ALASKA LNG

AKLNG-6020-AIR-COR-REC-00019

September 24, 2018

Mr. James Renovatio
Alaska Department of Environmental Conservation,
Division of Air Quality, Air Permits Division
410 Willoughby Avenue, Suite 303
Juneau, Alaska 99811-1800

RE: Response to Incompleteness Finding for the Liquefaction Plant, Air Quality Construction Permit Application AQ1539CPT01

Dear Mr. Renovatio:

Alaska Gasline Development Corporation (AGDC) received the Alaska Department of Environmental Conservation (Department) letter dated June 29, 2018 pertaining to the incompleteness findings for the Liquefaction Plant, Air Quality Construction Permit Application AQ1539CPT01. Attached to this letter please find our responses to the Department's findings, along with additional supporting documentation as necessary.

As specified under 18 AAC 50.205 AGDC based on information and belief formed after reasonable inquiry, I certify that the statements and information in and attached to this document are true, accurate, and complete.

If you have any questions regarding this submittal, please contact me at (907) 330-6352 or by email FRichards@agdc.us.

Sincerely,

Frank T. Richards, P.E.
Senior Vice President, Program Management

Enclosure(s):
Attachment 1: Incompleteness Items 1-3 and 5-6
Attachment 2: Incompleteness Item 4
Attachment 3: LNG Diesel BACT Appendices A-C.zip

Cc: Jim Plosay, ADEC
Aaron Simpson, ADEC
Lisa Haas, AGDC
Jim Pfeiffer, AGDC

ATTACHMENT 1

LNG Plant Response to Incompleteness Findings

Air Quality Construction Permit Application AQ1539CPT01

AGDC submits the following responses to the Departments findings (dated June 29, 2018) pertaining to the Liquefaction Plant, Air Quality Construction Permit Application AQ1539CPT01:

Prevention of Significant Deterioration (PSD): Pre-Construction Monitoring – 40 CFR 52.21(m):

1. Provide PSD-quality pre-construction monitoring data for carbon monoxide (CO) and sulfur dioxide (SO_2).

AGDC Response:

AGDC has begun the process of collecting the pre-construction monitoring data described by ADEC. The collection and processing of the required data is anticipated to be completed and ready for submission to ADEC sometime near third quarter 2019. As such, AGDC will submit the pre-construction monitoring data under separate cover once complete.

PSD: Best Available Control Technology (BACT) Review – 40 CFR 52.21(j):

2. Provide for turbine emissions units (EUs) 1 through 10, the vendor or manufacturer:
   a. Guaranteed emission rates and control efficiencies for all technically feasible control technologies, and
   b. Data for BACT floor emission rates at different load scenarios

AGDC Response:

As requested by the Alaska Department of Environmental Conservation (Department), below is a summary of additional information pertaining to the emission rates for Emission Units EU 1 through 10.

The applicant notes that we are unable to provide emission rates at all different load scenarios, as requested by the Department under Item #2b of the Incompleteness findings. The BACT analysis has been developed based on load ranges that the turbines are reasonably expected to operate at during normal operations in order to satisfy the permit application requirements. No specific vendor has been selected to provide this information.

Compression Turbines (EU1 – EU6)

Pollutant	Control System	Baseline (@ 15% O2)	Proposed Limit (@ 15% O2)	Baseline Notes	Proposed Limit Notes
NOx	UDLN	25 ppmvd	9 ppmvd	Preliminary data from vendors and review of EPA RBLC BACT determinations suggest this baseline limit for standard burners on simple cycle gas turbines > 25 MW.	Proposed limit is anticipated control efficiency for units with Ultra Dry Low NOx burners based on a review of EPA RBLC, as found in Appendix A of LNG BACT Analysis.

Pollutant	Control System	Baseline (@ 15% O2)	Proposed Limit (@ 15% O2)	Baseline Notes	Proposed Limit Notes
	DLN + SCR	25 ppmvd	2 ppmvd	Preliminary data from vendors and review of EPA RBLC BACT determinations suggest this baseline limit for standard burners on simple cycle gas turbines > 25 MW.	Proposed limit based on a review of EPA RBLC BACT determinations for similar simple cycle gas turbines as provided in Appendix A of the LNG BACT Analysis.
CO	CO Catalyst	50 ppmvd	10 ppmvd	Baseline assumed be application of good combustion practices.	Proposed limit based on review of EPA RBLC BACT determinations for similar installations, see Appendix A. Actual limit would be dependent upon vendor specific data.
	Good Combustion Practices	50 ppmvd	50 ppmvd	Baseline assumed be application of good combustion practices.	Proposed limit assumes good combustion practices are implemented, consistent with EPA RBLC BACT determination for Sabine Pass Liquefaction Project. Actual limit will be governed by use of CO catalyst, as both good combustion practices and a CO catalyst are expected to be installed.

