Liquefaction Plant Best Available Control Technology (BACT) Analysis

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MODIFICATION HISTORY

Rev	Section	Modification
1	All	Updated as an AGDC document, revised to exclude information subject to equipment manufacturer non-disclosure agreements
1	All	Shift from JVA DCN USAL-PL-SRZZZ-00-000002-000 to AGDC DCN
1	Appendices	Security Classifications for Appendices A & D are Public, whereas, Appendices B & C are Confidential/Trade Secret
2	8, 9, and 10	Added Condensate Tank and Diesel Fuel Storage Tank BACT Analyses sections. Security Classification for Appendix E is Public.
3	1.1, 1.2, 4.1, and 5.1	Update BACT Analysis to incorporate SCR controls for project turbines.
3	All	Updated DCN from AKLNG-4030-HSE-RTA-DOC-00001 to 3043-HSE-RTA-00008.

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ACRONYMS AND ABBREVIATIONS

%.................................percent
°F ....degrees Fahrenheit
AAC..............................Alaska Administrative Code
ADEC............................Alaska Department of Environmental Conservation
A/F...............................air-to-fuel
BACT............................Best Available Control Technology
BOG ....boil-off gas
BP ....British Petroleum
CAA..............................Clean Air Act
CCS ....Carbon Capture and Sequestration
CFR ....Code of Federal Regulations
CH_4..............................methane
CO................................carbon monoxide
CO_2 ....carbon dioxide
CO_2-e ....carbon dioxide equivalent
DLN..............................Dry Low NOx (Oxides of Nitrogen) Combustor
DOD.............................U.S. Department of Defense
EOR..............................enhanced oil recovery
EPA ..............................U.S. Environmental Protection Agency
g/bhp-hr ....grams per brake horsepower-hour
GHG.............................greenhouse gases
GWP ....global warming potential
GTP..............................Gas Treatment Plant
HC................................hydrocarbon
Hp-hr ....horsepower-hour
kW ....kilowatt
kWhr.............................kilowatt hour
LAER ....lowest achievable emission rate
lb ....pounds mass
LNG...............................liquefied natural gas
MMBtu ....million British thermal units
MW ....megawatt
N_2.................................nitrogen
N_2O ....nitrous oxide
NO ....nitric oxide
NO_2 ....nitrogen dioxide
NOx ....oxides of nitrogen
NSCR.............................Non-Selective Catalytic Reduction
NSPS ....New Source Performance Standards

O_2.................................oxygen
PGF ....power generation facility
PM ....particulate matter
ppm ....parts per million
ppmv ....parts per million by volume
ppmvd ....parts per million by dry volume
ppmvd@15%O_2............parts per million by dry volume corrected to 15% oxygen
Pre-FEED.......................Pre-Front End Engineering and Design
Project ....Alaska LNG Project
PSD ....Prevention of Significant Deterioration
RACT ....Reasonably Available Control Technology
RBLC ....RACT/BACT/LAER Clearinghouse
scf ....standard cubic foot
SCR ....Selective Catalytic Reduction
SF_6 ....sulfur hexafluoride
SNCR.............................Selective Non-Catalytic Reduction
SO_2................................sulfur dioxide
SO_X................................oxides of sulfur
tpy ....tons per year
UDLN ....ultra-dry low NOx combustor
ULSD ....ultra-low sulfur diesel
VOC ....volatile organic compound

1. INTRODUCTION

The Alaska LNG Project (Project) would be subject to Prevention of Significant Deterioration (PSD) permitting under Alaska Administrative Code. Permitting under these regulations would require the Project to install Best Available Control Technology (BACT) on the permitted equipment at the Liquefaction Plant, located in Nikiski, and at the Gas Treatment Plant (GTP) on the North Slope. BACT is determined following the United States Environmental Protection Agency (EPA) “Top-Down” analysis approach, which identifies each control technology, and then considers in the evaluation the technical feasibility, commercial availability, costs, and site-specific factors to ultimately make a control technology determination. BACT determinations are always evaluated on a case-by-case basis.

To support the design for the Alaska Liquefaction Plant, the Pre-Front End Engineering Design (Pre-FEED) and Optimization phase included a BACT analysis for various project options and driver selections. This report provides the BACT analysis for the mechanical drive compression turbines, the power generation turbines, vent gas disposal (flares and thermal oxidizer), as well as for the emergency compression ignition (diesel) engines for firewater and air. This analysis provides a review of the possible technologies and emissions limits that could be imposed as BACT for these devices. The information provided in this analysis will be used to support Liquefaction Plant design decisions regarding emission control technologies and BACT emission limits.

The analysis focuses on the following pollutants: nitrogen oxides (NOx), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter (PM – in all of its forms), volatile organic compounds (VOCs) and greenhouse gases (GHGs). Emission controls for each of these pollutants are evaluated and a BACT determination is made following the EPA “Top-Down” approach. Based on the information considered in the analysis, the presumptive BACT determinations are shown in Table 1, Table 2, Table 3, and Table 4 below.

1.1. Compression Turbines

Relative to NOx, the installation of Dry low NOx (DLN) plus Selective Catalytic Reduction (SCR) was voluntarily identified as the control measure to reduce NOx emissions below 2 parts per million by volume (ppmv).

The Alaska LNG Project’s (Project) proposal to install a catalyst bed to control carbon monoxide (CO) emissions achieves the most stringent level of control for this pollutant. BACT determinations for comparable gas compression and liquefied natural gas (LNG) facilities have set emission limits at 10 ppmv CO and lower, thus requiring a catalyst bed.

The BACT determination for sulfur dioxide (SO_2), particulate matter (PM) or volatile organic compounds (VOCs) is based on use of pipeline-quality natural gas and good combustion practices achieve the most stringent level of controls for these pollutants (Table 1).

The greenhouse gas (GHG) BACT determination relies upon efficiency improvement measures to reduce overall fuel use, which in turn results in lower GHG emissions. One GHG control strategy addressed in the analysis relates to alternative driver selections, such as the use of turbines of an aero-derivative design over modern light high-efficiency industrial turbines such as the compression turbine model evaluated here. Note, the evaluated model has achieved 38 percent (%) efficiency, which is only slightly lower that an aero-derivative machine. The analysis found that while aero-derivative turbines achieve thermal efficiencies greater than comparable industrial turbines, adopting the option as BACT was not cost-effective as compared to current and projected cost benchmarks for carbon pollution. The use of aero-derivative turbine technology would only be considered cost-effective for mitigating GHG emissions at fuel costs of approximately $7.50 per million British thermal units (MMBtu) and greater.

Table 1: BACT Determination for the Compression Turbines

Pollutant	BACT Determination
NOx	Installation of -dry low NOx (DLN) plus Selective Catalytic Reduction (SCR) technology on the turbines to achieve 2 ppmv NOx @ 15% oxygen (O_2)
SO_2	Good Combustion Practices/Clean Fuels
CO	Installation of CO catalyst to achieve 10 ppmv CO or lower @ 15% O_2
PM	Good Combustion Practices/Clean Fuels
VOC	Good Combustion Practices/Clean Fuels
GHGs	Use of low-carbon fuel (i.e., natural gas) and implementation of energy efficiency measures (e.g., good combustion practice, periodic burner tunings, instrumentation and controls to optimize fuel gas combustion, etc.)

1.2. Power Generation Turbines

For NOx, the installation of Dry low NOx (DLN) plus Selective Catalytic Reduction (SCR) was voluntarily identified as the control measure to reduce NOx emissions below 2 parts per million by volume (PPMV)..

For CO, catalyst controls are recommended given the prevalence of this technology employed at other Alaska and comparable liquefaction facilities.

The same BACT observations made for the compression turbines for SO_2, PM and VOC apply to the power generation turbines.

The GHG BACT determination reflects the most stringent measures implemented by other comparable sources (Table 2).

Table 2: BACT Determination for the Power Generation Turbines

Pollutant	BACT Determination
NOx	Installation of DLN plus SCR technology on the turbines to achieve 2 ppmv NOx @ 15% O_2
SO_2	Good Combustion Practices/Clean Fuels
CO	Installation of CO catalyst to achieve 10 ppmv CO or lower @ 15% O_2
PM	Good Combustion Practices/Clean Fuels
VOC	Good Combustion Practices/Clean Fuels

Pollutant	BACT Determination
GHGs	Use of combined cycle turbine using low-carbon fuel (i.e., natural gas) and implementation of energy efficiency measures

1.3. Vent Gas Disposal (Flare / Thermal Oxidizer)

The BACT determination found that proposed waste gas minimization techniques proposed by the Project meet current BACT (Table 3). The waste gas minimization techniques minimize not only VOC and GHGs, but also combustion contaminants (e.g., NOx, CO, SO_2, and PM).

Table 3: BACT Determination for Vent Gas Disposal (Flare / Thermal Oxidizer)

Pollutant	BACT Determination
VOC	Waste gas minimization, waste gas recovery and flare/thermal oxidizer design
GHG	Waste gas minimization, waste gas recovery and flare/thermal oxidizer design

1.4. Compression Ignition Engines

The United States (U.S.) Environmental Protection Agency (EPA) has established emissions standards for internal combustion engines. Manufacturers are required to produce engines that meet the EPA Tiered Emission Standards. Meeting EPA standards constitutes current BACT for all pollutants. BACT determination for the compression ignition engines is provided in Table 4.

Table 4: BACT Determination for the Compression Ignition Engines

Pollutant	BACT Determination
NOx	Good Combustion Practices/Clean Fuels Compliance with 40 CFR New Source Performance Standards (NSPS) Subpart IIII or 40 Code of Federal Regulations (CFR) Part 1039, as applicable
SO_2	Good Combustion Practices; use of ULSD
CO	Good Combustion Practices/Clean Fuels Compliance with 40 CFR NSPS Subpart IIII or 40 CFR Part 1039, as applicable
PM	Good Combustion Practices/Clean Fuels Compliance with 40 CFR NSPS Subpart IIII or 40 CFR Part 1039, as applicable
VOC	Good Combustion Practices/Clean Fuels Compliance with 40 CFR NSPS Subpart IIII or 40 CFR Part 1039, as applicable
GHGs	Good Combustion Practices/Clean Fuels

2. PURPOSE AND SCOPE

Per Alaska Administrative Code (AAC) Title 18, Section 50.306 (Prevention of Significant Deterioration [PSD]), evaluation of a stationary source that requires a PSD permit prior to construction must include a control technology review, as required by the CFR Title 40, Section 52.21(j), incorporated by reference per 18 AAC 50.040(h). 40 CFR 52.21(j)(2) specifies that "[a] new major stationary source shall apply best available control technology for each regulated New Source Review pollutant that it would have the potential to emit in significant amounts." BACT analyses are case-by-case evaluations and include consideration of cost, technical feasibility, commercial availability, and site-specific factors. EPA requires a "Top-Down" BACT analysis approach be used in these evaluations.

This report provides the BACT analysis for the mechanical drive compression turbines, the power generation turbines, waste gas mitigating devices (flare and thermal oxidizer), as well as for the emergency compression ignition (diesel) engines. This analysis provides a review of the possible technologies and emission limits that could be imposed as BACT for these devices. The information provided in this analysis would be used to support Liquefaction Plant design decisions regarding emission control technologies and permit emission limits that constitute BACT.

This BACT analysis addresses NOx, SO_2, CO, PM – including fine particulate (known as PM_{10}) and ultrafine particulate (known as $PM_{2.5}$), VOCs) and GHG emissions. The following key assumptions and boundary conditions were used to prepare this analysis:

- This BACT analysis is based on the Project design and equipment emissions at the time of this report's development.
- Vendor cost data were used to the extent feasible in this analysis. Where vendor data were unavailable, data from the EPA *Air Pollution Control Cost Manual*, Sixth Edition, January 2002 were used. The bases for all cost figures are documented in this analysis.
- NOx and CO emissions control limits and expectations for performance are based on vendor quotes, as given for Liquefaction Plant operating conditions.
- Technical data and costs from *Study 12.3.4 – Liquefaction Compressor Driver Selection Study Report* (USAL-CB-PRTEC-00-000009-000, Revision 1) were relied upon in the analysis.
- Preliminary guidance provided by ADEC during a May 2016 meeting to discuss Project BACT issues was incorporated into this analysis (See Appendix D)

3. BACT METHODOLOGY

BACT is defined in the Federal PSD regulations at 40 CFR 52.21(b)(12) as:

> *...an emission limitation, including a visible emission standard, based on the maximum degree of reduction for each pollutant subject to regulation…which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification…*

This BACT analysis follows the "Top-Down" methodology described in the EPA *New Source Review Workshop Manual.*[1] The "Top-Down" process involves the identification of all applicable control technologies according to control effectiveness. The "top", or most stringent, control alternative is evaluated first. If the most stringent alternative is shown to be technically infeasible, economically unreasonable, or if environmental or other impacts are severe enough to preclude its use, then the next

[1] *DRAFT New Source Review Workshop Manu*al, EPA, Office of Air Quality Planning and Standards, October 1990.

most stringent control technology is similarly evaluated. This process continues until the emissions control method under consideration is not eliminated by technical, economic, energy, environmental, or other impacts.

The five steps of a Top-Down BACT Analysis are described in the following steps, below:

1. Identify all available control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation.
2. Eliminate all technically infeasible control technologies.
3. Rank remaining control technologies by control effectiveness and tabulate a control hierarchy.
4. Evaluate most effective controls and document results.
5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, energy and other impacts.

A further summary of each step is provided below.

Step 1

Identify potential control technologies for the LNG Plant based on information found on the EPA's Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse (collectively referred to as RBLC), state websites, Freedom of Information Act requests, recent Alaskan projects with similar emissions units, and vendor input.

Step 2

Evaluate the operating principles, control efficiencies and technical feasibility of each potential control technology; technologies determined to be technically infeasible are eliminated in this step.

Step 3

The remaining technologies that are technically feasible are ranked based on control effectiveness.

Step 4

Under Step 4, energy, environmental, and cost-effectiveness impacts are evaluated. This evaluation begins with the analysis of the most stringent control option and continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts. The factors that are considered in these analyses are as follows:

- **Energy Impacts**: The energy requirements of a control technology can be examined to determine if the use of that technology results in any significant or unusual energy penalties or benefits. Energy impacts may be in the form of additional energy required to operate the emitting unit, or additional energy required to operate the control device.
- **Environmental Impacts**: Installation of control devices may result in environmental impacts separate from the pollutant being controlled. Environmental impacts may include solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, increased emissions

of other criteria or non-criteria pollutants, increased water consumption, and land use impacts from waste disposal. The environmental impact analysis is made taking consideration of site-specific circumstances.

- **Economic Impacts**: For a technology to be considered BACT, it must be considered "cost effective." The economic or "cost-effectiveness" analysis is conducted in a manner consistent with EPA's *Air Pollution Control Cost Manual*, Sixth Edition and subsequent revisions. 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.
- Cost effectiveness thresholds are not published, nor guaranteed by regulatory agencies; however, based on other BACT evaluations in Alaska, the threshold at which a NOx, SO_2, CO, PM or VOC control technology evaluated is likely to be considered cost effective is $3,000 per ton of pollutant removed or less. If the evaluated cost is greater than $10,000 per ton of pollutant removed, then the technology will likely not be considered cost effective. Evaluations where the cost-effectiveness is calculated to be between $3,000 and $10,000 should be validated with ADEC.

  At the time of developing this analysis, ADEC and EPA have not provided formal guidance on a cost-effectiveness threshold for GHG reductions. However, the following benchmarks are considered reasonable measures for determining what would be cost-effective:

  - $21 per ton of carbon dioxide equivalent (CO_2-e), based on the annual average secondary market price for California and Quebec Cap-and-Trade GHG allowances escalated by 7% in the year 2020.[2]
  - $12 - $40 per ton of CO_2-e escalating from 2016 to 2030 based on Alaska LNG estimates.

Step 5

The most stringent control that has not been eliminated in all prior steps is selected as BACT. With the control technology selection, a BACT emission target is established. The BACT target becomes a limit, which applies at all times, except during specific conditions listed in the permit (e.g., start-up and shutdown). Where a BACT emission limit cannot be achieved in operation, an alternative work practice or emissions limit must be proposed. That alternative limit must go through the same BACT analysis steps noted above.

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[2] See the California Carbon Dashboard [(http://calcarbondash.org/, produced by the Climate Policy Initiative) based on data reported by the Intercontinental Exchange (ICE), End of Day Reports]. The year 2020 was used in the analysis based on the timing of permit issuance. The BACT that is employed for a Project is considered at the time the permit is issued, and is not revisited during the operating life of the facility.

Greenhouse Gases (GHGs)

EPA recommends that the same "Top-Down" analysis approach used for criteria pollutants be used in evaluating GHGs subject to BACT.[3] The analysis that follows has been prepared, consistent with this guidance.

With respect to what constitutes "GHGs," Title 40 Code of Federal Regulations Section 52.21 (Prevention of Significant Deterioration) Paragraph (b)(49)(i) defines GHGs to include the following: CO_2, methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride (SF_6). Mass emissions of GHGs are converted into carbon dioxide equivalent (CO_2e) emissions for ease of comparison. CO_2-e is a quantity that equates the global warming potential (GWP) of a given mixture and amount of GHGs, to the amount of CO_2 that would have the same GWP in the atmosphere over a 100-year period. GWPs for these GHGs are provided in 40 CFR Part 98 (Mandatory Greenhouse Gas Reporting) Table A-1 (Global Warming Potentials).

As direct CO_2 emissions account for more than 99% of the combustion-related GHGs associated with the Project, and CH_4 and NOx account for less than 1% of the combustion-related turbine GHG emissions (measured as CO_2e), this analysis of BACT focuses on CO_2 as a surrogate for CO_2e.

4. COMPRESSION TURBINES

This section of the BACT analysis addresses the control technology options for the mechanical drive turbines, which provide refrigerant compression at the LNG Plant. This analysis is organized as follows:

- Section 4.1 – NOx BACT Analysis
- Section 4.2 – CO BACT Analysis
- Section 4.3 – SO_2 BACT Analysis
- Section 4.4 – PM and VOC BACT Analysis
- Section 4.5 – GHG BACT Analysis
- Section 4.6 – Conclusions

4.1. NOx BACT Analysis

NOx is formed during the combustion process due to high temperature zones in the combustion burner or chamber. This BACT analysis evaluates control techniques and technologies used to mitigate NOx emissions from the compression turbines with a rated output of nominally 115 megawatts (MW) per unit.

[3] See *PSD and Title V Permitting Guidance for Greenhouse Gases*, U.S. Environmental Protection Agency, Document No. EPA-457/B-11-001, March 2011, available at www.epa.gov/sites/production/files/2015-12/documents/ghgpermittingguidance.pdf

4.1.1. *Step 1: Identify All Control Technologies*

EPA, state, and local BACT clearinghouses/databases would classify the compression turbines as "Simple Cycle Natural-Gas Fired Combustion Turbines Greater than 25 MW." This class or category of source was used to investigate of the types of controls installed as BACT in recent permitting decisions. Appendix A includes a summary of NOx controls that have been installed between 2010 and the present to satisfy BACT for comparable Alaskan projects and LNG projects in the Continental U.S.

The compression turbines can be equipped with Dry Low-NOx (DLN) burners or UDLN technology. The DLN technology, which represents the "base case" for this analysis achieves 25 ppmv NOx at 15% O_2. The UDLN technology, which is discussed below, can achieve NOx emission concentrations of 9 ppmv or lower at 15% O_2.

Control technologies identified for NOx control of simple cycle gas turbines include the following:

1. DLN or UDLN Burners
2. Water/Steam Injection
3. Selective Catalytic Reduction (SCR)
4. Selective Non-Catalytic Reduction (SNCR)
5. Non-Selective Catalytic Reduction (NSCR)
6. XONON™
7. SCONOx™

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

DLN and UDLN Burners

DLN combustors (marketed under many similar names such as SoLoNOx or DLE) utilize multistage premix combustors where the air and fuel is mixed at a lean (high oxygen) fuel-to-air ratio. The excess air in the lean mixture acts as a heat sink, which lowers peak combustion temperatures and also ensures a more homogeneous mixture, both resulting in greatly reduced NOx formation rates. DLN combustors have the potential to reduce NOx emissions by 40 to 60%; this technology has an expected NOx performance of approximately 25 ppmv at 15% O_2.

