January 26, 2010

Mr. Donald Dahl
US EPA Region 1
5 Post Office Square - Suite 100
Boston, MA 02109-3912

RE: Revised BACT analysis information

Dear Mr. Dahl:

This letter is being submitted by Tetra Tech EC, Inc. on behalf of Northeast Gateway Energy Bridge L.L.C. (Northeast Gateway or NEG) for purposes of responding to EPA's letter of December 1, 2009 regarding the top-down BACT analysis which was included in Northeast Gateway's October 2008 permit modification application. Per our discussion on December 15, 2009, this memo includes information which was submitted to you by electronic mail on July 27, 2009 as well as the additional information which you requested regarding BACT for SO_2 and PM emissions from the main boilers on the LNG carriers (which was addressed in Section 6.3 of our October 2008 application) and for CO emissions from the auxiliary generators on 2nd generation LNG carriers (which was not proposed to be changed in the October 2008 application, but we have since proposed to change, based on the results of new vendor information). In accordance with our meeting, this letter is organized as follows:

1. BACT for SO_2 and PM Emissions from Main Boilers (B1 and B2)
    a. Candidate Controls
        i. Firing all gas
        ii. Minimization of oil consumption
            1. Minimize Burner Lighting Events
            2. Minimize Oil Consumption per Lighting Event
        iii. Ultra Low Sulfur and Low Sulfur Distillate Oils
        iv. Low Sulfur Residual Oils (<1% S, <1.5% S)
    b. Technical Feasibility
    c. Cost Effectiveness
2. BACT for CO from Auxiliary Generators on 2nd Generation Vessels (GE2)
    a. Candidate Controls/Technical Feasibility
        i. Oxidation Catalyst
        ii. Similar Size Alternative Dual-Fuel Generators
    b. Cost Effectiveness
    c. Conclusions

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1. BACT for SO_2 and PM Emissions from Main Boilers (B1 and B2)

As identified in our October 2008 permit application, the main boilers in the LNG carriers (LNGCs) capable of using the Northeast Gateway facility (which must have the capability of connecting to the Submerged Turret Loading™ buoy) are used for vessel propulsion purposes but some of the steam produced is also used for regasification purposes when connected to the buoy. The boilers in the LNGCs which have been constructed to date are each equipped with three burners, and shortly after the moored vessels' heat recovery system (HRS) is started up (as required by the facility's NPDES permit), only two of the three burners in each boiler may be lit. However, after initiation of regasification activities a steady increase in the sendout rate of natural gas occurs and eventually all three burners are needed in each boiler. Although the boilers are currently permitted to fire only LNG boil off gas (BOG) or regasified LNG, the boiler vendor, Mitsubishi Heavy Industries (MHI), has designed the boilers and the LNGCs' electronic boiler management system such that heavy (residual) fuel oil (which is used by large marine vessels in transit to and from the Northeast Gateway facility, and onshore ports in Massachusetts) must be fired for a short duration (typically ten minutes or less) while the third gas burner is being lit. One of the primary purposes of the October 2008 permit application was to incorporate the need for a limited amount of oil burning in Northeast Gateway's air permit.

a. Candidate Controls

In Section 1.2.3 and Section 4.1 of our October 2008 permit application, we identified our understanding that the use of oil for LNGC boiler burner relightings was required by both U.S. Coast Guard (USCG) regulations (46 CFR 154) and the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code), as had been indicated to us in the attached e-mail from Commander Rick Raksnis of the US Coast Guard (See Attachment B). However, you mentioned that you have since received conflicting information from USCG, stating that their regulations do not require the use of oil for vessels which are moored (and believe that the IGC Code could be interpreted similarly). Therefore, we have included an analysis of the potential for gas-only firing as a candidate control option. In addition, per your request, we are including discussion of LNGC types throughout the world (with regard to oil use in the main propulsion/regasification systems) and BACT determinations that have been made for LNGCs at other LNG ports.

The types of LNGCs have not changed appreciably since EPA's initial permitting of the Northeast Gateway facility. Dual-fuel boilers and steam turbines as are used on the Northeast Gateway vessels are by far the most prevalent type of propulsion systems for LNGCs today. There are two other types of propulsion systems that exist—i.e., dual-fuel diesel electric (DFDE) propulsion systems, which utilize diesel engines capable of firing either oil-only or a mixture of 99% gas and 1% marine gas oil (MGO), and slow-speed diesel (SSD) propulsion systems, which utilize engines fired on diesel only. However, as shown in Figures 1 and 2, these other propulsion systems are typically only available on LNGCs that are larger than those that were permitted for use at Northeast Gateway (which have capacities of 138,000-151,000 m^3 of LNG). In addition, only a small fraction of these vessels are capable of connecting to Northeast Gateway's Submerged Turret Loading™ (STL™) buoy. However, we are aware that the first LNGC capable of using the Neptune STL™ facility (*Suez Neptune*, a DFDE vessel) was delivered from Samsung Heavy Industries to Höegh LNG in November 2009 and that this vessel has an LNG capacity of only 145,130 m^3. According to Det Norske Veritas (DNV), the *Suez Neptune* is equipped with four

Wärtsilä engines (three 12V50DF and one 6L50DF), four MHI boilers (two MAC-100BF and two MC-55A), and a Cummins India VTA-28-DM emergency generator.[1] The specific details of how the boilers and engines need to be used during startup, load changes, and normal operation during regasification are not available to Northeast Gateway. Therefore, we cannot assess the extent to which there may be operational details for those vessels that are analogous to the burner-lighting operational requirements for the boiler-equipped vessels designed for use at Northeast Gateway. However, despite the fact that the boilers used only for regasification on the Neptune vessels can combust entirely natural gas because they were not built for propulsion purposes, this alternative vessel-based regasification technique does not totally eliminate the need for oil combustion at the Deepwater Port because the three large