Power Generation Turbines (EU7 – EU10)

Pollutant	Control System	Baseline (@ 15% O2)	Proposed Limit (@ 15% O2)	Baseline Notes	Proposed Limit Notes
NOx	UDLN	15 ppmvd	9 ppmvd	Preliminary data from vendors suggest this baseline limit for standard burners on simple cycle gas turbines similar in size to the power generation turbines.	Proposed limit is anticipated control efficiency for units with Ultra Dry Low NOx burners based on a review of EPA RBLC, as found in Appendix A of LNG BACT Analysis.
	DLN + SCR	15 ppmvd	2 ppmvd	Preliminary data from vendors suggest this baseline limit for standard burners on simple cycle gas turbines similar in size to the power generation turbines.	Proposed limit based on a review of EPA RBLC BACT determinations for similar simple cycle gas turbines as provided in Appendix A of the LNG BACT Analysis.

Pollutant	Control System	Baseline (@ 15% O2)	Proposed Limit (@ 15% O2)	Baseline Notes	Proposed Limit Notes
CO	CO Catalyst	50 ppmvd	10 ppmvd	Baseline limit assumed to implement good combustion practices.	Proposed limit based on review of EPA RBLC BACT determinations for similar installations, see Appendix A of LNG BACT Analysis. Actual limit would be dependent upon vendor specific data.
	Good Combustion Practices	50 ppmvd	50 ppmvd	Baseline limit assumed to implement good combustion practices.	Proposed limit assumes good combustion practices are implemented, consistent with EPA RBLC BACT determination for Sabine Pass Liquefaction Project. Actual limit will be governed by use of CO catalyst, as both good combustion practices and a CO catalyst are expected to be implemented.

3. Provide, for turbine EU's 1 through 10, additional cost estimate information associated with the per-ton removal for all pollutants in which the top emissions control option was not selected. Include accompanying vendor-supplied cost estimates or assumptions as warranted. A cost analyses must be based on emission unit-specific quotes for capital equipment purchase and installation costs at a particular facility.

AGDC Response:

Item #3 of the Incompleteness findings specified by the Department includes a request for additional cost estimate information associated with the proposed emission reductions indicated in the BACT analysis. Available information pertaining to cost data for control technologies evaluated for Emission Units EU 1 through 10 is presented below.

Compression Turbines (EU1 – EU6)

Control System	Cost Element	Basis
SCR + DLN	Equipment Cost	Received preliminary equipment cost data from vendors for purposes of establishing anticipated project costs.
	Installation Costs	Estimated using EPA OAQPS equations. Due to the remote location of the facility engineering contractor applied percentages appropriate for use in remote installations based on past project experience – particularly to account for higher freight costs.
	Indirect Capital Costs	Estimated using EPA OAQPS equations. Engineering contractor applied project specific cost effectiveness factors, again to address the unique/remote facility location in which higher costs associated with engineering and supervision are expected.
	Direct Annual Costs	Estimated using EPA OAQPS equations and terms.
	Indirect Annual Costs	Estimated using EPA OAQPS equations and terms.

Control System	Cost Element	Basis
	Capital Recovery Cost	7% Interest Rate applied as used in the Agrium US Inc, Kenai Nitrogen Operations Facility Air Quality Control Construction Permit. See AQCC AQ0083CPT06.
UDLN	Equipment Cost	Received preliminary equipment cost data from vendors for purposes of establishing anticipated project costs.
	Installation Costs	Estimated using EPA OAQPS equations. Due to the remote location of the facility engineering contractor applied percentages appropriate for use in remote installations based on past project experience – particularly to account for higher freight costs.
	Indirect Capital Costs	Estimated using EPA OAQPS equations. Engineering contractor applied project specific cost effectiveness factors, again to address the unique/remote facility location in which higher costs associated with engineering and supervision are expected.
	Direct Annual Costs	Estimated using EPA OAQPS equations and terms.
	Indirect Annual Costs	Estimated using EPA OAQPS equations and terms.
	Capital Recovery Cost	7% Interest Rate applied as used in the Agrium US Inc, Kenai Nitrogen Operations Facility Air Quality Control Construction Permit. See AQCC AQ0083CPT06.
CO Catalyst	Equipment Cost	No cost data presented. Assumed to implement all technically feasible control options: install CO catalyst and implement good combustion practices.
	Installation Costs	
	Indirect Capital Costs	
	Direct Annual Costs	
	Indirect Annual Costs	
	Capital Recovery Cost	

Power Generation Turbines (EU7 – EU10)

Control System	Cost Element	Basis
SCR + DLN	Equipment Cost	Received preliminary equipment cost data from vendors for purposes of establishing anticipated project costs.
	Installation Costs	Estimated using EPA OAQPS equations. Due to the remote location of the facility engineering contractor applied percentages appropriate for use in remote installations based on past project experience – particularly to account for higher freight costs.
	Indirect Capital Costs	Estimated using EPA OAQPS equations. Engineering contractor applied project specific cost effectiveness factors, again to address the unique/remote facility location in which higher costs associated with engineering and supervision are expected.
	Direct Annual Costs	Estimated using EPA OAQPS equations and terms.
	Indirect Annual Costs	Estimated using EPA OAQPS equations and terms.
	Capital Recovery Cost	7% Interest Rate applied as used in the Agrium US Inc, Kenai Nitrogen Operations Facility Air Quality Control Construction Permit. See AQCC AQ0083CPT06.