It is possible to equip the base model with compression turbine "Ultra-Low" (UDLN) combustors, reducing NOx emissions from 25 ppmv (DLN) to 9 ppmv (UDLN). This technology is relatively new and performance data is limited; however, for the purpose of this analysis, this option is deemed feasible and examined in the economic analysis below. Note that UDLN combustors have been studied and are considered selectable by the Project.

Water or Steam Injection

Water or steam injection is a commonly used control technique for combustion turbine applications (particularly for turbines/services for which dry low NOx combustors are not available). Water/steam injection involves the introduction of water or steam into the combustion zone of the turbine. The injected fluid provides a heat sink, which absorbs some of the heat of reaction, causing a lower flame temperature resulting in lower thermal NOx formation. The process requires approximately 0.8 to 1.0 pound of water or steam per pound of fuel burned. The water source used requires demineralization to avoid leaving deposits and causing corrosion on turbine internals. Demineralization incurs additional cost and complexity to turbine operation and utilities. Water/steam injection also increases CO emissions as it lowers the combustion temperature. Depending on baseline uncontrolled NOx levels, water or steam injection can reduce NOx by 60% or more.

Selective Catalytic Reduction (SCR)

SCR is a post-combustion gas treatment technique used to reduce NOx emissions from exhaust streams. In the SCR process, ammonia (anhydrous, aqueous or as 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 ammonia combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental nitrogen and water. SCR works best where inlet NOx concentrations and exhaust temperatures are constant. The operating temperature of conventional SCR systems ranges from 400 degrees Fahrenheit (°F) to 800°F. High temperature SCR relies on special material reaction grids and can operate at higher temperature ranges between 700°F to 1,075°F. High temperature SCR is most frequently installed on simple cycle turbines. Depending on the overall ammonia-to-NOx ratio, NOx removal efficiencies can be as high as 80 to 90%. When used in series with DLN combustors, or water/steam injection, SCR can result in low single digit NOx levels in the range of 2 ppmv to 5 ppmv.

As part of this BACT analysis, installations and operating experience of SCR systems at locations in Alaska were given special consideration. SCR units installed in Alaska have demonstrated a wider range of NOx reduction performance ranging from as low as 25% and up to 90%. Installations of SCR systems in the RACT/BACT/LAER Clearinghouse have shown that SCR can reduce NOx from turbines to as low as 2 ppmv; however, only while under very stringent operational control. Variability of NOx control efficiencies on SCR installations in Alaska are the result of its use on variable load applications, mechanical drive applications, as well as the difficulty in maintaining uniform ammonia injection rates due to varying ambient temperatures and load ranges. Alaska units specifically evaluated in this analysis are listed below.

- Teck Cominco Alaska, Inc. has installed SCR on the most recent engine addition at the Red Dog Mine located 90 miles north of Kotzebue, Alaska. This unit utilizes urea and requires an open catalyst cell structure to improve the NOx conversion to ~90% reduction.
- SCR is planned for the Healy Unit 2, which is located in Healy, Alaska, just south of Fairbanks at the edge of Denali National Park. However, the installation is not complete at the time of this analysis so there is no documentation regarding the operations.

- 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% (resulting in 11 ppmv instead of 15 ppmv).
- Kenai Nitrogen Operations (Agrium): Agrium proposed the installation of SCR on each of five simple cycle GGT-744 Solar Turbine/Generator sets. The SCR units have NOx limits of 7 ppmv at 15% O_2.
- Anchorage Municipal Light & Power permitted in 2013 two LM6000 turbines with DLN and SCR. SCR was used in this case to avoid PSD permitting.

SCR has the potential to reduce NOx emissions by 70 to 90% and is considered technically feasible in this analysis. As noted above, SCR units installed and operated in Alaska face design and operation challenges primarily due to low and wide ranges of ambient temperature. SCR may be combined with DLN and UDLN combustion technology to achieve NOx emission rates as low as 2 ppmv @ 15% O_2. This analysis conservatively assumes that SCR could be combined with DLN or UDLN, with either combination achieving the same 2 ppmv level of NOx control.

The selected mechanical drive turbines are anticipated to exhaust at a temperature of approximately 1,000°F, which is at the high end of the recommended temperature for high temperature SCR (700°F to 1,075°F). To optimize exhaust temperature, quenching, or air tempering, would be required to lower exhaust gas temperatures to acceptable SCR temperature ranges.

Selective Non-Catalytic Reduction (SNCR)

SNCR reduces NOx into nitrogen and water vapor by the reaction of the exhaust gas with a reducing agent, such as urea or ammonia; this technology does not require a catalyst. The SNCR system performance is dependent upon the reagent injector location and temperature in order to achieve proper reagent/exhaust gas mixing for maximum NOx reduction. SNCR systems require a fairly narrow temperature range for reagent injection to achieve a specific NOx reduction efficiency. The optimum temperature range for injection of reagent is approximately 1,500°F to 1,900°F. The NOx reduction efficiency of an SNCR system decreases rapidly at temperatures outside the optimum temperature window. In theory, selective non-catalytic reduction can achieve the same efficiency as SCR; however, the practical constraints of temperature, time, and mixing often lead to worse results in practice.

Non-Selective Catalytic Reduction (NSCR)

NSCR uses a catalyst to simultaneously reduce NOx, CO, and hydrocarbon (HC) to water, CO_2, and nitrogen (N_2). The catalyst is usually a noble metal. The control efficiency achieved for NOx ranges from 80% to 90%. The operating temperature for NSCR ranges from about 700°F to 1,500°F, depending on the catalyst. For NOx reductions of 90%, the temperature must be between 800°F to 1,200°F. In addition, NSCR requires a low excess oxygen concentration in the exhaust gas stream (typically less than 1%) in order to be effective because the oxygen must be depleted before the reduction chemistry can proceed. As such, NSCR is only effective with rich-burn gas-fired units that operate at all times with an air to fuel ratio controller at or close to stoichiometric conditions.

SCONOx™

The SCONOX™ technology was originally developed by Goal Line Environmental Technologies, Inc. to treat exhaust gas of natural gas and diesel fired turbines. Now offered by EmeraChem, the technology is marketed under the name EMx. The EMx catalytic absorption system uses a potassium carbonate coated catalyst to reduce nitrogen oxide emissions. The catalyst oxidizes CO to CO_2, and NO to NO_2 and potassium nitrates (KNO_2/KNO_3). The catalyst is regenerated by passing dilute hydrogen gas over the catalyst bed, which converts the KNO_2 and KNO_3 to K_2CO_3, water, and elemental nitrogen. The catalyst is renewed and available for further absorption while the water and nitrogen are exhausted. In order to maintain continuous operation during catalyst regeneration, the system is furnished in arrays of 5 module catalyst sections. During operation, 4 of the 5 modules are online and treating flue gas, while one module is isolated from the flue gas for regeneration. NOx reduction in the system occurs in an operating temperature range of 300°F to 700°F, and therefore, must be installed in the appropriate temperature section of the waste heat recovery unit. Additionally, the EMx catalyst must be recoated, or ”washed” every 6 months to 1 year, depending on the sulfur content of the fuel. The “washing” consists of removing the catalyst modules from the unit and placing each module in a potassium carbonate reagent tank, which is the active ingredient of the catalyst.

The EMx catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides, requiring an additional catalytic oxidation/absorption system (SMx) upstream of the EMx catalyst. The SMx catalyst is regenerated in the same manner as the EMx catalyst.

Commercial experience with EMx is limited, with a majority of the units operating on units of 15 MW or less. No known installations exist in low ambient temperature settings. At least one installation of EMx has reported difficulties meeting permit limits. While EMx might be applicable in theory, it is not considered feasible for the LNG Plant because it has limited commercial experience and has not been demonstrated in low ambient temperature settings.

XONON™

XONON™ is a catalytic technology developed by Catalytica Energy Systems, Inc. and is now owned by Kawasaki. XONON™ uses partial combustion of fuel in the catalyst module followed by complete combustion downstream of the catalyst in the burnout zone. Partial combustion within the catalyst produces no NOx. Homogeneous combustion downstream of the catalyst usually produces little NOx as combustion occurs at a uniformly low temperature. A small amount of fuel is combusted in a pre-burner, which results in a small amount of NOx emissions.

XONON™ was not identified as BACT in the RBLC and is considered technically infeasible because it is not yet commercially available. This catalyst technology is currently being tested by turbine manufacturers.

4.1.2. Step 2: Eliminate Technically Infeasible Options

This section summarizes the technical feasibility of each potential NOx control technology; technologies determined to be technically infeasible are summarized in Table 5, below.

Table 5: Control Technology Options Determined to be Technically Infeasible

Technology Alternative	Basis
Water/Steam Injection	The base model turbine is equipped with DLN combustors. Water/steam injection is not compatible with burners equipped with DLN.
SNCR	The exhaust temperature of the combustion turbine is less than the optimum temperature range (1,500°F to 1,900°F) for SNCR.
NSCR	The oxygen concentration of the combustion turbine is approximately 15% O_2, which is much higher than the optimum oxygen concentration range for NSCR.
SCONOx™	There are no documented installations of this type of control on large combustion turbines.
XONON™	There are no documented installations of this type of control on large combustion turbines.

Water/Steam Injection

Water/steam injection has the potential to reduce NOx emissions by 20% to 30%. Water/steam injection is not used in conjunction with DLN combustors. As the base model compressor turbine is equipped with DLN combustors, water/steam injection is not considered further in this analysis.

Selective Non-Catalytic Reduction (SNCR)

The turbine is anticipated to exhaust at a temperature of approximately 1,000°F, which is well below the recommended temperature (1,500°F to 1,900°F) for an SNCR system to achieve the desired NOx reduction efficiency. The NOx reduction efficiency of SNCR decreases rapidly at temperatures outside the optimum temperature window, additionally, operations below this temperature window result in excessive ammonia emissions (ammonia slip). As such, SNCR is not considered technically feasible for this analysis.

Non-Selective Catalytic Reduction (NSCR)

NSCR requires a low excess oxygen concentration in the exhaust gas stream (typically below 1%) in order to be effective, as the oxygen must be depleted before the reduction chemistry can proceed. As such, NSCR is only effective with rich-burn gas-fired units that operate at all times with an air to fuel ratio controller at or close to stoichiometric conditions. As gas turbines typically operated with an excess oxygen concentration of approximately 15%, the evaluated model is outside of the acceptable operating range for NSCR and is not considered technically feasible for this analysis.

SCONOx™

SCONOx™ technology has an operating temperature range of 300°F to 700°F. As noted above, the turbine is anticipated to exhaust at a temperature of approximately 1,000°F, which is above the recommended temperature for SCONOx™. To optimize exhaust temperature, quenching would be required to lower exhaust gas temperatures to acceptable SCONOx™ temperature ranges. SCONOx™ technology is still in the early stages of market introduction. Issues that may impact application of the technology include relatively high capital cost, a large reactor size compared to SCR, increased system complexity, high utilities cost and demand (steam, natural gas, compressed air and electricity are required), and a gradual rise in NOx emissions over time requiring a 1 to 2 day renewal of catalyst. Commercial experience with this technology is limited, with a majority of the SCONOx™ units operating on turbines units of 15 MW or less. No known installations exist in low ambient temperature settings similar to Alaska. At least one installation of SCONOx™ has reported trouble meeting permit limits. While SCONOx™ might be applicable in theory, it is not considered feasible for this Project as it has limited commercial experience and has not been demonstrated in low ambient temperature settings.

XONON™

The XONON™ catalyst has only ever been paired with the 1.5 MW Kawasaki M1A-13 simple cycle gas turbine generator. As this catalyst technology has only been applied in the smaller gas turbines manufactured by Kawasaki, and as testing and implementation of this control system among different gas turbine manufacturers and on larger units has not been performed, this technology is unproven for the size class proposed for this Project and is not considered technically feasible for this analysis.

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

The emission control technologies not eliminated by practical or operational limitations are listed in Table 6, below. These technologies are ranked by control efficiency.

Table 6: Remaining Control Options and Control Effectiveness

Rank	Control Technology	Control Efficiency (%) or Emissions Target (ppmv)
1	DLN plus SCR or UDLN plus SCR	25% to 90% (as low as 2 ppmv @ 15% O_2)
2	UDLN	9 ppmv @ 15% O_2

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

This section summarizes the energy, environmental, and economic impacts of the control technologies noted above. The cost-effectiveness calculations use a "NOx emission base case" of 25 ppmv (NSPS limit) and emission control endpoints of 2 ppmv (DLN or UDLN plus SCR) or 9 ppmv (UDLN only). It should be noted that a base-case emission rate of 25 ppmv is used because it represents the base-case offering from the turbine vendor. An aggressive endpoint of 2 ppmv in the SCR evaluation provides a conservative evaluation of cost-effectiveness. A controlled NOx emission rate of 5 ppmv would be a more achievable performance objective to accommodate fluctuations in operations and site-specific conditions in Alaska (e.g., temperature fluctuations between summer and winter, etc.).

4.1.4.1. Energy Impact Analysis

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

4.1.4.2. 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.

4.1.4.3. Economic Analysis

Economic analysis of costs to install NOx control is not required as the Project applicant proposes to install the most stringent controls.

4.1.5. Step 5: Select BACT

The Project is voluntarily selecting the most stringent NOx control which includes the use of DLN plus SCR at 2 ppmv NOx, as the BACT level of control to be installed. DLN plus SCR is a common BACT emissions control approach for turbine installations, including LNG projects (see Appendix A for other comparable BACT determinations).

4.2. 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.

4.2.1. Step 1: Identify All Control Technologies

As noted above, EPA, state, and local BACT clearinghouses/databases would classify the compression turbines as "Simple Cycle Natural-Gas Fired Combustion Turbines Greater than 25 MW." This class or category of source was used to investigate of the types of controls installed as BACT in recent permitting decisions. Appendix A includes a summary of CO controls that have been installed between 2010 and present to satisfy BACT for comparable Alaska projects and LNG projects in the Continental U.S.

Control technologies identified for CO control of simple cycle gas turbines include the following:

- Good Combustion Practices/Clean Fuel
- Catalytic Oxidation
- SCONOx™
- NSCR

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

Good Combustion Practices/Clean Fuel

The rate of CO emissions is dependent on fuel choice and good combustion practices including proper mixing of fuel and combustion air, as well as adequate residence time at temperatures to complete the oxidation process. The compression turbine base model is designed to combust natural gas and optimizes CO emissions through use of natural gas and good combustion practices.

CO Oxidation Catalyst

Catalytic oxidation is a flue gas control that oxidizes CO to CO_2 in the presence of a noble metal catalyst; no reaction reagent is necessary. Catalytic oxidizers can provide oxidation efficiencies of 80% or greater at temperatures between 750°F and 1,000°F; the efficiency of the oxidation temperature quickly deteriorates as the temperature decreases. The temperature of the turbine is expected to exhaust at approximately 1,000°F or less, remaining within the temperature range for CO oxidation catalysts.

SCONOx™

As discussed in the NOx BACT analysis above, SCONOx™ reduces CO emissions by oxidizing the CO to CO_2. This technology combines catalytic conversion of CO with an absorption and regeneration process without using ammonia reagent. SCONOx™ catalyst must operate in a temperature range of 300°F to 700°F, and therefore, turbine exhaust temperature must be reduced through the installation of a cooling system prior to entry to the SCONOx™ system. Notably, demonstrated applications for this technology are currently limited to combined cycle combustion turbine units rated less than 40 MW.

Non-Selective Catalytic Reduction (NSCR)

As discussed in the NOx BACT analysis, above, NSCR uses a catalyst reaction to reduce CO to CO_2. The catalyst is usually a noble metal. The operating temperature for NSCR system ranges from about 700°F to 1,500°F, depending on the catalyst. NSCR requires a low excess oxygen concentration in the exhaust gas stream (typically less than 1%) to be effective because the oxygen must be depleted before the reduction chemistry can proceed. As such, NSCR is only effective with rich-burn gas-fired units that operate at all times with an air-to-fuel (A/F) ratio controller at or close to stoichiometric conditions.

4.2.2. Step 2: Eliminate Technically Infeasible Options

This section summarizes the potential technical feasibility for CO control of each air pollution control technology; technologies determined to be technically infeasible are summarized in Table 8, below.

Table 7: Control Technology Options Determined to be Technically Infeasible

Technology Alternative	Basis
SCONOx™	There are no documented installations of this type of control on large simple cycle combustion turbines.
NSCR	The oxygen concentration of the combustion turbine is approximately 15% O_2, which is much higher than the optimum oxygen concentration range for NSCR.

SCONOx™

SCONOx™ technology is still in the early stages of market introduction. Issues that may impact application of the technology include relatively high capital cost, a large reactor size, increased system complexity, high utilities cost and demand (steam, natural gas, compressed air and electricity are required), and a gradual decrease in effectiveness over time, requiring a 1 to 2 day renewal of catalyst. Commercial experience with this technology is limited, with a majority of the units operating on units of 15 MW or less. No known installations exist in low ambient temperature settings similar to Alaska. At least one installation of has reported trouble meeting permit limits. While SCONOx™ may be applicable in theory, it is not considered feasible for the LNG Project because it has limited commercial experience and has not been demonstrated in low ambient temperature settings.

Non-Selective Catalytic Reduction (NSCR)

NSCR requires a low excess oxygen concentration in the exhaust gas stream (typically below 1%) to be effective, as the oxygen must be depleted before the reduction chemistry can proceed. As such, NSCR is only effective with rich-burn gas-fired units that operate at all times with an A/F ratio controller at or close to stoichiometric conditions. As gas turbines typically operate with an excess oxygen concentration of approximately 15%, it is outside of the acceptable operating range for NSCR and is not considered technically feasible for this analysis.

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

The emission control technologies not eliminated by practical or operational limitations are listed in Table 9, below. These technologies are ranked by control efficiency.

Table 8: Remaining Control Options and Control Effectiveness

Rank	Control Technology	Control Efficiency (%) or Emissions Target (ppmv)
1	CO Catalyst	10 ppmv (or lower) at 15% O_2
2	Good Combustion Practices/Clean Fuels	50 ppmv at 15% O_2 (varies with loading and ambient temperature and maintenance of NOx target)

This analysis assumes a 10 ppmv (or lower) controlled emissions level similar to other LNG turbines of this size. This BACT analysis also identifies other installations, which achieve less than 10 ppmv CO (e.g., Point Thompson Production Facility with a CO limit of 2.5 ppmv at 15% O_2); therefore, BACT for CO would be based on the vendor guarantee for this unit, which may be lower than 10 ppmv.

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

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

4.2.4.1. Energy Impact Analysis

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

4.2.4.2. Environmental Impact Analysis

Implementation of good combustion practices/clean fuels 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. This conclusion is based on comparable BACT determinations for other facilities.

4.2.4.3. Economic Impact Analysis

The Project proposes to install a CO catalyst bed as part of the compression turbine design. Additionally, good combustion practices/clean fuels would be implemented. As both technically feasible options would be implemented for this Project, economic analysis is not required.

4.2.5. Step 5: Select BACT

This BACT analysis concludes, similar to other comparable projects evaluated, that good combustion practices/clean fuels, as well as operation of an oxidation catalyst likely constitutes BACT for a gas turbine of this type and application (see Appendix A for a list of other BACT determinations reviewed).

4.3. SO_2 BACT Analysis

SO_2 is formed as a result of the combustion of sulfur compounds in fuels. This BACT analysis evaluates control techniques and technologies used to mitigate SO_2 emissions.

4.3.1. Step 1: Identify All Control Technologies

The only technique identified to mitigate SO_2 emissions for simple cycle gas turbines at an LNG Plant is the use of clean fuels (i.e., pipeline quality natural gas). The compression turbine base model is designed to combust natural gas, which is low in sulfur.

4.3.2. Step 2: Eliminate Technically Infeasible Options

Use of pipeline quality natural gas is a common BACT control for gas turbines and is considered a technically feasible control option for the LNG turbines for the purposes of this analysis.

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

Use of pipeline quality natural gas is a common BACT control for gas turbines and is considered a technically feasible control option for the LNG turbines for the purposes of this analysis. As this is the only control option considered, ranking by emissions control effectiveness is unnecessary.