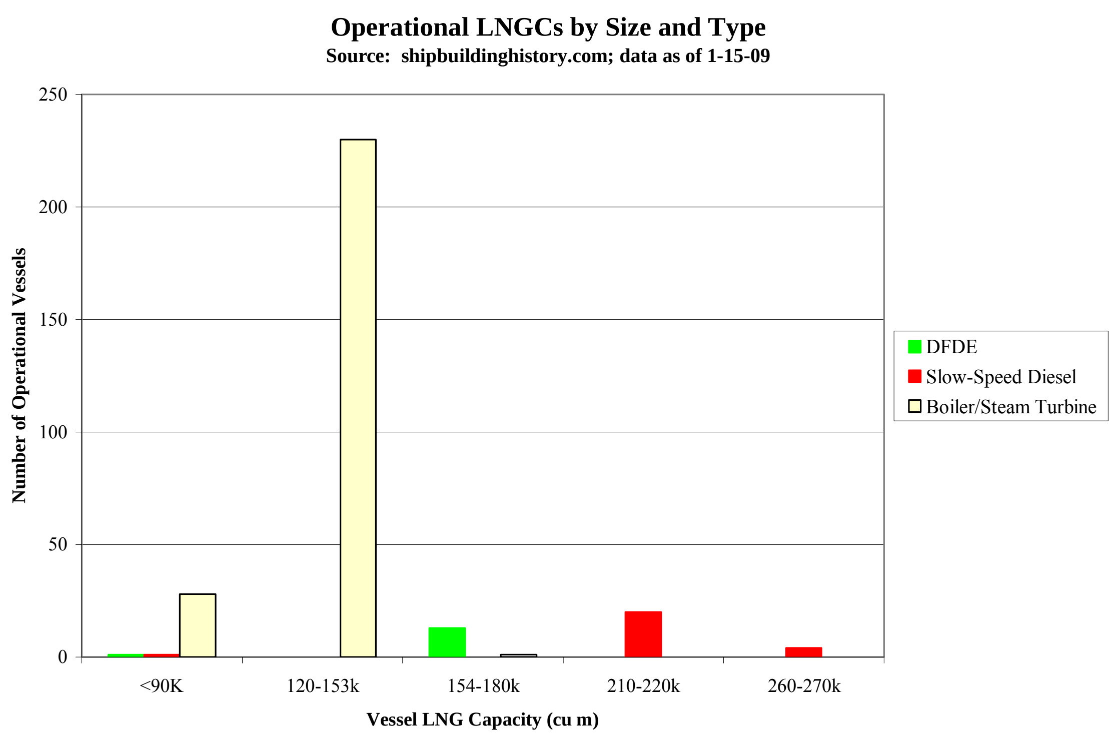

Figure 1. Prevalence of Propulsion Types in Existing LNGCs.

[1] These specifications are available from http://exchange.dnv.com/exchange/main.aspx?extool=vessel&subview=machinerysummary&vesselid=27995.

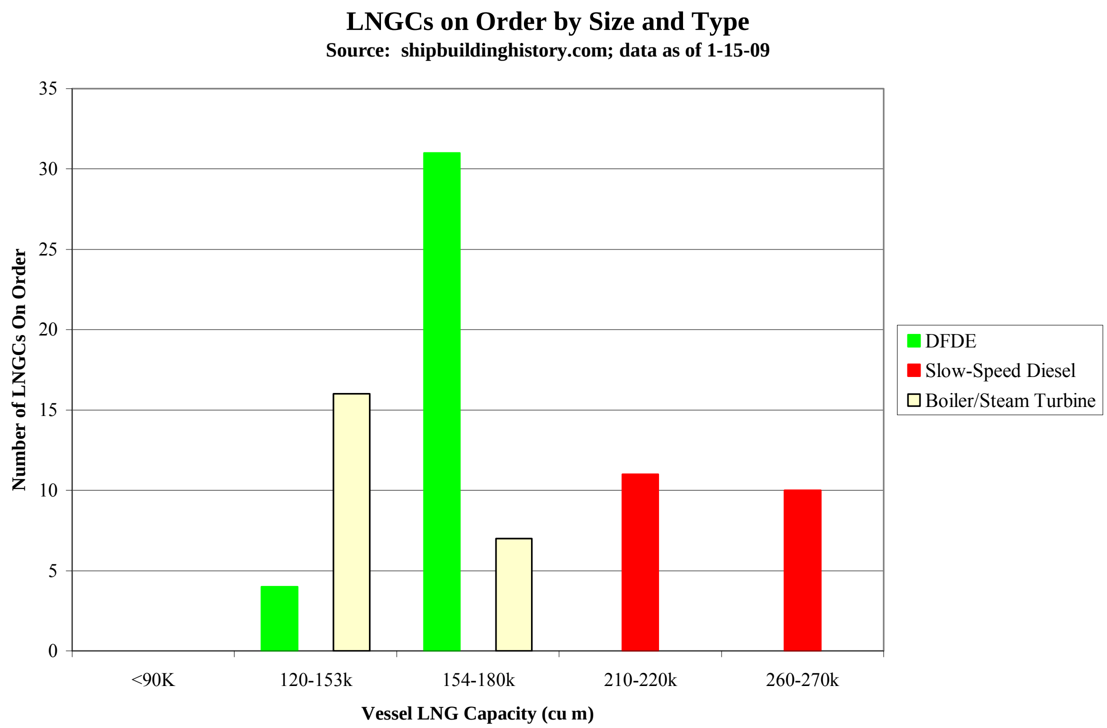

Figure 2. Prevalence of Propulsion Types in LNGCs on Order.

