ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION
Air Permits Program

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION
for
Golden Valley Electric Association
Zehnder Facility

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Abbreviations/Acronyms

AAC .... Alaska Administrative Code
AAAQS .... Alaska Ambient Air Quality Standards
Department................... Alaska Department of Environmental Conservation
BACT .... Best Available Control Technology
CFB……………………Circulating Fluidized Bed
CFR. .... Code of Federal Regulations
Cyclones……………….Mechanical Separators
DFP……………………Diesel Particulate Filter
DLN............................ Dry Low NOx
DOC…………………...Diesel Oxidation Catalyst
EPA .... Environmental Protection Agency
ESP…………………….Electrostatic Precipitator
EU .... Emission Unit
FITR…………………...Fuel Injection Timing Retard
GCPs…………………..Good Combustion Practices
HAP .... Hazardous Air Pollutant
ITR…………………….Ignition Timing Retard
LEA……………………Low Excess Air
LNB……………………Low NOx Burners
MR&Rs........................ Monitoring, Recording, and Reporting
NESHAPS.................... National Emission Standards for Hazardous Air Pollutants
NSCR…………………Non-Selective Catalytic Reduction
NSPS .... New Source Performance Standards
ORL .... Owner Requested Limit
PSD............................. Prevention of Significant Deterioration
PTE............................. Potential to Emit
RICE, ICE.................... Reciprocating Internal Combustion Engine, Internal Combustion Engine
SCR .... Selective Catalytic Reduction
SIP .... Alaska State Implementation Plan
SNCR…………………Selective Non-Catalytic Reduction
ULSD.......................... Ultra Low Sulfur Diesel

Units and Measures

gal/hr........................... gallons per hour
g/kWh .... grams per kilowatt hour
g/hp-hr .... grams per horsepower hour
hr/day........................... hours per day
hr/yr .... hours per year
hp................................ horsepower
lb/hr .... pounds per hour
lb/MMBtu .... pounds per million British thermal units
lb/1000 gal .... pounds per 1,000 gallons
kW .... kilowatts
MMBtu/hr .... million British thermal units per hour
MMscf/hr .... million standard cubic feet per hour
ppmv............................ parts per million by volume
tpy............................... tons per year

Pollutants

CO .... Carbon Monoxide
HAP .... Hazardous Air Pollutant
NOx .... Oxides of Nitrogen
SO_2 .... Sulfur Dioxide
PM-2.5 .... Particulate Matter with an aerodynamic diameter not exceeding 2.5 microns
PM-10 .... Particulate Matter with an aerodynamic diameter not exceeding 10 microns

1. INTRODUCTION

The Zehnder Facility (Zehnder) is an electric generating facility that combusts distillate fuel in combustion turbines to provide power to the Golden Valley Electric Association (GVEA) grid. The power plant contains two fuel oil-fired simple cycle gas combustion turbines and two diesel-fired generators (electro-motive diesels) used for emergency power and to serve as black start engines for the GVEA generation system. The primary fuel is stored in two 50,000 gallon aboveground storage tanks. Turbine startup fuel and electro-motive diesels primary fuel is stored in a 12,000 gallon above ground storage tank.

In a letter dated April 24, 2015, the Alaska Department of Environmental Conservation (Department) requested the stationary sources expected to be major stationary sources in the particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers (PM-2.5) serious nonattainment area perform a voluntary Best Available Control Technology (BACT) review in support of the state agency's required SIP submittal once the nonattainment area is re-classified as a Serious PM-2.5 nonattainment area. The designation of the area as "Serious" with regard to nonattainment of the 2006 24-hour PM-2.5 ambient air quality standards was published in Federal Register Vol. 82, No. 89, May 10, 2017, pages 21703-21706, with an effective date of June 9, 2017.[1]

This report addresses the significant emissions units (EUs) listed in the Zehnder facility's operating permit AQ0109TVP03. This report provides the Department's review of the BACT analysis for PM-2.5 and BACT analyses provided for oxides of nitrogen (NOx) and sulfur dioxide (SO_2) emissions, which are precursor pollutants that can form PM-2.5 in the atmosphere post combustion.

The following sections review GVEA's BACT analysis for the Zehnder Facility for technical accuracy and adherence to accepted engineering cost estimation practices.

2. BACT EVALUATION

A BACT analysis is an evaluation of all available control options for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts. 40 CFR 52.21(b)(12) defines BACT as a site-specific determination on a case-by-case basis. The Department's goal is to identify BACT for the permanent emission units (EUs) at the GVEA Zehnder facility that emit NOx, PM-2.5, and SO_2, establish emission limits which represent BACT, and assess the level of monitoring, recordkeeping, and reporting (MR&R) necessary to ensure GVEA applies BACT for the EUs. The Department based the BACT review on the five-step top-down approach set forth in Federal Register Volume 61, Number 142, July 23, 1996 (Environmental Protection Agency). Table A presents the EUs subject to BACT review.

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)

Table A: Emission Units Subject to BACT Review

EU ID	Description of EU	Rating/Size	Installation or Construction Date
1	Fuel Oil-Fired Regenerative Simple Cycle Gas Turbine	268 MMBtu/hr (18.4 MW)	1971
2	Fuel Oil-Fired Regenerative Simple Cycle Gas Turbine	268 MMBtu/hr (18.4 MW)	1972
3	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr (2.75 MW)	1970
4	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr (2.75 MW)	1970
10	Diesel-Fired Boiler	1.7 MMBtu/hr	2012
11	Diesel-Fired Boiler	1.7 MMBtu/hr	2012

Five-Step BACT Determinations
The following sections explain the steps used to determine BACT for NOx, PM-2.5, and SO_2 for the applicable equipment.

Step 1 Identify All Potentially Available Control Technologies
The Department identifies all available control options for the EU and the pollutant under consideration. This includes technologies used throughout the world or emission reductions through the application of available control techniques, changes in process design, and/or operational limitations. To assist in identifying available controls, the Department reviews available controls listed on the Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC). The RBLC is an EPA database where permitting agencies nationwide post imposed BACT for PSD sources. It is usually the first stop for BACT research. In addition to the RBLC search, the Department used several search engines to look for emerging and tried technologies used to control NOx, PM-2.5, and SO_2 emissions from equipment similar to those listed in Table A.

Step 2 Eliminate Technically Infeasible Control Technologies:
The Department evaluates the technical feasibility of each control technology based on source specific factors in relation to each EU subject to BACT. Based on sound documentation and demonstration, the Department eliminates control technologies deemed technically infeasible due to physical, chemical, and engineering difficulties.

Step 3 Rank the Remaining Control Technologies by Control Effectiveness
The Department ranks the remaining control technologies in order of control effectiveness with the most effective at the top.

