small burners, both of which will operate rarely compared to the larger burners. The manufacturer's estimated NO_X emission factor is 8 ppmv (0.025 lb/MMBtu) for the two large low-NO_x burners and 22 ppmv (0.06 lb/MMBtu) for the two small regular burners.

In order to achieve lower CO emissions, in recognition of the SCAQMD LAER determination, the ground flare manufacturer would need to reduce the excess air to the combustion chamber from 178% to 159%, thereby increasing the combustion temperature from 1,600 °F to 1,700 °F. This could reduce CO emissions to as low as 15 ppmv (0.029 lb/MMBtu). However, the increase in combustion temperature would result in an increase to the manufacturer's NOx emission rate guarantee from 8 to 10 ppmv. To minimize NOx emissions, we recommend leaving the combustion temperature at 1,600 °F and adopting a BACT limit for CO of 43 ppmv. Note, that although the LAER limit was set by SCAQMD at 10 ppmv, the limit recommended by the flare vendor for that source was 50 ppmv.

<u>Question 6: Include BACT analysis for SO_2 for ground flare.</u>

The only available and feasible control technologies for reduction of SO_2 emissions from a ground flare are desulfurization of the inlet waste gas. Post-combustion controls are not technically feasible for an enclosed ground flare. Desulfurization technologies remove sulfur from the waste gas stream prior to combustion in the flare.

A BACT cost-effectiveness evaluation was completed for a Merox desulfurization unit and is presented in Attachment C. The cost-effectiveness for SO_2 removal was conservatively calculated by dividing the total life-cycle annualized cost (dollars per year) by the tons of SO_2 removed from the control device. The total annualized cost considering a capital recovery factor is estimated at $823,500, which does not include the cost of freight, tax, foundations and supports, installation costs, electrical, piping, annual maintenance, annual operating cost, and other indirect expenses (i.e., engineering, etc.); therefore, this cost is considered conservatively low. The Merox treatment unit could potentially achieve a 90% sulfur removal rate, giving a calculated cost benefit of more than $100,000 per ton of SO_2 removed. Please see Attachment C for detailed annualized cost and cost effectiveness calculations. As demonstrated with this cost-effectiveness evaluation, the cost of a Merox unit is disproportionate to the emission reduction that can be achieved. Therefore, sulfur control with Merox does not pass the cost effectiveness test for BACT.

Question 7: Provide documentation for each of the sulfur inlet concentrations for each case.

Table B-2 of the NOC Application presents sulfur content values for natural gas and for five different flare inlet waste gas cases. You requested that we provide documentation of the sulfur inlet concentrations for each waste gas case. By inlet concentrations, we understand that you are referring to inlet gas to the flare. As mentioned in our June 30, 2017 response letter, each flare inlet gas case for facility operations represents an aggregate of various waste gas streams routed to the flare. The different cases were provided by CB&I and represent various potential feed gas (natural gas entering the facility before pretreatment) compositions and processing flow rates as follows:

- **Case 1:** Base Design / Low Btu; Design Composition (2% CO_2)
- **Case 2:** Facility Turndown; Average Composition (~0.5% CO_2)
- **Case 3:** “Normal” Operation; Alternative Heavy Composition (~0.2% CO_2)
- **Case 4:** Maximum Hydraulic Flare Case; Alternative Heavy Composition (2% CO_2)
- **Case 5:** High Specific Btu to Flare; Alternative Heavy Composition (~0.2% CO_2)
- **Holding:** Facility Holding, No Liquefaction[1]

As several sources of waste gas are disposed of via the flare, their relative compositions and flows vary depending on feed gas composition and operating rates of the various facility processes, which in turn affects the fraction of sulfur in each flare inlet case. The six facility operating cases presented are intended to bracket the operating ranges the flare is expected to accommodate during operation.

Sulfur in the feed gas is a combination of total sulfur (reported as H_2S) in natural gas from the Williams Northwest Pipeline and odorants added later (methyl ethyl sulfide, C_3H_8S; and tert-Butyl Mercaptan, tert-$C_4H_{10}S$). The amount of total sulfur and odorants in the facility feed gas

[1] The holding waste gas case was added by CB&I after the May 22, 2017 permit application was submitted. This flare holding mode would occur when vaporizing LNG (up to 10 days per year) or any other time the facility is not liquefying. The waste gas is composed of small amounts of gases from gas chromatograph speed loops; flare header sweeps; seal vents from one feed gas compressor and one refrigerant compressor; and heavy hydrocarbon storage flash gas.

varies continuously. The maximum H_2S and total sulfur content of the pipeline gas is limited by the Williams Northwest Pipeline tariff to be below 0.25 grain of H_2S per one hundred cubic feet (gr/hcf) and 5 gr/hcf total sulfur (reported as H_2S). Odorants are added to the pipeline gas when the gas enters the distribution system. Odorant is injected by Williams Northwest Pipeline at a rate of approximately 0.077 gr/hcf and injected by PSE at a rate of 0.15 gr/hcf. This adds 0.23 gr/hcf of sulfur to the feed gas of the plant. CB&I's sulfur estimates for flare inlet cases, as presented in the May 22, 2017 permit application, were based on historical H_2S measurements reported by Williams Northwest Pipeline (maximum and average values in 2012 for cases 1 and 2, and 2015 for cases 3 through 5), excluding other reduced sulfur compounds in the pipeline gas and odorants added to gas in the distribution line that will feed the LNG Facility.

In order to provide a more conservative estimate, we are updating our flare inlet sulfur loading estimates by using more recent data. Total sulfur and H_2S levels reported daily by the Williams Northwest Pipeline have been steadily decreasing in recent years due to changes in natural gas supply sources with a lower sulfur content and are expected to continue to drop. In the past 12 months, the maximum total sulfur concentration reported by Williams Northwest Pipeline was 0.603 gr/hcf (reported as H_2S) and the maximum H_2S concentration was 0.238 gr/hcf. The 12-month averages were 0.421 gr/hcf total sulfur (as H_2S) and 0.057 gr/hcf H_2S.

Most of the incoming H_2S and some of the other reduced sulfur compounds will be removed in the LNG Facility's pretreatment process and off gases from the pretreatment process will be sent to the flare (see attached flow chart in Attachment D). In the calculations, we conservatively assume that the H_2S concentration in the feed gas is equal to the tariff value of 0.25 gr/hcf and that all sulfur from H_2S is sent to the flare. We have conservatively assumed that 80% of the other reduced sulfur compounds and odorants will be removed in the pretreatment process and sent to the flare. The rest of the sulfur is removed with the heavy hydrocarbons or stays in the natural gas that is liquefied.

We believe that this approach conservatively estimates the worst case total sulfur going to the flare. Please see Attachment D (electronic Excel file) for detailed calculations of the estimated worst-case short-term sulfur inlet concentrations for each flare case and resultant SO_2 and H_2S emission factors for each operating case.

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Please do not hesitate to contact me (or Bill Steiner of Landau Associates at (503) 347-3162 if I am not available) if you have any questions regarding this submittal or any further questions regarding the application.

Sincerely,

Keith Faretra

Attachments

- Attachment A – Updated Table 1
- Attachment B – Additional BACT Review Results
- Attachment C – BACT Cost-Effectiveness Evaluation for SO_2
- Attachment D – Flare Inlet Sulfur Calculations (electronic)

cc (by email):

- Jim Hogan
- Lorna Luebbe
- Bill Steiner
- Tom Wood