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

Since the use of clean fuels would be implemented for this Project, economic analysis is not required.

4.3.5. Step 5: Select BACT

Use of clean fuels has been chosen to satisfy BACT for reduction of SO_2 emissions. This is consistent with the BACT required of other comparable projects.

4.4. PM and VOC BACT Analysis

PM and VOC are emitted from gas turbines. Excessive amounts of these pollutants can occur from incomplete fuel combustion, including 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 analysis evaluates control techniques and technologies used to mitigate PM and VOC emissions.

4.4.1. Step 1: Identify All Control Technologies

Good combustion practice/clean fuels is identified as the main technique to mitigate PM and VOC from natural gas combustion. The rate of PM and VOC emissions is dependent on fuel choice and good combustion practices, including proper mixing of fuel and combustion air, as well as adequate residence time at temperatures to complete the oxidation process. The compression turbine base model is designed to combust natural gas and minimize PM and VOC emissions through good combustion practices.

CO catalyst also has the potential to reduce VOC emissions from combustion turbines. As CO catalyst has already been selected for use as BACT (see Section 4.2), no further evaluation of this technology for VOC control is provided.

4.4.2. Step 2: Eliminate Technically Infeasible Options

The use of good combustion practices/clean fuels, is a common PM and VOC BACT control for gas turbines and is considered a technically feasible control option for the LNG turbines for the purposes of this analysis.

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

Good combustion practices/clean fuel is a common PM and VOC BACT control for gas turbines and is considered a technically feasible control option for the LNG turbines for the purposes of this analysis. As this is the only control option considered, ranking by emissions control effectiveness is unnecessary.

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

As good combustion practices/clean fuel would be implemented for this Project, economic analysis is not required.

4.4.5. Step 5: Select BACT

Good combustion practices/clean fuels constitutes BACT for the reduction of PM and VOC emissions.

4.5. GHG BACT Analysis

CO_2, a GHG, is the main combustion product from gas turbines. Incomplete combustion would also cause methane to be emitted, which is also a GHG. This section describes the techniques that would be employed to reduce GHGs from the compression turbines.

4.5.1. Step 1: Identify All Control Technologies

This review focused on simple cycle natural-gas fired combustion turbines greater than 25 MW from year 2010 to the present. A summary of the data collected by this review is included in Appendix A.

Control technologies identified for GHG control of simple cycle gas turbines include the following:

- Use of Low-Carbon Fuel
- Design and Operational Energy Efficiency
- Alternate Design – Electric Compressors
- Use of Heat Recovery (Combined Heat and Power or Combined Cycle)
- Alternate Design – Use of Aero-Derivative Turbines

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

Notably, another emission control technique, which is identified in the EPA GHG BACT guidance, is the use of Carbon Capture and Sequestration (CCS), which is discussed in its own section (see Section 8, Carbon Capture and Sequestration). As shown in the BACT analysis for CCS, the technology is potentially infeasible and is not cost-effective. CCS will not be discussed further in this section of the analysis.

Use of Low-Carbon Fuel

Pipeline quality natural gas and boil-off gas (BOG) (i.e., fuel gas predominately consisting of methane) is the cleanest and lowest-carbon fuel available at the LNG Facility.

Design and Operational Energy Efficiency

Design and operational energy efficiencies affecting emissions and efficiency include the following:

- Output Efficiency per Heat Input
- Periodic Burner Tuning
- Proper Instrumentation and Controls
- Reliability

Each of these is summarized below.

- **Efficiency**: Turbine models under consideration should be evaluated for output efficiency compared to the heat input rate. More efficient models require less heat input for the equivalent amount of fuel consumed. Additionally, turbine hot air recirculation should be minimized per vendor recommendations.
- **Periodic Burner Tuning**: Periodic inspections and tuning should be planned in order to maintain/restore high efficient and low-emissions operation.
- **Instrumentation and Controls**: Control systems should be of the type to monitor and modulate fuel flow and/or combustion air, and other vital parameters in order to achieve optimal high efficiency low-emission performance for full load and part-load conditions.
- **Reliability**: Turbine models under consideration should be evaluated for reliability of design for the specific operational design and range of conditions.

Alternate Design – Electric Compressors

Motor driven gas compression systems use electricity as the power source for the compressor rather than a gas turbine compressor. Electrically driven motors for compressors of this size require a large source of electrical power.

Use of Waste Heat Recovery (Combined Heat and Power or Combined Cycle)

Simple Cycle Turbines with heat recovery or turbines with a combined cycle configuration convert exhaust heat into mechanical energy (steam or electricity or both), increasing the overall net efficiency of the system.

Alternate Design – Use of Aero-Derivative Turbines

Aero-Derivative turbines are used in gas compression and electrical power generation operations due to their ability to be shut down and handle load changes quickly. They are also used in the marine industry due to their reduced weight. In general, aero-derivative machines are more efficient than industrial machines of comparable size and capacity.

4.5.1.1. Technologies Excluded Based on a Fundamental Change to the Nature of the Source

The EPA has recognized that the list of potential control technologies in Step 1 of a BACT analysis should not redefine the nature of the source proposed by an applicant. As stated by the EPA in its guidance, "BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility."[4] Notwithstanding this guideline, permitting agencies are provided discretion in recommending minor changes or adjustments to a BACT proposal, which achieve lower overall emissions without disrupting the applicant's basic business purpose for the facility.

To evaluate whether or not a proposed control technology or strategy "fundamentally redefines the nature of the source," EPA has established a framework to evaluate control technologies during the permitting process.[5] This framework is briefly summarized below, along with its applicability to the LNG Plant and the mechanical drive turbines:

1. **Evaluation of Basic Design and Purpose**: First, the basic design, purpose, and objectives should be evaluated based on the information provided as part of the permitting process.

   Relative to the LNG Plant, the purpose or objective of the LNG turbines is to compress refrigerants required for the liquefaction process. The purpose of the turbines is not to produce power; rather, power is generated onsite by a separate and independent power generation facility (PGF), which is designed to specifically meet the power demands of the operation. The facility cannot be connected to the grid due to the significant electrical power needs of the facility, and the

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[4] *PSD and Title V Permitting Guidance for Greenhouse Gases* (EPA-457/B-11-001), U.S. Environmental Protection Agency, March 2011, page 26, available at http://www.epa.gov/sites/production/files/2015-12/documents/ghgpermittingguidance.pdf

[5] IBID, pgs. 26-31

unavailability of sufficient off site on-demand power to provide anything other than the essential power required by the plant.

2. **Design Features Analysis:** Second, the proposed design is then evaluated to determine which design elements are inherent to the facility purpose and should not be changed, versus the design elements that may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility.

   With respect to the LNG Plant, simple cycle turbines are the best design in meeting the operational requirements of the refrigerant compressor drivers. Once ready, a simple-cycle combustion turbine can be started and reach full load in a matter of minutes. These units can also be shut down almost instantaneously. As a result, simple cycle turbines are typically used for services that require variable loads and quick recovery time. Additionally, as the majority of the natural gas treatment occurs at the GTP, there would be only minor needs for excess heat or power that could be provided by recovering the heat from the mechanical drive turbines. Specifically, the Project has proposed use of compression turbines operating in simple cycle mode as it is one of the most efficient commercially proven industrial gas turbines available in terms of its heat rate (approximately 39% based on lower heat value).

3. **Exclusion of Control Technologies that Potentially Redefine the Source:** Third, a control technology can be excluded from consideration as BACT if it can be shown that application of the control option would disrupt the facility's basic/fundamental purpose or objective. Justification for excluding an option should not rely upon later steps of the Top-Down BACT process, including:

   a. Technical Feasibility (Step 2)

   b. Cost Impacts (Step 4)

   c. Energy Impacts (Step 4)

   Of the potential GHG control technologies noted above in Section 4.5.1, the following technologies redefine the nature of the proposed source and were removed from additional consideration in the BACT analysis:

   - Use of Motors to Drive Electric Compressors
   - Use of Turbines in Combined Cycle Mode

   Use of aero-derivative turbines possibly redefines the nature of the source; however, this option is carried forward in the BACT analysis for the reasons set forth below.

Electric Compressors

Use of electric motors to drive compressors has been removed from further consideration as a potential control technology, as its use would fundamentally redefine the nature of the proposed source as follows:

- As noted above, the LNG Plant would not be connected to the local electrical power grid as the grid does not provide adequate energy to power the facility.

- Use of motors to drive compressors may not constitute control technology because use of large electric motors would require installation of significant additional PGF capacity in excess of the equivalent turbine horsepower, which may actually result in increased GHG emissions from the facility.
- Use of electric motors to drive compressors would fundamentally alter the facility's PGF base load profile, requiring the PGF to be redesigned with added capacity to ensure adequate power availability and system reliability.

Use of Heat Recovery (Combined Heat and Power or Combined Cycle)

Use of heat recovery or turbines in a combined cycle mode has been removed from further consideration as a potential control technology, as its use would fundamentally redefine the nature of the proposed source as follows:

- The heat recovered from the proposed mechanical drive turbines has no useful purpose at the LNG facility. All heat requirements are satisfied by the efficient design of the facilities.
- The proposed facility would not be connected to the local external power grid and must generate its own electric power. The facility has been designed to generate its own electric power including design elements to ensure reliable and consistent electric power availability. The facility's PGF has been designed to have the flexibility to adjust the loads to meet facility demand, independent of the mechanical drive turbines.
- The proposed facility would be supplied with gas already treated at the GTP. As such, very little additional treatment is required, greatly reducing the need for heat within the plant. The heat that is required is low enough to be mostly provided by electricity and the waste heat recovered at the power plant and within the processing facilities. Thus, there is no need for additional waste heat recovery from the mechanical drive turbines.
- The proposed facility chose a simple cycle turbine design to avoid the complications of a combined cycle plant, adding to the reliability of refrigerant compression operations by separating power production from the mechanical drivers and reducing the chance of PGF upset conditions affecting the liquefaction process.
- Simple cycle turbines for mechanical drive provide for added flexibility to variable load conditions avoiding impacts to the liquefaction trains performance demands. Additionally, the selection of simple cycle mechanical driver turbines was based on an engineered process matching power performance and quality requirements with engine models and availability.

Aero-Derivative Turbines

Use of natural gas-fired aero-derivative turbines potentially redefines the source, as their use would require a complete redesign of the compression and liquefaction processes at the facility. Turbines vary in size and capacity. The physical capacity of a specific aero-derivative turbine selection alone would necessitate a change in plant configuration (e.g., four aero-derivative gas turbines vs. two turbines of the evaluated model per liquefaction train). Additionally, the performance characteristics of an aero-derivative turbine (e.g., operational flexibility, reliability, etc.) would need to be considered in the plant redesign. Turbines of different designs have unique operational and maintenance requirements. Simply put, a “like for like” replacement of an industrial turbine for an aero-derivative turbine is not possible or feasible without completely changing the configuration of the process facilities and revising the emissions profiles from the plant.

Despite arguments supporting the elimination of aero-derivative turbines from further consideration, this BACT analysis carries the aero-derivative turbine type forward as a potential GHG control option or strategy. The turbine type is carried forward because other comparable LNG projects have incorporated them into their design, including:

- **Sabine Pass**: The proposed combustion turbines for the Sabine Pass Liquefaction Project M3 (finalized December 6, 2011) and the Sabine Pass Liquefaction Project M4 (not yet finalized, submitted September 20, 2013) are aero-derivative compressor turbines.
- **Trunkline Project**: The Lake Charles Liquefaction Export Terminal Project (also referred to as the Trunkline Project – not yet finalized, submitted December 20, 2013) proposed aero-derivative compressor turbines.
- **Corpus Christi**: The Corpus Christi Liquefaction Project (GHG BACT draft issued by EPA Region 6 on July 8, 2013) includes 18 aero-derivative compressor turbines.

4.5.2. Step 2: Eliminate Technically Infeasible Options

This section summarizes the technical feasibility for GHG control of each air pollution control technology; no technologies evaluated by this analysis (other than those deemed to redefine the source) are determined to be technically infeasible.

Low-Carbon Fuels

Low-Carbon Fuel is considered a technically feasible control option for the purposes of this analysis. The proposed compression turbines would be fueled with pipeline quality natural gas, predominantly consisting of methane. This is the cleanest and lowest-carbon fuel available for use in combustion turbines.

Operational Energy Efficiencies

Use of operational energy efficiency measures is considered a technically feasible control option for the purposes of this analysis. Efficiency measures that could be incorporated into the Project include periodic tune-ups to maximize operational efficiency (according to manufacturer’s specifications), operating in accordance with general good combustion practices, and/or installing fuel and oxygen sensors to maintain optimum combustion properties to reduce emissions while also considering operational safety.

Aero-Derivative Turbines

For the purposes of this analysis, aero-derivative turbines are deemed technically feasible, as they have been incorporated into other LNG facility designs. As referenced in permitting documents for other projects, aero-derivative turbines are an attractive option, as they typically represent the most efficient simple-cycle turbine design available. Thermal efficiency increases between 4% and 8% are possible over comparable industrial/frame design turbines.

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

The emission control technologies not eliminated by practical or operational limitations are listed in Table 10, below. These technologies are ranked by control efficiency.

Table 9: Remaining Control Options and Control Effectiveness

Rank	Control Technology	Control Efficiency (%)
1	Aero-Derivative Design	4% – 8% increased thermal efficiency over comparable industrial/frame design turbines
2	Operational Efficiencies/ Low Carbon Fuels	Variable

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

The only technology evaluated for cost-effectiveness is the use of aero-derivative turbines. The other measures identified in Step 3 would already be incorporated into the design and operation of the gas turbines; no analysis of cost is required for these options.

4.5.4.1. Energy Impact Analysis

As GHG controls incorporate energy efficiency elements and do not result in impacts, an energy impact analysis is not required.

4.5.4.2. Environmental Impact Analysis

Relative to GHG controls, none of the proposed GHG measures result in adverse environmental impacts.

4.5.4.3. Economic Analysis

Table 11 summarizes the incremental cost analysis to achieve GHG reductions via changes in turbine design and thermal efficiency. For purposes of calculating the cost of incremental GHG reductions, the analysis treats the evaluated compression turbine model as the base case and calculates the additional cost per ton of using an aero-derivative design to further reduce GHG emissions. The economic analysis relies upon efficiency improvement measures to reduce overall fuel use, which in turn results in lower GHG emissions. The analysis found that while aero-derivative turbines achieve thermal efficiencies of four to 8% greater than comparable industrial turbines on a per machine basis, adopting the option as BACT was not cost-effective as compared to projected \$12 to \$40 per ton of CO_2-e projected cost benchmarks for carbon pollution (see Table 11).

Table 10: Economic Analysis

Estimated Cost-Effectiveness for GHG Reductions			
	Turbine Technology Alternatives		
	Evaluated Model (Industrial)	**Aero-Derivative**	**Difference**
GHG Emissions (tons/year)	3,060,573	2,694,852	365,721
Total Incremental Annualized Cost	$553,075,457	$564,678,098	$11,602,641*
Incremental Cost of GHG Reductions ($/ton) Calculated at a Fuel Cost of $7.50/MMBtu	--	--	$32*
Note: Incremental annualized cost considers differential capital, operational, and maintenance costs for the evaluated model and the Aero-derivative cases. *Aero-derivative turbine technology could be considered cost-effective for mitigating GHG emissions at turbine fuel costs of greater than $7.50/MMBtu. Note that actual Project economics considers fuel costs negligible.			

4.5.5. Step 5: Select BACT

This BACT analysis concludes that use of low-carbon fuel and implementation of operational energy efficiency measures achieve BACT for the evaluated simple cycle gas turbine. The BACT determination is consistent with other comparable projects (see Appendix A for a full list of BACT determinations reviewed).

Notably, EPA encourages comparisons of the proposed design with other similar facilities as a demonstration of efficiency. The compression turbine yields 1,163 pounds carbon dioxide per megawatt-hour (lb CO_2/MWh) as the base case emission level for the evaluated turbine model, which is more efficient than most industrial turbine designs.

4.6. Conclusions

The objective of this analysis was to examine turbines used as the mechanical driver selected for refrigerant compression. The analysis considered the technology, feasibility, cost, and other site-specific factors to control of emissions. The BACT analysis confirmed the following levels of control for the compressor turbine drivers:

- NOx: DLN plus SCR achieving 2 ppmv NOx @ 15% O_2
- CO: CO Catalyst achieving 10 ppmv (or lower) CO @ 15% O_2
- SO_2: Clean Fuels
- PM and VOC: Good Combustion Practices/Clean Fuels
- GHGs: Use of pipeline quality natural gas, implementation of measures to improve overall efficiency of the gas turbine operations. Installation of an aero-derivative turbine would only be considered BACT if turbine fuel costs are $7.50/MMBtu or greater.

Notably, a cost effectiveness evaluation of SCR was not conducted given the Project applicant is voluntarily accepting to install DLN plus SCR, Relative to CO, the most stringent control option was selected.

Relative to SO_2, PM and VOC, this BACT analysis did not identify any more stringent control technologies that could impact compression turbine design.

The BACT determination for GHGs did not incorporate the most stringent and feasible control option. The most stringent control option was eliminated in the analysis based on technical feasibility and/or cost-effectiveness. It also should be noted that GHG BACT determinations made for the compressor turbine driver option cannot be extended to other potential driver selections or options. BACT is always a case-by-case analysis and the conclusions will vary based on design and other site-specific considerations.

5. POWER GENERATION TURBINES

This section of the BACT analysis addresses the Power Generation Turbines to be used to generate power at the LNG Plant. These turbines would be in a combined cycle configuration. This analysis provides a review of the possible technologies and emission limits that could be imposed as BACT, including estimated cost of each technology.

The turbines are equipped with DLN technology capable of achieving 15 ppmv NOx and 15 ppmv CO at 15% O_2. These emissions levels represent the "base case" conditions for this analysis.

This BACT analysis is organized, as follows:

- Section 5.1 – NOx BACT Analysis
- Section 5.2 – CO BACT Analysis
- Section 5.3 – SO_2, VOC, and PM BACT Analysis
- Section 5.4 – GHG BACT Analysis
- Section 5.5 – Conclusions

5.1. NOx BACT Analysis

NOx is formed during the combustion process due to high temperature zones in the combustion burner or chamber. This BACT analysis evaluates control techniques and technologies used to mitigate NOx emissions from the gas turbine.

5.1.1. Step 1: Identify All Control Technologies

This review focuses on natural gas-fired combustion turbines greater than 25 MW from year 2010 to the present. A summary of the data collected by this review is included in Appendix A.

Control technologies identified for NOx control of gas turbines include the following:

1. DLN
2. Water/Steam Injection
3. SCR

4. SNCR
5. NSCR
6. XONON™
7. SCONOx™

These control methods may be used alone or in combination to achieve the various degrees of NOx emissions control. A description of each of these control technologies is provided in Section 4.1 of this document. Conditions specific to the turbine are provided below.

Dry Low NOx Burners

The Power Generation Turbine base model is equipped with DLN combustors; this technology has an expected NOx performance of approximately 15 ppmv @ 15% O_2.

It is also possible to equip the base model with "Ultra-Low" combustors, reducing NOx emissions from 15 ppmv @ 15% O_2 (DLN) to 9 ppmv @ 15% O_2 (UDLN). This technology is new and performance data is limited but is considered by the Project to be "selectable" in power generation service.

5.1.2. Step 2: Eliminate Technically Infeasible Options

This section summarizes the operating principles, NOx control efficiency and technical feasibility of each potential NOx control technology; technologies determined to be technically infeasible are summarized in Table 12, below.

Table 11: Control Technology Options Determined to be Technically Infeasible

Technology Alternative	Basis
Water/Steam Injection	The base model turbine is equipped with DLN combustors. Water/steam injection is not compatible with burners equipped with DLN.
SNCR	The exhaust temperature of the combustion turbine is less than the optimum temperature range (1,500°F to 1,900°F) for SNCR.
NSCR	The oxygen concentration of the combustion turbine is approximately 15% O_2, which is much higher than the optimum oxygen concentration range for NSCR.
XONON™	There are no documented installations of this type of control on large combustion turbines.
SCONOx™	There are no documented installations of this type of control on large combustion turbines.