Control System	Cost Element	Basis
UDLN	Equipment Cost	Received preliminary equipment cost data from vendors for purposes of establishing anticipated project costs.
	Installation Costs	Estimated using EPA OAQPS equations. Due to the remote location of the facility engineering contractor applied percentages appropriate for use in remote installations based on past project experience – particularly to account for higher freight costs.
	Indirect Capital Costs	Estimated using EPA OAQPS equations. Engineering contractor applied project specific cost effectiveness factors, again to address the unique/remote facility location in which higher costs associated with engineering and supervision are expected.
	Direct Annual Costs	Estimated using EPA OAQPS equations and terms.
	Indirect Annual Costs	Estimated using EPA OAQPS equations and terms.
	Capital Recovery Cost	7% Interest Rate applied as used in the Agrium US Inc, Kenai Nitrogen Operations Facility Air Quality Control Construction Permit. See AQCC AQ0083CPT06.
CO Catalyst	Equipment Cost	Received preliminary equipment cost data from vendors for purposes of establishing anticipated project costs.
	Installation Costs	Estimated using EPA OAQPS equations. Due to the remote location of the facility engineering contractor applied percentages appropriate for use in remote installations based on past project experience – particularly to account for higher freight costs.
	Indirect Capital Costs	Estimated using EPA OAQPS equations. Engineering contractor applied project specific cost effectiveness factors, again to address the unique/remote facility location in which higher costs associated with engineering and supervision are expected.
	Direct Annual Costs	Estimated using EPA OAQPS equations and terms. Received preliminary catalyst replacement cost data from vendors for purposes of establishing anticipated project costs.
	Indirect Annual Costs	Estimated using EPA OAQPS equations and terms.
	Capital Recovery Cost	7% Interest Rate applied as used in the Agrium US Inc, Kenai Nitrogen Operations Facility Air Quality Control Construction Permit. See AQCC AQ0083CPT06.

4. Provide an updated BACT analysis for the two reciprocating internal combustion engines (RICE) EUs 11 and 12.

AGDC Response:

Please see the attached updated BACT analysis (Attachment II) which addresses the 429 kW emergency diesel firewater pump (operating less than 100 hours per year, in non-emergency use) and 224 kW diesel auxiliary air compressor proposed for installation at the LNG facility. As described in greater detail in the attached analysis, BACT for these engines is defined as compliance with NSPS Subpart IIII, use of clean/low sulfur diesel fuels, and good combustion practices.

5. Provide additional clarification regarding the CO emission limit that the Compression Turbines, EUs 1 through 6 will achieve through BACT.

AGDC Response:

The CO emission limit (25 ppmv) as identified in the emission calculations a part of the permit application was used to define a conservative estimate of potential emissions. AGDC presented the lower, BACT limit of 10 ppmv in the BACT analysis, as AGDC understood that the final emission limit would be defined by the approved BACT. AGDC understands that the PTE will be defined at the BACT limit.

6. Provide the certification required under 18 AAC 50.205 that the supplemental information submitted in response to the above items is true, accurate, and complete.

AGDC Response:

Please see the cover letter for AGDC’s certification statement. Please note that Alaska LNG is unable to provide certain requested information (e.g., vendor guarantees, etc).

ATTACHMENT 2

IC Engine BACT Analysis

Response to Item #4

Air Quality Construction Permit Application AQ1539CPT01

1. PURPOSE

This BACT analysis addresses the 429 kW emergency diesel firewater pump (operating less than 100 hours per year, in non-emergency use) and 224 kW diesel auxiliary air compressor that would be installed at the facility. This analysis provides a review of the possible technologies and emission limits that could be imposed as BACT.

It is important to note that the emissions baseline used for these diesel-fired engines is based on EPA's NSPS Subpart IIII standards. For engine model year 2009 and later, the NSPS Subpart IIII emissions limits for the diesel-fired firewater pump engine, which is between 300 and 600 hp, are 2.85 g/hp-hr NOx (or 95% of NMHC+NOx), 2.6 g/hp-hr CO, 0.15 g/hp-hr VOC (or 5% of NMHC+NOx), and 0.15 g/hp-hr PM. NSPS Subpart IIII under 40 CFR 60.4201 states that a non-emergency stationary diesel engine rated for less than 3000 hp and less than 10 liters per cylinder of displacement must certify emissions standards for new nonroad CI engines in 40 CFR 89 and 40 CFR 1039, as applicable. Thus, the emissions baseline for the diesel auxiliary air compressor (model year 2014 or later) are 0.298 g/hp-hr NOx, 2.61 g/hp-hr CO, 0.142 g/hp-hr VOC, and 0.015 g/hp-hr PM. These emissions levels are known as EPA Tier 4 limits and typically require post-combustion exhaust treatment such as selective catalytic reduction (SCR), diesel particulate filters (DPF), or another equivalent emissions control technology.

This analysis provides a review of the possible technologies and emission limits that could be imposed as BACT. Control technologies identified for NOx, CO, VOC, PM, and SO2 include the following:

- Good combustion practices/clean fuels (all pollutants);
- Compliance with 40 CFR NSPS Subpart IIII (NOx, CO, VOC, and PM);
- Selective catalytic reduction (NOx);
- CO catalyst (CO); and
- •Diesel particulate filters (PM).