Step 4 Evaluate the Most Effective Controls and Document the Results as Necessary
The Department reviews the detailed information in the BACT analysis about the control efficiency, emission rate, emission reduction, cost, environmental, and energy impacts for each option to decide the final level of control. The analysis must present an objective evaluation of both the beneficial and adverse energy, environmental, and economic impacts. A proposal to use the most effective option does not need to provide the detailed information for the less effective options. If cost is not an issue, a cost analysis is not required. Cost effectiveness for a control

option is defined as the total net annualized cost of control divided by the tons of pollutant removed per year. Annualized cost includes annualized equipment purchase, erection, electrical, piping, insulation, painting, site preparation, buildings, supervision, transportation, operation, maintenance, replacement parts, overhead, raw materials, utilities, engineering, start-up costs, financing costs, and other contingencies related to the control option. Sections 3, 4, and 5 present the Department's BACT Determinations for NOx, PM-2.5, and SO_2.

Step 5 Select BACT

The Department selects the most effective control option not eliminated in Step 4 as BACT for the pollutant and EU under review and lists the final BACT requirements determined for each EU in this step. A project may achieve emission reductions through the application of available technologies, changes in process design, and/or operational limitations. The Department reviewed GVEA's BACT analysis and made BACT determinations for NOx, PM-2.5, and SO_2 for the GVEA Zehnder Facility. These BACT determinations are based on the information submitted by GVEA in their analysis, information from vendors, suppliers, sub-contractors, RBLC, and an exhaustive internet search.

3. BACT DETERMINATION FOR NO_X

The NOx controls proposed in this section are not planned to be implemented. The optional precursor demonstration (as allowed under 40 C.F.R. 51.1006) for the precursor gas NOx for point sources illustrates that NOx controls are not needed. DEC is planning to submit with the Serious SIP a final precursor demonstration as justification not to require NOx controls. Please see the precursor demonstration for NOx posted at http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. The PM2.5 NAAQS Final SIP Requirements Rule states if the state determines through a precursor demonstration that controls for a precursor gas are not needed for attaining the standard, then the controls identified as BACT/BACM or Most Stringent Measure for the precursor gas are not required to be implemented.[2] Final approval of the precursor demonstration is at the time of the Serious SIP approval.

The GVEA Zehnder Facility has two existing 268 MMBtu/hr General Electric Frame 5 MS 5001-M simple cycle combustion gas turbines, two 28 MMBtu/hr General Motors Electro-Motive Diesel Generators, and two 1.7 MMBtu/hr Weil-Mclain diesel-fired boilers subject to BACT. The Department based its NOx assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility, Aurora Energy, LLC (Aurora) for the Chena Power Plant, U.S. Army Corps of Engineers (US Army) for Fort Wainwright, and the University of Alaska Fairbanks (UAF) for the Fairbanks Campus Power Plant.

3.1 NOx BACT for the Fuel Oil-Fired Simple Cycle Gas Turbines

Possible NOx emission control technologies for the fuel oil-fired simple cycle turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf

under the process code 15.190, Liquid Fuel-Fired Simple Cycle Gas Turbines (> 25 MW). The search results for simple cycle gas turbines are summarized in Table 3-1.

Table 3-1. RBLC Summary of NOx Controls for Fuel Oil-Fired Simple Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits (ppmv)
Selective Catalytic Reduction	2	7
Low NOx Burners	12	5 – 15
Good Combustion Practices	3	15

RBLC Review
A review of similar units in the RBLC indicates selective catalytic reduction, low NOx burners, and good combustion practices are the principle NOx control technologies installed on fuel oil-fired simple cycle gas turbines. The lowest NOx emission rate listed in the RLBC is 5 parts per million by volume (ppmv).

Step 1 - Identification of NOx Control Technology for the Simple Cycle Gas Turbines
From research, the Department identified the following technologies as available for control of NOx emissions from fuel oil-fired simple cycle gas turbines rated at 25 MW or more:

(a) Selective Catalytic Reduction (SCR)
SCR is a post-combustion gas treatment technique for reducing nitric oxide (NO) and nitrogen dioxide (NO_2) in the turbine exhaust stream to molecular nitrogen (N_2), water, and oxygen (O_2). In the SCR process, aqueous or anhydrous ammonia (NH_3) is injected into the flue gas upstream of a catalyst bed. The catalyst lowers the activation energy of the NOx decomposition reaction. NOx and NH_3 combine at the catalyst surface forming an ammonium salt intermediate, which subsequently decomposes to produce elemental N_2 and water. Depending on the overall NH_3-to-NOx ratio, removal efficiencies are generally 80 to 90 percent. Challenges associated with using SCR on fuel oil-fired simple cycle gas turbines include a narrow window of acceptable inlet and exhaust temperatures (500°F to 800°F), emission of NH_3 into the atmosphere (NH_3 slip) caused by non-stoichiometric reduction reaction, and disposal of depleted catalysts. The Department considers SCR a technically feasible control technology for the fuel oil-fired simple cycle gas combustion turbines.

(b) Water Injection
Water/steam injection involves the introduction of water or steam into the combustion zone. The injected fluid provides a heat sink which absorbs some of the heat of reaction, causing a lower flame temperature. The lower flame temperature results in lower thermal NOx formation. Both steam and water injections are capable of obtaining the same level of control. The process requires approximately 0.8 to 1.0 pound of water or steam per pound of fuel burned. The main technical consideration is the required purity of the water or steam, which is required to protect the equipment from dissolved solids. Obtaining water or steam of sufficient purity requires the installation of rigorous water treatment and deionization systems. Water/steam injection is a proven technology for NOx emissions reduction from turbines. However, the arctic environment presents significant challenges to water/steam injection due to cost of water treatment, freezing potential due to extreme cold ambient temperatures, and increased maintenance problems due to

accelerated wear in the hot sections of the turbines. Moreover, the vendor of the turbines does not recommend using water/steam injection to control NO_x emissions from the turbines because of the extra maintenance problems. The Department considers water/steam injection a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(c) Dry Low NOx (DLN)
Two-stage lean/lean combustors are essentially fuel-staged, premixed combustors in which each stage burns lean. The two-stage lean/lean combustor allows the turbine to operate with an extremely lean mixture while ensuring a stable flame. A small stoichiometric pilot flame ignites the premixed gas and provides flame stability. The NOx emissions associated with the high temperature pilot flame are insignificant. Low NOx emission levels are achieved by this combustor design through cooler flame temperatures associated with lean combustion and avoidance of localized "hot spots" by premixing the fuel and air. DLN is designed for natural gas-fired or dual-fuel fired units and is not effective in controlling NOx emissions from fuel oil-fired units. The Department does not consider DLN a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(d) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(e) Good Combustion Practices (GCPs)
GCPs typically include the following elements:

1. Sufficient residence time to complete combustion;
2. Providing and maintaining proper air/fuel ratio;
3. High temperatures and low oxygen levels in the primary combustion zone;
4. High enough overall excess oxygen levels to complete combustion and maximize thermal efficiency.

Combustion efficiency is dependent on the gas residence time, the combustion temperature, and the amount of mixing in the combustion zone. GCPs are accomplished primarily through combustion chamber design as it relates to residence time, combustion temperature, air-to-fuel mixing, and excess oxygen levels. The Department considers GCPs a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

Step 2 - Elimination of Technically Infeasible NOx Control Technologies for Gas Turbines
As explained in Step 1 of Section 3.1, the Department does not consider dry low NOx as technically feasible technology to control NO_x emissions from the fuel oil-fired simple cycle gas turbines.

