TETRA TECH EC, INC.

August 19, 2011

Mr. Donald Dahl
U.S. EPA New England
5 Post Office Square, Suite 100
Boston, MA 02109-3912

Subject: Northeast Gateway Energy Bridge L.P. (CAA Permit No. RG1-DPA-CAA-01) Supplemental Material for Main Boiler SO_2 BACT Analysis and Auxiliary Generator CO Emissions Compliance

Dear Mr. Dahl:

Tetra Tech EC, Inc. (Tetra Tech) has prepared and submits this letter addressing remaining issues for the Northeast Gateway Deepwater Port (Port) air permit modification on behalf of Northeast Gateway Energy Bridge, L.P. (NEG). In our discussions and email correspondence over the past year, EPA has emphasized that the key items needed for approval of the air permit modification application for the Port are related to the Best Available Control Technology (BACT) analysis for SO_2 from the main boilers on the vessels. The specific items requested by EPA were: 1) documentation from the United States Coast Guard (USCG) of the need for oil combustion for burner lightings in the main boilers, and 2) better documentation that the sulfur in fuel oil during burner lightings is representative of BACT for SO_2.

Both of these items have been addressed in previous submittals to EPA, i.e., the original modification application from October of 2008 (relevant portions of which are included in Attachment A to this letter) and the supplemental BACT analysis from January 2010 (relevant portions of which are included in Attachment B to this letter). The January 2010 submittal contained a BACT presentation in a complete top-down manner in response to a previous EPA request. Portions of these prior submittals have been attached to this letter for reference because the analyses presented in those prior submittals form the basis for the updates contained in this letter.

On February 21, 2011, Mark Prescott of the USCG provided a letter to you describing the necessity for fuel oil for burner light-off in the main boilers and you indicated by email on February 22 that the USCG letter is sufficient to satisfy that portion of EPA's request. The primary purpose of this letter is to respond to EPA's request for additional documentation that the proposed sulfur content of the fuel oil necessary during burner lightings is representative of BACT for SO_2. Over the past several months since our last correspondence, NEG has been evaluating various options to reduce sulfur in fuel oil during burner lightings as well as alternatives for achieving compliance with current carbon monoxide (CO) permit limits for the dual fuel auxiliary generator (GE2).

SGS

160 Federal Street, 3rd Floor, Boston, MA 02110
Tel 617.443.7500 Fax 617.737.3480
www.tteci.com

The sulfur in fuel oil evaluations are addressed in the following Sections 1 and 2 and the CO emissions compliance evaluation for the dual fuel auxiliary generator is addressed in Section 3.

1. Background for Sulfur in Fuel Oil Evaluation

The previously submitted BACT analyses concluded that conversions of the main boiler fuel systems and burners are necessary to combust the grade of oil that can achieve the lowest sulfur content (0.1 percent sulfur in marine diesel oil or MDO) and that these conversions are not cost effective and therefore do not represent BACT for SO_2. For other grades of marine fuel oil that could be used for burner lightings without physical modification to the boilers, only fuel with a sulfur content up to 1.5% sulfur was available in adequate supply internationally. The grades of fuel oil that can be used without boiler modification are called heavy fuel oil (HFO) or intermediate fuel oil (IFO) and these grades are somewhat similar to land-based residual fuel oil. Therefore, HFO at less than or equal to 1.5% sulfur was considered BACT for SO_2 along with a commitment to minimize the amount of fuel oil combusted during burner lightings. Please refer to Attachments A and B to this letter.

2. Updated Evaluations for SO_2 BACT for Main Boilers

Given the time that has elapsed since the latest BACT evaluation in January of 2010, NEG and Tetra Tech have undertaken evaluations of three aspects of the BACT analysis to determine whether there are updates to the information presented a year and a half ago. The aspects considered are:

- The availability of HFO or IFO with lower sulfur content than 1.5%;
- The amount of fuel oil necessary for burner lightings; and
- The technical feasibility and cost of converting the fuel and burner systems to combust 0.1% sulfur fuel oil.

HFO and IFO Sulfur Content Evaluation

NEG recently commissioned a survey of the availability and cost of 1.0% sulfur IFO from 11 major regions of the world. The results indicate that 1.0% sulfur IFO is currently available in 33 of the 73 international ports surveyed and may be available at 10 additional ports in the near future. This lower sulfur fuel is now more widely available because MARPOL Annex VI Regulation 14 on SO_2 emissions includes a requirement of 1.0% sulfur fuel oil for marine vessels in Sulfur Emission Control Areas (SECAs) effective July 1, 2010. Regulation 14 also contains a future reduction to 0.1% sulfur fuel oil in these areas in January 2015.