Water/Steam Injection

Water/steam injection has the potential to reduce NOx emissions by 20% to 30%. Water/steam injection is not used in conjunction with DLN combustors. As the base model is equipped with DLN combustors, water/steam injection is not considered further in this analysis.

Selective Non-Catalytic Reduction (SNCR)

The turbine is anticipated to exhaust at a temperature of approximately 800-900°F, which is well below the recommended temperature (1,500°F to 1,900°F) for an SNCR system to achieve the desired NOx reduction efficiency. The NOx reduction efficiency of SNCR decreases rapidly at temperatures outside the optimum temperature window, additionally, operations below this temperature window result in excessive ammonia emissions (ammonia slip). As such, SNCR is not considered technically feasible for this analysis.

Non-Selective Catalytic Reduction (NSCR)

NSCR requires a low excess oxygen concentration in the exhaust gas stream (typically below 1%) to be effective, as the oxygen must be depleted before the reduction chemistry can proceed. As such, NSCR is only effective with rich-burn gas-fired units that operate at all times with an A/F ratio controller at or close to stoichiometric conditions. As gas turbines typically operated with an excess oxygen concentration of approximately 15% it is outside of the acceptable operating range for NSCR and is not considered technically feasible for this analysis.

XONON™

The XONON™ catalyst has only ever been paired with the 1.5 MW Kawasaki M1A-13 simple cycle gas turbine generator. As this catalyst technology has only been applied in the smaller gas turbines manufactured by Kawasaki, and as testing and implementation of this control system among different gas turbine manufacturers and on larger units has not been performed, this technology is unproven for the size class proposed for this Project and is not considered technically feasible for this analysis.

SCONOx™

SCONOx™ technology has an operating temperature range of 300°F to 700°F. As noted above, the turbine is anticipated to exhaust at a temperature of approximately 800°F to 900°F, which is above the recommended temperature for SCONOx™. To optimize exhaust temperature, quenching would be required to lower exhaust gas temperatures to acceptable SCONOx™ temperature ranges. SCONOx™ technology is still in the early stages of market introduction. Issues that may impact application of the technology include relatively high capital cost, a large reactor size compared to SCR, increased system complexity, high utilities cost and demand (steam, natural gas, compressed air and electricity are required), and a gradual rise in NOx emissions over time requiring a 1 to 2 day renewal of catalyst. Commercial experience with this technology is limited, with a majority of the SCONOx™ units operating on turbines units of 15 MW or less. No known installations exist in low ambient temperature settings similar to Alaska. At least one installation of SCONOx™ has reported challenges in meeting permit limits in California. While SCONOx™ might be applicable in theory, it is not considered feasible for this Project as it has limited commercial experience and has not been demonstrated in low ambient temperature settings.

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

The emission control technologies not eliminated by practical or operational limitations are listed in Table 13, below. These technologies are ranked by control efficiency.

Table 12: Remaining Control Options and Control Effectiveness

Rank	Control Technology	Control Efficiency (%) or Emissions Target (ppmv)
1	DLN plus SCR or UDLN plus SCR	25% to 90% (as low as 2 ppmv @ 15% O_2)
2	UDLN	9 ppmv @ 15% O_2

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

This section summarizes the energy, environmental, and economic impacts of the control technologies noted above. The cost-effectiveness calculations use a "NOx emission base case" of 15 ppmv (base-case offering from the manufacturer) and emission control endpoints of 2 ppmv (DLN or UDLN plus SCR) or 9 ppmv (UDLN only). It should be noted that a base-case emission rate of 15 ppmv is used because it represents the base-case offering from the manufacturer. An aggressive endpoint of 2 ppmv in the SCR evaluation provides a conservative evaluation of cost-effectiveness. A controlled NOx emission rate of 5 ppmv would be a more likely performance objective to accommodate fluctuations in operations and site-specific conditions in Alaska (e.g., temperature fluctuations between summer and winter, etc.).

5.1.4.1. Energy Impact Analysis

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

5.1.4.2. 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.

5.1.4.3. Economic Analysis

Economic analysis of costs to install NOx control is not required as the Project applicant proposes to install the most stringent controls.

5.1.5. Step 5: Select BACT

The Project is voluntarily selecting the most stringent NOx control which includes the use of DLN plus SCR at 2 ppmv NOx, as the BACT level of control to be installed. DLN plus SCR is a common BACT emissions control approach for turbine installations, including LNG projects (see Appendix A for other comparable BACT determinations).

5.2. CO BACT Analysis

CO 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.

5.2.1. Step 1: Identify All Control Technologies

This review focused on natural gas-fired combustion turbines greater than 25 MW from year 2010 to the present. A summary of the data collected by this review is included in Appendix A.

Control technologies identified as potential CO control technologies for combined cycle gas turbines include the following:

- Good Combustion Practices/Clean Fuel
- Catalytic Oxidation
- SCONOx™
- NSCR

These control methods may be used alone or in combination to achieve the various degrees of CO emissions control. A description of each of these control technologies is provided in Section 4.2.1of this document.

5.2.2. Step 2: Eliminate Technically Infeasible Options

This section summarizes the potential technical feasibility for CO control of each air pollution control technology; technologies determined to be technically infeasible are summarized in Table 15, below.

Table 13: Control Technology Options Determined to be Technically Infeasible

Technology Alternative	Basis
SCONOx™	There are no documented installations of this type of control on large combustion turbines.
NSCR	The oxygen concentration of the combustion turbine is approximately 15% O_2 which is much higher than the optimum oxygen concentration range for NSCR.

SCONOx™

SCONOx™ technology is still in the early stages of market introduction. Issues that may impact application of the technology include relatively high capital cost, a large reactor size, increased system complexity, high utilities cost and demand (steam, natural gas, compressed air and electricity are required), and a gradual decrease in effectiveness over time, requiring a one to two day renewal of catalyst. Commercial experience with this technology is limited, with a majority of the units operating on units of 15 MW or less. No known installations exist in low ambient temperature settings similar to Alaska. At least one installation of has reported challenges in meeting permit limits. While SCONOx™ may be applicable in theory, it is not considered feasible for the LNG Project because it has limited commercial experience and has not been demonstrated in low ambient temperature settings.

Non-Selective Catalytic Reduction (NSCR)

NSCR requires a low excess oxygen concentration in the exhaust gas stream (typically below 1%) to be effective, as the oxygen must be depleted before the reduction chemistry can proceed. As such, NSCR is only effective with rich-burn gas-fired units that operate at all times with an A/F ratio controller at or close to stoichiometric conditions. As gas turbines typically operate with an excess oxygen concentration of approximately 15%, it is outside of the acceptable operating range for NSCR and is not considered technically feasible for this analysis.

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

The emission control technologies not eliminated by practical or operational limitations are listed in Table 16, below. These technologies are ranked by control efficiency.

Table 14: Remaining Control Options and Control Effectiveness

Rank	Control Technology	Control Efficiency (%) or Emissions Target (ppmv)
1	CO Catalyst	10 ppmv (or lower) at 15% O_2
2	Good Combustion Practices/ Clean Fuels	15 ppmv or more at 15% O_2

This analysis assumes a 10 ppmv (or lower) controlled emissions level similar to other LNG turbines of this size.

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

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

5.2.4.1. Energy Impact Analysis

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

5.2.4.2. Environmental Impact Analysis

For this analysis, implementation of good combustion practices/clean fuels 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.

5.2.4.3. Economic Impact Analysis

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

- Capacity of the turbine
- Baseline emissions levels
- Controlled emissions levels
- Emission control installation and operating costs

The cost-effectiveness of a CO catalyst installation on the power generation turbines is summarized in Table 17, below. As shown in this table, CO catalyst is above the ADEC cost-effectiveness threshold guidance of $10,000 per ton.

Table 15: Economic Analysis

Control Technology	CO Catalyst
Control Option	**1**
Uncontrolled Baseline ppmvd@15%O_2	15
Uncontrolled emissions (tpy)	62
Controlled emissions ppmvd@15%O_2	5
Controlled emissions (tpy)	21
CO emission reduction (tpy)	42
Total Annualized Operating Cost	$663,165
Cost of CO removal ($/ton)	$15,801

While the cost-effectiveness shown in Table 17 is higher than the “rule of thumb” cost-effectiveness range, ADEC may be inclined to discount the cost-effectiveness result in the BACT determination for the following reasons:

- Other recent Alaska permitting actions have required CO catalysts to reduce CO emissions. For example, the Point Thomson BACT determination issued in 2012 sets a reasonable precedent for these CO controls.
- The above cost-effectiveness calculations used an aggressive baseline emission rate (i.e., 15 ppmv CO). If ADEC were to require that a more relaxed baseline emission rate be used in the calculations (e.g., 25 or 50 ppmv CO), the installation of CO catalyst would become cost-effective.

5.2.5. Step 5: Select BACT

This BACT analysis concludes, similar to other comparable projects evaluated, that good combustion practices/clean fuels, as well as operation of an oxidation catalyst likely constitutes BACT for a gas turbine of this type and application (see Appendix A for a list of other BACT determinations reviewed).

5.3. SO_2, VOC, and PM BACT Analysis

The SO_2, VOC, and PM BACT analysis for the power generation turbine is identical to the compressor turbines; see Sections 4.3 and 4.4, above.

5.4. GHG BACT Analysis

CO_2, a GHG, is the main combustion product from gas turbines. Incomplete combustion would cause methane to be emitted, which is also a GHG. This section describes the techniques that would be employed to reduce GHGs from the power generation turbines.

5.4.1. Step 1: Identify All Control Technologies

This analysis focused on natural-gas fired combustion turbines greater than 25 MW from year 2010 to the present. A summary of the data collected by this review is included in Appendix A.

Control technologies identified for GHG control of combined cycle gas turbines include the following:

- Use of Low-Carbon Fuel
- Design and Operational Energy Efficiency
- Alternate Design – Use of Grid Power

These control methods may be used alone or in combination to achieve the various degrees of GHG emissions control. Each of the control methods are described below.

Notably, another emission control technique, which is identified in the EPA GHG BACT guidance, is the use of CCS, which is discussed in its own section (see Section 8). As shown in the BACT analysis for CCS, the technology is potentially infeasible and is not cost-effective. CCS will not be discussed further in this section of the analysis.

Use of Low-Carbon Fuel

Use of pipeline quality natural gas and BOG (i.e., fuel gas predominately consisting of methane) is the cleanest and lowest-carbon fuel available at the LNG Plant.

Design and Operational Energy Efficiency

Design and operational energy efficiencies affecting emissions and efficiency include the following:

- Output Efficiency per Heat Input
- Periodic Burner Tuning
- Proper Instrumentation and Controls
- Reliability

Each of these is summarized below.

- **Efficiency**: Turbine models under consideration should be evaluated for output efficiency compared to the heat input rate. More efficient models require less heat input for the equivalent amount of fuel consumed.
- **Periodic Burner Tuning**: Periodic inspections and tuning should be planned in order to maintain/restore high efficient and low-emissions operation.
- **Instrumentation and Controls**: Control systems should be of the type to monitor and modulate fuel flow and/or combustion air, and other vital parameters in order to achieve optimal high efficiency low-emission performance for full load and part-load conditions.
- **Reliability**: Turbine models under consideration should be evaluated for reliability of design for the specific operational design and conditions.

Alternate Design – Use of Electrical Grid Power

Connection to the electrical grid power system in order to eliminate the need to install power generation turbines at the LNG Plant was considered.

5.4.2. Step 2: Eliminate Technically Infeasible Options

The only technology eliminated at Step 2 is the use of electrical grid power as the primary power source. This technology choice is infeasible as the grid does not provide adequate energy to meet the normal operating requirements of the facility. Electrical grid primary power is not an option for the Project.

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

The emission control technologies not eliminated by practical or operational limitations are listed in Table 18, below. These technologies are ranked by control efficiency.

Table 16: Remaining Control Options and Control Effectiveness

Rank	Control Technology	Control Efficiency (%)
1	Combined Cycle Turbine (Base Case)	No change to control efficiency; however, fewer combined cycle turbines would be required to be installed as compared to simple cycle turbines.
2	Operational Efficiencies/ Low Carbon Fuels	Variable

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

The only technology evaluated for control-effectiveness is the use of combined cycle vs simple cycle turbines. The other measures identified in Step 3 would be incorporated into the design and operation of the gas turbines; no analysis of cost is required for these options.

5.4.4.1. Energy Impact Analysis

Since GHG controls incorporate energy efficiency elements and do not result in impacts, an energy impact analysis is not required.

5.4.4.2. Environmental Impact Analysis

Relative to GHG controls, none of the proposed GHG measures result in adverse environmental impacts.

5.4.4.3. Economic Analysis

An economic analysis is not required as the Project proposes to implement all of the above measures listed in Step 3.

5.4.5. Step 5: Select BACT

This BACT analysis concludes that use of a combined cycle turbine using low-carbon fuel, and implementing operational energy efficiency measures achieves BACT for the power generation gas turbines. The BACT determination is consistent with other comparable projects (see Appendix A for a full list of BACT determinations reviewed).

5.5. Conclusions

The objective of this analysis was to examine the power generation combustion turbine as the driver selection for power generation. The analysis considered the technology, feasibility, cost, and other site-specific factors to control of NOx, CO, PM, SO_2, VOC, and GHG emissions. The BACT analysis confirmed the following levels of control for the combustion turbine drivers:

- NOx: DLN plus SCR achieving 2 ppmv NOx @ 15% O_2
- CO: CO Catalyst achieving 10 ppmv CO or lower @ 15% O_2
- SO_2: Clean Fuels
- PM and VOC: Good Combustion Practices/Clean Fuels
- GHGs: Use of a combined cycle turbine using low-carbon fuel, and implementing operational energy efficiency measures

Notably, a cost effectiveness evaluation of SCR was not conducted given the Project applicant is voluntarily accepting to install DLN plus SCR.

The installation of a catalyst bed to control CO emissions achieves the most stringent level of control for this pollutant.

Relative to SO_2, PM, and VOC, this BACT analysis did not identify any more stringent control technologies that could impact turbine design.

For GHGs, the most stringent controls, which have been achieved in practice, are proposed for the gas turbine generators.

6. VENT GAS DISPOSAL (FLARES AND THERMAL OXIDIZER)

Vent gases may be emitted by the facility during periods of blowdown, start-up, shutdown, and malfunction events. Vent gases at the LNG Plant would contain VOC and high concentrations of methane, which has a relatively high GHG GWP. Vapor recovery, flares and thermal oxidizers are used to control these emissions.

The LNG Plant would have three flare gas systems (i.e., wet, dry, and low-pressure), to route relief vapors from separate sections of the plant into their respective flare collection headers. The wet flare gas system would control waste gas streams containing a significant concentration of water (i.e., around the molecular sieve dehydration beds), or contain a significant concentration of heavier compounds, which could freeze out at colder temperatures (i.e., pressure relief and de-pressuring flow from the debutanizer column). The dry flare gas system would be used for safe disposal of dry hydrocarbons streams discharged downstream of the dehydration unit both under emergency condition and during a start-up condition. The low-pressure BOG flare gas system would be used for safe disposal of low-pressure operational releases from the LNG Storage and Loading System and intermittent maintenance purging of inert gas from LNG carriers. A thermal oxidizer would be used to control off-gas emissions from the condensate tank. Gases from storage tanks and LNG carrier loading would be captured and reused as fuel gas, where possible.

This analysis provides a review of the possible technologies and emission limits that could be imposed as BACT for vent gas from the wet gas hydrocarbon streams and the dry gas hydrocarbon streams. Technologies considered for the third vent gas disposal system handling the emissions from the condensate storage and loading operations are discussed later in Sections 9 and 10 of this document.

6.1. VOC and GHG “Top-Down” BACT Analysis

This BACT analysis evaluates control techniques and technologies used to mitigate waste gas emissions, which can result in VOC and GHG emissions.

6.1.1. Step 1: Identify All Control Technologies

Control technologies identified to mitigate emissions include the following:

- Flare Gas Reduction Best Practices
- Flare Gas Recovery
- Flare/Thermal Oxidizer Design

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

Notably, another emission control technique, which is identified in the EPA GHG BACT guidance, is the use of CCS, which is discussed in its own section (see Section 8). As shown in the BACT analysis for CCS, the technology is potentially infeasible and is not cost-effective. CCS will not be discussed further in this section of the analysis.

Flare Gas Reduction Best Practices

The most practical way to reduce the amount of emissions generated from combustion in a flare/thermal oxidizer is to minimize the amount of waste gas produced. The LNG Plant would be designed to avoid routine continuous flaring (other than pilot gas used to maintain the presence of a flame and purge gas used to prevent oxygen ingress into the flare systems). Additionally, LNG would maintain and follow an Operations Emissions Management Plan, part of which would be flare gas reduction provisions to reduce the frequency, magnitude and duration of flaring events. The plan would present procedures and process controls that would be used to minimize or prevent emissions from the flares while providing for safe operation of the facility. The plan would address anticipated causes of flaring including emergency, operational upsets and commissioning/start-up/shutdown/maintenance activities.

Flare Gas Recovery

Flare gas recovery is a method of capturing streams normally diverted to the flare for re-use in the facility as fuel gas.

Flare/Thermal Oxidizer Design

Proper flare design can improve the thermal destruction of waste gases and also the combustion efficiency of the flare. Design considerations include maintaining a pilot flame, ensuring the heating value of the flare gas is adequate and restricting the velocity of low-BTU flare gas for flame stability.

Thermal oxidizers are not subject to 40 CFR 60.18 requirements; however, good combustion practices including proper mixing of fuel and combustion air would minimize combustion emissions.

6.1.2. Step 2: Eliminate Technically Infeasible Options

None of the technologies discussed in Section 6.1.1 are infeasible. None are eliminated at this step.

Flare Gas Reduction Best Practices

Flare gas reduction best practices are a common BACT control for flares/thermal oxidizers and are considered a technically feasible control option for flares/thermal oxidizers for the purposes of this analysis.

Flare Gas Recovery

Flare gas recovery is a common BACT control for flares/thermal oxidizers and is considered a technically feasible control option for flares/thermal oxidizers for the purposes of this analysis. Flare gas recovery is most applicable for facilities that continuously vent gases with fuel value to the flare.

Flare gas recovery becomes infeasible for gases that contain significant concentrations of inert materials. Inert gases can disrupt the operation of the fuel gas system or freeze in the liquefaction system. Hydrocarbon gases that are contaminated with significant concentrations of inert gases are best disposed at a flare or thermal oxidizer using good combustion practice.

Flare/Thermal Oxidizer Design

Flare/thermal oxidizer is a common BACT control for waste gas minimization and is considered a technically feasible control option for the purposes of this analysis.

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

The emission control technologies not eliminated by practical or operational limitations are listed in Table 19, below. These technologies are ranked by control efficiency.

Table 17: Remaining Control Options and Control Effectiveness

Rank	Control Technology	Control Efficiency (%) or Emissions Target (ppmv)
1	Flare Gas Reduction Best Practices	Variable
2	Flare Gas Recovery	Variable

Rank	Control Technology	Control Efficiency (%) or Emissions Target (ppmv)
3	Flare/Thermal Oxidizer Design	Variable

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

6.1.4.1. Energy Impact Analysis

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

6.1.4.2. Environmental Impact Analysis

For this analysis, implementation of good combustion practices/clean fuels is not expected to cause an environmental impact.

6.1.4.3. Economic Impact Analysis

As flare gas reduction best practices, flare gas recovery and flare/thermal oxidizer design would be implemented for this Project, economic analysis is not required.

6.1.5. Step 5: Select BACT

This BACT analysis concludes that a combination of flare gas reduction best practices, flare gas recovery and flare/thermal oxidizer design meet BACT for waste gas emissions mitigations.

6.2. Conclusions

The objective of this analysis was to examine the mitigation of waste gas emissions mitigation for the facility. The analysis considered the technology, feasibility, cost, and other site-specific factors to control waste gas emissions. Flare gas reduction best practices, flare gas recovery, and flare/thermal oxidizer design achieve the most stringent level of controls for this pollutant.

7. COMPRESSION IGNITION ENGINES – FIREWATER PUMP/INSTRUMENT AIR COMPRESSOR

This BACT analysis addresses the 627 kW emergency diesel firewater pump (operating less than 100 hours per year, in non-emergency use) and 224 kW emergency diesel instrument air compressor (operating less than 100 hours per year, in non-emergency use) 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. Relative to internal combustion engines, only a cursory BACT analysis was performed.