Step 3 - Rank the Remaining NOx Control Technologies for the Simple Cycle Gas Turbines
The following control technologies have been identified and ranked for control of NOx emissions from the fuel oil-fired simple cycle gas turbines:

(a + b)	Selective Catalytic Reduction and Water Injection	(95% Control
(a)	Selective Catalytic Reduction	(90% Control)
(b)	Water Injection	(70% Control)
(g)	Good Combustion Practices	(Less than 40% Control)
(d)	Limited Operation	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis of the control technologies available for the fuel oil-fired simple cycle turbines to demonstrate that the use of water injection with SCR, SCR, or water injection in conjunction with limited operation is not economically feasible on these units. A summary of the analyses for EUs 1 and 2 is shown in Table 3-2:

Table 3-2. GVEA Economic Analysis for Technically Feasible NOx Controls per Turbine

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR and Water Injection	1,033	929.7	$18,729,680	$4,915,081	$5,287
SCR	1,033	878.1	$12,931,360	$2,837,279	$3,231
Water Injection	1,033	754.1	$3,710,000	$1,673,057	$2,219
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates the level of NOx reduction does not justify the use of SCR, Water Injection, or SCR and Water Injection for the fuel oil-fired simple cycle gas turbines based on the excessive cost per ton of NOx removed per year.

GVEA proposes the following as BACT for NOx emissions from the fuel oil-fired simple cycle gas turbines:

(a) NOx emissions from the operation of the fuel oil-fired simple cycle gas turbines will be controlled with good combustion practices; and

(b) NOx emissions from the fuel oil-fired simple cycle gas turbines will not exceed 0.88 lb/MMBtu over a 4-hour averaging period.

Department Evaluation of BACT for NOx Emissions from the Simple Cycle Gas Turbines

The Department revised the cost analyses provided by GVEA for the installation of SCR and Water Injection using the unrestricted potential to emit from the fuel oil-fired simple cycle turbines, a baseline emission rate of 0.88 lb NOx/MMBtu, a NOx removal efficiency of 95% for SCR and Water Injection, an interest rate of 5.5% (current bank prime interest rate), and a 20 year equipment life. A summary of the analysis is shown below:

Table 3-3. Department Economic Analysis for Technically Feasible NOx Controls per Turbine

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
SCR and Water Injection	1,033	981.4	$18,729,680	$3,820,990	$3,894
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

The Department's economic analysis indicates the level of NOx reduction justifies the installation of SCR and water injection for the fuel oil-fired simple cycle gas turbines located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of NOx BACT for the Simple Cycle Gas Turbines
The Department's finding is that the BACT for NOx emissions from the fuel oil-fired simple cycle gas turbines is as follows:

(a) NOx emissions from EUs 1 & 2 shall be controlled by operating and maintaining selective catalytic reduction and water injection at all times the units are in operation;

(b) NOx emissions from EUs 1 & 2 shall not exceed 0.044 lb/MMBtu averaged over a 3-hour period; and

(c) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation.

Table 3-4 lists the proposed NOx BACT determination for this facility along with those for other fuel oil-fired simple cycle turbines in the Serious PM-2.5 nonattainment area.

Table 3-4. Comparison of NOx BACT for Simple Cycle Gas Turbines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
North Pole	Two Fuel Oil-Fired Simple Cycle Gas Turbines	1,344 MMBtu/hr	0.044 – 0.070 lb/MMBtu	Selective Catalytic Reduction Water Injection
Zehnder	Two Fuel Oil-Fired Simple Cycle Gas Turbines	536 MMBtu/hr	0.044 lb/MMBtu	Selective Catalytic Reduction Water Injection

3.2 NOx BACT for the Large Diesel-Fired Engines

Possible NOx emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 to 17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 3-5.

Table 3-5. RBLC Summary of NOx Controls for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Selective Catalytic Reduction	3	0.5 - 0.7
Other Add-On Control	1	1.0
Federal Emission Standards	13	3.0 - 6.9
Good Combustion Practices	31	3.0 - 13.5
No Control Specified	60	2.8 - 14.1

RBLC Review
A review of similar units in the RBLC indicates selective catalytic reduction, good combustion practices, and compliance with federal emission standards are the principle NOx control technologies installed on large diesel-fired engines. The lowest NOx emission rate listed in the RBLC is 0.5 g/hp-hr.

Step 1 - Identification of NOx Control Technology for the Large Diesel-Fired Engines
From research, the Department identified the following technologies as available for control of NOx emissions from diesel-fired engines rated at 500 hp or greater:

(a) Selective Catalytic Reduction
The theory of SCR was discussed in detail in the NOx BACT for the turbines and will not be repeated here. The Department considers SCR a technically feasible control technology for the large diesel-fired engines.

(b) Turbocharger and Aftercooler
Turbocharger technology involves the process of compressing intake air in a turbocharger upstream of the air/fuel injection. This process boosts the power output of the engine. The air compression increases the temperature of the intake air so an aftercooler is used to reduce the intake air temperature. Reducing the intake air temperature helps lower the peak flame temperature which reduces NOx formation in the combustion chamber. EU 3 and 4 are currently operating with a turbocharger and aftercooler. The Department considers turbocharger and aftercooler a technically feasible control technology for the large diesel-fired engines.

(c) Fuel Injection Timing Retard (FITR)
FITR reduces NOx emissions by the delay of the fuel injection in the engine from the time the compression chamber is at minimum volume to a time the compression chamber is expanding. Timing adjustments are relatively straightforward. The larger volume in the compression chamber produces a lower peak flame temperature. With the use of FITR the engine becomes less fuel efficient, particular matter emissions increase, and there is a limit with respect to the degree the timing may be retarded because an excessive timing delay can cause the engine to misfire. The timing retard is generally limited to no more than three degrees. Diesel engines may also produce more black smoke due to a decrease in exhaust temperature and incomplete combustion. FITR can achieve up to 50 percent NOx reduction. Due to the increase in particulate matter emissions resulting from FITR, this technology will not be carried forward.

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

(e) Federal Emission Standards
RBLC NOx determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 NSPS Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. NSPS Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or reconstructed after July 11, 2005. The Department considers meeting the technology based New Source Performance Standards (NSPS) of Subpart IIII as a technically feasible control technology for the large diesel-fired engines.

(f) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. The Department considers limited operation a technically feasible control technology for the large diesel-fired engines.

(g) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of NOx emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engine.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Large Engines
As explained in Step 1 of Section 3.2, the Department does not consider fuel injection timing retard and ignition timing retard as technically feasible technologies to control NOx emissions from the large diesel-fired engines.

Step 3 - Rank the Remaining NOx Control Technologies for the Large Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the large diesel-fired engines.

(f)	Limited Operation	(94% Control)
(a)	Selective Catalytic Reduction	(90% Control)
(g)	Good Combustion Practices	(Less than 40% Control)
(e)	Federal Emission Standards	(Baseline)
(b)	Turbocharger and Aftercooler	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes the following as BACT for NOx emissions from the large diesel-fired engines:

(a) NOx emissions from the operation of the diesel-fired engines shall be controlled with turbocharger and aftercooler;

(b) NOx emissions from the operation of the diesel-fired engines shall not exceed 0.024 lb/hp-hr over a 4-hour averaging period; and

(c) Limited Operation.