Currently, the only SECAs are areas within the Baltic Sea (designated in 1997), the North Sea (designated in 2006), and North America (designated in 2010). The North American SECA, applicable to coastal waters within 200 nautical miles of the continental U.S. and Canada, is expected to become effective in late 2012. Not surprisingly, there is better availability of 1.0% sulfur fuel oil in ports closer to the SECAs. Based on the recent NEG survey, the price premium of the 1.0% sulfur IFO over the originally proposed 1.5% sulfur HFO (RMG 380 LS) ranges from approximately $30 per metric ton to $60 per metric ton, depending on the port.

Based on the proposed annual limit for the Port of 640 metric tons of fuel oil in the main boilers (see October 2008 NEG permit modification application), this price premium represents \$19,200 to \$38,400 annually. The reduction of sulfur in fuel for burner lightings from 1.5% to 1.0% results in a smaller increase of potential SO_2 emissions from the Port (14.1 additional tons per year versus 21.2 additional tons per year previously) with a control cost of \$2,700 per ton to \$5,400 per ton of SO_2 controlled versus using 1.5% sulfur fuel. NEG considers this cost-effective.

The availability of IFO with even lower sulfur content (i.e., 0.5% sulfur) was also investigated but there is essentially no availability of this product worldwide since there is no MARPOL driver for this grade of marine fuel oil in the near term. Sulfur in fuel could be reduced through MARPOL to 0.5% for all areas (outside of SECAs) in 2020 but this date is subject to a review in 2018 so almost no suppliers are currently providing IFO or HFO at significantly less than 1.0% sulfur on a consistent basis.

In summary, NEG considers both the recent availability of the 1.0% sulfur IFO and the cost effectiveness of this control strategy to be acceptable and now proposes 1.0% sulfur IFO (or 1.0% HFO if available) for burner lightings in the main boilers as a revision to the modification application of October 2008. Potential emissions of SO_2 from oil firing in the main boilers are reduced from 21.2 tons per year to 14.1 tons per year and the PTE for SO_2 including all other sources and fuels at the Port is reduced to 19.0 tons per year. (The facility-wide PTE for SO_2 can be further reduced to 15.5 tons per year if the auxiliary generators are deleted from the permit, which we propose inSection 3 of this letter.

Fuel Oil Quantity for Burner Lightings

NEG has also reevaluated whether less fuel oil could be fired during the main boiler burner lightings at the Port. However, the only additional data available on this issue are from the six regasification events that occurred at the NEG Port during the 2009-2010 winter season (November 2009 through February 2010). This data base is too limited to propose a change to the previously requested 640,000 kg per year Port limitation as well as the requested 24-hour limitation of 4,800 kg per main boiler. **However, based on the data evaluated from the 2009-2010 winter season, NEG is confident that it can reduce the originally proposed short-term oil limitation of 1,400 kg per main boiler (2,800 kg per vessel) per 3-hour period. In consideration of the recent promulgation by EPA of the 1-hour SO_2 ambient air quality standard, NEG proposes to revise the short term limitation of fuel oil consumption in the main boilers to 800 kg per one-hour period per vessel and requests reformatting the 24-hour limitation to 9,600 kg per 24-hour period per vessel (instead of 4,800 kg per main boiler).**

0.1% Sulfur Fuel Oil

Pursuant to your email of February 22, 2011, following is a brief discussion of the reanalysis that NEG and Tetra Tech have conducted on the viability of 0.1% sulfur fuel oil for burner lightings. Significant developments in the availability of low sulfur (e.g., 0.1% sulfur) fuel have occurred since the initial SO_2 BACT analysis presented to EPA in the 2008 modification application. The most significant development to the NEG Port is that marine diesel oil (MDO) is being phased out internationally as a marine fuel to the point that it is now rarely available. The cost estimate previously provided by Mitsubishi (the main boiler vendor) to retrofit pilot burners in the main boilers was based on the use of 0.1% sulfur MDO. MDO is a blend of heavy gasoil that often contains minor amounts of black refinery feedstocks. The only other marine oil available with sulfur contents as low as 0.1% is marine gas oil (MGO), which is similar to a distillate No. 2 fuel oil. However, according to Mitsubishi, MGO cannot safely be co-fired with LNG boil-off gas (BOG) as MDO can, so MGO cannot be used for burner lightings in the main boilers. A letter from Mitsubishi addressing this issue is contained in Attachment C to this letter.