(11.4 MW each) main generator engines are necessary to operate at a significant load during Neptune regasification operations and these engines are all dual fuel fired. In summary, the only currently available alternative to the boiler/steam turbine based LNG vessels for vessel-based regasification (as are currently permitted for and used at the Northeast Gateway Port) are the LNG vessels with dedicated regasification boilers and separate engines with generators to provide electrical power for the vessels (as are currently permitted for the Neptune Port). These alternative vessels do not represent a material improvement overall in environmental impact from the boiler/steam turbine based vessels since they require dual fuel fired engines to generate electrical power. These additional emissions sources are not necessary on the boiler/steam turbine based vessels and they of course create additional environmental impacts. Therefore, the remainder of this BACT analysis only addresses the types of vessels identified in the Northeast Gateway permit.

To address your request to identify BACT determinations for other LNG ports, we obtained information for both the 11 LNG terminals (not including Northeast Gateway) that are either existing or under construction, and for the 16 LNG facilities which have been approved (by FERC or MARAD/USCG) but which are not under construction. Details of this information are provided in Attachment A to this letter. In most cases, regulatory agencies exempted all LNGC emissions from regulation in the air permits; in some cases, vessel emissions were included in impacts analyses, based on various emissions and/or fuel assumptions, but in the majority of cases there are no enforceable requirements: i.e., the terminals can accept LNG deliveries from any type of LNGC physically capable of using their terminal, and those LNGCs are allowed to fire 100% high-sulfur residual oil during all unloading activities. For a few facilities—namely Gulf Landing and Casotte in Mississippi, Bradwood and Jordan Cove in Oregon, and

AES Sparrows Point in Maryland—vessel unloading emissions were included (or are proposed to be included) in the air permit, but emissions were either below BACT thresholds or (in the case of AES Sparrows Point) the permit application was never filed. The few cases where LNGC emissions associated with unloading were included in air permits, the only facilities for which they were subjected to BACT requirements were facilities located within EPA Region 1/Massachusetts DEP jurisdiction and/or deepwater ports with on-vessel regasification: i.e., Weaver's Cove, Northeast Gateway, Neptune, and Gulf Gateway.

The investigation of these other facilities identified no new control alternatives for purposes of the BACT analysis; therefore, the candidates for emissions control are the same as those which we discussed in our December 15, 2009 meeting: i.e., the alternative of firing no oil; the minimization of oil consumption, when oil needs to be used, and the use of lower sulfur fuel oils (specifically, the use of ultra-low sulfur and low sulfur distillate oils, and the use of lower sulfur residual oils). Each of these is discussed in more detail in Sections i-iv below.

i. Firing All Gas / Use of Different LNG Carriers

Clearly, there are stationary gas-fired boilers which do not require that oil be fired when lighting gas burners; it is likely to be technically feasible to design systems which can do this for marine vessel boilers as well.

ii. Minimization of Oil Consumption

As identified in Sections 6.3.1 and 6.3.2 of our October 2008 application, the minimization of oil consumption associated with the lighting of the third gas burner in each boiler is a candidate control. Such minimization could take the form of (1) minimizing the number of burner lighting events, and/or (2) minimizing the oil consumption per lighting events.

iii. Ultra Low Sulfur and Low Sulfur Distillate Oils

As was identified in Section 6.3.4 of our October 2008 application, the use of low or ultra-low sulfur distillate oil instead of residual oil is a candidate control for reducing SO_2 and PM emissions.

iv. Low Sulfur Residual Oils (<1% S, <1.5% S)

As identified in Section 6.3.3 of our October 2008 application, lowering the sulfur content of the residual oil used is a candidate control for reducing SO_2 and PM emissions.

b. Technical Feasibility

i. Firing All Gas

As identified in Section a. above, it is likely to be technically feasible to design an LNGC that can burn 100% gas while moored and regasifying; however, we do not know of any such vessels that have been constructed or that are commercially available. As stated previously, the USCG regulations and IGC code require that some oil be used while LNG carriers (LNGCs) are underway. Our understanding is that no vendors of LNGC marine boilers have produced commercially available systems with gas-only burner lighting capability, and that the market for such systems is relatively limited, since (a) that capability would only be usable when the vessels are moored (oil firing capability would still be needed for when the vessels are underway), (b) the quantity of oil currently used during burner lighting activities is very small; as we have previously discussed with EPA, MHI had previously represented to Northeast Gateway that their boilers could regasify LNG and unload it using gas only (i.e., they apparently ignored the small amount of oil used for burner lighting when making this claim) and to our knowledge this is the only LNG port in the world where the use of small quantities of oil to relight gas burners has been raised as an issue.

Although EPA has not clearly identified criteria for what is or is not technically feasible, the primary guidance document available for feasibility evaluations is EPA's draft 1990 New Source Review Workshop Manual. That manual states that:

> "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice...Two key concepts are important in determining whether an undemonstrated technology is feasible: 'availability' and 'applicability'. A technology is considered 'available' if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term...A technology that is available and applicable is technically feasible." (pp.. B.12, B.17).

NEG therefore asserts that the gas-only option is technically infeasible. In the case of LNGCs using boilers for both propulsion and regasification, the processes are sufficiently complex that the installation of a gas-only ignition system and modification of Mitsubishi's burner management software would trigger the need for a reevaluation of the vessels with respect to IGC Code compliance; that is, engineers experienced in these evaluations do not simply presume that because a technology has been demonstrated on land-based gas-fired boilers, that will work in an LNGC. However, if EPA disagrees with NEG's assertion that gas-fired pilots are technically infeasible, this letter also provides information relevant to economic feasibility (see Section c. below).

ii. Minimization of Oil Consumption

We previously addressed the technical feasibility of minimizing oil consumption in our October 2008 permit application, but we have reiterated the key issues below for completeness.