Control technologies identified for NOx, SO_2, CO, PM, VOC, and GHGs include the following:

- Good Combustion Practices/Clean Fuels (All Pollutants)
- Compliance with 40 CFR NSPS Subpart IIII (NOx, VOC, CO, and PM)
- Diesel Particulate Filters (PM)

- CO Catalyst (CO and VOC)
- Selective Catalytic Reduction (NOx)[6]

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

Notably, another emission control technique, which is identified in the EPA GHG BACT guidance, is the use of CCS, which is discussed in its own section (see Section 8). As shown in the BACT analysis for CCS, the technology is potentially infeasible and is not cost-effective. CCS will not be discussed further in this section of the analysis.

Good Combustion Practices/Clean Fuels

The rate of combustion emissions is dependent upon fuel choice and good combustion practices including proper mixing of fuel and combustion air as well as the proper operation and maintenance of the engines. These engines are designed to combust low-sulfur diesel fuel and optimized to minimize combustion emissions through use of good combustion practices.

Compliance with 40 CFR NSPS Subpart IIII

These compression ignition engines would be subject to 40 CFR NSPS Subpart IIII emission limits. Based on the horsepower rating and service of these engines, these engines are subject to the following EPA Tier 3 standards: CO – 2.6 grams per brake horsepower-hour (g/bhp-hr); non-methane hydrocarbon + NOx – 3.0 g/bhp-hr; PM – 0.15 g/bhp-hr.

Diesel Particulate Filter, CO Catalyst, and SCR

Due to the limited use and the urgent nature of emergency situations, emergency type engines are not typically required to install diesel particulate filters, CO or SCR catalysts.

7.1. Conclusions

Based on the foregoing, the likely BACT for compression ignition engines would be compliance with NSPS Subpart IIII and the combustion of clean fuels. Compliance with this NSPS would require installation of engines that meet EPA Tier 3 standards.

[6] There are other potential catalytic type control technologies that could be analyzed as part of this compression ignition BACT analysis; however, SCR is the most commonly utilized catalytic control technology for BACT applicability and is the focus of this analysis.

8. DIESEL FUEL STORAGE TANKS

This BACT analysis addresses the three diesel fuel storage tanks needed for support equipment at the facility. A summary of the required storage tanks is provided below:

Tank Emission Unit ID	Equipment Description	Product Stored
24	Diesel Storage Tank	ULSD
25	Air Compressor Diesel Day Tank	ULSD
26	Firewater Pump Diesel Day Tank	ULSD

This analysis provides a review of the possible technologies and emission limits that could be imposed as BACT.

8.1. VOC and GHG "Top-Down" BACT Analysis

VOC is released to the atmosphere due to working and breathing losses from the tanks. This BACT analysis evaluates control techniques and technologies used to mitigate VOC emissions from the tanks.

8.1.1. Step 1: Identify All Control Technologies

Control technologies identified to mitigate emissions include the following:

- Floating Roof (External or Internal)
- Vapor Recovery System
- Flare or Thermal Oxidizer
- Submerged Fill

The following subsections discuss the general operating principles of each technology and their potential technical feasibility for VOC control of the LNG condensate and fuel storage tanks.

Floating Roof Tanks

External floating roof tanks are designed with a roof consisting of a double deck or pontoon single deck which rests or floats on the liquid being contained. An internal floating roof includes a fixed roof over the floating roof, to protect the floating roof from damage and deterioration. In general, the floating roof covers the entire liquid surface except for a small perimeter rim space. Under normal floating conditions, the roof floats essentially flat and is centered within the tank shell. The floating roof must be designed with perimeter seals (primary and secondary seals) which slide against the tank wall as the roof moves up and down. The use of perimeter seals minimizes emissions of VOCs from the tank. Sources of emissions from floating roof tanks include standing storage loss and withdrawal losses. Standing losses occur due to improper fits between tank seal and the tank shell. Withdrawal losses occur when liquid is removed from the tank, lowering the floating roof, revealing a liquid on the tank walls which vaporize.

Vapor Recovery System

A vapor recovery system (VRS) can be used to draw vapors out of the storage tank, which are routed through a compressor. Compressed vapors may be used onsite as fuel for combustion units or routed to sales gas compressors for further compression to pipeline specifications. VRSs can recover over 95% of the hydrocarbon emissions that accumulate in the storage tanks.

Flare/Thermal Oxidizer Design

Proper flare design can improve the thermal destruction of waste gases recovered from the tanks and also the combustion efficiency of the flare. Design considerations include maintaining a pilot flame, ensuring the heating value of the flare gas is adequate and restricting the velocity of low-BTU flare gas for flame stability. A continuously lit pilot ensures that vent gases are combusted at the flare tip. A properly operated flare can achieve a destruction efficiency of 98 percent or greater.

Thermal oxidizers are not subject to 40 CFR 60.18 requirements; however, good combustion practices including proper mixing of fuel and combustion air would minimize combustion emissions. Thermal oxidizers can achieve control efficiencies greater than 98 percent.

Submerged Fill

The use of submerged fill during tank loading operations can reduce vaporization of the liquid on the between 40 – 60% from traditional splash loading operations. Note that the use of submerged fill is a control technique specific to the filling of a tank and does not affect the day-to-day emissions of the tank.

8.1.2. Step 2: Eliminate Technically Infeasible Options

Floating Roof Tanks

An external floating roof tank would not be technically feasible in the harsh environment where the proposed tanks will be operated. Snow and ice on the tank surfaces will potentially damage the roofs and seals – making such a system impractical.

Internal floating roof tanks have the potential to be an effective emission control system for the tanks. However, due to the small size of the diesel fuel storage tanks (less than 20,000 gal), the tanks are expected to be horizontal, square or rectangular in shape, not suitable for internal floating roofs. Should the tanks be installed underground, internal floating roofs would also not be technically feasible.

Flare/Thermal Oxidizer Design

Flare/thermal oxidizer is a technically feasible control option for the diesel fuel storage tanks. However, it is not identified as BACT for small (<20,000 gal) diesel fuel storage tanks in the BACT Clearinghouse databases (See Appendix C). Notwithstanding, this technology is carried forward for further analysis in this BACT determination.

Vapor Recovery System

Use of a vapor recovery system to control VOC emissions is a common BACT control for storage tanks and is considered technically feasible for this application when operated in conjunction with a flare/thermal oxidizer. If operated alone, the VRS would either need an outlet from the plant for the recovered vapors, or the vapors would be used for fuel gas for the external combustion devices. Use of recovered vapors from diesel storage is not desirable for the external combustion equipment as they compromise the quality of the gas burned. The external combustion devices, particularly the gas turbines, must meet exacting emissions specifications for NOx and CO. However, if the vapors are routed to a thermal oxidizer/flare installed specifically to capture and combust the vapors from the diesel tanks, then a VRS is technically feasible.

Submerged Fill

Submerged fill operation is a common BACT control for the diesel fuel storage tanks and is considered a technically feasible control option for the purposes of this analysis.

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

The emission control technologies not eliminated by practical or operational limitations are listed in Table 20, below. These technologies are ranked by control efficiency.

Table 18: Remaining Control Options and Control Effectiveness

Rank	Control Technology	Control Efficiency (%) or Emissions Target (ppmv)
1	**Flare/Thermal Oxidizer Design with** Vapor Recovery System	>98%
2	Submerged Fill	40 – 60%

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

8.1.4.1. Energy Impact Analysis

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

8.1.4.2. Environmental Impact Analysis

For this analysis, implementation of the technologies noted above is not expected to cause an environmental impact.

8.1.4.3. Economic Impact Analysis

The most-effective control system remaining that is not already part of the Project includes the installation of a vapor recovery system routed to a thermal oxidizer/flare. The cost of installing a vapor recovery system with vapors routed to a thermal oxidizer for destruction of the emissions from the diesel tanks was considered based on equipment cost equations developed by EPA in the US EPA Air Pollution Control Cost Manual.

Table 19: Thermal Oxidizer with Vapor Recovery System Cost and Control Effectiveness

	Thermal Oxidizer with Vapor Recovery
Baseline VOC emissions (tpy)	0.0015
Control Efficiency	98%
Controlled emissions (tpy)	0.00003
VOC emission reduction (tpy)	0.00151
Total Annualized Operating Cost	$81,901
Cost of VOC removal ($/ton)	**$54,260,681**

Based on the calculations summarized in Table 21, the use of a thermal oxidizer would not be cost-effective, and the control technologies have been eliminated for further consideration.

8.1.5. Step 5: Select BACT

This BACT analysis concludes that the use of a fixed roof tank and submerged fill operations is BACT for the diesel fuel storage tanks.

8.2. Conclusions

Based on the foregoing, the likely BACT for the diesel fuel storage tanks is a fixed roof tank with submerged fill.

9. CONDENSATE STORAGE TANKS

This BACT analysis addresses the two condensate storage tanks needed to store residual condensate recovered from the pipeline. A summary of the required storage tanks is provided below:

Tank Emission Unit ID	Equipment Description	Product Stored
21	Condensate Storage Tank	Condensate
22	Offspec Condensate Storage Tank	Condensate

This analysis provides a review of the possible technologies and emission limits that could be imposed as BACT.

9.1. VOC and GHG “Top-Down” BACT Analysis

VOC is released to the atmosphere due to working and breathing losses from the tanks. This BACT analysis evaluates control techniques and technologies used to mitigate VOC emissions from the tanks.

9.1.1. Step 1: Identify All Control Technologies

Control technologies identified to mitigate emissions include the following:

- Floating Roof (External or Internal)
- Vapor Recovery System

- Flare or Thermal Oxidizer
- Submerged Fill

The following subsections discuss the general operating principles of each technology and their potential technical feasibility for VOC control of the LNG condensate storage tanks.

Floating Roof Tanks

External floating roof tanks are designed with a roof consisting of a double deck or pontoon single deck which rests or floats on the liquid being contained. An internal floating roof includes a fixed roof over the floating roof, to protect the floating roof from damage and deterioration. In general, the floating roof covers the entire liquid surface except for a small perimeter rim space. Under normal floating conditions, the roof floats essentially flat and is centered within the tank shell. The floating roof must be designed with perimeter seals (primary and secondary seals) which slide against the tank wall as the roof moves up and down. The use of perimeter seals minimizes emissions of VOCs from the tank. Sources of emissions from floating roof tanks include standing storage loss and withdrawal losses. Standing losses occur due to improper fits between tank seal and the tank shell. Withdrawal losses occur when liquid is removed from the tank, lowering the floating roof, revealing a liquid on the tank walls which vaporize.

Flare/Thermal Oxidizer Design

Proper flare design can improve the thermal destruction of waste gases recovered from the tanks and also the combustion efficiency of the flare. Design considerations include maintaining a pilot flame, ensuring the heating value of the flare gas is adequate and restricting the velocity of low-BTU flare gas for flame stability. A continuously lit pilot ensures that vent gases are combusted at the flare tip. A properly operated flare can achieve a destruction efficiency of 98 percent or greater.

Thermal oxidizers are not subject to 40 CFR 60.18 requirements; however, good combustion practices including proper mixing of fuel and combustion air would minimize combustion emissions.

Vapor Recovery System

A vapor recovery system (VRS) can be used to draw vapors out of the storage tank, which are routed through a compressor. Compressed vapors may be used onsite as fuel for combustion units or routed to sales gas compressors for further compression to pipeline specifications. VRSs can recover over 95% of the hydrocarbon emissions that accumulate in the storage tanks.

Submerged Fill

The use of submerged fill during tank loading operations can reduce vaporization of the liquid on the between 40 – 60% from traditional splash loading operations. Note that the use of submerged fill is a control technique specific to the filling of a tank and does not affect the day-to-day emissions of the tank.

9.1.2. Step 2: Eliminate Technically Infeasible Options

Floating Roof Tanks

An external floating roof tank would not be technically feasible in the harsh environment where the proposed tanks will be operated. Snow and ice on the tank surfaces will potentially damage the roofs and seals – making such a system impractical.

Both internal and external floating roof tanks are infeasible in the application because the vapor pressure of condensate can be quite high (i.e., exceed 11 psia) under certain temperature conditions. This highly volatile liquid would compromise the integrity of the seal systems on these tank types.

Flare/Thermal Oxidizer Design

Flare/thermal oxidizer is a common BACT control for condensate storage tanks and is considered a technically feasible control option for the purposes of this analysis.

Vapor Recovery System

Use of a vapor recovery system to control VOC emissions is a common BACT control for storage tanks and is considered technically feasible for this application when operated in conjunction with a flare/thermal oxidizer. If operated alone, the VRS would either need an outlet from the plant for the recovered vapors, or the vapors would be used for fuel gas for the external combustion devices. Use of recovered vapors from condensate storage is not desirable for the external combustion equipment as they compromise the quality of the gas burned. The external combustion devices, particularly the gas turbines, must meet exacting emissions specifications for NOx and CO. However, if the vapors collected and routed to a thermal oxidizer/flare installed specifically to capture and combust the vapors from the condensate tanks, then a VRS, is technically feasible.

Notably, the design of the proposed vapor recovery system for the project includes a vapor balance feature, which allows vapors from the condensate loading operation (discussed in Section 10) to be commingled with condensate tank vapors and balanced in the system. Vapors from both the loading operation and the condensate tanks themselves are controlled by a thermal oxidizer.

Submerged Fill

Submerged fill operation is a common BACT control for the condensate storage tanks is considered a technically feasible control option for the purposes of this analysis.

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

The emission control technologies not eliminated by practical or operational limitations are listed in Table 22, below. These technologies are ranked by control efficiency.

Table 20: Remaining Control Options and Control Effectiveness

Rank	Control Technology	Control Efficiency (%) or Emissions Target (ppmv)
1	Flare/Thermal Oxidizer with vapor balance/recovery system	>98%
2	Submerged Fill	Variable

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

The use of a vapor recovery system to recover vapors from the condensate tanks and route to a flare/thermal oxidizer is anticipated to provide the most effective control system for the condensate storage tanks.

9.1.4.1. Energy Impact Analysis

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

9.1.4.2. Environmental Impact Analysis

For this analysis, implementation of a vapor balance system routed to a flare/thermal oxidizer is not expected to cause an environmental impact.

9.1.4.3. Economic Impact Analysis

As a vapor balance system routed to a flare/thermal oxidizer would be implemented for this Project, economic analysis is not required because the technology is the highest rank in Step 3.

9.1.5. Step 5: Select BACT

This BACT analysis concludes that a vapor balance system routed to a flare/thermal oxidizer to control emissions from condensate storage tanks meets BACT.

9.2. Conclusions

Based on the foregoing, the likely BACT for the condensate storage tanks is capture and recovery through a vapor balance system and combustion of vapors in a properly designed flare/thermal oxidizer.

10. CONDENSATE TANK LOADING

This BACT analysis addresses the use of a condensate loading system for transporting the condensate of offsite sales. A review of the possible technologies and emission limits that could be imposed as BACT is described below.

10.1. VOC and GHG "Top-Down" BACT Analysis

VOC is released to the atmosphere due to loading losses that occur as the product is transferred from the tank to the trucks. This BACT analysis evaluates control techniques and technologies used to mitigate VOC emissions from the loading operation as found in EPA's RBLC (See Appendix E).

10.1.1. Step 1: Identify All Control Technologies

Control technologies identified to mitigate emissions include the following:

- Vapor Recovery System with Carbon Adsorption
- Flare or Thermal Oxidizer
- Submerged Fill

The following subsections discuss the general operating principles of each technology and their potential technical feasibility for VOC control of the condensate loading operation.

Vapor Recovery System with Carbon Adsorption

A vapor recovery system (VRS) combined with carbon adsorption can be used to capture vapors displaced from the truck as condensate is pumped into the truck tank. Condensate vapors are collected from the loading rack and routed to a carbon adsorption vessel which adsorbs the hydrocarbon the vapor stream, releasing clean air via vents in the vessel. The system maintains two carbon vessels – one which is actively collecting the hydrocarbon vapors, the other is regenerating via vacuum and purge air stripping methods. The vacuum pump extracts the hydrocarbon vapor routing it to an absorption column where the concentrated hydrocarbon vapor is liquefied and then returned to the original product storage tank. VRS combined with carbon adsorption can recover on the order of 98% of the hydrocarbon emissions that would otherwise be released during the loading process.

Flare/Thermal Oxidizer Design

Proper flare design can improve the thermal destruction of waste gases recovered during loading operation and can improve the combustion efficiency of the flare. Design considerations include maintaining a pilot flame, ensuring the heating value of the flare gas is adequate and restricting the velocity of low-BTU flare gas for flame stability. A continuously lit pilot ensures that vent gases are combusted at the flare tip. A properly operated flare can achieve a destruction efficiency of 98 percent or greater.

Thermal oxidizers are not subject to 40 CFR 60.18 requirements; however, good combustion practices including proper mixing of fuel and combustion air would minimize combustion emissions.

Submerged Fill

The use of submerged fill during tank loading operations can reduce vaporization of the liquid between 40 – 60% from traditional splash loading operations.

10.1.2. Step 2: Eliminate Technically Infeasible Options

Vapor Recovery System with Carbon Adsorption

Use of a vapor recovery system to control VOC emissions is a common BACT control for loading operations and is considered technically feasible for this application.

Flare/Thermal Oxidizer Design

Flare/thermal oxidizer is a common BACT control for loading operations and is considered a technically feasible control option for the purposes of this analysis.

Submerged Fill

Submerged fill operation is a common BACT control for the condensate loading operation and is considered a technically feasible control option for the purposes of this analysis.

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

The emission control technologies not eliminated by practical or operational limitations are listed in Table 23, below. These technologies are ranked by control efficiency.

Table 21: Remaining Control Options and Control Effectiveness

Rank	Control Technology	Control Efficiency (%) or Emissions Target (ppmv)
1	Flare/Thermal Oxidizer with vapor balance/recovery system	>98%
2	Vapor Recovery with Carbon Adsorption	98%
3	Submerged Fill	Variable

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

While a vapor recovery system with regenerative carbon adsorption may provide a similar level of emission reduction as the use of a flare/thermal oxidizer, the project proposes to use a thermal oxidizer to control the emissions from the loading operation. Therefore, a vapor recovery system with carbon absorption is eliminated for further consideration in this BACT analysis.

Notably, the design of the proposed system for the project includes a vapor balance feature, which allows for vapors to be commingled with condensate tank vapors and balanced in the system with the tanks. Vapors from the loading operation and the condensate tanks themselves are controlled by a thermal oxidizer. Additionally, the loading operation itself will include submerged fill to help minimize vapors recovered and combusted at the thermal oxidizer.

10.1.4.1. Energy Impact Analysis

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

10.1.4.2. Environmental Impact Analysis

For this analysis, implementation of submerged filling with a vapor balance/recovery system routed to a flare/thermal oxidizer is not expected to cause an environmental impact.

10.1.4.3. Economic Impact Analysis

As submerged filling with a vapor balance/recovery system routed to a flare/thermal oxidizer would be implemented for this Project, economic analysis is not required because the technology is the highest rank in Step 3.

10.1.5. Step 5: Select BACT

This BACT analysis concludes that submerged filling with a vapor balance/recovery system routed to a flare/thermal oxidizer to control emissions from condensate storage tanks meets BACT.

10.2. Conclusions

Based on the foregoing, the likely BACT for the condensate loading operations is submerged filling with a vapor balance/recovery system routed to a flare/thermal oxidizer.

11. CARBON CAPTURE AND SEQUESTRATION (CCS)

For the purposes of a BACT analysis for GHG, EPA classifies CCS as an add-on pollution control technology that is "available" for facilities emitting CO_2. Technical feasibility and cost have generally eliminated this GHG reduction technology from further consideration in all BACT analyses reviewed at EPA, state, and local BACT clearinghouses and databases. Below is a description of the technology and its potential application to the LNG Plant.

11.1. Overview of CCS

CCS consists of two main operations: (1) CO_2 capture, compression and transport; and (2) sequestration (storage). To capture CO_2, CCS systems generally involve use of adsorption or absorption processes to remove CO_2 from exhaust gas, with subsequent desorption to produce a concentrated CO_2 stream. Research into technically and economically feasible capture systems is ongoing and is the focus of many large scale grants from the U.S. Department of Energy.