The main boilers could be retrofitted to combust 0.1% sulfur MGO as their primary fuel in lieu of BOG (with IFO for burner lightings only), but this would produce potential SO_2 emissions of approximately 200 tons per year from the NEG Port which is significantly more than the proposed potential emissions of 14.1 tons per year from lighting the burners with 1.0% sulfur IFO.

In summary, combustion of 0.1% sulfur MDO or MGO for burner lightings in the main boilers at the NEG Port is no longer a technically feasible option for SO_2 BACT.

Regarding compliance with MARPOL requirements for 0.1% sulfur fuel in the North American SECA in 2015, NEG believes that one or more of the following events is very likely to occur by that time:

- Refiners will develop IFO with a 0.1% sulfur content, which can be used for burner lightings without modification of the main boilers (as the decision to produce new low-sulfur fuels tends to be driven by MARPOL sulfur in fuel requirements rather than the isolated requests of end users like NEG);

- Alternatively, a blended 0.1% sulfur fuel oil with characteristics that allow dual firing with BOG will be developed and made available internationally;

- A waiver from the SECA sulfur in fuel requirements will be made available to LNG vessels using steam boilers for propulsion; or

- A fuel averaging provision will be made available to LNG vessels similar to the recent EU Port Directive allowing LNG vessels firing primarily BOG to meet the intent of the MARPOL 0.1% sulfur fuel oil requirements (as explained below in more detail).

As you may be aware, the Council of the European Union established a directive regarding the sulfur content of marine fuels in 2005, based on MARPOL requirements for SECAs in the North and Baltic Seas. This directive (2005/33/EC) requires member states to comply with pertinent provisions of MARPOL but also requires heavy fuel oils to be limited to 1% sulfur content by mass within their territories and, more significantly, requires ships at berth in Community ports to use marine fuels with sulfur contents less than or equal to 0.1% by mass after January 1, 2010. The directive also contains provisions for trials and use of new emission abatement technologies in lieu of the fuel sulfur limits.

However, on December 13, 2010, the Council of the European Union adopted a final decision (which was previously adopted by the European Parliament) establishing an alternative compliance method for the 0.1% sulfur fuel oil requirement, specifically applicable to LNG vessels at berth in European ports (see Attachment D to this letter). Since LNG tankers typically fire a combination of BOG and marine fuel oil, this decision allows for the use of BOG and marine fuel oil in any ratio, so long as the total sulfur emissions generated while at berth are equal to or lower than those that would be generated by the use of

0.1% sulfur fuel. The decision provides a formula to be used for calculating the allowable ratio of BOG to marine fuel oil, which varies based on the sulfur content of the fuel oil used. For a fuel oil sulfur content of 1.0%, the mass ratio of BOG to fuel oil burned while at berth must be at least 7.8 to 1 on a mass basis. The use of 1.0% sulfur IFO for burner lightings at the Port would be in compliance with this recent European decision.

3. Compliance Evaluation for CO Emissions from the Dual Fuel Auxiliary Generator

The only other issue that NEG is aware of at the Port that could influence the issuance of the permit modification is the fact that the dual fuel auxiliary generator (GE2) cannot achieve the revised CO emission limit requested by NEG in July of 2009. A finding of noncompliance for this emission unit was included in EPA's October 22, 2010 Finding of Violation (FOV) and the issue with these engines was explained in detail in NEG's December 2, 2010 response to the FOV.

Based on emissions test data to date and discussions with Wartsila (the manufacturer of the dual fuel auxiliary generator) NEG has determined that to assure compliance the CO limit in the permit would have to be increased by 20% to 40% from the limit requested in supplemental material submitted to EPA in July of 2009. This is because Wartsila has been unable to provide a revised CO emission guarantee, so this additional margin would be necessary to mitigate the manufacturer's uncertainty about its engine performance.

Given this information, NEG has, over the past several months, conducted an evaluation of compliance options for this generator. In addition to a reassessment of future operations at the NEG Port, NEG has evaluated operational practices over the past year at other Excelerate Energy GasPorts around the world to determine if operation of the auxiliary generators (both GE1 and GE2) could be further restricted beyond the 370 hours per year in the current NEG permit. **Based on this evaluation, NEG has determined that it can and will make a commitment that the auxiliary generators (GE1 and GE2) will no longer be operated at the Port for commercial operations. During future LNG regasification events, these generators will only be run during emergency situations involving loss of a main boiler/steam generator. This operation would be necessary in order to maintain vessel systems on a short term basis from the malfunction/breakdown condition through safe shutdown of regasification operations and disconnecting from the buoy. Therefore, NEG requests that the auxiliary generators GE1 and GE2 be deleted from the NEG permit.**