1. Minimizing the Number of Burner Lighting Events

As explained in Section 6.3.1 of our October 2008 application, Northeast Gateway is committed to requiring the LNGCs at its facility to minimize the number of burner lighting events during regasification, but (a) the LNGCs are required by contract to deliver cargo at the maximum rate allowable by onshore pipeline conditions, and (b) the LNGCs cannot "dump steam" to minimize burner lightings because of the NPDES permit requirement to operate the HRS. It is therefore not technically feasible to make a binding commitment to light the burners any less frequently.

2 Minimizing Oil Consumption Per Lighting Event

As explained in Section 6.3.2 of our October 2008 application, it is in the LNGCs' interests to get the gas burners lit as efficiently as possible, with a minimum amount of oil. The only technically feasible alternative to the current configurations would involve the installation of distillate-fueled pilot lights and implementation of associated changes to fuel piping and the burner management system software; this is discussed in more detail in Section iii below.

iii. Ultra Low Sulfur and Low Sulfur Distillate Oils

As was identified in Section 6.3.4 of our October 2008 application, it is technically feasible to install oil-fired pilot lights to reduce SO_2 and PM emissions.

iv. Low Sulfur Residual Oils (<1% S, <1.5% S)

As identified in Section 6.3.3 of our October 2008 application, the residual fuel with the lowest sulfur content that can be obtained reliably internationally is RMG 380 LS, which has a maximum sulfur content of 1.5%. Actual sulfur contents are by necessity lower than the specification, and sometimes can be considerably lower (e.g., less than 0.4%), but NEG cannot guarantee that such fuel will be available. A survey of most of Excelerate Energy's fuel oil suppliers shows that while most have 1.5% sulfur fuel oil available most of the time (these suppliers include Peninsula, Nustar, Macoil International Sa., Bominflot, Cepsa, and Aegean), only one supplier (Ventrin in Trinidad) has fuel oil available in the 0.4% sulfur range and that supply is far from reliably below 0.4% sulfur at all times.

In response to your comments to us in July 2009, we provided you with an electronic mail message which identified that we are aware that the International Maritime Organization's Marine Environment Protection Committee adopted Annex 13/Resolution MEPC.176(58) on October 10, 2008, and that Regulation 14 of this resolution identifies a general requirement that the sulfur content of fuel oil used in Emission Control Areas (ECAs) contain no more than 1.00% by mass on and after July 1, 2010. However, Regulation 18 also contains provisions that account for availability issues: i.e., if a ship is found to not comply with the limits, it may be required to present a record of actions taken to attempt to achieve compliance, and

> "provide evidence that it attempted to purchase compliant fuel oil in accordance with its voyage plan and, if it was not made available where planned, that attempts were made to locate alternative sources for such fuel oil and that despite best efforts to obtain compliant fuel oil, no such fuel oil was made available for purchase....The ship should not be required to deviate from its intended voyage or to delay unduly the voyage in order to achieve compliance."

In addition, EPA's current estimate is that its proposed ECA could enter into force "as early as August 2012",[2] taking into account the fact that Regulation 14 exempts vessels from fuel sulfur limitation during the first twelve months immediately following an amendment designating a specific ECA.

NEG will certainly require its vessels to comply with the abovementioned MARPOL requirements. It may be possible to acquire residual fuel oils containing less than 1.5% sulfur, but NEG cannot guarantee that this will be the case.

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[2] See US EPA's "Regulatory Announcement: Proposal of Emission Control Area Designation for Geographic Control of Emissions from Ships," http://www.epa.gov/otaq/regs/nonroad/marine/ci/ 420f09015.htm.

c. Cost Effectiveness

Of the candidate options identified in Section a. above, NEG has identified in Section b. that only one is technically feasible: i.e., the potential redesign of the boilers, boiler management system, etc. to incorporate commercially available distillate oil-fired pilots for purposes of lighting the third burner in each boiler during regasification activities.

In our October 2008 permit application, we estimated the costs of converting fuel systems and burners on NEG's vessels over to those that are capable of using distillate oil: i.e., labor and installation alone would cost \$435,000 per vessel, based largely on a quote from Mitsubishi for burner replacement, which was equivalent to \$14,500 per ton of SO_2 reduced during the firing of pilot fuel. This did not include the additional costs associated with coordinating such efforts, vessel re-routing, or the cost differential between residual oil and distillate oil, and was also based on the conservative assumption that 100% of the SO_2 would be removed.

In our July 29, 2009 electronic mail message to you, we also noted that EPA's cost analysis for its ECA designation identified lower cost-effectiveness numbers of \$2,600/ton NO_x, \$1,200/ton SO_2, and \$11,000/ton $PM_{2.5}$; however, EPA considered only changes to the fuel handling system for vessels propelled by diesel engines (\$44,000-\$99,000 per vessels), and did not consider burner changeouts on boiler-equipped vessels.[3] Mitsubishi identified the approximate costs of the replacement equipment alone (no labor or other costs) as being approximately ¥17,500,000 (≈ \$175,000). In addition, EPA's cost estimate assumes that highly specialized and skilled labor to conduct the fuel system modifications would cost only \$23.80 per hour, which is a gross underestimate (Mitsubishi charges approximately ¥16,000/hr ≈ \$160/hr for its labor). EPA's estimate of \$/ton is also based on reductions from a scenario where vessels are burning 100% residual oil; as noted in our application, we will be burning boil-off gas or regasified LNG almost the entire time that we are in port, with the use of oil restricted to burner lighting operations.

The development of and purchase/installation of gas-fired pilots is speculative but would be even less cost-effective (i.e., more costs associated with development, etc., and the same emissions reductions – i.e., no more than 100% of the SO_2 emissions can be reduced).