These control methods may be used alone or in combination to achieve the various degrees of emissions control. Each technology is summarized below.

2. NOX BACT ANALYSIS

Possible NOx emissions control technologies for engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under process code 17.210 - Small Internal Combustion Engines (note that this process code represents < 500 HP but several engines with HP greater than 500 HP were included in the search results). The search results are summarized in the below table.

Table 1: RBLC Summary for NOx Control for Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/kw-hr)
Good Combustion Practices	55	3.7 – 18.1
Federal Emissions Standards	16	4 - 7.5
Limited Operation	6	3.8 - 6
No Control Specified	19	1.8 – 6.4

A review of similar units in the RBLC indicates good combustion practices, limited operation, and compliance with the federal emissions standards are the NOx control technologies identified as BACT for diesel-fired engines.

2.1. Step 1: Identify All Control Technologies

The following subsections discuss the general operating principles of each technology and their potential technical feasibility for NOx control of the LNG operations camp and buyback gas bath diesel-fired engines.

Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment technique for reduction of NO and NO_2 in the turbine exhaust stream to molecular nitrogen, water, and oxygen. In the SCR process, ammonia (NH3, anhydrous, aqueous or urea) is used as the reducing agent, and is injected into the flue gas upstream of a catalyst bed. The function of the catalyst is to lower the activation energy of the NOx decomposition reaction. NOx and NH3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. Depending on the overall ammonia-to-NOx ratio, removal efficiencies can be as high as 80 to 93%.

To evaluate the technical feasibility of an SCR system, installations and operating experience of SCR systems at other locations in Alaska was sought[1]. Only a few SCR units in Alaska have been identified to date.

- Teck Cominco Alaska, Inc. has installed an SCR on the most recent engine addition at the Red Dog Mine located 90 miles north of Kotzebue, Alaska. This unit utilizes Urea and required an open catalyst cell structure to improve the NOx conversion to ~90% reduction[2].
- An SCR is planned for the Healy Unit 2, which is located in Healy, AK, just south of Fairbanks at the edge of Denali National Park. However, the installation will not be complete until 2017 so there is no documentation regarding the success of this design[2].
- The Southcentral Power Project at the Anchorage Airport (Chugach Electric Association) includes SCR on each of the LM6000PF turbines. These SCR units utilize 29% aqueous ammonia and only reduce NOx emissions by approximately 25% (11 parts per million [ppm] instead of 15 ppm)[3].

The SCR units installed in Alaska, as described above, include design elements that would be challenging to incorporate. The SCR unit at the Red Dog Mine uses urea, which is easier to transport but requires more on-site equipment, including a hydrolyser, solid material handling equipment, and extensive heat tracing. Utility consumption and equipment cost for a urea system is high compared to other ammonia solutions, rendering utilization of urea uncompetitive except for small capacity units[4].

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[1] SCR Study Summary: Document Number USAG-EC-PRZZZ-00-00004-000, Rev. 0

[2] Golden Valley Electric Association: Healy Unit 2 Power Plant. URL: http://www.gvea.com/energy/healy2

[3] Top Plant: Southcentral Power Project, Anchorage,Alaska. PowerMag, vol. 157 (9), September 2013.

[4] Case No. 504: Urea SCR System Installed on a 6555 HP Wartsila 16V32 Diesel Engine Used for Prime Power. URL: jmsec.com/Library/Fact-Sheets/504-Red_Dog_Mine.pdf

Aqueous ammonia is commercially available in 19 wt.% and 32 wt.% solutions. The advantage of aqueous ammonia is that it is safer to store and use than anhydrous ammonia. However, it requires larger storage volumes, greater truck traffic, and a more complicated delivery system. Of the two varieties of aqueous ammonia, 32 wt.% has greater regulatory reporting requirements than 19 wt.%. Therefore, of the two aqueous ammonia solutions, 19 wt.% aqueous ammonia is deemed to be the safest alternative.

One disadvantage of 19 wt.% aqueous ammonia is it has a freeze point near -30°F. Consequently, utilization of 19 wt.% aqueous ammonia would require extensive heat tracing to ensure operation is maintained. There is no documentation to confirm that a complicated, heat traced 19 wt.% aqueous ammonia injection unit could be constructed, maintained, and provide reliable support for a use in a location with cold ambient temperatures.

It is expected that operating an SCR on a diesel-fired engine would have some challenges, such as reliability of heat tracing to keep aqueous ammonia from freezing, NOx reduction, and uniform ammonia injection over a range of ambient temperatures and load ranges. Despite these technical concerns, SCR is considered a technically feasible control option for the LNG diesel-fired engines for the purposes of this analysis.