This permit change would make the requested changes to dual fuel generator monitoring described in Section 2 of the October 2008 modification application moot and would eliminate potential emissions of the following amounts from the auxiliary generators on an annual basis:

- NO_x = 18 tons per year
- CO = 5 tons per year
- VOC = 1.9 tons per year
- $PM_{10}/PM_{2.5}$ = 0.6 tons per year
- SO_2 = 3.7 tons per year

4. **Summary of Potential Emissions from the NEG Port**

The following table summarizes the total potential emissions from the NEG Port for: 1) the current effective permit (RG1-DPA-CAA-01) dated May 14, 2007, 2) the permit modification application of October 2008 for limited use of 1.5% sulfur IFO during burner lightings and for a larger auxiliary boiler (Aux2) on third generation vessels, and 3) the revisions to that modification application requested in this letter: 1.0% sulfur IFO for burner lightings, and elimination of the auxiliary generators GE1 and GE2 from the permit.

Pollutant	Total Potential Emissions (tons per year)		
	Current permit dated May 2007	October 2008 application	August 2011 letter
NO_x	49	49	40.7
CO	99	99	99
VOC	16.1	16.1	15.6
$PM_{10}/PM_{2.5}$	20.6	21.6	20.7
SO_2	4.9	26.1	15.5

Please feel free to contact Ernest Ladkani of Excelerate Energy at 832-813-7687 or me at 617-803-7809 if you have any questions.

Sincerely,

Tetra Tech EC, Inc.

Keith H. Kennedy

Keith H. Kennedy
Senior Consultant

Attachments

Cc: Ernest Ladkani, Excelerate Energy

Attachment A

Excerpts from October 2008 Application for Minor Source Air Permit Modification

50 metric tonnes/hr of steam). Like the auxiliary boilers on the second-generation vessels, the auxiliary boilers are capable of firing oil or gas but will be restricted to firing only gas while at the Northeast Gateway Port, and will also have emissions controlled with SCR systems that reduce NO_x emissions to no more than 15 ppmvd @ 3% O_2. **Northeast Gateway is therefore proposing that the permit be revised to include these 50 tonne/hr boilers (as emission units "Aux2"), as described in more detail in Section 3 of this application, and require any auxiliary boiler installed on future Excelerate Energy vessels to have its emissions controlled with an SCR system and reduce NO_x emissions to no more than 15 ppmvd @ 3% O_2.** Although maximum hourly emissions from the 50 tonne/hr boilers are higher than those of the 30 tonne/hr boilers, Northeast Gateway is not proposing to change its current 12-month rolling-average facilitywide emissions caps of 49 tons/year NO_x and 99 tons/year carbon monoxide (CO).

1.2.3 Oil Burning in Main Boilers for Purposes of Lighting Gas Burners

Each LNGRV is equipped with two main boilers that are used for purposes of vessel propulsion, regasification, and hoteling, and are designed to operate in a gas-only mode, oil-only mode, or in a combination mode. For purposes of operating at the Northeast Gateway Port, the current permit requires LNGRVs to regasify their cargos while operating in a gas-only mode. Each boiler on the LNGRV is equipped with three burners to heat the vessel boilers. When the vessel arrives at the Northeast Gateway Port, prior to retrieval of the STL buoys, they are typically operating only two of the three burners while in the vicinity of the Port. While operating in the gas-only mode, boiler loads fluctuate with steam demand and the on-board burner management system for the vessel decides whether and when the boilers fire on two burners or three. When the boiler is operating on two burners and the burner management system calls for the third burner to be lit, the boilers momentarily switch to a dual-fuel mode and a small quantity of oil is used to ignite the gas in the third burner. The use of oil to light the gas-fired burner is 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). One interim solution contemplated by Northeast Gateway to eliminate the need to light additional burners and having to use oil during the regasification process was to operate the vessel with all three burners lit for the duration of the regasification activities. However, in order to comply with the NPDES permit, the LNGRV is required to reduce the amount of water utilized on the vessel while in regasification mode. To do this, Excelerate Energy developed and installed a Heat Recovery System (HRS) which allows the vessel to reduce their daily water intake and discharge amounts by about 95% over other similar vessels. It is not technically feasible for LNGRVs keep all three burners continuously lit, especially while the HRS is in use to comply with the EPA's NPDES permit. During these short events, a very limited quantity of oil will need to be burned for purposes of lighting of the third burner, whereas the current permit only addresses emissions from burning gas. **Northeast Gateway is proposing that the permit be modified to allow for a limited amount of oil burning for purposes of lighting the gas burners, as is discussed in more detail in Section 4.**

system has not been designed for CO catalysts on marine vessels, nor does there appear to be sufficient space). Northeast Gateway believes that CO catalysts should therefore be considered technically infeasible.