In conclusion, NEG still contends that BACT for the vessel main boilers consists of using BOG or regasified LNG at all times except when burners need to be lit, in which cases small amounts of residual oil (meeting the most stringent fuel sulfur specifications for this fuel, 1.5%) may be used.

2. BACT for CO from Auxiliary Generators on 2nd Generation Vessels (GE2)

Each second generation vessel is equipped with an auxiliary generator, referred to as "GE2" in Northeast Gateway's Deepwater Port Permit Number RG1-DPA-CAA-01 dated May 14, 2007 ("the Permit"). The GE2 engine a dual fuel Wartsila Model 12V32DF, with a maximum rating of 4020 kW (mechanical). Five (5) second generation vessels are equipped with GE2. These engines (when the vessels are moored) will fire approximately 99% "boil-off" LNG, with 1% marine diesel "pilot oil" necessary to achieve compression ignition. The use of dual-fuel engines for GE2 results in significantly lower emissions of both NO_x and SO_2 compared to firing all liquid fuel.

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[3] US EPA, "Proposal to Designate an Emission Control Area for Nitrogen Oxides, Sulfur Oxides and Particulate Matter Technical Support Document," EPA-420-R-09-007, April 2009.

The Permit contains allowable CO emissions for GE2 of 2.1 grams/kW-hr or 15.5 lb/hr, whichever is less stringent. Initial exhaust measurements of GE2 on the first two second generation vessels to be commissioned indicated that GE2 cannot be tuned to meet the CO limits in the Permit. Based on these exhaust measurements, it was determined that GE2 can meet CO emissions of 2.7 grams/kW-hr or 19.9 lbs/hr, whichever is less stringent. A request was made in a letter from Northeast Gateway to David Conroy (EPA) dated July 17, 2009 to revise the CO limits for GE2 to 2.7 grams/kW-hr or 19.9 lb/hr, whichever is less stringent.

The December 1, 2009 letter from EPA requested that additional information be provided to support that the revised CO limits represent BACT. Therefore, a supplemental BACT evaluation has been undertaken to determine if any available options to reduce CO emissions from GE2 are warranted in terms of BACT.

a. Candidate Controls/Technical Feasibility

In general, the most stringent method for controlling CO emissions from fuel combustion sources is an oxidation catalyst. An oxidation catalyst is normally designed as a passive "flow-through" device containing a substrate with a large surface area which is coated with (or contains) active catalyst material, such as platinum. The active catalyst material facilitates the oxidation of CO to CO_2 (based on excess O_2 in the engine exhaust) without the use of any reagents. Oxidation catalysts are a proven technology for compression ignition engines.

The other candidate control methodology for reducing CO emissions from compression ignition engines is low emission engine design. This is normally accomplished during the engine procurement stage, when a low emission engine is purchased. However, it is technically feasible to replace an existing engine with an alternate dual fuel engine if one is available with lower CO emissions. Therefore, this candidate control technology is also considered feasible.

Tuning of an individual engine to reduce CO emissions is also a feasible control technology for compression ignition engines. However, engine tuning has already been employed to the maximum extent possible to reduce CO emissions from GE2, consistent also with meeting the NO_x emission limits. Therefore, tuning of GE2 to further reduce CO emissions is not considered feasible for purposes of BACT.

b. Cost Effectiveness

i. Oxidation Catalyst

An economic evaluation has been done for the installation of oxidation catalysts on the five second generation vessels equipped with GE2. This economic evaluation is summarized in Table 1. The key elements of this evaluation are as follows:

- An equipment budgetary price for five (5) oxidation catalysts was obtained from a manufacturer's representative for GTE Industries.
- The total capital investment required for catalyst purchase and installation was estimated using USEPA OAQPS installation cost factors.
- The catalyst material life has been assumed to be five years based on discussion with the vendor.

- It is conservatively assumed there will be no other operational costs (such as catalyst cleanings or housing repairs) over the economic life of the catalyst.
- Conservatively, no costs have been assumed for the vessels to travel to a Port where the oxidation catalysts could be installed or alternatively for technicians to travel to the vessels.

Table 1 – Economic Analysis of Oxidation Catalyst for Five (5) GE2 (Wartsila 12V32DF) Dual Fuel Engines

Item	Cost
1. Vendor Equipment Budgetary Estimate for Five (5) Oxidation Catalysts	$172,931
2. Total Capital Investment (TCI) Required[1]	$328,535
3. Annual Capital Recovery for TCI[2]	$28,024
4. Annualized Cost for Catalyst Replacement[3]	$18,627
5. Total Annual Cost (Item 3 plus Item 4)	$46,651
6. Annual Emissions Reduction based on Maximum Allowable Emissions[4]	4.3 tons
7. Cost Effectiveness of Oxidation Catalyst	$10,849 per ton of CO

Table 1 notes:

1. Total Capital Investment (TCI) is based on Table 2.8 (Capital Cost Factors for Thermal and Catalytic Incinerators) from EPA/452/B-02-001, as follows: B (Purchased Equip Cost) = A (Equip Cost)*1.18, for instrumentation, sales taxes, and freight. TCI = B*1.61, for direct and indirect installation costs.
2. Annual Capital Recovery Factor (CRF) is based on a 15 year project economic life, and an interest rate of 3.25% (prime rate as of January 2009) (CRF = 0.0853).
3. The annualized cost of catalyst replacement is based on catalyst replacements at year 5 and again at year 10 at a cost of 80% of the original equipment cost ($138,345, based on vendor input). (Conservatively, no inflation is assumed.) The annualized cost is then calculated by determining the present worth of these two catalyst replacements, and then multiplying by the 15-year CRF of 0.0853.
4. The annual emission reduction assumes the maximum allowable operation of GE2 for 370 hours per year at 4020 kW output and the revised emission limit proposed of 2.7 grams/kW-hr. (The annual limit of 370 hours actually applies to both GE1 (two vessels) and GE2 (five vessels). No contribution to annual hours for GE1 has been conservatively assumed.) The CO reduction achieved by the oxidation catalyst is assumed to be 97% based on the vendor data.