Turbocharger and Aftercooler

Turbocharger technology involves the process of compressing intake air in a turbocharger upstream of the air/fuel injection for the purpose of boosting power output of the engine. The compression of the intake air also increases the temperature of the air and thus an aftercooler is needed to reduce this air temperature prior to mixing with fuel in the combustion chamber or piston cylinder. Reducing the intake air temperature helps lowers the peak flame temperature, which in turn reduces NOx formation during the combustion process. Today, manufacturers typically design new diesel engines with a turbocharger and aftercooler technology as part of standard equipment. Turbocharger and aftercooler is a technically feasible control technology for diesel-fire engines

Fuel Injection Timing Retard (FITR)

FITR reduces NOx emissions by the delay of the fuel injection in the engine from the time the compression chamber is at minimum volume to a time the compression chamber is expanding. The larger the volume in the compression chamber is, the lower the peak flame temperature will be. The disadvantage of retarding the timing is that the engine will become less fuel efficient, produce more particulate emissions, and possibly misfire (causing a reduction in power output). Another disadvantage is that retarding the timing could produce more black smoke due to a decrease in exhaust temperature and incomplete combustion. FITR can achieve up to 50 percent NOx reduction but due to the increase in particulate matter emissions, this technology is not selected as a NOx control technique.

Ignition Timing Retard (ITR)

ITR lowers NOx emissions by moving the ignition event to later in the power stroke, after the piston has begun to move downward. Because the combustion chamber volume is not at a minimum, the peak flame temperature is not as high, which lowers combustion temperature and produces less thermal NOx. Use of ITR can cause an increase in fuel usage, and increase in particulate matter emissions, and engine misfiring. ITR can achieve between 20 to 30 percent NOx reduction. Due to the increase in the particulate matter emissions resulting from ITR, this technology is not selected as a NOx control technique.

Federal Emissions Standards

RBLC NOx determinations for federal emission standards require the engines meet the requirements of 40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ, or EPA tier certifications. Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. Meeting the Subpart IIII standards is considered technically feasible for diesel-fired engines.

Limited Operation

As stated above, these engines will be used to provide assistance during LNG emergency air compressor operations and fire water. Both diesel internal combustion engines are assumed to operate less than 500 hours per year for emergencies, periodic testing and other minimal operations. Because their normal use is limited, their total emissions are very small. Limited operation is a technically feasible control technology for the diesel-fired engines.

Good Combustion Practices

Good combustion practices typically include sufficient residence time, high enough temperature, and the proper amount of air and fuel in the combustion zone to ensure complete combustion. This is accomplished by maintaining proper air/fuel ratio and manufacture's recommendations for fuel injection and ignition timing. Good combustion is a technically feasible control technology for the diesel-fired engines.

2.2. Step 2: Eliminate Technically Infeasible Options

Based on the discussion under Step 1, none of the technologies were determined to be technically infeasible.

2.3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

The NOx control technologies discussed above that have been identified as feasible and applicable to the LNG diesel-fired engines in order of effectiveness are:

- SCR (93% control)
- Good Combustion Practices (less than 40% control)
- Federal Emissions Standards (baseline)
- Turbocharger and Aftercooler (0% control)
- Limited Operation (0% control)

Control technologies that will be in practice or already included in the design of the engine are considered 0% control for the purpose of this BACT analysis.

Table 1 provides the baseline NOx emissions (using federal emissions standards) and the emissions reduction potential for using SCR. The NOx emissions are based on information provided by the LNG design team. Emissions in this table represent operation of each engine 500 hours/yr. This is deemed to be conservative.

Table 1: Base Case NOx Emissions for Diesel Engines

Engine	Rating (hp)	Baseline NOx Emission Rate	Baseline NOx Emission (tpy)	NOx Emissions with SCR (tpy)	NOx Emissions Reduction (tpy)
Diesel Auxiliary Air Compressor	300	0.298 g/hp-hr	Tier 4 Certification – includes SCR or equivalent		
Diesel Firewater Pump	575	2.85 g/hp-hr	0.90	0.06	0.84

Note: Per engine, assume 100% load and 500 hours of operation per year.

2.4. Step 4: Evaluate Most Effective Controls and Document Results

This section summarizes the energy, environmental, and economic impacts of the control technologies noted above. For this analysis, the cost data are obtained primarily from vendor supplied information and supplemented with estimates provided in the EPA's Control Cost Manual where vendor supplied information was not available.

Energy Impact Analysis

No unusual energy impacts were identified for the technically feasible NOx controls evaluated in this BACT analysis.

Environmental Impact Analysis

For this analysis, operation of SCR would result in some "slip" of ammonia releases to the environment as well as disposal of spent catalyst. Neither ammonia slip nor waste disposal considerations are expected to preclude use of SCR as a potential control device for this BACT analysis.

Economic Analysis

Economic analysis of costs to install NOx control is based on the following key factors:

- Size of the engines;
- Baseline emissions levels;
- Controlled emissions levels; and
- Emission control installation and operating costs.

The cost-effectiveness of SCR is summarized in Table 2. As shown in this table, SCR is not cost-effective, as it exceeds the $10,000 per ton guideline.

Table 2: Economic Analysis – Estimated NOx Emissions from Alternative Control Technologies

Control Option	Diesel Firewater Pump
	Control Technology Alternatives
	SCR
Baseline emissions (tpy)	0.90
Controlled emissions (tpy)	0.06
NOx emission reduction (tpy)	0.84
Total Annualized Operating Cost ($ Per Engine)	$67,502
Cost of NOx removal ($/ton) Per Engine	$80,320

The SCR capital and installation cost estimate are based on a vendor quote, as provided by the Project team. Annual operating costs were also estimated by the engineering teams based on predicted catalyst replacement costs, ammonia reagent costs, power costs, and other factors. The total annual cost for each engine represents the sum of the annual operating costs, plus the "annualized" total capital investment, assuming 7% interest over 20 years.