In the CCS process, the concentrated CO_2 would be compressed to "supercritical" temperature and pressure, a state in which CO_2 exists neither as a liquid nor a gas, but instead has physical properties of both liquids and gases. The supercritical CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery. Transportation of "supercritical" temperature and pressure CO_2 can be accomplished via truck, ship, or pipeline depending on the location of the generation site and the storage site. However, unless the storage site is relatively close to the site of generation, this transportation is costly and increases significantly with distance. The concentration of CO_2 is required because injection of exhaust streams containing high levels of N, O_2, and dilute CO_2 is not technically feasible. Adequate techniques for compression of CO_2 exist, but such compression systems require large amounts of energy, typically then resulting in the generation of even more CO_2.

Carbon sequestration is the long-term isolation of CO_2 from the atmosphere through physical, chemical, biological, or engineered processes. In general, carbon sequestration is achieved through storage in geologic formations or in terrestrial ecosystems, or through conversion into commercial products. Without an existing market to use recovered CO_2, the material would instead require sequestration, or permanent storage. Geologic sequestration refers to the injection and storage of captured CO_2 in an underground location where it will not readily escape into the atmosphere, such as within deep rock formations at pressures and temperatures where CO_2 is in the supercritical phase (typically 0.5 miles or more below ground surface). In general, CO_2 storage could be successful in porous, high-permeability rock formations or deep saline aquifer formations that are overlain by a thick, continuous layer of low-permeability rock, such as shale, where CO_2 may remain immobilized beneath the ground surface for extended periods of time. Other geologic formations deemed suitable for geologic sequestration include coal beds that are too thin or deep to be cost effectively mined and depleted oil and gas reservoirs, where in addition to CO_2 storage, economic gains may also be achieved (most notably through the use of enhanced oil recovery to obtain residual oil in mature oil fields).

An understanding of site-specific geologic studies and formation characteristics is critical to determine the ultimate CO_2 storage capacity and, ultimately the feasibility of geologic sequestration, for a particular area. Other factors to consider when determining the feasibility (both technical and economic) of geologic sequestration are:

- The cost, constructability, safety and potential environmental impacts of infrastructure necessary for the transportation of captured CO_2 from the source to the ultimate geologic sequestration site;
- The amount of measurement, monitoring (baseline, operational, etc.); and
- Verification of CO_2 distribution required following injection into the subsurface to ensure the risk of leakage of CO_2 is minimized or eliminated.

Potential uses/long term storage options for CO_2 are described below:

Enhanced Oil Recovery

Enhanced Oil Recovery (EOR) injection systems pump CO_2 into partially depleted oil reservoirs. Injection enhances the recovery of oil from partially depleted reservoirs allowing additional recovery. EOR systems have been used to enhance oil recovery at many oil reservoirs. Optimal EOR operation is dependent upon reservoir temperature, pressure, depth, net pay, permeability, remaining oil and water saturations, porosity, and fluid properties such as API gravity and viscosity.

Saline Aquifer Injection

Saline aquifer injection systems pump CO_2 into deep saline aquifers. Saline aquifers may be the largest long-term subsurface CCS option. Such aquifers are generally saline and are usually hydraulically separated from the shallower "sweet water" aquifers and surface water supplies accessible by drinking water wells. The injected CO_2 displaces the existing liquid and is trapped as a free phase (pure CO_2), which is referred to as "hydrodynamic trapping." A fraction of the CO_2 will dissolve into the existing fluid. The ultimate CO_2 sequestration capacity of a given aquifer is the difference between the total capacity for CO_2 at saturation and the total inorganic carbon currently in solution in that aquifer. The solubility of CO_2 depends on the pressure, temperature, and salinity of the formation water. Low salinity, low temperature, and high pressure environment is the most effective for sequestering CO_2 in widespread, deep, saline aquifers. The potential sequestration capacity of deep horizontal reservoirs is many times that of depleted, really restricted, structural or stratigraphic oil and gas reservoirs.

Sequestration of CO_2 is generally accomplished via available geologic reservoirs that must be either local to the point of capture, or accessible via pipeline to enable the transportation of recovered CO_2 to the permanent storage location. The *United States 2012 Carbon Utilization and Storage Atlas* (Fourth Edition published by the U.S. Department of Energy, Office of Fossil Energy) identifies an extensive saline aquifer directly below Nikiski as being "screened, high sequestration potential." However, this area has not had detailed evaluation for CO_2 sequestration and lies in a fault zone. Thus, this saline aquifer is not deemed to be suitable for CCS at this time by the Project.

Oceanic Dispersion

Ocean dispersion has not yet been deployed or demonstrated and is still in the research phase. This CCS system would inject CO_2 directly into the ocean at depths greater than 3,000 feet. Injection is achieved by transporting CO_2 via pipelines or ships to an ocean storage site where it is injected. The dissolved and dispersed CO_2 would subsequently become part of the global carbon cycle. At this depth, it is theorized that most of the CO_2 would be isolated from the atmosphere for centuries.

11.2. CCS Feasibility

CCS has many technical challenges from facility design and operation to transport and ultimate disposal of CO_2 streams. At present, it is unclear if the technology could be employed at the LNG Plant. Detailed design studies would be required to assess CCS feasibility, including the investigation of possible uses and/or disposal of the recovered CO_2 stream. Additional work would be required to address legal liability and permitting concerns. A detailed assessment of the feasibility of CCS is beyond the scope of this analysis.

11.3. Economic Analysis

This section presents a summary cost analysis for CCS as potentially applied to the LNG Plant. Costs presented below are based on data from other comparable facility analyses, or data provided by the EPA.

Economic analysis of CCS systems is based on the following key factors:

- CO_2 capture costs
- Constructions and operation costs of CO_2 transfer (pipeline, container, rail, etc.)
- Costs to secure the rights for the geologic reservoir
- Operational costs of the sequestration facility

Costs presented below are based on the information from a comparable U.S. LNG liquefaction plant (see notes 1, 2 and 3 in Table 20, below). Comparable costs were determined based on transport to a disposal site within 25 miles of the LNG Plant. The cost-effectiveness of CCS is summarized in Table 20, below. As shown in this table, CCS is not cost-effective, as it greatly exceeds typical benchmarks for GHG control discussed in Section 3, and the $12 - $40 per ton benchmark set by the Project.

Table 22: Economic Analysis

	Control Cost [1,3]	**Total Cost**
Capture and Compression	$132.28/ton	$447,300,000
Transport (20-inch pipe/25 miles)	$9.18/ton	$31,000,000
Operating	$19.23/ton	$65,000,000
Total Annualized CCS Costs		$543,300,000
CO_2 Removed Per Year (Tons)[2]	1.2 million	
Cost of CO_2 removal ($/ton)	$455	

[1] Costs were taken on a per ton basis from "*Golden Pass Products LNG Export Project - Application for a Prevention of Significant Deterioration (PSD) for Greenhouse Gas Emissions*," June 2014.
[2] Estimated GHG emission from Emission Calculations 194210-USAL-CB-PCCAL-00-000014-000 and 194210-USAL-CB-PCCAL-00-000014-002.
[3] DOD AREA COST FACTORS (ACF) PAX Newsletter No 3.2.1, dated 25 Mar 2015 TABLE – 4-1, UFC 3-701-01, Change 7, March 2015

11.4. Conclusions

This analysis concludes that CCS is potentially infeasible and definitely not cost effective for this Project.

12. REFERENCES

Reference Number	Document Number	Document Title
[1]	USAL-CB-SRZZZ-00-000005-000 Revision 0	APP Preliminary BACT Analysis.
[2]	USAKL-PT-BYRFP-00-0001	Alaska LNG Project – LNG Facility Pre-Feed Scope of Services
[3]	EPA/452/B-02-001	Air Pollution Control Cost Manual, Sixth Edition, January 2002, http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf.
[4]	USAL-CB-PRTEC-00-000009-000	Alaska LNG Study 12.3.4 – Liquefaction Compressor Driver Selection Study Report.
[5]	USAI-PS-BPDCC-00-000002-005	Alaska LNG Minutes of Meeting with ADEC, BACT and Dispersion Modeling Overview, GTP and Liquefaction Facilities, May 18, 2016. Reference included in Appendix B.
[6]	USAI-PE-SRZZZ-00-000001-000	Alaska LNG BACT Survey Report.
[7]	EPA-457/B-11-001	U.S. EPA, PSD and Title V Permitting Guidance for Greenhouse Gases.
[8]	NA	U.S. EPA, Draft New Source Review Workshop Manual, Chapter B. Research Triangle Park, North Carolina, October. 1990.
[9]	NA	U.S. EPA's database "Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse" (RBLC). April 2015.
[10]	DE-FC02-97CHIO877	U.S. Department of Energy / ONSITE SYCOM Energy Corporation, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines. U.S. Department of Energy Environmental Programs Chicago Operations Office 9800 South Cass Avenue Chicago, IL 60439. 1999.
[11]	NA	EPA Office of Air Quality Planning and Standards, June 17, 2011: Panel Outreach with SERS; Rulemaking for Greenhouse Gas Emissions from Electric Utility Steam Generating Units.

APPENDIX A

Summary of BACT Determinations

Simple Cycle Combustion Turbines and Heaters.

Summary of BACT Determinations (2010 - 2015)

Project	Item	App	Permit	Status	NOx BACT	NOx BACT Limit	CO BACT	CO BACT Limit	VOC BACT	VOC BACT Limit	PM BACT	PM BACT Limit	GHG BACT	GHG BACT Limit
Natural Gas/Dual Fuel Simple Cycle Combustion Turbines ≤ 25MW														
Point Thomson Production Facility	8 MW Gas Fired Simple Cycle CTs	7/9/2011	8/20/2012	Final	DLN (SoloNOx) and inlet air heating	15 ppmv @ 15% O_2; 60 ppmv @ 15% O_2 w/o SoloNOx (limited hours)	Catalytic oxidizer	2.5 ppmv @ 15% O_2; 1350 ppmv @ 15% O_2 w/o SoloNOx (limited hours)			Good operation and combustion practices	0.0066 lb/MMBti (average rate)	DLN with inlet air heating and good combustion practice	--
Point Thomson Production Facility	8 MW Dual Fueled Simple Cycle CTs (Gas)	7/9/2011	8/20/2012	Final	DLN (SoloNOx) and inlet air heating	25 ppmv @ 15% O_2; 60 ppmv @ 15% O_2 w/o SoloNOx (limited hours)	Catalytic oxidizer	5 ppmv @ 15% O_2; 1350 ppmv @ 15% O_2 w/o SoloNOx (limited hours)			Good operation and combustion practices	0.0066 lb/MMBti (average rate)	DLN with inlet air heating, good combustion practice, and waste heat recovery	--
Point Thomson Production Facility	8 MW Dual Fueled Simple Cycle CTs (Diesel)	7/9/2011	8/20/2012	Final	DLN (SoloNOx) and inlet air heating	96 ppmv @ 15% O_2; 120 ppmv @ 15% O_2 w/o SoloNOx (limited hours)	Catalytic oxidizer	5 ppmv @ 15% O_2; 462-981 ppmv @ 15% O_2 w/o SoloNOx (load-dependent, limited hours)			Good operation and combustion practices	0.012 lb/MMBti (average rate)	DLN with inlet air heating, good combustion practice, and waste heat recovery	--
Kenai Nitrogen Operations	Five (5) Natural Gas Fired Combustion Turbines	11/24/2014	1/6/2015	Final	Selective Catalytic Reduction	7 ppmv at 15% O_2		50 ppmv at 15% O_2		0.0021 lb/MMBtu		0.0074 lb/MMBtu		59.61 Tons/MMScf
Consumers Energy Company Thetford Generating Station	Two (2) 13 MW natural gas simple cycle turbines - Peaker Units	5/8/2013	7/25/2013	Final	Dry Low-NOx combustors	0.090 lb/MMBtu	Good combustion	0.1100 lb/MMBtu	Efficient combustion, natural gas fuel	0.017 lb/MMBtu	Efficient combustion, natural gas fuel	0.010 lb/MMBtu	Efficient combustion; energy efficiency	20141 Tons/year
Qualcomm Inc.	Solar Turbine, 4.37 MW	5/23/2012	7/9/2012	Final	SoLoNOx Burner (Ultra lean premix)	5 ppmv at 15% O2				7 ppmv at 15% O2				
Cheniere Corpus Christi Pipeline - Sinton Compressor Station	Two Solar Titan 130S Turbines	9/4/2012	12/2/2013	Final	DLN (SoloNOx)	25 ppmv @ 15% O2	DLN (SoloNOx)	50 ppmv @ 15% O2						
Natural Gas Simple Cycle Combustion Turbines > 25MW														
Guadalupe Generating Station	Two (2) Natural Gas Simple-Cycle peaking combustion turbines	9/24/2012	10/4/2013	Final	DLN Burners, Limited operation	9 ppmv at 15% O_2	DLN Burners, Limited operation	9 ppmv at 15% O_2						
Freeport LNG Liquefaction Project - Pre Treatment Facility	87 MW Simple Cycle CT	7/20/2012	7/16/2014	Final	SCR (LAER)	2.0 ppmv @ 15% O_2 (LAER)	Oxidation catalyst	4.0 ppmv @ 15% O_2	Oxidation catalyst	2.0 ppmv @ 15% O_2	Natural gas fuel; ammonia slip limited to 10 ppmv @ 15% O_2	--	Efficient design, including waste heat recovery; natural gas or BOG fuel; good combustion practices; air intake chiller; and oxidation catalyst	738 lbs CO_2/MWh (365-day rolling average)
Corpus Christi Liquefaction Project	37 MW Simple Cycle CT	8/1/2012	9/12/2014	Final	Water injection	25 ppmv @ 15% O_2	Good combustion practices	29 ppmv @ 15% O_2	Pipeline quality natural gas fuel and maintenance of optimum combustion conditions and practices	0.6 lb/hr	Good combustion practices and natural gas fuel	--	BOG or natural gas fuel; efficient CTs with waste heat recovery on ethylene units; and good combustion, operating, and maintenance practices	8,041 lb CO_2e/MMscf of LNG produced (12-month rolling average)
Cameron Liquefaction Project	853.9 MMBtu/hr Simple Cycle CT	8/21/2012	10/1/2013	Final	Dry LNB with good combustion practices	15 ppmv @ 15% O_2	Good combustion practices and natural gas fuel	0.040 lb/MMBtu	Good combustion practices and natural gas fuel	--	Good combustion practices and natural gas fuel	--	Natural gas fired high thermal efficiency turbines with good combustion/operating practices	--
Sabine Pass Liquefaction Expansion Project (M5)	34.3 MW (286 MMBtu/hr) Simple Cycle CTs (Refrigeration and Power Generation)	9/20/2013	6/3/2015	Final	Water injection (refrig.); DLN (power gen)	25 ppmv at 15% O_2 (all CTs)	Good combustion practices	50 ppmv at 15% O2 (refrig) and 58.4 ppmv at 15% O2 (Power Gen)	Good combustion practices	0.66 lb/hr	Good combustion practices and natural gas fuel	--	Natural gas fuel; good combustion/operating practices (CO_2); fuels selection, energy efficient design, adoption of best operational practices (CH_4)	--
Lake Charles Liquefaction Export Terminal Project	467 MMBtu/hr Simple Cycle CTs	12/20/2013	5/1/2015	Final	LNB and SCR	5 ppmv @ 15% O_2 (3-hour average)	Catalytic oxidation and CO turndown	10 ppmv @ 15% O_2 (3-hour average)	Good combustion practices and catalytic oxidation	--	Good combustion practices and clean fuel	--	Low-carbon fuels, catalytic oxidation, design energy efficiency, and operational energy efficiency	--

Summary of BACT Determinations (2010 - 2015)

Project	Item	App	Permit	Status	NOx BACT	NOx BACT Limit	CO BACT	CO BACT Limit	VOC BACT	VOC BACT Limit	PM BACT	PM BACT Limit	GHG BACT	GHG BACT Limit
Heaters														
Point Thomson Production Facility	Diesel Fired Heaters	7/9/2011	8/20/2012	Final	LNB	4 lb/1000 gal (vendor guarantee)	Good combustion practices	5 lb/1000 gal			Good operational practices	0.25 lb/1000 gal	Good combustion practices	--
Freeport LNG Liquefaction Project - Pre Treatment Facility	130 MMBtu/hr Heating Medium Heaters	7/20/2012	7/16/2014	Final	ULNB (LAER)	5.0 ppmv @ 3% O_2 (LAER)	Natural gas fuel and good combustion practices	25 ppmv @ 3% O_2 (one hour average)	Gaseous fuel	--	Gaseous fuel	--	Efficient heater and system design, including insulation and waste heat recovery from the CT; natural gas or BOG fuel; good combustion practices; and limiting hours of use	117 lb CO_2e/MMBtu for each heater (12-month rolling average)
Galena Park Terminal (KM Liquids)	129 MMBtu/hr Heaters	2/23/2012	6/12/2013	Final	ULNB and SCR	0.01 lb/MMBtu	Good combustion practices	50 ppmv						
Oregon LNG Bidirectional Terminal Project	115 MMBtu/hr Regasification Process Heaters	7/2/2013	--	Proposed	ULNB	--	Good combustion practices	--			Good combustion practices and natural gas fuel	--	Natural gas fuel; good combustion, operating, and maintenance practices; efficient heater design; and limiting the heaters to 2,880 operating hours (total) per year	155,000 short tons of CO_2 per year for all the heaters as a group (12-month rolling average)
Oregon LNG Bidirectional Terminal Project	86/92 MMBtu/hr Process Heaters	7/2/2013	--	Proposed	ULNB	--	Good combustion practices	--			Good combustion practices and natural gas fuel	--	Natural gas fuel; good combustion, operating, and maintenance practices; and efficient heater design	155,000 short tons of CO_2 per year for all the heaters as a group (12-month rolling average)
Lake Charles Liquefaction Export Terminal Project	110 MMBtu/hr Hot Oil Heater	12/20/2013	5/1/2015	Final	LNB and good combustion practices	--	Good combustion practices	--	Good combustion practices	--	Good combustion practices	--	(none proposed)	--
Elba Island LNG Liquefaction Project	122 MMBtu/hr Heating Medium Heaters	1/2/2014	--	Proposed			Low-carbon fuel selection (natural gas), efficient heater design with heat recovery from the thermal oxidizers, good combustion practices, and good operating and maintenance practices	0.04845 lb/MMBtu					Low-carbon fuel selection (natural gas), efficient heater design and heat recovery when practical, good combustion practices, and good operating and maintenance practices	95,402 tons of CO_2e (12-month rolling total)

Combined Cycle Combustion Turbines

Summary of BACT Determinations (2010 - 2015)