The cost effectiveness value for oxidation catalysts for GE2, as shown in Table 1, is over $10,800 per ton. This is not warranted for purposes of BACT. A key factor of course is the very limited allowable annual hours of operation for both GE1 and GE2 (all vessels combined) of 370 hours per year, which renders the expense of an oxidation catalyst not cost effective for GE2.

ii. Alternate Dual Fuel Generators

A review of available dual fuel engines in the size range of 4000 kW has been undertaken to determine if any such engines are available with lower CO emissions than 2.7 grams/kW-hr. There is only one other manufacturer of dual fuel engines in the 4000 kW size range for the marine market other than Wartsila. This manufacturer is MAN B&W. The MAN B&W dual fuel engine in the 4000 kW size range is marketed under an alliance with Fairbanks-Morse. This engine is the FM-MAN 32/40 DF. The smallest engine available for the 32/40 DF is a 12 cylinder engine, rated at 6195 bhp (4620 kW) mechanical power. This is somewhat larger than the current GE2 engine (4020 kW Wartsila 32 DF), but is still within the size range that could be considered “feasible” as an alternative GE2 engine.

This review of available alternate engines has been limited to dual fuel (rather than diesel) engines. This is because the diesel (liquid fuel) engines have higher NO_x and SO_2 emissions compared to dual fuel engines. In terms of overall BACT, it is considered more important to maintain the lower overall emission profile of dual fuel engines, than to consider diesel engines solely for the purpose of reducing CO emissions.

Based on literature available on the Fairbanks Morse website (www.fairbanksmorse.com), the FM-MAN 32/40 DF has nominal CO emissions of 3.3 grams/bhp-hr (4.4 grams/kW-hr). This is greater than the revised limit of 2.7 grams/kW-hr proposed for the current GE2. Therefore, the conclusion of this review of available alternate dual fuel engines is that no alternate engines are available that can provide lower CO emissions.

c. Conclusion

In conclusion, the supplemental BACT review for CO has found that the revised CO limit of 2.7 grams/kW-hr proposed for GE2 still represents BACT. The cost effectiveness of installing oxidation catalysts has been examined, and is found to clearly not be cost effective. There are no alternate dual fuel engines available in the 4000 kW size range with lower CO emission available.

This letter has responded to the specific issues that you have identified to us. If you have any questions or comments, please do not hesitate to contact me at (617) 803-7809.

Sincerely,

Keith H. Kennedy

Keith H. Kennedy
Air Permitting Lead

Attachments

cc: Mike Trammel (Northeast Gateway)
Ernest Ladkani (Northeast Gateway)
George Lipka (Tetra Tech)
Todd Tamura (Tetra Tech)

ATTACHMENT A

REVIEW OF BACT AT OTHER U.S. LNG TERMINALS

ATTACHMENT A: REVIEW OF BACT AT OTHER U.S. LNG TERMINALS

The Federal Energy Regulatory Commission (FERC) has identified[4] that as of December 17, 2009, there are 9 existing LNG terminals in the U.S. (including Northeast Gateway); two of these were recently expanded, one has a FERC-approved expansion that is currently under construction, and two have FERC-approved expansions that are not under construction. Three additional terminals are FERC-approved and currently under construction. BACT information for the 11 facilities other than Northeast Gateway is identified below:

1. Everett, MA (Suez LNG – DOMAC) [existing]. Marine vessel emissions are excluded from this facility's air permits and therefore have not been subjected to BACT assessments. Vessels are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.

2. Cove Point, MD (Dominion – Cove Point LNG) [existing facility, expansion recently approved and constructed]. This facility received an air permit from the Maryland Department of Environment (MDE); Table 4.11.1.2-3 of the Final EIS for the expansion[5] shows that evaluations of air permitting regulatory applicability excluded all marine vessel emissions, and therefore BACT was not assessed for these emissions. MDE has confirmed that although the facility did receive a PSD permit, BACT was not applied to any emissions from vessels.[6] Vessels are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.

3. Elba Island, GA (El Paso – Southern LNG) [existing facility, expansion approved and currently under construction]. This facility received an air permit from the Georgia Department of Natural Resources (GDNR); Section 4.11.1 of the Final EIS for the "Elba III" expansion identifies that all marine vessel emissions, including those associated with LNG unloading, are indirect emissions not subject to permitting, and therefore BACT was not assessed for these emissions.[7] Vessels are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.

4. Lake Charles, LA (Southern Union – Trunkline) [existing]. Trunkline's air permits do not include any emissions from marine vessels, and therefore BACT was not assessed for these emissions.[8] Vessels are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.

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[4] This information is from http://www.ferc.gov/industries/lng.asp. (The construction status of the three MARAD/USCG-approved LNG projects was last identified by FERC in October 2009.)

[5] The FEIS for the Cove Point expansion is available from http://www.ferc.gov/industries/lng/enviro/eis/2006/04-28-06-eis-cove.asp.

[6] William Paul (MDE), telephone conversation with Todd Tamura (Tetra Tech), January 13, 2010.

[7] The FEIS for the Elba III expansion is available from http://www.ferc.gov/industries/lng/enviro/eis/2007/08-03-07-eis.asp.

[8] Permitting documents for the Southern Union Trunkline terminal are available from http://www.deq.louisiana.gov/apps/pubNotice/show.asp?qPostID=4027&SearchText=trunkline&startDate=1/1/2005&endDate=1/7/2010&category=.