Based on these cost-effectiveness estimates, it appears that SCR would not be cost-effective as BACT for the LNG engine listed.

2.5. Step 5: Select BACT

Since SCR was determined to not be cost-effective and turbocharger/aftercooler is inherent in the engine design, the highest or "top" control technologies are good combustion practices and limited operation.

3. CO BACT ANALYSIS

Carbon monoxide is formed during the combustion process as a result of incomplete fuel combustion. Factors contributing to incomplete fuel combustion include, low air temperatures, insufficient combustion zone turbulence and residence times, inadequate amounts of excess air, as well as competing combustion conditions employed to mitigate NOx formation. This BACT analysis evaluates control techniques and technologies used to mitigate CO emissions.

3.1. Step 1: Identify All Control Technologies

Below are the potential control measures that have been used to control CO emissions from diesel-fired engines:

- Diesel Oxidation Catalyst
- Good combustion practice
- Federal Emissions Standards
- Limited Operation

Diesel Oxidation Catalyst (DOC)

DOC can reportedly reduce CO emissions by 70% or greater at temperatures between 750°F and 1,000°F. A DOC is a form of "bolt on" technology that uses a chemical process to reduce pollutants in the diesel exhaust into decreased concentrations. More specifically, this is a honeycomb type structure that is coated with an active catalyst layer. As CO and other gaseous hydrocarbon particles travel along the catalyst, they are oxidized thus reducing pollution. DOC is considered a technically feasible control technology for diesel-fired engines.

Good Combustion Practices

Ultra-low sulfur diesel (ULSD) is a clean burning fuel and naturally results in fairly low CO emissions. The rate of CO emissions is dependent on proper mixing of the fuel and combustion air and adequate residence time at temperatures to complete the oxidation process. The LNG diesel engines are expected to use ULSD to minimize CO emissions through maximizing the efficiency of fuel combustion and operation with sufficient excess oxygen.

Federal Emissions Standards

RBLC CO determinations for federal emissions standards require the engines meet the requirements of 40 CFR 60 (or NSPS) Subpart IIII, 40 CFR 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. NSPS Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. NSPS Subpart IIII is considered technically feasible control technology for diesel-fired engines.

Limited Operation

As stated above, the diesel-fired engines supply power intermittent or for emergencies and will operate less than 500 hours per year. Limiting the operation of emissions units reduces the potential to emit of these units. Limited operation is considered technically feasible control technology for the diesel-fired engines.

3.2. Step 2: Eliminate Technically Infeasible Technologies

Based on the discussion under Step 1, none of the technologies are considered infeasible.

3.3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

The emission control technologies not eliminated by practical or operational limitations are listed in Table 44. These technologies are ranked by control efficiency.

Table 4: Remaining Control Options and Control Effectiveness

Rank	Control Technology	Control Efficiency (%)
1	Limit Operation	94% Reduction
2	Diesel Oxidation catalyst	70% Reduction
3	Good combustion practices/clean fuels	Variable
4	Federal Emissions Standards	Baseline

Good combustion practices are a part of the base case design and operation of the diesel-fired engines. An evaluation of the economic feasibility of oxidation catalyst is presented below. This analysis assumes 40 CFR 60 (or NSPS) Subpart IIII or EPA Tier 3 controlled emissions levels as a baseline for the diesel-fired engines.

3.4. Step 4: Evaluate Most Effective Controls and Document Results

This section summarizes the energy, environmental, and economic impacts of the control technologies noted above.

For this analysis, the cost data are obtained primarily from vendor supplied information and supplemented with estimates provided in the EPA's Control Cost Manual where vendor supplied information was not available.

Energy Impact Analysis

No unusual energy impacts were identified for the technically feasible CO controls evaluated in this BACT analysis.

Environmental Impact Analysis

For this analysis, implementation of good combustion practices/clean fuels or limited operation is not expected to cause an environmental impact. Operation of a CO catalyst would result in the disposal of spent catalyst; however, waste disposal considerations are not expected to preclude use of a CO catalyst as a potential control device for this BACT analysis.

Economic Analysis

Economic analysis of costs to install CO control is based on the following key factors:

- Size of the diesel-fired engines;
- Baseline emissions levels;
- Controlled emissions levels; and
- Emission control installation and operating costs.

The cost-effectiveness of an oxidation catalyst is summarized in Table 3. As shown in this table, an oxidation catalyst is higher than the informal ADEC cost-effectiveness threshold of $10,000 per ton for all of the diesel-fired engines.