Project	Item	Code	App	Permit	Status	NOx BACT	NOx BACT Limit	CO BACT	CO BACT Limit	VOC BACT	VOC BACT Limit	PM BACT	PM BACT Limit	GHG BACT	GHG BACT Limit
Natural Gas/Dual Fuel Combined Cycle Combustion Turbines ≤ 25MW															
SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL SABINE PASS LNG TERMINAL CAMERON, LA	Combined Cycle Refrigeration Compressor Turbines (8) GE LM2500+G4	LA-0257	12/06/2011 ACT			water injection	20 PPMV AT 15% O2	Good combustion practices and fueled by natural gas	58.4 PPMV AT 15% O2	Good combustion practices and fueled by natural gas		Good combustion practices and fueled by natural gas			
DOMINION COVE POINT LNG, LP COVE POINT LNG TERMINAL CALVERT, MD	TWO GENERAL ELECTRIC (GE) FRAME 7EA COMBUSTION TURBINES (CTS) WITH A NOMINAL NET 87.2 MEGAWATT (MW) RATED CAPACITY, COUPLED WITH A HEAT RECOVERY STEAM GENERATOR (HRSG), EQUIPPED WITH DRY LOW-NOX COMBUSTORS, SELECTIVE CATALYTIC REDUCTION SYSTEM (SCR), AND OXIDATION CATALYST	MD-0044	06/09/2014 ACT			USE OF DRY LOW-NOX COMBUSTOR TURBINE DESIGN (DLN1), USE OF FACILITY PROCESS FUEL GAS AND PIPELINE NATURAL GAS DURING NORMAL OPERATION AND SCR SYSTEM	2.5 PPMVD @ 15% O2 3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	EXCLUSIVE USE OF FACILITY PROCESS FUEL GAS OR PIPELINE QUALITY NATURAL GAS, USE OF AN OXIDATION CATALYST AND EFFICIENT COMBUSTION	1.5 PPMVD @ 15% O2 3-HOUR BLOCK AVERAGE, EXLUDING SU/SD	THE USE OF PROCESS FUEL GAS AND PIPELINE NATURAL GAS, GOOD COMBUSTION PRACTICES, AND USE OF AN OXIDATION CATALYST	0.7 PPMVD @ 15% O2 3-HOUR BLOCK AVERAGE, EXCLUDING SU/SD	EXCLUSIVE USE OF FACILITY PROCESS FUEL GAS OR PIPELINE QUALITY NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0033 LB/MMBTU 3-HOUR BLOCK AVERAGE	HIGH EFFICIENCY GE 7EA CTS WITH HRSGS EQUIPPED WITH DLN1 COMBUSTORS AND EXCLUSIVE USE OF FACILITY PROCESS FUEL GAS OR PIPELINE QUALITY NATURAL GAS	117 LB/MMBTU 3-HOUR BLOCK AVERAGE
BASIN ELECTRIC POWER COOPERATIVE DEER CREEK STATION BROOKINGS, SD	Combustion turbine/heat recovery steam generator	*SD-0005	06/29/2010 ACT		Draft	Selective catalytic reduction	3 PPMVD AT 15% O2 3-HOUR, EXCLUDES SSM	Catalytic oxidation	2 PPMVD @ 15% O2 3-HOUR, EXCLUDES SSM PERIODS			Good Combustion	0.01 LB/H 3-HOUR		
BRITISH PETROLEUM EXPLORATION ALASKA (BPXA) ENDICOTT PRODUCTION FACILITY, LIBERTY DEVELOPMENT PROJECT PRUDHOE BAY, AK	EU ID 10A, TURBINE	AK-0066	06/15/2009 ACT		Final	DRY LOW NOX COMBUSTORS (DLN)	25 PPMV AT 15% O2 WHEN AMBIENT TEMPERATURE => 10 DEG-F	CATALYTIC OXIDATION	5 PPMV @ 15% O2 WHEN AMBIENT TEMPERATURE => 10 DEG-F						
CPV SHORE, LLC WOODBRIDGE ENERGY CENTER MIDDLESEX, NJ	Combined Cycle Combustion Turbine w/o duct burner two GE 7FA CC turbines (each with a maximum heat input of 2, 307 MMBtu/hr)and two duct burners (each with a maximum heat input of 500 MMBtu/hr)	NJ-0079	07/25/2012 ACT		Final	DLN combustion system with SCR on each of the two combustion turbines and use of only natural gas as fuel.	2 PPMVD 3-HR ROLLING AVE BASED ON 1-HR BLOCK	Oxidation Catalyst, good combustion practices and use only natural gas a clean burning fuel	2 PPMVD 3-HR ROLLING AVE BASED ON 1-HR BLOCK	Oxidation catalyst and good combustion practices, use of natural gas a clean burning fuel	2.9 LB/H AVERAGE OF THREE TESTS	Use of Natural gas,a clean burning fuel.	12.1 LB/H AVERAGE OF THREE TESTS		
HESS NEWARK ENERGY CENTER, LLC HESS NEWARK ENERGY CENTER ESSEX, NJ	Combined Cycle Combustion Turbine	NJ-0080	11/01/2012 ACT		Final	Selective Catalytic Reduction (SCR) System and use of natural gas a clean burning fuel	2 PPMVD 3-HR ROLLING AVE BASED ON 1-HR BLOCK AVE	Oxidation Catalyst and Good combustion Practices and use of natural gas a clean burning fuel	2 PPMVD 3-HR ROLLING AVE BASED ON 1-HR BLOCK AVE	Oxidation Catalyst and Good combustion Practices and use of natural gas a clean burning fuel	1 PPMVD 3-HR ROLLING AVERAGE BASED ON 1-HR BLOCK	Use of natural gas a clean burning fuel	11 LB/H AVERAGE OF THREE TESTS	Good Combustion Practices	887 LB/MW-H CONSCUTV 12 MONTH PERIOD ROLLING 1 MONTH
PANDA SHERMAN POWER LLC PANDA SHERMAN POWER STATION GRAYSON, TX	2 Siemens SGT6-5000F or 2 GE Frame 7FA. Both capable of combined or simple cycle operation. 468 MMBtu/hr duct burners.	TX-0551	02/03/2010 ACT		Final	Dry low NOx combustors and Selective Catalytic Reduction	9 PPMVD @ 15% O2, RLNG 24-HR AVG, SIMPLE CYCLE 2 PPMVD @ 15% O2, RLNG 24-HR AVG, COMBINED CYCLE	Good combustion practices	4 PPMVD @ 15% O2, RLNG 24-HR AVG, SIMPLE CYCLE 15 PPMVD @ 15% O2, RLNG 24-HR AVG, COMBINED CYCLE	Good combustion practices	1 PPMVD @ 15% O2, 3-HR AVG, SIMPLE CYCLE MODE 4 PPMVD @ 15% O2, 3-HR AVG, COMBINED CYCLE MODE				
STARK POWER GENERATION II HOLDINGS, LLC WOLF HOLLOW POWER PLANT NO. 2 HOOD, TX	Project will be either 2 MHI501G gas turbines plus 230 MMBtu/hr duct burner firing for each turbine or 2 GE 7FA gas turbines plus 570 MMBtu/hr duct burner firing for each turbine.	TX-0552	03/03/2010 ACT		Final	Dry low NOx combustors plus selective catalytic reduction	2 PPMVD @ 15% O2, ROLLING 24-HR AVG, FULL LOAD	Good combustion practices	10 PPMVD @ 15% O2, ROLLING 3-HR AVG, MHI501G	Good combustion practices	4 PPMVD @ 15% O2, 3-HR AVG, MHI501G				
NRG TEXAS POWER LLC WA PARISH ELECTRIC GENERATING STATION - DEMONSTRATION PROJECT FORT BEND, TX	General Electric (GE) Frame 7EA (or a similar sized unit), which is rated at a maximum base-load electric output of approximately 80 megawatts (MW). HRSG duct burner has a maximum heat input capacity of 225 million British thermal units per hour (MMBtu/hr) based on the high heating value (HHV) of the fuel fired. The steam will be used for the regeneration of the Demonstration Unit solvent.	TX-0625	12/19/2012 ACT		Final	DLN combusters on the turbine and selective catalytic reduction (SCR)	2 PPMVD 3-HR ROLLING AVG, AT 15% OXYGEN	oxidation catalyst	4 PPMVD 24 HR ROLLING, AT 15% OXYGEN	oxidation catalyst	2 PPMVD INITIAL STACK TEST	good combustion and use of natural gas	16.58 LB/H 1 HR		
M & G RESINS USA LLC UTILITY PLANT NUECES, TX	General Electric LM6000 natural gas-fired combustion turbine equipped with lean pre-mix low-NOx combustors. One heat recovery steam generator (HRSG) with 263 million British thermal units per hour (MMBtu/hr) natural gas-fired duct burner system containing a selective catalytic reduction system (SCR)	TX-0704	12/02/2014 ACT		Final	Selective Catalytic Reduction	2 PPMVD @15% O2, 24-HR ROLLING AVERAGE	oxidation catalyst	4 PPMVD @15% O2, 24-HR ROLLING AVERAGE	oxidation catalyst	4 PPMVD @15% O2, 24-HR ROLLING AVERAGE				
NRG TEXAS POWER LLC W. A. PARISH ELECTRIC GENERATING STATION FORT BEND, TX	GE 7EA turbine, 225 million British thermal units per hour duct burner. Steam created in the heat recovery steam generator will be used as process steam.	TX-0737	12/21/2012 ACT		Final	Selective catalytic reduction	2 PPMVD @ 15% O2 3-HR AVERAGE	Oxidation catalyst	4 PPMVD @ 15% O2 24-HR AVERAGE	Oxidation catalyst	2 PPMVD @ 15% O2				

Combined Cycle Combustion Turbines

WILLIAMS FIELD SERVICES COMPANY ECHO SPRINGS GAS PLANT CARBON, WY	12,555 HP SOLAR MARS100-15000S OR 16,162 HP SOLAR TITAN 130-20502S TURBINE	WY-0067	04/01/2009 ACT		Final	GOOD COMBUSTION PRACTICES	15 PPMV	GOOD COMBUSTION PRACTICES	25 PPMV	GOOD COMBUSTION PRACTICES	25 PPMV				

Natural Gas/Dual Fuel Combined Cycle Combustion Turbines > 25MW

Project	Item	Code	App	Permit	Status	NOx BACT	NOx BACT Limit	CO BACT	CO BACT Limit	VOC BACT	VOC BACT Limit	PM BACT	PM BACT Limit	GHG BACT	GHG BACT Limit
BASIN ELECTRIC POWER COOPERATIVE DEER CREEK STATION BROOKINGS, SD	Combustion Turbine - 1,713 million Btus per hour (Lower Heating Value) heat input Duct Burner- 615.2 million Btus per hour (Lower Heating Value) heat input	*SD-0005	06/29/2010 ACT		Draft	Selective catalytic reduction	3 PPMVD AT 15% O2 3-HOUR, EXCLUDES SSM	Catalytic oxidation	2 PPMVD @ 15% O2 3-HOUR, EXCLUDES SSM PERIODS			Good Combustion	0.01 LB/H 3-HOUR		
CPV SHORE, LLC WOODBRIDGE ENERGY CENTER MIDDLESEX, NJ	WEC will consist of two General Electric (GE) combustion turbine generators (CTGs) each with a maximum rated heat input of 2,307 million British thermal units per hour (MMBtu/hr), that will utilize pipeline natural gas only, with 2 HRSGs, 2 Duct Burners (each 500 MMBtu/hr).	NJ-0079	07/25/2012 ACT		Final	DLN combustion system with SCR on each of the two combustion turbines and use of only natural gas as fuel.	2 PPMVD 3-HR ROLLING AVE BASED ON 1-HR BLOCK	Oxidation Catalyst, good combustion practices and use only natural gas a clean burning fuel	2 PPMVD 3-HR ROLLING AVE BASED ON 1-HR BLOCK	oxidation Catalyst and Good Combustion Practices and use of Clean fuel (Natural gas)	2 PPMVD 3-HR ROLLING AVERAGE BASED ON 1-HR BLK				
PANDA SHERMAN POWER LLC PANDA SHERMAN POWER STATION GRAYSON, TX	2 Siemens SGT6-5000F or 2 GE Frame 7FA. Both capable of combined or simple cycle operation. 468 MMBtu/hr duct burners.	TX-0551	02/03/2010 ACT		Final	Dry low NOx combustors and Selective Catalytic Reduction	9 PPMVD @ 15% O2, ROLLNG 24-HR AVG, SIMPLE CYCLE		4 PPMVD @ 15% O2, ROLLNG 24-HR AVG, SIMPLE CYCLE	Good combustion practices	1 PPMVD @ 15% O2, 3-HR AVG, SIMPLE CYCLE MODE				
STARK POWER GENERATION II HOLDINGS, LLC WOLF HOLLOW POWER PLANT NO. 2 HOOD, TX	Project will be either 2 MHI501G gas turbines plus 230 MMBtu/hr duct burner firing for each turbine or 2 GE 7FA gas turbines plus 570 MMBtu/hr duct burner firing for each turbine.	TX-0552	03/03/2010 ACT		Final	Dry low NOx combustors plus selective catalytic reduction	2 PPMVD @ 15% O2, ROLLING 24-HR AVG, FULL LOAD	Good combustion practices	10 PPMVD @ 15% O2, ROLLING 3-HR AVG, MHI501G	Good combustion practices	4 PPMVD @ 15% O2, 3-HR AVG, MHI501G				
NRG TEXAS POWER LLC WA PARISH ELECTRIC GENERATING STATION - DEMONSTRATION PROJECT FORT BEND, TX	General Electric (GE) Frame 7EA (or a similar sized unit), which is rated at a maximum base-load electric output of approximately 80 megawatts (MW). HRSG duct burner has a maximum heat input capacity of 225 million British thermal units per hour (MMBtu/hr) based on the high heating value (HHV) of the fuel fired. The steam will be used for the regeneration of the Demonstration Unit solvent.	TX-0625	12/19/2012 ACT		Final	DLN combusters on the turbine and selective catalytic reduction (SCR)	2 PPMVD 3-HR ROLLING AVG, AT 15% OXYGEN	oxidation catalyst	4 PPMVD 24 HR ROLLING, AT 15% OXYGEN	proper design and operation, good solvent maintenance, LDAR program	3.1 PPMV	good combustion and use of natural gas	16.58 LB/H 1 HR		
M & G RESINS USA LLC UTILITY PLANT NUECES, TX	General Electric LM6000 natural gas-fired combustion turbine equipped with lean pre-mix low-NOx combustors. One heat recovery steam generator (HRSG) with 263 million British thermal units per hour (MMBtu/hr) natural gas-fired duct burner system containing a selective catalytic reduction system (SCR)	TX-0704	12/02/2014 ACT		Final	Selective Catalytic Reduction	2 PPMVD @15% O2, 24-HR ROLLING AVERAGE	oxidation catalyst	4 PPMVD @15% O2, 24-HR ROLLING AVERAGE	oxidation catalyst	4 PPMVD @15% O2, 24-HR ROLLING AVERAGE				
NRG TEXAS POWER LLC W. A. PARISH ELECTRIC GENERATING STATION FORT BEND, TX	GE 7EA turbine, 225 million British thermal units per hour duct burner. Steam created in the heat recovery steam generator will be used as process steam.	TX-0737	12/21/2012 ACT		Final	Selective catalytic reduction	2 PPMVD @ 15% O2 3-HR AVERAGE	oxidation catalyst	4 PPMVD @ 15% O2 24-HR AVERAGE	oxidation catalyst	2 PPMVD @ 15% O2				

Note:
LNG and Alaska BACT determinations are highlighted.

Loading Operations

Summary of BACT Determinations (2010 - 2017)

Project	Location	Process	Date	Product Loaded	Throughput	VOC BACT	VOC BACT Limit	Control Efficiency	Other Requirements
Gasoline Terminals		42.002							
COUNTRYMARK REFINING AND LOGISTICS, LLC COUNTRYMARK REFINING AND LOGISTICS, LLC	MIAMI, IN	Loading Rack	12/3/2015	Gasoline	404.71 MMGAL	Relief Stack, Vapor Knockout box, flare vapor control unit.	35 MG/L		
MARATHON PETROLEUM COMPANY LP MARATHON PETROLEUM COMPANY LP	POSEY, IN	Loading Rack	8/13/2015	Gasoline	741.2 MMGAL	Vapor Recovery Unit (Carbon Adsorption)	0.159 LB/GAL		
COUNTRYMARK REFINING & LOGISTICS, LLC COUNTRYMARK REFINING & LOGISTICS, LLC	GREENE, IN	Loading Rack	6/30/2015		46200 GAL/H	test method - 1	35 MG/LITER		
Volatile Organic Liquid Marketing		42.01							
MAGELLAN TERMINALS HOLDINGS, L.P. PASADENA TERMINAL	HARRIS, TX	Tank Truck Loading	7/14/2017	Gasoline	120000 GAL/HR	Submerged fill and vented to a vapor recovery unit. Vapor collection system routed to vapor recovery unit	1 MG/LTR	Vapor collection system 100% capture efficiency	NSPS XX MACT R
MAGELLAN TERMINALS HOLDINGS, L.P. PASADENA TERMINAL	HARRIS, TX	Tank Truck Loading	7/14/2017	Denatured ethanol	120000 GAL/HR	Submerged fill and vented to a vapor recovery unit.	4.48 T/YR	Air eliminator venting will result in emissions to the atmosphere at less than 3 lb/hr for air purging in truck tanks.	NSPS XX MACT R
MAGELLAN TERMINALS HOLDINGS, L.P. PASADENA TERMINAL	HARRIS, TX	Tank Truck Unloading	7/14/2017	Pressurized Butane	0	Specialized connection system of transfer valves that minimize the volume of piping containing residual butane after unloading	33 T/YR		NSPS XX MACT R
PHILLIPS 66 PIPELINE LLC BEAUMONT TERMINAL	JEFFERSON, TX	Truck and railcar loading	6/8/2016	VOLs and refined petroleum products	0	Loading vapors of materials with a TVP of 0.5 psia or greater are controlled by a flare.	28.83 T/YR	Railcar capture efficiency of 100% will be verified annually by Class DOT-111AW or Class DOT-115AW testing, and truck capture efficiency of 100% will be verified annually by DOT testing specified in 49 CFR 180.407.	40 CFR Part 63, Subparts A, R, & EEEE
PHILLIPS 66 PIPELINE LLC BEAUMONT TERMINAL	JEFFERSON, TX	Truck and railcar loading	6/8/2016	VOLs and refined petroleum products	0	Flare	0.376 LB/MMBTU		Good combustion practices

Loading Operations

Summary of BACT Determinations (2010 - 2017)

Project	Location	Process	Date	Product Loaded	Throughput	VOC BACT	VOC BACT Limit	Control Efficiency	Other Requirements
PHILLIPS 66 PIPELINE LLC BEAUMONT TERMINAL	JEFFERSON, TX	Truck and railcar loading	6/8/2016	VOLs and refined petroleum products	0	Flare	4885.75 T/YR	Railcar capture efficiency of 100% will be verified annually by Class DOT-111AW or Class DOT-115AW testing, and truck capture efficiency of 100% will be verified annually by DOT testing specified in 49 CFR 180.407.	Good combustion practices
Other									
SEMGAS LP ROSE VALLEY PLANT	WOODS, OK	TRUCK LOADING	3/1/2013	CONDENSATE	9198000 GAL/YR	Enclosed Flare			
GULF CROSSING PIPELINE CO. LLC. STERLINGTON COMPRESSOR STATION	OUACHITA, LA	TRUCK LOADING	6/24/2008	CONDENSATE	5760 BBL/YR	Submerged loading and dedicated service.			

Condensate Storage

Summary of BACT Determinations (2010 - 2017)

Project	Location	Process	Date	Product Stored	Tank Capacity	VOC BACT	VOC BACT Limit	Control Efficiency	Other Requirements
Petroleum Liquid Storage in Fixed Roof Tanks		42.005							
GULF CROSSING PIPELINE CO. LLC. STERLINGTON COMPRESSOR STATION	OUACHITA, LA	Storage Tank	6/24/2008	Condensate	100 BBL	Submerged fill pipe			
DCP MIDSTREAM, LP LUCERNE GAS PROCESSING PLANT	WELD, CO	Storage Tank	1/13/2014	Condensate	4 X 1,000 BBL	Enclosed combustor		95%	
SEMGAS LP ROSE VALLEY PLANT	WOODS, OK	Storage Tank	3/1/2013	Condensate	4 X 1,000 BBL	Flare.			
MARKWEST BUFFALO CREEK GAS CO LLC BUFFALO CREEK PROCESSING PLANT	BECKHAM, OK	Petroleum Storage-Fixed Roof Tanks	9/12/2012	Condensate		Flare.		95%	Closed Vent and Control.
MARKWEST BUFFALO CREEK GAS CO LLC BUFFALO CREEK PROCESSING PLANT	BECKHAM, OK	Petroleum Storage-Fixed Roof Tanks	9/12/2012	Condensate		Flare.			Closed Vent and Control.

Diesel Storage

Summary of BACT Determinations (2010 - 2017)

Project	Location	Process	Date	Product Stored	Tank Capacity	VOC BACT	VOC BACT Limit	Control Efficiency	Other Requirements
Petroleum Liquid Storage in Fixed Roof Tanks		42.005							
ST. JOSEPH ENERGY CENTER ST. JOSEPH ENERGY CENTER	ST. JOSEPH, IN	Diesel Storage Tanks	6/22/2017	Diesel	650 GALLONS	Fixed Roof Tank			Good design and operating practices
ST. JOSEPH ENERGY CENTER ST. JOSEPH ENERGY CENTER	ST. JOSEPH, IN	DIESEL STORAGE TANK TK50	6/22/2017	Diesel	5000 GALLONS	Fixed Roof Tank			Good design and operating practices
BASF PEONY CHEMICAL MANUFACTURING FACILITY	BRAZORIA, TX	Diesel Storage Tanks	4/1/2015	Diesel	10708 gallons/yr	low vapor pressure fuel, submerged fill, white tank	0.02 LB/H		The tanks are painted white. Loading is done via submerged piping. The volatile organic compound (VOC) vapor pressure of the diesel and lube oil stored is below 0.0002 pounds per square inch actual (psia), so a fixed roof is reasonable.