Department Evaluation of BACT for NOx Emissions from the Large Diesel-Fired Engines

The Department reviewed GVEA's proposal and finds that NOx emissions from the large diesel-fired engines can additionally be controlled by good combustion practices.

Step 5 - Selection of NOx BACT for the Large Diesel-Fired Engines

The Department's finding is that the BACT for NOx emissions from the large diesel-fired engines is as follows:

(a) NOx emissions from the operation of the diesel-fired engines will be controlled with turbocharger and aftercooler;

(b) Limit non-emergency operation of EUs 3 and 4 to no more than 100 hours per year each for maintenance checks and readiness testing;

(c) NOx emissions from EUs 3 and 4 shall not exceed 10.9 g/hp-hr[3] over a 3-hour averaging period; and

(d) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation.

Table 3-6 lists the proposed BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 3-6. Comparision of NOx BACT for Large Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	3.0 – 10.9 g/hp-hr	Limited Operation Good Combustion Practices Federal Emission Standards
UAF	Large Diesel-Fired Engine	13,266 hp	1.3 g/hp-hr	Selective Catalytic Reduction Turbocharger and Aftercooler Good Combustion Practices Limited Operation
GVEA North Pole	Large Diesel-Fired Engine	600 hp	10.9 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp (each)	10.9 g/hp-hr	Turbocharger and Aftercooler Good Combustion Practices Limited Operation

3.3 NOx BACT for the Diesel-Fired Boilers

Possible NOx emission control technologies for diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Commercial/Institutional Size Boilers (<100 MMBtu/hr). The search results for diesel-fired engines are summarized in Table 3-7.

[3] Emission rate from AP-42 Table 3.4-1 for large stationary diesel-fired engines.

Table 3-7. RBLC Summary of NOx Control for Diesel-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Low-NOx Burner	8	0.023 - 0.14
Good Combustion Practices	1	0.01
No Control Specified	2	0.070 - 0.12

RBLC Review
A review of similar units in the RBLC indicates low-NOx burners and good combustion practices are the principle NOx control technologies installed on diesel-fired boilers. The lowest NOx emission rate listed in the RBLC is 0.01 lb/MMBtu.

Step 1 - Identification of NOx Control Technology for the Diesel-Fired Boilers
From research, the Department identified the following technologies as available for control of NOx emissions from diesel fired boilers rated at less than 100 MMBtu/hr:

(a) Low NOx Burners
Using LNBs can reduce formation of NOx through careful control of the fuel-air mixture during combustion. Control techniques used in LNBs includes staged air, and staged fuel, as well as other methods that effectively lower the flame temperature. Experience suggests that significant reduction in NOx emissions can be realized using LNBs. The U.S. EPA reports that LNBs have achieved reduction up to 80%, but actual reduction depends on the type of fuel and varies considerably from one installation to another. Typical reductions range from 40% - 60% but under certain conditions, higher reductions are possible. Air staging or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Overfire air is the injection of air above the main combustion zone. As indicated by EPA's AP-42, LNBs are applicable to tangential and wall-fired boilers of various sizes but are not applicable to other boiler types such as cyclone furnaces or stokers. The Department considers LNB a technically feasible control technology for the diesel-fired boilers.

(b) Flue Gas Recirculation (FGR)
Flue gas recirculation involves extracting a portion of the flue gas from the economizer section or air heater outlet and readmitting it to the furnace through the furnace hopper, the burner windbox, or both. This method reduces the concentration of oxygen in the combustion zone and may reduce NOx by as much as 40 to 50 percent in some boilers. Chapter 1.3-7 from AP-42 indicates that FGR can require extensive modifications to the burner and windbox and can result in possible flame instability at high FGR rates. The Department does not consider FGR a technically feasible control technology for the diesel-fired boilers.

(c) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. The Department considers GCPs a technically feasible control technology for the mid-sized diesel fired boilers.

Step 2 - Eliminate Technically Infeasible NOx Control Technologies for the Diesel-Fired Boilers
As explained in Step 1 of Section 3.3, the Department does not consider flue gas recirculation as technically feasible technologies for the diesel-fired boilers.

Step 3 - Rank the Remaining NOx Control Technologies for the Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of NOx emissions from the diesel-fired boilers:

(a) Low NOx Burners (40% - 60% Control)
(c) Good Combustion Practices (Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis for the installation of LNB per diesel-fired boiler. A summary of the analysis is shown below:

Table 3-8. Economic Analysis for Low NOx Burners per Diesel-Fired Boiler

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
LNB	1.1	0.37	$21,820	$3,107	$8,396
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates the level of NOx reduction does not justify installing LNBs on the diesel-fired boilers based on the excessive cost per ton of NOx removal per year.

GVEA proposes the following as BACT for NOx emissions from the diesel-fired boilers:

(a) NOx emissions from the operation of the diesel fired boilers shall be controlled by good combustion practices; and

(b) NOx emissions from EU 10 and 11 shall not exceed 20 lb/1000 gallons of diesel fuel over a 4-hour averaging period.

Department Evaluation of BACT for NOx Emissions from the Diesel-Fired Boilers

The Department reviewed GVEA's proposal and finds that the two diesel-fired boilers have a combined potential to emit (PTE) of less than three tons per year (tpy) for NOx based on continuous operation of 8,760 hours per year. At three tpy, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible.

Step 5 - Selection of NOx BACT for the Diesel-Fired Boilers
The Department's finding is that BACT for NOx emissions from the diesel-fired boilers is as follows:

(a) NOx emissions from the diesel-fired boilers shall not exceed 0.15 lb/MMBtu[4]; and

(b) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation.

Table 3-9 lists the proposed NOx BACT determination for the facility along with those for other diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 3-9. Comparison of NOx BACT for the Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	3 Small Diesel-Fired Boilers	< 100 MMBtu/hr	0.15 lb/MMBtu	Limited Operation
Fort Wainwright	27 Small Diesel-Fired Boilers	< 100 MMBtu/hr	0.15 lb/MMBtu	Limited Operation for Non-Emergency Use (500 hours per year each) Good Combustion Practices
GVEA Zehnder	2 Small Diesel-Fired Boilers	< 100 MMBtu/hr	0.15 lb/MMBtu	Low NOx Burners

4. BACT DETERMINATION FOR PM-2.5

The Department based its PM-2.5 assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power Plant and Zehnder Facility, Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

4.1 PM-2.5 BACT for the Fuel Oil-Fired Simple Cycle Gas Turbines (EUs 1 and 2)

Possible PM-2.5 emission control technologies for the fuel oil-fired simple cycle gas turbines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.190, Simple Cycle Gas Turbines (> 25 MW) The search results for simple cycle gas turbines are summarized in Table 4-1.

Table 4-1. RBLC Summary of PM-2.5 Control for Simple Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices	25	0.0038 – 0.0076 lb/MMBtu
Clean Fuels	12	5 – 14 lb/hr

RBLC Review

A review of similar units in the RBLC indicates restrictions on fuel sulfur contents and good combustion practices are the principle PM control technologies installed on simple cycle gas turbines. The lowest PM-2.5 emission rate listed in the RBLC is 0.0038 lb/MMBtu.