5. Gulf of Mexico (Gulf Gateway) [existing]. This facility received a PSD air permit from EPA Region 6 which included vessel unloading emissions as direct emissions, and identified BACT as the use of BOG/regasified natural gas in the boilers. (While in transit, vessels are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.) Excelerate Energy and Tetra Tech met with EPA Region 6 on May 20, 2009 to inform them of future permit modifications that would be requested for Gulf Gateway. It was stated that upon finalizing permit modifications for Northeast Gateway, similar modifications would be requested for Gulf Gateway. The Gulf Gateway Port is currently inactive primarily due to receiving gas pipelines seriously damaged by Hurricane Ike.

6. Freeport, TX (Cheniere/Freeport LNG) [existing facility, expansion approved but not currently under construction]. The Texas Commission on Environmental Quality (TCEQ) confirmed that vessels utilizing this facility are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.[9]

7. Sabine, LA (Sabine Pass Cheniere LNG) [existing facility, expansion recently approved and constructed]. Louisiana DEQ's Statement of Basis for the facility's 2009 Title V operating permit excludes all emissions associated with marine vessels.[10] Vessels are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.

8. Hackberry, LA (Cameron LNG – Sempra Energy) [existing facility, expansion approved but not currently under construction]. Cameron LNG's air permits do not include any emissions from marine vessels, and therefore BACT was not assessed for these emissions.[11] Vessels are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.

9. Sabine, TX (Golden Pass – ExxonMobil) [FERC-approved, under construction]. This facility received an air permit from the Texas Commission on Environmental Quality (TCEQ); Section 4.11.1 of the Final EIS for the expansion[12] shows that evaluations of air permitting regulatory applicability excluded all marine vessel emissions, and therefore BACT was not assessed for these emissions. Vessels are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.

10. Pascagoula, MS (Gulf LNG Energy LLC) [FERC-approved, under construction]. This facility received a preconstruction air permit from the Mississippi Department of Environmental Quality (MDEQ) which incorporates emissions from vessels while unloading but has no applicable

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[9] Ruth Alvarez (Texas CEQ), telephone conversation with Todd Tamura (Tetra Tech), January 8, 2010.

[10] Permitting documents for Sabine Pass are available from http://www.deq.louisiana.gov/apps/pubNotice/show.asp?qPostID=4828&SearchText=&startDate=1/1/2005&endDate=1/7/2010&category=.

[11] Permitting documents for Cameron LNG are available from http://www.deq.louisiana.gov/apps/pubNotice/show.asp?qPostID=4243&SearchText=cameron&startDate=1/1/2005&endDate=1/7/2010&category=.

[12] The FEIS for the Golden Pass project is available from http://www.ferc.gov/industries/lng/enviro/eis/2005/06-03-05-eis.asp.

requirements associated with these emissions.[13] (Section 4.12.1 of the FEIS states that the vessels are not under the control of the facility.) Vessels are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.

11. Offshore Boston, MA (Neptune LNG – Suez) [FERC-approved, under construction]. This facility received an air permit from EPA Region 1, which identifies that the only marine vessels that can use the port must be equipped with two 312 mmBtu/hr boilers and two 11,400 kW dual fuel power generator engines, with NO_x from all four controlled by Selective Catalytic Reduction (SCR).

Separately, FERC has identified 13 additional FERC-approved projects and 3 additional MARAD/USCG-approved projects that are not under construction:

12. Corpus Christi, TX (Ingleside Energy – Occidental Energy). This facility received an air permit from the Texas Commission on Environmental Quality (TCEQ); Section 4.11.1 of the Final EIS for the expansion[14] shows that evaluations of air permitting regulatory applicability excluded all marine vessel emissions, and therefore BACT was not assessed for these emissions. Vessels are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.

13. Corpus Christi, TX (Cheniere LNG). This facility received a preconstruction air permit from TCEQ. The Texas Commission on Environmental Quality (TCEQ) confirmed that vessels utilizing this facility are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.[15]

14. Corpus Christi, TX (Vista Del Sol – 4Gas). The Final EIS for this project[16] shows that evaluations of air permitting regulatory applicability excluded all marine vessel emissions, and therefore BACT was not assessed for these emissions. Vessels are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.

15. Fall River, MA (Weaver's Cove Energy/Hess LNG). Massachusetts DEP issued a preconstruction approval for this facility in March 2008, but as indicated above FERC has identified that the project is not under construction, and the facility is appealing the permit. The permit only allows LNGCs that are DFDEs with four Wärtsilä 50DF engines and capacities of approximately 55,000 m^3, and no such vessels are identified by shipbuildinghistory.com as being in the existing fleet or even on order. There is only one LNGC which is even close to this size with these powerplants: the *Gaz de France Energy*, which has four Wärtsilä 50DF but a capacity of 74,100 m^3. That being said, for the hypothetical vessel identified in the permit, DEP identified that the only restrictions were that the vessel use only one engine (a 6L50DF) to

[13] The preconstruction permit for Gulf LNG is available from http://opc.deq.state.ms.us/ai_info.aspx?ai=23844.

[14] The FEIS for the Ingleside project is available from http://www.ferc.gov/industries/lng/enviro/eis/2005/06-10-05-eis.asp.

[15] See Footnote 9.

[16] The FEIS for Vista Del Sol is available from http://www.ferc.gov/industries/lng/enviro/eis.asp.

unload and use 99% gas and 1% oil at all times, where the oil contains no more than 1.5% sulfur by weight.[17]

16. Port Arthur, TX (Sempra). The Final EIS for this project[18] shows that evaluations of air permitting regulatory applicability excluded all marine vessel emissions, and therefore BACT was not assessed for these emissions. Vessels are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.