Table 3: Economic Analysis – Estimated CO Emissions from Alternative Control Technologies

	Diesel Auxiliary Air Compressor	Diesel Firewater Pump
Control Option	Control Technology Alternatives	Control Technology Alternatives
	CO Catalyst	CO Catalyst
Baseline emissions (tpy)	0.43	0.82
Controlled emissions (tpy)	0.13	0.25
CO emission reduction (tpy)	0.30	0.58
Total Annualized Operating Cost	$6,857	$6,857

Control Option	Diesel Auxiliary Air Compressor	Diesel Firewater Pump
	Control Technology Alternatives	Control Technology Alternatives
	CO Catalyst	CO Catalyst
Cost of CO removal ($/ton)	$22,671	$11,883

The oxidation catalyst capital and installation cost estimates are based on vendor quotes as provided by the Project design team for the diesel-fired engines. The total annual cost for each diesel-fired engine represents the sum of the annual operating costs plus the "annualized" total capital investment, assuming 7% interest over 20 years.

3.5. Step 5: Select BACT

The installation of a CO catalyst is not cost effective for the diesel-fired engines. Use of good combustion practices and clean fuels is determined to be BACT for CO for all the diesel-fired engines.

4. PM AND VOC BACT ANALYSIS

Particulate Matter (PM) and Volatile Organic Compounds (VOC) are emitted from the combustion process as a result of dirty fuels and/or incomplete fuel combustion. Factors contributing to incomplete fuel combustion include, low air temperatures, insufficient combustion zone turbulence and residence times, inadequate amounts of excess air, as well as competing combustion conditions employed to mitigate NOx formation. This BACT analysis evaluates control techniques and technologies used to mitigate PM and VOC emissions.

4.1. Step 1: Identify All Control Technologies

Potential control technologies for this project were based on information found on the EPA's RBLC. This review focused on diesel-fired engines from year 2010 to the present. From research, the following technologies were identified as available for control of PM emissions from diesel-fired engines.

Diesel Particulate Filter (DPF)

DPFs are a control technology that are designed to physically filter particulate matter from the exhaust stream. Several designs exist which require cleaning and replacement of the filter media after soot has become caked onto the filter media. Regenerative filter designs are also available that burn the soot on a regular basis to regenerate the filter media. DPF is considered a technically feasible control technology for the diesel-fired engines.

Diesel Oxidation Catalyst (DOC)

DOC can reportedly reduce PM and VOC emissions by more than 30%. A DOC is a form of "bolt on" technology that uses a chemical process to reduce pollutants in the diesel exhaust into decreased concentrations. More specifically, this is a honeycomb type structure that is coated with an active catalyst layer. As CO and other gaseous hydrocarbon particles travel along the catalyst, they are oxidized thus reducing pollution. DOC is considered a technically feasible control technology for diesel-fired engines.

Positive Crankcase Ventilation

Positive crankcase ventilation is the process of re-introducing the combustion air into the cylinder chamber for a second chance at combustion after the air has seeped into and collected in the crankcase during the downward stroke of the piston cycle. This process allows any unburned fuel to be subject to a second combustion opportunity. Any combustion products act as a heat sink during the second pass through the piston, which will lower the temperature of the combustion and reduce the thermal NOx formation. Positive crankcase ventilation is considered a technically feasible control technology for diesel-fired engines.

Low Sulfur Fuel

Low sulfur fuel has been known to reduce particulate matter emissions. Low Sulfur fuel is considered a feasible control technology for diesel-fired engines.

Low Ash Diesel

Residual fuels and crude oil are known to contain ash forming components, while refined fuels are low ash. Fuels containing ash can cause excessive wear to equipment and foul engine components. Low ash diesel is considered to be a technically feasible control technology for diesel-fired engines.

Federal Emissions Standards

RBLC PM and VOC determinations for federal emissions standards require the engines meet the requirements of 40 CFR 60 (or NSPS) Subpart IIII, 40 CFR 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. NSPS Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. NSPS Subpart IIII is considered technically feasible control technology for diesel-fired engines.

Limited Operation

As stated above, the diesel-fired engines supply power intermittent or for emergencies and will operate less than 500 hours per year. Limiting the operation of emissions units reduces the potential to emit of these units. Limited operation is considered technically feasible control technology for the diesel-fired engines.

Good Combustion Practices

Proper management of the combustion process will result in a reduction of PM and VOC emissions. Good combustion practices are considered technically feasible control technology for diesel-fired engines.

4.2. Step 2: Eliminate Technically Infeasible Options

PM emissions rates for low sulfur fuel are not available and therefore a BACT emissions rate cannot be set for low sulfur fuel. Low sulfur fuel is not a technically feasible control technology.

4.3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

The following control technologies have been identified and ranked by efficiency for the control of PM emissions from diesel-fired engines.

Table 6: Remaining Control Options and Control Effectiveness

Rank	Control Technology	Control Efficiency (%)
1	Limit Operation	94% Reduction PM & VOC
2	Diesel Particulate Filters	90% Reduction PM
3	Good combustion practices/clean fuels	Variable PM & VOC
4	Diesel Oxidation Catalyst	30% Reduction PM & VOC
5	Low Ash Diesel	25% Reduction PM
6	Positive Crankcase Ventilation	10% Reduction PM and VOC
7	Federal Emissions Standards	Baseline PM and VOC

Good combustion practices are a part of the base case design and operation of the diesel-fired engines. An evaluation of the economic feasibility of oxidation catalyst is presented below. This analysis assumes 40 CFR 60 (or NSPS) Subpart IIII or EPA Tier 3 controlled emissions levels as a baseline for the diesel-fired engines.