APPENDIX B

Alaska LNG Minutes of Meeting with ADEC, BACT and Dispersion Modeling Overview, GTP and Liquefaction Facilities, May 18, 2016

MEETING DETAILS			
Sub-Project Name	Integrated	**Date of Meeting**	May 18, 2016
Meeting Subject	BACT and Dispersion Modeling Overview, GTP and Liquefaction Facilities	**Location**	ADEC Juneau, AK offices

ATTENDEES			
Attended By	**Organization**	**Attended By**	**Organization**
Jim Pfeiffer	AkLNG	James Renovatio	ADEC
Bart Leininger	ALG for AkLNG	Alan Schuler	ADEC
Tom Damiana	AECOM for AkLNG		
John Kuterbach	ADEC		
Zeena Siddeek	ADEC		

DISTRIBUTION (Attendees plus the following individuals)			
Name	**Organization**	**Name**	**Organization**

AGENDA ITEMS			
Item	**Agenda Item(s)**	**Leader**	**Time**
1	Introductions and Safety Moment	Jim Pfeiffer	15 min.
2	Project Overview and Status	Jimi Pfeiffer	30 min.
3	BACT Considerations	Bart Leininger	30 min.
4	Dispersion Modeling Considerations	Tom Damiana	30 min.
5	Wind Tunnel Overview (not covered due to time constraints)	Tom Damiana	NA
6	Next Steps	Jim Pfeiffer	15 min.

ACTION ITEMS			
Item	**Action Items/Topics**	**Assigned To**	**Due Date**
1	Determine the appropriate baseline NOx and CO emission rate for gas turbines – BACT cost-effectiveness calculations	Zeena Siddeek	May 31, 2016
2	Determine the appropriate interest rate to be used in BACT cost-effectiveness calculations	Zeena Siddeek	May 31, 2016
3	Provide wind tunnel protocol to ADEC and EPA for their review and consideration.	Jim Pfeiffer	Early June 2016
4	Provide a workshop for ADEC staff on the wind tunnel experiments.	Jim Pfeiffer	TBD

DISCUSSION		
Item	**Agenda Item(s) / Notes**	**Comments**
1	Jim provided an overview of the project and summarized the current status of the NEPA analysis. During the discussion, Kuterbach indicated that the ADEC Commissioner will be very interested project GHG emissions and reduction/energy efficiency strategies.	Discussions about the project were characterized as preliminary and ADEC should expect the project designs to change as engineering progresses.
2	BACT assumptions for cost-effectiveness calculations were reviewed. The following points were gleaned from the discussion: • According to Siddeek, baseline NOx and CO emissions from turbines should follow the assumptions used for Pt. Thomson Project. Siddeek thought that 25 ppmv for NOx and 50 ppmv for CO was used. Siddeek would confirm the baseline that should be used in the analysis. • Siddeek indicated that 7% interest is the guideline for cost-effectiveness calculations. However, lower interest rates have been used (e.g., 4%). Siddeek was going to review the Pt. Thomson BACT determination to see what was assumed. • Kuterbach would not provide an exact cost-effectiveness guideline for criteria pollutant emissions (i.e., NOx, CO, etc.). He suggested that if costs were less than $6,000 - $7,000 per ton, a technology would be cost-effective. EPA has been looking at ADEC BACT determinations and have implied that technologies costing $10,000 - $12,000 per ton could be cost-effective. • ADEC indicated that BACT must consider normal operations and transient operations, including start-up and shutdown. ADEC would impose numerical emissions limitations for normal operations (e.g., ppmv NOx @ 15% O_2); work practices standards (e.g., time limitations, etc.) would be imposed for transient operations. • Kuterbach indicated that the permit would be issued on the basis of the control technology *and* BACT emission limit. ADEC expects that the control technology will be active at all times, unless otherwise specified in the permit. His example: IC engine BACT determination using water injection for NOx controls means that water injection must occur at all times, and not just to meet the associated numeric performance limit.	
3	GHG BACT was discussed. Below are the following points from the discussion: • ADEC does not have a BACT cost-effectiveness threshold for GHGs and admitted that they have limited experience considering BACT for GHGs. • ADEC indicated that Carbon Capture and Sequestration (CCS) must be evaluated in the BACT analysis. Kuterbach indicated that AkLNG must consider the feasibility and cost-effectiveness of installing facilities at GTP to concentrate and re-inject CO2 emissions from dilute streams (e.g., turbine exhaust). • Kuterbach indicated that BACT must consider energy efficiency options, including heat recovery. Specifically, the analysis must consider how energy is used and the options for recovering energy from the combustion processes. For cases where waste heat recovery is not used, the analysis must address/justify the reasons why. Inherent design limitations must be explicitly stated.	

DISCUSSION		
Item	**Agenda Item(s) / Notes**	**Comments**
4	The topic of temporary raw gas usage during GTP start-up was discussed. ADEC (Kuterbach) agreed that raw gas could be used at GTP if justified under a separate BACT analysis. The separate BACT analysis may consider feasibility, duration, and cost for implementing more significant controls to achieve lower emissions. Alternative BACT limits are acceptable under these conditions.	
5	AkLNG inquired about potential expiration of the PSD permits during the extended construction period. Kuterbach stated that PSD permits do not expire due to the length of construction. They only expire if the project does not commence construction within 18 months or when construction goes dormant for 18 months or longer.	
6	The following discussion points came up during the dispersion modeling portion of the presentation. • ADEC (Schuler) indicated that EPA OAQPS and ADEC will need to approve the use of the wind tunnel results to characterize downwash at CCP and CGF. Approval will be required for PSD permit issuance. ADEC agreed that EPA and ADEC approval will not be required for the NEPA analysis. However, any potential objections by EPA and ADEC should be addressed during the NEPA process. • Schuler confirmed that the use of the wind tunnel results is a technical issue and not an alternative modeling approach. ADEC is looking to EPA for expertise on the wind tunnel issues because ADEC staff lacks experience with these methods. • Schuler noted that the State of Idaho is requesting EPA Region X approval/expertise in using wind tunnel results in modeling. • AkLNG agreed to provide the wind tunnel protocol and results to ADEC and the EPA within the next few weeks. • AkLNG indicated that upper atmospheric meteorological data from Barrow, AK, and the onsite data collected from LNG will be used to demonstrate that existing met. data sources from 10 meter towers are conservative in characterizing the meteorological conditions at tall stacks. ADEC (Schuler) did not object to this approach. AkLNG confirmed that upper atmospheric met. data will be collected at Deadhorse to support the PSD permit application. • Schuler noted that the Modeling Review Procedures Manual was issued on May 18th. Schuler reminded the Project that the manual is only a guideline.	The following was not discussed with ADEC during the meeting: • Minor source modeling for the compressor stations. • AQRV (i.e., visibility) modeling, which is under consideration by the Federal Land Managers (FLMs).
7	Due to time constraints, the wind tunnel overview slides were not discussed. AkLNG agreed to provide a workshop to ADEC staff if interested.	

Bart Leininger

From: Siddeek, Fathima Z (DEC) <fathima.siddeek@alaska.gov>
Sent: Wednesday, May 25, 2016 2:59 PM
To: Bart Leininger
Cc: 'james.pfeiffer@exxonmobil.com'; Dunn, Patrick E (DEC); Siddeek, Fathima Z (DEC)
Subject: Baseline for NOx and CO controls for BACT cost effectiveness

Bart,

During the May 18th meeting, you asked what we would accept for baseline emissions for NOx and CO and the interest rates for BACT cost estimates. I did some investigation on our recent BACT decisions and here is what I found:

For NOx BACT cost estimates, we have accepted baseline emissions calculated using manufacturer guaranteed NOx emission rates for gas turbines equipped with DLN technology. We found that turbines without Dry Low NOx (DLN) are no longer available in the market. We also verified from a turbine vendor that a base model turbine without controls, will have to be designed and custom built and that it would cost significantly more.

Although we did not have to review CO BACT cost estimates for a turbine equipped with DLN, we would similarly accept baseline emissions calculated using manufacturer emission rates. ExxonMobil opted to use catalytic oxidation in their SoLoNOx turbines to reduce the CO emissions to 2.5 ppmv. Since they used maximum CO controls, we did not review BACT cost analysis.

The 1990 EPA draft guidance manual, although not legally binding, is still adopted as a guide for estimating BACT cost estimates. This manual being 26 years old, does not address this specific case, but we think that it is reasonable to assume Dry Low NOx (DLN) technology as the base for the turbine emissions.

With regard to the interest rate, we accepted 7% because a lower rate would not have altered the conclusion for cost effectiveness in all of the BACT decisions in the past 4 years.

Let me know if you have any further questions.

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APPENDIX C

Emissions and BACT Cost Effectiveness Calculations (Diesel Tanks, Condensate Tanks, and Emissions and Condensate Loading)

Alaska LNG Project
Condensate Loading Operation
Product Loading Activity Emission Calculation

Input Parameters

S = Saturation Factor	**0.60**	Submerged Loading, Dedicated Normal Service
M = Molecular Weight	**77**	Condensate Estimate
P = True Vapor Pressure (psia)	**4.275**	See "Condensate Properties"
T = Liquid Temperature ^{0}R	**505**	45 ^{0}F + 460 = ^{0}R
C = Storage Capacity (bbl)	**589,197**	24,746,280 gallons (42 gallons = 1 bbl)
A = Annual Production (bbl)	**589,197**	24,746,280 gallons (42 gallons = 1 bbl)
R = Max Loading Rate (bbl/hr)	**67.26**	2,825 gallons (42 gallons = 1 bbl)
D = Max Daily Production (bbl)	**1,614**	67,798 gallons (42 gallons = 1 bbl)
D2 = Average Daily Production (bbl)	**1,291**	54,238 gallons (42 gallons = 1 bbl)
eff = Vapor Recovery Efficiency	**0.95**	Thermal Oxidizer plus VRU
VOC/THC = Reactivity	**1.000**	Assume all THC is VOC.

L_{LTHC} = Loading loss (lb/1000 gal) = 12.46 (S)(P)(M)/T =	**4.8737**	**lbTHC/1000 gal**
L_LVOC= Loading loss (lb/1000 gal) = 12.46 (S)(P)(M)*React/T =	**4.8737**	**lb ROC/1000 gal**
<u>Total Uncontrolled Hydrocarbon Losses (VOC):</u>		
Hourly		
THL_H = (R)(42 gal/bbl)(L_{LROC}/1000) =	**13.77**	**lbs/hr**
Max Daily		
THL_D = (D)(42 gal/bbl)(L_{LROC}/1000) =	**330.43**	**lbs/day**
Average Daily		
THL_{D2} = (D2)(42 gal/bbl)(L_{LROC}/1000) =	**264.34**	**lbs/day**
Quarterly		
THL_Q = THLD(91)(1/2000) =	**15.08**	**TPQ**
Total Emissions		
THL_A = (A)(42 gal/bbl)(L_{LROC}/1000)(1/2000) =	**60.30**	**TPY**
<u>Total Controlled Hydrocarbon Losses (VOC):</u>		
Hourly		
THL_{HC} = (THL_H)(1-eff) =	**0.69**	**lbs/hr**
Max Daily		
THL_{DC} = (THL_D)(1-eff) =	**16.52**	**lbs/day**
Quarterly		
$THLQ_C$ = (THLQ)(1-eff) =	**0.75**	**TPQ**
Total Emissions		
THL_{AC} = (THL_A)(1-eff) =	**3.02**	**TPY**

Notes:
1. Data provided by the applicant
   C = Annual Transport Volume.
2. AP-42, (Chapter 5, 5th Edition, January 1995), Table 5.2-1
3. Molecular weight of condensate based on estimated mole fraction of condensate constituents.
4. Vapor pressure for condensate based on estimated mole fractions.
5. R is calculated by adding 460 to ^{0}F. Average annual high temperature at the Kenai Airport used.
6. Assumed 24 hours/day of loading operations.
7. Assumed 95% capture and control efficiency for use of thermal oxidizer and VRU.

Alaska LNG Project
Condensate and Diesel Tanks
Tank Emission Calculations

Source	Stream	Capacity	Throughput	Turnover
		gal	gal/year	
Tank 21	Condensate	475,890	24,746,280	52.0
Tank 22	Condensate	126,904	15,330,000	120.8
Tank 23	ULSD	3,520	364,600	103.6
Tank 24	ULSD	342	17,766	51.9
Tank 25	ULSD	342	17,766	51.9

Source	Stream	Uncontrolled VOC Emissions (lb/yr)			Uncontrolled VOC Emissions (tpy)		
		(Working)	(Standing)	(Total)	(Working)	(Standing)	(Total)
Tank 21	Condensate	146,010.07	7,556.65	153,566.72	73.01	3.78	76.78
Tank 22	Condensate	50,482.53	3,100.55	53,583.07	25.24	1.55	26.79
Tank 23	ULSD	2.44	0.32	2.76	0.00	0.00	0.00
Tank 24	ULSD	0.14	0.02	0.16	0.00	0.00	0.00
Tank 25	ULSD	0.14	0.02	0.16	0.00	0.00	0.00
Tank Totals		**196,495.31**	**10,657.56**	**207,152.87**	**98.25**	**5.33**	**103.58**

Source	Stream	Controlled VOC Emissions	
		(lb/year)	(TPY)
Tank 21	Condensate	1,535.67	0.77
Tank 22	Condensate	535.83	0.27
Tank 23	ULSD	2.76	0.00
Tank 24	ULSD	0.16	0.00
Tank 25	ULSD	0.16	0.00
Tank Totals		**2,074.58**	**1.04**

Notes:
Condensate Tanks to be controlled by a thermal oxidizer. Assume 99% control efficiency (capture and control).
Diesel tank controls include the use of fixed roof tanks and submerged loading operations.

Alaska LNG Project
Diesel Storage Tanks
Thermal Oxidizer Cost Effectiveness Analysis

Cost Quantification:

Cost Category	Project Cost	Default Estimate	Default % Applied	EPA Equation / Estimate Basis	Reference
Direct Capital Costs					
Purchased Equipment:					
Purchased Equipment Costs	$96,287		-	A	EPA Cost Control Manual, Equation 2.29
Instrumentation & Controls		$2,889	3%	C = 0.03 x A	AECOM equipment estimating data
Freight		$49,106.55	51%	D = 0.51 x (A+B)	AECOM equipment estimating data
Taxes (Enter sales tax rate in "% Applied")		$0	0.0%	TaxRate x (A+B+C)	No sales tax in Alaska
Total Purchased Equipment Cost (PE)	$148,283		-	PE	
Direct Installation Costs:					
Foundation & Supports		$2,966	2%	0.02 x PE	AECOM equipment estimating data
Erection and Handling		$23,725	16%	0.16 x PE	AECOM equipment estimating data
Electrical		$31,139	21%	0.21 x PE	AECOM equipment estimating data
Piping		$11,863	8%	0.08 x PE	AECOM equipment estimating data
Insulation		$10,380	7%	0.07 x PE	AECOM equipment estimating data
Painting		$148	0%	0.00 x PE	AECOM equipment estimating data
Site Preparation	$6,740.11		7%	Project-Specific	engineering judgement
Total Direct Installation Cost (DI)	$86,961		-	DI	
Total Direct Capital Costs (DC)	**$235,243**		-	**DC = PE + DI**	

Cost Category	Project Cost	Default Estimate	Default % Applied	EPA Equation / Estimate Basis	Reference
Indirect Capital Costs					
Indirect Costs:					
Engineering & Supervision		$41,519	28%	0.28 x PE	AECOM equipment estimating data
Construction and Field Expenses		$13,345	9%	0.09 x PE	AECOM equipment estimating data
Contractor Fees		$4,448	3%	0.03 x PE	AECOM equipment estimating data
Startup-up		$2,966	2%	0.02 x PE	AECOM equipment estimating data
Performance Testing		$1,483	1%	0.01 x PE	AECOM equipment estimating data
Total Indirect Costs (TIC)	**$63,761**		-	IC	

Cost Category	Project Cost	Default Estimate	Default % Applied	EPA Equation / Estimate Basis	Reference
Capital Investment:					
Project Contingency		$44,850.74	15%	E = 0.15 x (DC+IC)	OAQPS (15% of DC & TIC)
Preproduction Cost		$10,315.67	3%	F = 0.03 x (DC+IC+Cont)	OAQPS (2% of DC & TIC & Proj Contingency)
Total Capital Investment	**$354,171**		-	**TCI = DC + IC + E + F + G**	

Liquefaction BACT Analysis
Trade Secrets

Direct Annual Costs					
Direct Annual Costs:					
Operating Labor	$ -		-		Vendor Supplied
Supervisory Labor		$0	15%	15% of Op. Labor	OAQPS (15% of Op Labor)
Maintenance Labor		$5,313	1.5%	0.015 x TCI	OAQPS (1.5% of TCI)
Maintenance Materials		$5,313	-	100% of Maint. Labor	OAQPS (15% of Maint. Labor)
Annual Electricity Cost		$307	-	See parameters below	See parameters below
Fuel Penalty Costs (specify)	$ -		-		Vendor Supplied
Other Maintenance Cost (specify)	$ -		-		Vendor Supplied
Total Direct Annual Costs	**$10,933**		-	**DAC**	

Indirect Annual Costs					
Indirect Annual Costs:					
Overhead		$6,375	60.0%	0.600 x Op/Super/Maint Labor & Mtls	OAQPS (60% of Op/Super/Maint. Labor & Mtls)
Property Tax		$3,542	1.0%	0.0100 x TCI	OAQPS (1%)
Insurance		$3,542	1.0%	0.010 x TCI	OAQPS (1%)
General Administrative		$7,083	2.0%	0.020 x TCI	OAQPS (2%)
Total Indirect Annual Costs	**$20,542**		-	**DAC**	

Capital Recovery Cost					
Equipment Life (years)		10	-	n	Vendor Supplied
Interest Rate	7.00%	7.00%	-	i	7% per Agrium US Inc, Kenai Nitrogen Operations Facility Air Quality Control Construction Permit AQ0083CPT06
Capital Recovery Factor	0.1424		-	CRF = i/(1-(1+i)^-n)	-
Capital Recovery Cost (CRC)	**$50,426**		-		OAQPS Eqn 2.54 (Section 4.2, Ch. 2)

Total Annual Costs	**$81,901**		-	**TAC = DA + IDAC + CRC**	OAQPS Eqn 2.56 (Section 4.2, Ch. 2)

Cost Effectiveness Analysis:

		Reference
Uncontrolled VOC (tpy)	0.0015	Calculated below
Controlled VOC Emissions (tpy)	0.00003	Calculated below
VOC Reduction (tpy)	0.0015	Calculated below

Total Annual Costs	$81,901	Calculated above
Cost Effectiveness ($/ton/yr)	**$54,260,681**	OAQPS Eqn 2.58 (Section 4.2, Ch. 2)

Design Parameters:

Enter values in boxes below. Where default value is available, entered value will override default.
Required data is highlighted yellow.

Combustion Unit Sizing

			Reference
Thermal Oxidizer Sizing	500	scfm	Engineering Estimate

VOC Emission Rates

			Reference
Diesel Tank Uncontrolled Emissions	0.0015	TPY	EPA TANKS Calculations
Controlled Diesel Tank Emissions:	98%	Control Efficiency	Engineering Estimate

Operational Parameters

			Reference
Max annual op hours [Default: 8760 hr/yr]	8760	hr/yr	

Annual Electricity Costs: Enter values below. Where default value is available, entered number overrides default.

			Reference
Power demand:	0.39	kW	EPA Cost Control Manual, Equation 2.42
Electricity Cost [Default: 0.1572 $/kWh]	0.09	$/kWh	

Power demand estimated per EPA Cost Control Manual, Ch 3-2, Equation 2.42 for fan power demands.