As shown in Appendix B, the burner vendor (Hamworthy) for these boilers has stated that "carbon monoxide emissions for the boiler/burner combination operating at its design conditions (e.g., clean, etc.) will be extremely low and of the order of 10-20 ppm (13-27 mg/Nm^3 @ 3% O_2, 273K and 101 kPa)." This is identical to what was identified for the 30 tonne/hr boilers in the application May 2007 Permit, although BACT was conservatively determined to be 60 ppmvd @ 3% O_2 (0.044 lb/MMBtu) for that Permit (which is still substantially lower than the CO emission factor of 0.082 lb/MMBtu estimated for uncontrolled natural gas boilers by EPA's AP-42 publication). Nothing has changed appreciably in the field of CO control since the time of the May 2007 Permit, and therefore BACT for the new boilers is also 60 ppmvd @ 3% O2 (0.044 lb/MMBtu).

6.3 BACT for Oil-Firing in Main Boilers

BACT for the main boilers firing natural gas was already determined in the 2007 Permit and has been applied. As stated previously, oil firing will increase emissions of SO_2, PM, and some individual HAP (but not total HAP).

With respect to Step 1 of the BACT analysis procedure identified previously, "identify all alternatives," we have developed the following list:

1. Minimize the number of burner lighting events during regasification
2. Use less oil per burner lighting
3. Use oil with lower sulfur content

Step 2 of the BACT analysis procedure requires an analysis of technical feasibility. With respect to (1), Northeast Gateway is already committed to minimizing the number of burner lighting events during regasification. It is in our business interests to regasify the cargo as quickly as possible, which means using all three burners in both boilers if needed, when onshore pipeline conditions allow.

6.3.1 Technical Feasibility Assessment – Minimizing the Number of Lightings

With respect to minimizing the number of burner lightings, Northeast Gateway is already committed to minimizing the number of burner lighting events during regasification. The rate at which Northeast Gateway delivers its cargo is dependent upon the contractual terms under which the cargo was purchased, which means using all three burners in both boilers if needed, when onshore pipeline conditions allow. Typically, when the vessel is operating all three burners, excess steam generated during periods of low loads would normally be redirected into the vessel's condensers and cooled; however, this is not possible in the closed-loop mode with the HRS active because the system is designed in such a way that dump valves are to be kept closed to maintain adequate steam production since additional water intakes are secured. While utilizing the HRS, heat input to the main condenser would be too high and the main condenser could lose the vacuum if the steam pressure were to be dumped.

As described in Section 4, there is one lighting event (per boiler) that occurs prior to activation of the HRS. It is possible that the vessels could start out being moored with all three burners active and dump steam prior to activation of the HRS, but the water permit for the Northeast Gateway Port includes stringent limitations on the effluent temperature and flow conditions during the interval prior to the startup of the HRS. Northeast Gateway cannot confirm that it is possible to use three burners while maintaining compliance with the facility's water permit, and definitely cannot commit to doing this without additional operating experience at the Northeast Gateway Port. It is not technically feasible to further reduce the number of burner lighting events.

6.3.2 Technical Feasibility Assessment – Minimizing the Quantity of Oil Used Per Lighting

With respect to using less oil per burner lighting, it is in Northeast Gateway's interests to get the gas burners lit as efficiently as possible, with a minimum amount of oil. Each of the boiler's oil-fired burners can fire oil at rates between 99 kg/h/burner (minimum flow, dual-fuel mode) and 1,980 kg/h (burner capacity). The boiler manufacturer, Mitsubishi Heavy Industries (MHI), was asked to identify whether it was technically feasible to operate only the third oil burner to light the third gas burner, rather than having to turn on all three oil burners. MHI responded that they could not perform this action due to safety concerns; there are many factors which need to be addressed by the burner management system on LNG carriers, and for reasons of safety, these systems are not to be tampered with. This is therefore not a technically feasible option. It may, however, be technically feasible to install oil-fired pilots which would use less oil than the boiler's original oil burners and that are also capable of burning lighter distillate fuels. This option will be discussed in more detail in Section 6.3.4.

6.3.3 Technical Feasibility Assessment – Minimizing the Oil Sulfur Content

With respect to using oil with a lower sulfur content, the residual fuel with the lowest sulfur content that can be obtained reliably internationally is RMG 380 LS (low sulfur, residual marine gas with a maximum viscosity of 380 at 50 deg C), which has a maximum sulfur content of 1.5%. Northeast Gateway is committed to carrying RMG 380 LS onboard each vessel that regasifies at Northeast Gateway Port for purposes of burner lighting events. Although distillate fuels with lower sulfur contents are available, these cannot be used in the boiler's burners for purposes of lighting the gas burners because MHI has stated that it is technically infeasible. Lighter distillate oil (e.g., diesel fuel) can be used in oil-fired pilots; this is discussed in more detail in Section 6.3.4.