Step 1 - Identification of PM-2.5 Control Technology for the Simple Cycle Gas Turbines

From research, the Department identified the following technologies as available for control of PM-2.5 emissions from fuel oil-fired simple cycle gas turbines:

[4] Emission rate from AP-42 Table 1.3-1 for boilers smaller than 100 MMBtu/hr (20 lb/1,000 gallons of diesel) and converted to lb/MMBtu assuming 0.137 MMBtu/gal diesel (AP-42).

(a) Low Sulfur Fuel
Low sulfur fuel has been known to reduce particulate matter emissions. PM-2.5 emission rates for low sulfur fuel are not available and therefore a BACT emissions rate cannot be set for low sulfur fuel. The Department does not consider low sulfur fuel a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(b) Low Ash Fuel
Residual fuels and crude oil are known to contain ash forming components, while refined fuels are low ash. Fuels containing ash can cause excessive wear to equipment and foul combustion components. EUs 1 and 2 are fired exclusively on distillate fuel which is a form of refined fuel, and potential PM-2.5 emissions are based on emission factors for distillate fuel. The Department considers low ash fuel a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(c) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. Due to EUs 1 and 2 currently operating under limits, the Department considers limited operation as a feasible control technology for the fuel oil-fired simple cycle gas turbines.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of PM. The Department considers GCPs a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

Step 2 - Eliminate Technically Infeasible PM-2.5 Controls for the Simple Cycle Gas Turbines
As explained in Step 1 of Section 4.1, the Department does not consider low sulfur fuel as technically feasible technology to control PM-2.5 emissions from the fuel oil-fired simple cycle gas turbines.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Simple Cycle Gas Turbines
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the fuel oil-fired simple cycle gas turbines:

(d) Good Combustion Practices	(Less than 40% Control)
(b) Low Ash Fuel	(0% Control)
(c) Limited Operation	(0% Control)

Control technologies already in practice at the stationary source or included in the design of the EU are considered 0% control for the purpose of the SIP BACT for existing stationary sources.

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes the following as BACT for PM-2.5 emissions from the fuel oil-fired simple cycle gas turbines:

(a) PM-2.5 emissions from EUs 1 and 2 shall not exceed 0.012 lb/MMBtu over a 4-hour averaging period; and

(b) Maintaining good combustion practices.

Step 5 - Selection of PM-2.5 BACT for the Simple Cycle Gas Turbines
The Department's finding is that BACT for PM-2.5 emissions from the fuel oil-fired simple cycle gas turbines is as follows:

(a) PM-2.5 emissions from EUs 1 and 2 shall be controlled by combusting only low ash fuel;

(b) Maintain good combustion practices at all times of operation by following the manufacturer's operation and maintenance procedures; and

(c) PM-2.5 emissions from EUs 1 & 2 shall not exceed 0.012 lb/MMBtu[5] over a 3-hour averaging period.

Table 4-2 lists the proposed PM-2.5 BACT determination for this facility along with those for other fuel oil-fired simple cycle gas turbines located in the Serious PM-2.5 nonattainment area.

Table 4-2. Comparison of PM-2.5 BACT for Simple Cycle Gas Turbines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
GVEA – North Pole	Two Fuel Oil-Fired Simple Cycle Gas Turbines	1,344 MMBtu/hr	0.012 lb/MMBtu[5] (3-hour averaging period)	Good Combustion Practices
GVEA – Zehnder	Two Fuel Oil-Fired Simple Cycle Gas Turbines	536 MMBtu/hr	0.012 lb/MMBtu[5] (3-hour averaging period)	Good Combustion Practices

4.2 PM-2.5 BACT for the Large Diesel Fired Engines

Possible PM-2.5 emission control technologies for large engine was obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.110-17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 4-3.

Table 4-3. RBLC Summary of PM-2.5 Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Federal Emission Standards	12	0.03 – 0.02
Good Combustion Practices	28	0.03 – 0.24
Limited Operation	11	0.04 – 0.17
Low Sulfur Fuel	14	0.15 – 0.17
No Control Specified	14	0.02 – 0.15

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices, compliance with the federal emission standards, low ash/sulfur diesel, and limited operation are the principle PM-2.5 control technologies installed on large diesel-fired engines. The lowest PM-2.5 emission rate in the RBLC is 0.02 g/hp-hr.

[5] Table 3.1-2a of US EPA's AP-42 Emission Factors. https://www3.epa.gov/ttnchie1/ap42/ch03/final/c03s01.pdf

Step 1 - Identification of PM-2.5 Control Technology for the Large Diesel-Fired Engines
From research, the Department identified the following technologies as available for controls of PM-2.5 emissions from diesel fired engines rated at 500 hp or greater:

(a) Diesel Particulate Filter (DPF)
DPFs are a control technology that is designed to physically filter particulate matter from the exhaust stream. Several designs exist which require cleaning and replacement of the filter media after soot has become caked onto the filter media. Regenerative filter designs are also available that burn the soot on a regular basis to regenerate the filter media. DPF can reduce PM-2.5 emissions by 85%. The Department considers DPF a technically feasible control technology for the large diesel-fired engines.

(b) Diesel Oxidation Catalyst (DOC)
DOC can reportedly reduce PM-2.5 emissions by 30% and PM emissions by 50%. A DOC is a form of "bolt on" technology that uses a chemical process to reduce pollutants in the diesel exhaust into decreased concentrations. They replace mufflers on vehicles, and require no modifications. More specifically, this is a honeycomb type structure that has a large area coated with an active catalyst layer. As CO and other gaseous hydrocarbon particles travel along the catalyst, they are oxidized thus reducing pollution. The Department considers DOC a technically feasible control technology for the large diesel-fired engines.

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

(d) Low Sulfur Fuel
Low sulfur fuel has been known to reduce particulate matter emissions. The Department considers low sulfur fuel as a technically feasible control technology for the large diesel-fired engine.

(e) Low Ash Diesel
Residual fuels and crude oil are known to contain ash forming components, while refined fuels are low ash. Fuels containing ash can cause excessive wear to equipment and foul engine components. The Department considers low ash diesel a technically feasible control technology for the large diesel-fired engines.

(f) Federal Emission Standards
RBLC NOx determinations for federal emission standards require the engines meet the requirements of 40 C.F.R. 60 NSPS Subpart IIII, 40 C.F.R 63 Subpart ZZZZ, non-road engines (NREs), or EPA tier certifications. NSPS Subpart IIII applies to stationary compression ignition internal combustion engines that are manufactured or

reconstructed after July 11, 2005. The Department considers meeting the technology based New Source Performance Standards (NSPS) as a technically feasible control technology for the large diesel-fired engines.

(g) Limited Operation
Limiting the operation of emissions units reduces the potential to emit of those units. The Department considers limited operation as a feasible control technology for the large diesel-fired engines.