4.4. Step 4: Evaluate Most Effective Controls and Document Results

This section summarizes the energy, environmental, and economic impacts of the control technologies noted above.

For this analysis, the cost data are obtained primarily from vendor supplied information and supplemented with estimates provided in the EPA's Control Cost Manual where vendor supplied information was not available.

Energy Impact Analysis

No unusual energy impacts were identified for the technically feasible PM controls evaluated in this BACT analysis.

Environmental Impact Analysis

For this analysis, implementation of good combustion practices/clean fuels or limited operation is not expected to cause an environmental impact. Operation of a DPF would result in the periodic disposal of ash collected on the filters during annual maintenance; however, waste disposal considerations are not expected to preclude use of a DPF as a potential control device for this BACT analysis.

Economic Analysis

Economic analysis of costs to install DPF PM control is based on the following key factors:

- Size of the diesel-fired engines;
- Baseline emissions levels;
- Controlled emissions levels; and
- Emission control installation and operating costs.

The cost-effectiveness of a DPF is summarized in Table 7. As shown in this table, DPF is significantly higher than the informal ADEC cost-effectiveness threshold of $10,000 per ton.

Table 7: Economic Analysis – Estimated PM Emissions from Alternative Control Technologies

Control Option	Diesel Auxiliary Air Compressor Control Technology Alternatives DPF for PM	Diesel Firewater Pump Control Technology Alternatives DPF for PM
Baseline emissions (tpy)	Tier 4 Certification – includes DPF	0.05
Controlled emissions (tpy)		<0.01
PM emission reduction (tpy)		0.04
Total Annualized Operating Cost		$8,202
Cost of PM removal ($/ton)		$191,617

The DPF capital and installation cost estimates are based on a vendor quote and data provided by the Project design team for the diesel-fired engines. The total annual cost for each diesel-fired engine represents the sum of the annual operating costs plus the "annualized" total capital investment, assuming 7% interest over 20 years.

4.5. Step 5: Select BACT

Limited operation, good combustion practices/ULSD fuel and compliance with NSPS Subpart IIII and EPA tier certification emissions have been chosen to satisfy BACT for reduction of PM and VOC emissions. This BACT analysis concludes, similar to other comparable projects evaluated, that good combustion practices/clean fuel meets BACT for diesel-fired engines of this type and application.

5. SO2 BACT ANALYSIS

Sulfur Dioxide (SO_2) emissions are formed as a result of combusting sulfur containing fuels. This BACT analysis evaluates control techniques and technologies used to mitigate SO_2 emissions from diesel-fired engines.

5.1. Step 1: Identify All Control Technologies

Potential control technologies for this project were based on information found on the EPA's RBLC. This review focused on diesel-fired engines from year 2010 to the present. A review of similar units in the RBLC indicates combustion of low sulfur fuel, limited operation, good combustion practices, and compliance with the federal emissions standards are the principle SO_2 control technologies for diesel-fired engines.

Ultra-Low Sulfur Diesel (ULSD)

ULSD has a fuel sulfur content of 0.0015 percent sulfur by weight or less. Using ULSD instead of diesel containing 0.5 percent sulfur by weight could control 99 percent of SO_2 emissions from the diesel-fired engines. ULSD is considered a technically feasible control technology for diesel-fired engines.

Federal Emissions Standards

NSPS Subpart IIII includes requirements limiting fuel sulfur content in diesel fuel. Meeting the requirements of NSPS Subpart IIII is considered a technically feasible control technology for diesel-fired engines.

Limited Operation

Limiting the operation of emissions units reduces the potential to emit for these units. Limited operation is considered a technically feasible control technology for the diesel-fired engines.

Good Combustion Practices

Proper management of the combustion process will result in a reduction of SO_2 emissions. Good combustion practices are considered a technically feasible control technology for diesel-fired engines.

5.2. Step 2: Eliminate Technically Infeasible Options

All identified control technologies are technically feasible for the diesel-fired engines.

5.3. Step 3: Rank Remaining Control Technologies by Control Effectiveness

The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from diesel-fired engines.

Table 8: Remaining Control Options and Control Effectiveness

Rank	Control Technology	Control Efficiency (%)
1	Ultra-Low Sulfur Diesel	99% Reduction
2	Limited Operation	94% Reduction
3	Good combustion practices/clean fuels	Variable
4	Federal Emissions Standards	Baseline

5.4. Step 4: Evaluate Most Effective Controls and Document Results

As use of clean fuels would be implemented for this project, economic analysis is not required.

5.5. Step 5: Select BACT

Limited operation, good combustion practices/ULSD fuel and compliance with NSPS Subpart IIII have been chosen to satisfy BACT for reduction of SO_2 emissions for diesel-fired engines. This BACT analysis concludes, similar to other comparable projects evaluated, that good combustion practices/clean fuel meets BACT for diesel-fired engines of this type and application.

APPENDIX A

BACT Cost Effectiveness Calculations

APPENDIX B

Vendor Emissions Control Quotes

APPENDIX C

RBLC Search Results for Diesel-Fired Engines (Process Code 17.210)