6.3.4 Evaluation of Installing Diesel Oil-Fired Pilot Burners

It is possible to light the gas burners using diesel oil-fired pilot burners. However, installing these diesel oil-fired pilot burners on existing vessels would have substantial economic and environmental costs. It is important to keep in mind that at Northeast Gateway, we have conservatively proposed a limit of

320 metric tonnes of heavy oil usage per year (actual oil usage is likely to be much less), which corresponds to 21 tons SO_2 per year for the low sulfur intermediate fuel oil with the maximum allowable sulfur content of 1.5%. Vessels would burn approximately 174 metric tons of heavy oil per day for deviating to a suitable location to carry out installation works. If only two days of travel were necessary to reach such a location, the amount of fuel oil would exceed the amount projected to be burned for the entire year. The quantity of emissions of SO_2 (and carbon dioxide [CO_2]) associated with such travel would far exceed the benefits of installing these burners. The economic costs of such a modification—i.e., those associated with the crews' time, taking the ship out of service for a month, lost revenues from LNG deliveries—would also be enormous.

The cost just for Mitsubishi to do the installation on a single burner per boiler on a single vessel has been quoted as being $26.4 million yen (roughly $250,000). It is expected that two out of three burners would need to be replaced by these diesel oil pilot burners for purposes of burner flexibility and/or redundancy for a conservative total price of about $435,000 per vessel. An additional $5,000 is needed for re-piping, and $2,000 is needed for re-inspection by the Class Society (Bureau Veritas). Costs for adding a fuel flow meter for the pilot and integrating fuel flow information into the Integrated Automation System software have not yet been estimated. Even considering only the $452,000 associated with the previously identified labor and installation, this translates into approximately $3.164 million for all seven vessels, which (applying a Capital Cost Recovery Factor of 0.096 based on 5% interest and 15 year equipment life) translates to approximately $304,000 per year. Emissions reductions are difficult to quantify, insofar as it is not clear exactly how much fuel the pilots would need to burn (they might not operate at their maximum capacity). However, even if it were assumed that essentially all of the 21 tons SO_2/yr were removed by use of the pilots, the costs associated with only the identified labor and installation are equivalent to approximately $14,500 per ton of SO_2 removed. As noted above, this cost effectiveness figure does not include all of the real costs of implementing the pilot burners.

6.4 Conclusion

BACT for the auxiliary boilers will involve the use of the regasified LNG as the only fuel, Hamworthy DF burners to minimize NO_x and CO, and the Argillon SCR system to reduce NO_x down to 15 ppmvd @ 3% O_2 or less.

BACT for oil firing in the main boilers will involve the minimizing the number of gas burner lighting events, minimizing the quantity of oil used per lighting, and utilizing RMG 380 LS fuel with a maximum sulfur content of 1.5% (wt.).