(h) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions.The Department considers GCPs a technically feasible control technology for the large diesel-fired engines.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for the Large Engines
PM-2.5 emission rates for low sulfur fuel are not available and therefore a BACT emissions rate cannot be set for low sulfur fuel. Low sulfur fuel is not a technically feasible control technology.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Large Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the large diesel-fired engines:

(g)	Limited Operation	(94% Control)
(a)	Diesel Particulate Filters	(85% Control)
(h)	Good Combustion Practices	(Less than 40% Control)
(b)	Diesel Oxidation Catalyst	(30% Control)
(e)	Low Ash Diesel	(25% Control)
(c)	Positive Crankcase Ventilation	(10% Control)
(f)	Federal Emission Standards	(Baseline)

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes limited operation as BACT for PM-2.5 emissions from the large diesel-fired engines:

(a) Limit non-emergency operation of EUs 3 and 4 to no more than 500 hours per year each for maintenance checks and readiness testing; and

(b) PM-2.5 emissions from EUs 3 and 4 shall not exceed 0.1 lb/MMBtu[6] over a 4-hour averaging period.

Department Evaluation of BACT for PM-2.5 Emissions from the Large Diesel-Fired Engines
The Department reviewed GVEA's proposal finds that PM-2.5 emissions from the large diesel-fired engines can also be controlled by good combustion practices.

[6] Table 3.4-1 of US EPA's AP-42 Emission Factors (PM). https://www3.epa.gov/ttn/chief/ap42/ch03/final/c03s04.pdf

Step 5 - Selection of PM-2.5 BACT for the Large Diesel-Fired Engines

The Department's finding is that the BACT for PM-2.5 emissions from the large diesel-fired engines is as follows:

(a) Limit non-emergency operation of EUs 3 and 4 to no more than 100 hours per year each for maintenance checks and readiness testing;

(b) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(c) PM-2.5 emissions from EUs 3 and 4 shall not exceed 0.32 g/hp-hr[6] over a 3-hour averaging period.

Table 4-4 lists the proposed PM-2.5 BACT determination for the facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 4-4. Comparison of PM-2.5 BACT for Large Diesel Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	Large Diesel-Fired Engine	13,266 hp	0.32 g/hp-hr	Positive Crankcase Ventilation Limited Operation
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	0.15 – 0.32 g/hp-hr	Limited Operation Ultra-Low Sulfur Diesel Federal Emission Standards
GVEA North Pole	Large Diesel-Fired Engine	600 hp	0.32 g/hp-hr	Positive Crankcase Ventilation Good Combustion Practices
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp (each)	0.32 g/hp-hr	Limited Operation Good Combustion Practices

4.3 PM-2.5 BACT for the Diesel Fired Boilers

Possible PM-2.5 emission control technologies for small diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Commercial/Institutional Size Boilers (<100 MMBtu/hr). The search results for diesel-fired boilers are summarized in Table 4-5.

Table 4-5. RBLC Summary of PM-2.5 Control for Diesel Fired Boilers

Control Technology	Number of Determinations	Emission Limits
Good Combustion Practices	3	0.25 lb/gal 0.1 tpy 2.17 lb/hr

RBLC Review

A review of similar units in the RBLC indicates that good combustion practices is the principle PM-2.5 control technology determined for small diesel-fired boilers. The lowest PM-2.5 emission rate listed in the RBLC is 0.1 tpy.

Step 1 - Identification of PM-2.5 Control Technology for the Diesel Fired Boilers
From research, the Department identified the following technologies as available for control of PM-2.5 emissions from diesel-fired boilers:

(a) Wet Scrubbers
Wet scrubbers use a scrubbing solution to remove $PM/PM_{10}/PM_{2.5}$ from exhaust gas streams. The mechanism for particulate collection is impaction and interception by water droplets. Wet scrubbers are configured as counter-flow, cross-flow, or concurrent flow, but typically employ counter-flow where the scrubbing fluid is in the opposite direction as the gas flow. Wet scrubbers have control efficiencies of 50% - 99%.[7] One advantage of wet scrubbers is that they can be effective on condensable particulate matter. A disadvantage of wet scrubbers is that they consume water and produce water and sludge. For fine particulate control, a venturi scrubber can be used, but typical loadings for such a scrubber are 0.1-50 grains/scf. The Department considers the use of wet scrubbers a technically feasible control technology for the diesel-fired boilers.

(b) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of PM-2.5 emissions. The Department considers GCPs a technically feasible control technology for the diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible PM-2.5 Control Technologies for the Diesel Fired Boilers
All identified control devices are technically feasible for the diesel-fired boilers.

Step 3 - Rank the Remaining PM-2.5 Control Technologies for the Diesel Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of PM-2.5 emissions from the diesel-fired boilers:

(a)	Wet Scrubbers	(50% - 99% Control)
(b)	Good Combustion Practices	(Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes the following as BACT for PM-2.5 emissions from the diesel-fired boilers:

(a) Good Combustion Practices; and

(b) PM-2.5 emissions shall not exceed 2.13 lb/1,000 gallons[8] over a 4-hour averaging period.

Department Evaluation of BACT for PM-2.5 Emissions from Diesel-Fired Boilers

The Department reviewed GVEA's proposal and finds that the two diesel-fired boilers have a combined PTE of less than two tpy for PM-2.5 based on continuous operation of 8,760 hours per

[7] https://www3.epa.gov/ttn/catc/dir1/fcondnse.pdf
https://www3.epa.gov/ttn/catc/dir1/fiberbed.pdf
https://www3.epa.gov/ttn/catc/dir1/fventuri.pdf

[8] Tables 1.3-2 & 1.3-7 of US EPA's AP-42 Emission Factors: https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s03.pdf

year. At two tpy, the cost effectiveness in terms of dollars per ton for add-on pollution control for these units is economically infeasible.

Step 5 - Selection of PM-2.5 BACT for the Diesel-Fired Boilers

The Department's finding is that BACT for PM-2.5 emissions from the diesel-fired boilers is as follows:

(a) PM-2.5 emissions from the diesel-fired boilers shall not exceed 0.012 lb/MMBtu[9] over a 3-hour averaging period; and

(b) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation.

Table 4-6 lists the proposed PM-2.5 BACT determination for this facility along with those for other diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 4-6. Comparison of PM-2.5 BACT for the Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
UAF	3 Small Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMbtu[9]	Limited Operation
Fort Wainwright	27 Small Diesel-Fired Boilers	< 100 MMBtu/hr	0.012 lb/MMbtu[9]	Good Combustion Practices
GVEA Zehnder	2 Small Diesel-Fired Boilers	1.7 MMBtu/hr (each)	0.012 lb/MMbtu[9]	Good Combustion Practices

5. BACT DETERMINATION FOR SO_2

The Department based its SO_2 assessment on BACT determinations found in the RBLC, internet research, and BACT analyses submitted to the Department by GVEA for the North Pole Power Plant and Zehnder Facility, Aurora for the Chena Power Plant, US Army for Fort Wainwright, and UAF for the Combined Heat and Power Plant.

5.1 SO_2 BACT for the Fuel Oil-Fired Simple Cycle Gas Turbines

Possible SO_2 emission control technologies for the large dual fuel fired boiler was obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 15.190, Liquid Fuel-Fired Simple Cycle Gas Turbines (> 25 MW). The search results for simple cycle gas turbines are summarized in Table 5-1.