17. Logan Township, NJ (Crown Landing LNG – BP). The Final EIS for this project[19] shows that while emissions from vessels while docked were interpreted as being part of the stationary source, LAER evaluations were limited to the stationary sources located on shore. This project has subsequently been cancelled as the result of a U.S. Supreme Court decision allowing the state of Delaware to block the project.

18. Cameron, LA (Creole Trail LNG – Cheniere LNG). Creole Trail's air permits do not include any emissions from marine vessels, and therefore BACT was not assessed for these emissions.[20] Vessels are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.

19. Pascagoula, MS (Casotte Landing – ChevronTexaco). The Final EIS for this project[21] shows that while emissions from vessels while docked were interpreted as being part of the stationary source, they did not cause the facility to trigger PSD permitting, and therefore BACT did not need to be assessed for either the vessels or the onshore sources.

20. Port Lavaca, TX (Calhoun LNG – Gulf Coast LNG Partners). The Final EIS for this project[22] shows that evaluations of air permitting regulatory applicability excluded all marine vessel emissions, and therefore BACT was not assessed for these emissions. Vessels are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.

21. Long Island Sound, NY (Broadwater Energy-TransCanada/Shell). The Broadwater project was opposed by (and therefore blocked by) the Governor of New York.

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[17] Massachusetts DEP Southeast Regional Office, Conditional Non-Major Comprehensive Plan Approval of Application No. 4B04016, Transmittal Number W041433, Source No. 120-0176, March 13, 2008 (requirements for Unit No. 17).

[18] The FEIS for Port Arthur is available from http://www.ferc.gov/industries/lng/enviro/eis/2006/04-28-06-eis-port.asp.

[19] The FEIS for Crown Landing is available from http://www.ferc.gov/industries/lng/enviro/eis/2006/04-28-06-eis-crown.asp.

[20] Permitting documents for Creole Trail are available from http://www.deq.louisiana.gov/apps/pubNotice/show.asp?qPostID=3835&SearchText=creole&startDate=1/1/2005&endDate=1/7/2010&category=.

[21] The FEIS for Bradwood is available from http://www.ferc.gov/industries/lng/enviro/eis/2008/06-06-08-eis.asp.

[22] The FEIS for Calhoun is available from http://www.ferc.gov/industries/lng/enviro/eis/2007/08-10-07-eis.asp.

22. Bradwood, OR (Northern Star LNG – Northern Star Natural Gas). This facility has applied for an air permit, and the application includes vessel emissions associated with unloading. However, these emissions did not cause the facility to trigger PSD permitting, and therefore BACT did not need to be assessed.[23]

23. Baltimore, MD (AES Sparrows Point – AES Corporation). The Final EIS for this project[24] shows that evaluations of air permitting regulatory applicability included emissions from marine vessels during unloading. This project has been in litigation over non air-related issues and has not submitted an air permit application.[25]

24. Coos Bay, OR (Jordan Cove Energy Project). The Final EIS for this project[26] shows that while emissions from vessels while docked were interpreted as being part of the stationary source, they did not cause the facility to trigger PSD permitting, and therefore BACT did not need to be assessed for either the vessels or the onshore sources. This facility has submitted an air permit application, but the permit has not yet been granted.[27]

25. Port Pelican (ChevronTexaco). EPA Region 6 issued a Title V operating permit for this facility in 2004 which excludes all marine vessel emissions.[28] BACT was therefore not assessed for these emissions, and vessels are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.

26. Gulf of Mexico (Main Pass McMoRan Exp.). EPA has received a permit application for this facility in 2004, but has not issued a permit.[29]

27. Offshore Florida (Höegh LNG – Port Dolphin Energy). The preconstruction air permit for this facility excludes emissions from marine vessels.[30] BACT was therefore not assessed for these emissions, and vessels are allowed to burn heavy (residual) fuel oil with no enforceable Federal or local restrictions.

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[23] George Davis (Oregon DEQ), telephone conversation with Todd Tamura (Tetra Tech), January 13, 2010.

[24] The FEIS for Port Arthur is available from http://www.ferc.gov/industries/lng/enviro/eis/2006/04-28-06-eis-port.asp.

[25] See Footnote 6.

[26] The FEIS for Jordan Cove is available from http://www.ferc.gov/industries/lng/enviro/eis/2009/05-01-09-eis.asp.

[27] Martin Abts (Oregon DEQ), telephone conversation with Todd Tamura (Tetra Tech), January 13, 2010.

[28] The Port Pelican permit is available from http://www.epa.gov/earth1r6/6pd/air/pd-r/portpelicanfinal.pdf.

[29] The Main Pass permit application is available from http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

[30] The Port Dolphin air permit is available from http://www.dep.state.fl.us/air/emission/apds/listpermits.asp.

ATTACHMENT B:

USCG (RAKSNIS) EMAIL TO EXCELERATE ENERGY (TRAMMEL)

Mike Trammel

From:	Richard.J.Raksnis@uscg.mil on behalf of Raksnis, Richard CDR [Richard.J.Raksnis@uscg.mil]
Sent:	Tuesday, April 15, 2008 3:46 PM
To:	Mike Trammel
Subject:	RE: Follow Up - Natural Gas Fuel

Mr. Trammel -

Thank you for your e-mail regarding 46 CFR 154.1854 and the requirement for an oil-fired pilot. You are correct in your understanding. Both the Federal Regulations and the IGC Code (Reg 16.5.4) require that when boilers are operating on boil-off, there must be a fuel oil fired pilot for ignition. The reason for this is to provide a level of redundancy in case the gas-fired pilot does not work properly in close-quarters situations in a port's waters.

Please don't hesitate to contact me or Mr. Wayne Lundy, 202-372-1379 if you have any further questions.

Sincerely,

Rick Raksnis, CDR
Chief, HazMat Standards Div
USCG Headquarters
Ph: 202-372-1420