Attachment B

Excerpts from January 26, 2010 Revised BACT Analysis Letter

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

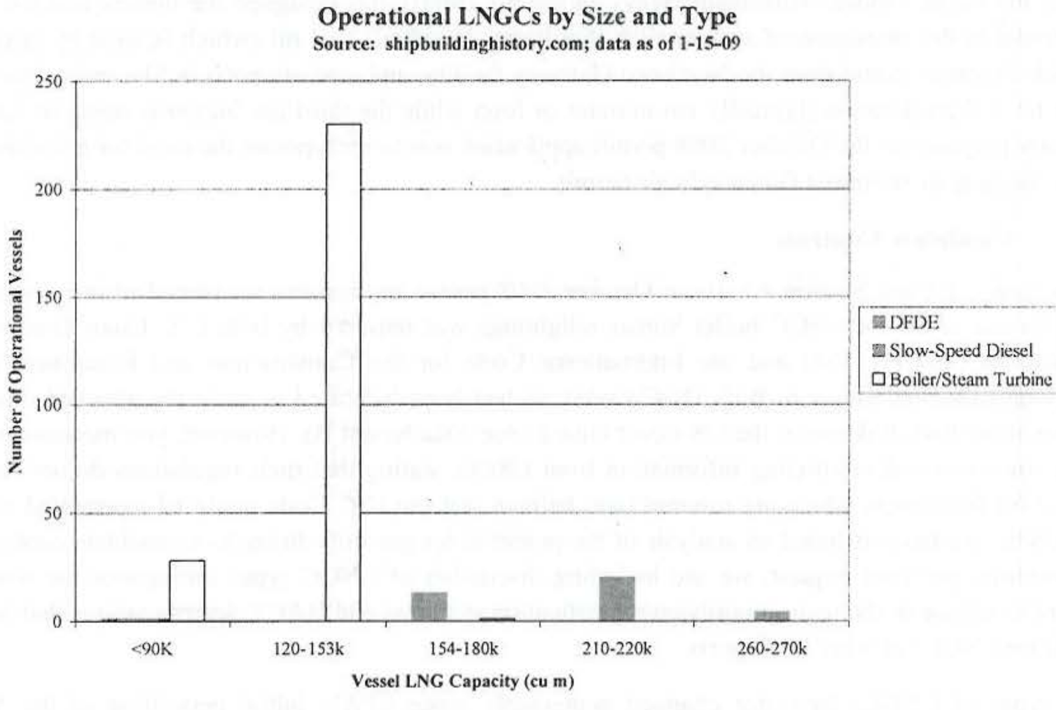

Figure 1. Prevalence of Propulsion Types in Existing LNGCs.

---

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

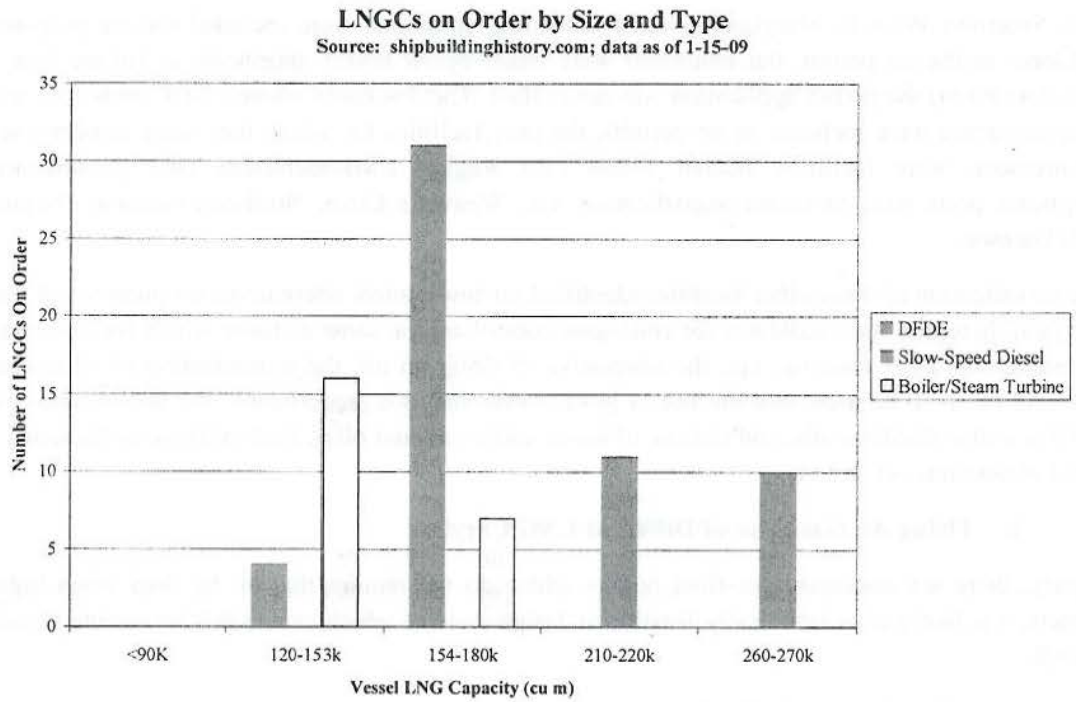

Figure 2. Prevalence of Propulsion Types in LNGCs on Order.

(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.

[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.

---

[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.

Attachment C

April 20, 2011 Letter from Mitsubishi Heavy Industries Regarding Use of MDO for Burner Lightings

MITSUBISHI HEAVY INDUSTRIES, LTD.
16-5, KONAN 2-CHOME, MINATO-KU
TOKYO, JAPAN

20 April, 2011

Attn : Mr. Fred Van Nimmen
LNG Fleet Manager
EXMAR Shipmanagement n.v.

Re : Mitsubishi Maine Boiler for your LNG Carriers

Dear Sir,

We would like to express our sincere thanks for continuous cooperation extended to us. Regarding fuel application for subjected Boiler, please be informed as follow ;

Boilers burner and piping are designed to fire high through intermediate viscosity (IFO 380-180) fuel oil and boil off gas only, either as single fuels or in combination. Only lighter fuels (marine diesel or gasoil) can be used for start-up of the boiler only, on manual control.