Table 5-1. RBLC Summary of SO_2 Controls for Fuel Oil-Fired Simple Cycle Gas Turbines

Control Technology	Number of Determinations	Emission Limits
Ultra-Low Sulfur Diesel	7	0.0015 % S by wt.
Low Sulfur Fuel	2	0.0026 – 0.055 lb/MMBtu
Good Combustion Practices	3	0.6 lb/hr

RBLC Review

A review of similar units in the RBLC indicates that limiting the sulfur content of fuel and good combustion practices are the principle SO_2 control technologies determined as BACT for fuel

[9] Emission factor from AP-42 Table's 1.3-2 (total condensable particulate matter from No. 2 oil, 1.3 lb/1,000 gal) and 1.3-6 (PM-2.5 size-specific factor from distillate oil, 0.25 lb/1,000 gal) converted to lb/MMBtu.

oil-fired simple cycle gas turbines. The lowest SO_2 emission rate listed in the RBLC is combustion of ULSD at 0.0015 % S by wt.

Step 1 - Identification of SO_2 Control Technology for the Simple Cycle Gas Turbines
From research, the Department identified the following technologies as available for control of SO_2 emissions from fuel oil-fired simple cycle gas turbines:

(a) Ultra Low Sulfur Diesel (ULSD)
ULSD has a fuel sulfur content of 0.0015 percent sulfur by weight or less. Using ULSD would reduce SO_2 emissions because the fuel oil-fired simple cycle gas turbines are combusting standard diesel that has a sulfur content of up to 0.5 percent sulfur by weight. Switching to ULSD could reach a great than 99 percent decrease in SO_2 emissions from the fuel oil-fired simple cycle gas turbines. The Department considers ULSD a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(b) Low Sulfur Fuel
Low sulfur fuel has a fuel sulfur content of 0.05 percent sulfur by weight. Using low sulfur fuel would reduce SO_2 emissions because the fuel oil-fired simple cycle gas turbines are combusting standard diesel that has a sulfur content of up to 0.5 percent sulfur by weight. Switching to low sulfur fuel could reach a 93 percent decrease in SO_2 emissions from the fuel oil-fired simple cycle gas turbines during non-startup operation. The Department considers low sulfur diesel a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

(c) Good Combustion Practices (GCPs)
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2. The Department considers GCPs a technically feasible control technology for the fuel oil-fired simple cycle gas turbines.

Step 2 - Eliminate Technically Infeasible SO_2 Controls for the Simple Cycle Gas Turbines
All control technologies identified are technically feasible for the fuel oil-fired simple cycle gas turbines.

Step 3 - Rank Remaining SO_2 Control Technologies for the Simple Cycle Gas Turbines
The following control technologies have been identified and ranked for control of SO_2 emissions from the fuel oil-fired simple cycle turbines:

(a) Ultra Low Sulfur Diesel (99.7% Control)
(b) Low Sulfur Fuel (93% Control)
(c) Good Combustion Practices (Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis for switching the fuel combusted in the simple cycle gas turbines to ultra-low sulfur diesel (ULSD). A summary of the analysis for both of the turbines combined is shown below:

Table 5-2. GVEA Economic Analysis for Technically Feasible SO_2 Controls for Turbines

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD (0.0015 % S wt.)	580	578	$8,674,362	$8,239,935	$14,250
Low Sulfur Fuel (0.05 % S wt.)	580	522	???	???	???
Capital Recovery Factor = 0.0944 (7% interest rate for a 20 year equipment life)					

GVEA contends that the economic analysis indicates the level of SO_2 reduction does not justify the fuel switch to ULSD in the simple cycle turbines based on the excessive cost per ton of SO_2 removed per year.

GVEA proposes the following as BACT for SO_2 emissions from the simple cycle gas turbines:

(a) SO_2 emissions from the operation of the fuel oil-fired simple cycle gas turbines will be controlled with good combustion practices; and

(b) Fuel burned in the fuel oil-fired simple cycle gas turbine will be limited to a sulfur content of 0.5 percent by weight.

Department Evaluation of BACT for SO_2 Emissions from the Simple Cycle Gas Turbines

The Department revised the cost analysis provided for the fuel switch to ULSD in the simple cycle gas turbines using the existing 580 tons of sulfur per year limit for the facility, an interest rate of 5.5% (current bank prime interest rate), a 20 year equipment life, and a fuel cost increase of $0.2668/gallon. Additionally, the Department reviewed the cost information provided by GVEA to appropriately evaluate the total capital investment of installing two new 1.5 million gallon ULSD storage tanks at GVEA's North Pole Facility. A summary of this analysis for both of the turbines combined is shown in Table 5-3:

Table 5-3. Department Economic Analysis for Technically Feasible SO_2 Controls for Turbines

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	580	578	$8,674,362	$5,354,581	$9,260
Capital Recovery Factor = 0.0837 (5.5% interest rate for a 20 year equipment life)					

The Department's economic analysis indicates the level of SO_2 reduction justifies the use of ULSD as BACT for the fuel oil-fired simple cycle gas turbines located in the Serious PM-2.5 nonattainment area.

Step 5 - Selection of SO_2 BACT for the Simple Cycle Gas Turbines

The Department's finding is that BACT for SO_2 emissions from the fuel oil-fired simple cycle gas turbines is as follows:

(a) SO_2 emissions from EUs 1 and 2 shall be controlled by limiting the sulfur content of fuel combusted in the turbines to no more than 0.0015 percent by weight;

(b) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(c) Compliance with the proposed fuel sulfur content limit will be demonstrated with fuel shipment receipts and/or fuel test results for sulfur content.

Table 5-4 lists the proposed SO_2 BACT determination for this facility along with those for other fuel oil-fired simple cycle gas turbines located in the Serious PM-2.5 nonattainment area.

Table 5-4. Comparison of SO_2 BACT for Simple Cycle Gas Turbines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
GVEA – North Pole	Two Fuel Oil-Fired Simple Cycle Gas Turbines	1,344 MMBtu/hr	0.0015 % S wt.	ULSD
GVEA – Zehnder	Two Fuel Oil-Fired Simple Cycle Gas Turbines	536 MMBtu/hr	0.0015 % S wt.	ULSD

5.2 SO_2 BACT for the Large Diesel-Fired Engines

Possible SO_2 emission control technologies for large engines were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process codes 17.100 to 17.190, Large Internal Combustion Engines (>500 hp). The search results for large diesel-fired engines are summarized in Table 5-5.

Table 5-5. RBLC Summary Results for SO_2 Control for Large Diesel-Fired Engines

Control Technology	Number of Determinations	Emission Limits (g/hp-hr)
Low Sulfur Diesel	27	0.005 – 0.02
Federal Emission Standards	6	0.001 – 0.005
Limited Operation	6	0.005 – 0.006
Good Combustion Practices	3	None Specified
No Control Specified	11	0.005 – 0.008

RBLC Review

A review of similar units in the RBLC indicates combustion of low sulfur fuel, limited operation, good combustion practices, and compliance with the federal emission standards are the principle SO_2 control technologies installed on large diesel-fired engines. The lowest SO_2 emission rate listed in the RBLC is 0.001 g/hp-hr.