Sincerely yours,

for

I. Uchida, Manager

Marine Boiler Designing Section
Marine Machinery & Engine Division
Power Systems
Mitsubishi Heavy Industries, LTD.
Nagasaki Shipyard & Machinery works

Attachment D

December 13, 2010 Decision of the European Commission Establishing Alternative Low Sulfur Compliance Methods for LNG Carriers

DECISIONS

COMMISSION DECISION

of 13 December 2010

on the establishment of criteria for the use by liquefied natural gas carriers of technological methods as an alternative to using low sulphur marine fuels meeting the requirements of Article 4b of Council Directive 1999/32/EC relating to a reduction in the sulphur content of certain liquid fuels as amended by Directive 2005/33/EC of the European Parliament and of the Council on the sulphur content of marine fuels

(notified under document C(2010) 8753)

(Text with EEA relevance)

(2010/769/EU)

THE EUROPEAN COMMISSION,

Having regard to the Treaty on the Functioning of the European Union,

Having regard to the Council Directive 1999/32/EC of 26 April 1999 relating to a reduction in the sulphur content of certain liquid fuels [1] as amended by Directive 2005/33/EC of the European Parliament and of the Council [2], and in particular Article 4c thereof,

Whereas:

(1) Article 4b of the Directive requires that ships at berth in Community ports do not use, from 1 January 2010, marine fuels with a sulphur content exceeding 0,1 % by mass. This requirement does not apply, however, to fuels used on board vessels employing approved emission abatement technologies in accordance with Article 4c.

(2) Article 4c(4) provides that Member States may allow ships to use an approved emission abatement technology as an alternative to using sulphur marine fuels meeting the requirements of Article 4b, provided that these ships continuously achieve emission reductions which are at least equivalent to those which should be achieved through the limits on sulphur in fuel specified in the Directive.

(3) Article 4c(3) provides for the establishment of criteria for the use of technological methods by ships of all flags in enclosed ports, harbours and estuaries in the Community in accordance with the procedure referred to in Article 9(2) of the Directive. These criteria are to be communicated to the IMO.

(4) Liquefied natural gas (LNG) Carriers are frequently fitted with dual fuel boilers, using boil-off gas and heavy fuel oil for propulsion and cargo-related operations. In order to meet the requirements of the Directive most LNG Carriers calling at EU ports could use emission abatement technology employing a mixture of marine fuels and boil-off gas to produce sulphur emissions equal to or lower than 0,1 % sulphur fuel emissions.

(5) In the long-term, boil-off gas could be used as a primary fuel at berth, producing lower sulphur emissions than those which would be achieved through the limits on sulphur in fuel specified in the Directive.

(6) The measures provided for in this Decision are in accordance with the opinion of the Regulatory Committee established in accordance with Article 9(2) of the Directive,

HAS ADOPTED THIS DECISION:

Article 1

A Liquefied Natural Gas Carrier (LNG Carrier) is a cargo ship constructed or adapted and used for the carriage in bulk of liquefied natural gas as defined under the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC) Code.

Article 2

To meet the objective on reducing emissions from ships through an alternative technological abatement method by a mixture of marine fuel and boil-off gas the LNG Carriers shall use and comply with the calculation criteria set out in Annex.

[1] OJ L 121, 11.5.1999, p. 13.
[2] OJ L 191, 22.7.2005, p. 59.

The LNG Carriers may use the alternative technological abatement method while at berth in Community ports, allowing sufficient time for the crew to accomplish any necessary measures to employ a mixture of marine fuel and boil-off gas as soon as possible after arrival at berth and as late as possible before departure.

Article 3

The achieved emission reductions in sulphur emissions due to the application of the method referred to in Article 2 must be at least equivalent to the reduction that would be achieved through the limits of the sulphur in fuel specified in the Directive.

Article 4

Member States shall require LNG Carriers which use the alternative technological abatement method and call at ports under their jurisdiction to provide detailed record in the ship's logbook, containing the type and quantity of fuels used on board.

For this purpose, these ships shall be equipped for continuous monitoring and metering of the boil-off gas and marine fuel consumption.

Article 5

Member States shall take appropriate measures to monitor and verify the use of the alternative technological abatement method while at berth based on the achieved emissions reductions provided by LNG Carriers.

Article 6

This Decision is addressed to the Member States.

Done at Brussels, 13 December 2010.

For the Commission
Siim KALLAS
Vice-President