Step 1 - Identification of SO_2 Control Technology for the Large Diesel-Fired Engines

From research, the Department identified the following technologies as available for control of SO_2 emissions from diesel fired engines rated at 500 hp or greater:

(a) Ultra Low Sulfur Diesel

The theory of ULSD was discussed in detail in the SO_2 BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. The Department considers ULSD a technically feasible control technology for the large diesel-fired engines.

(b) Federal Emission Standards
The theory of federal emission standards was discussed in detail in the NOx BACT for the large diesel-fired engine and will not be repeated here. The Department considers meeting the technology based NSPS of Subpart IIII as a technically feasible control technology for the large diesel-fired engines.

(c) Limited Operation
Limiting the operation of emission units reduces the potential to emit for those units. The Department considers limited operation a technically feasible control technology for the large diesel-fired engines.

(d) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbines and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the large diesel-fired engines.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Large Engines
All identified control technologies are technically feasible for the large diesel-fired engines.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Large Diesel-Fired Engines
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the large diesel-fired engines.

(a) Ultra-Low Sulfur Diesel (99% Control)
(c) Limited Operation (94% Control)
(d) Good Combustion Practices (Less than 40% Control)
(b) Federal Emission Standards (Baseline)

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA provided an economic analysis of the control technologies available for the large diesel-fired engine to demonstrate that the use of ULSD with limited operation is not economically feasible on these units. A summary of the analysis for EUs 3 and 4 is shown below:

Table 5-6. GVEA Economic Analysis for Technically Feasible SO_2 Controls per Engine

Control Alternative	Potential to Emit (tpy)	Emission Reduction (tpy)	Total Capital Investment ($)	Total Annualized Costs ($/year)	Cost Effectiveness ($/ton)
ULSD	3.71	3.70	--	$28,732	$7,768
Capital Recovery Factor = 0.1424 (7% interest rate for a 10 year equipment life)					

GVEA contends that the economic analysis indicates the level of SO_2 reduction does not justify the use of ULSD for the large diesel-fired engines based on the excessive cost per ton of SO_2 removed per year.

GVEA proposes the following as BACT for SO_2 emissions from the diesel-fired engines:

(a) SO_2 emissions from the operation of the diesel fired engines will be controlled with good combustion practices; and

(b) Limit the sulfur content of fuel combusted in EUs 3 and 4 to no more than 0.5 percent sulfur by weight.

Department Evaluation of BACT for SO_2 Emissions from the Diesel-Fired Engines

The Department reviewed GVEA's proposal for EUs 3 and 4 and finds that ULSD is an economically feasible control technology for large diesel-fired engines located in the Serious PM-2.5 nonattainment area. The Department does not agree with some of the assumptions provided in GVEA's cost analysis that cause an overestimation of the cost effectiveness. However, since this overestimation is still cost effective, the Department did not revise the cost analysis. The Department further finds that SO_2 emissions from the large diesel-fired engines can additionally be controlled by limiting the use of the units during non-emergency operation.

Step 5 - Selection of SO_2 BACT for the Diesel Fired Engines

The Department's finding is that the BACT for SO_2 emissions from the diesel-fired engines is as follows:

(a) SO_2 emissions from EUs 3 and 4 shall be controlled limiting the sulfur content of fuel combusted in the engines to no more than 0.0015 percent by weight;

(b) Limit non-emergency operation of EUs 3 and 4 to no more than 100 hours per year each, for maintenance checks and readiness testing;

(c) Maintain good combustion practices by following the manufacturer's maintenance procedures at all times of operation; and

(d) Compliance with the proposed fuel sulfur content limit will be demonstrated with fuel shipment receipts and/or fuel test results for sulfur content.

Table 5-7 lists the proposed SO_2 BACT determination for this facility along with those for other diesel-fired engines rated at more than 500 hp located in the Serious PM-2.5 nonattainment area.

Table 5-7. Comparison of SO_2 BACT for Large Diesel-Fired Engines at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	8 Large Diesel-Fired Engines	> 500 hp	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
UAF	Large Diesel-Fired Engine	13,266 hp	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
GVEA North Pole	Large Diesel-Fired Engine	600 hp	500 ppmw S in fuel	Limited Operation Good Combustion Practices

Facility	Process Description	Capacity	Limitation	Control Method
GVEA Zehnder	2 Large Diesel-Fired Engines	11,000 hp	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

5.3 SO_2 BACT for the Diesel Fired Boilers

Possible SO_2 emission control technologies for small diesel-fired boilers were obtained from the RBLC. The RBLC was searched for all determinations in the last 10 years under the process code 13.220, Industrial Size Boilers (<100 MMBtu/hr). The search results for diesel-fired engines are summarized in Table 5-8.

Table 5-8. RBLC Summary of SO_2 Control for the Small Diesel-Fired Boilers

Control Technology	Number of Determinations	Emission Limits (lb/MMBtu)
Low Sulfur Fuel	5	0.0036 – 0.0094
Good Combustion Practices	4	0.0005
No Control Specified	5	0.0005

RBLC Review
A review of similar units in the RBLC indicates that good combustion practices and combustion of low sulfur fuel are the principle SO_2 control technologies installed on diesel-fired boilers. The lowest SO_2 emission rate listed in the RBLC is 0.0005 lb/MMBtu.

Step 1 - Identification of SO_2 Control Technology for the Diesel Fired Boilers
From research, the Department identified the following technologies as available for SO_2 control for the diesel-fired boilers:

(a) Ultra Low Sulfur Diesel
ULSD has a fuel sulfur content of 0.0015 percent sulfur by weight or less. Using ULSD would reduce SO_2 emissions because the mid-sized diesel boilers are combusting standard diesel that has a sulfur content of up to 0.5 percent sulfur by weight. Switching to ULSD could control 99 percent decrease in SO_2 emissions from the diesel fired boilers. The Department considers ULSD a technically feasible control technology for the diesel-fired boilers.

(b) Good Combustion Practices
The theory of GCPs was discussed in detail in the NOx BACT for the fuel oil-fired simple cycle gas turbine and will not be repeated here. Proper management of the combustion process will result in a reduction of SO_2 emissions. The Department considers GCPs a technically feasible control technology for the diesel-fired boilers.

Step 2 - Eliminate Technically Infeasible SO_2 Control Technologies for the Diesel-Fired Boilers
All identified control technologies are technically feasible for the diesel-fired boilers.

Step 3 - Rank the Remaining SO_2 Control Technologies for the Diesel-Fired Boilers
The following control technologies have been identified and ranked by efficiency for the control of SO_2 emissions from the diesel-fired boilers.

(a) Ultra Low Sulfur Diesel (99% Control)
(b) Good Combustion Practices (Less than 40% Control)

Step 4 - Evaluate the Most Effective Controls

GVEA BACT Proposal

GVEA proposes the following as BACT for SO_2 emissions from the diesel-fired boilers:

(a) Combust only ULSD.

Department Evaluation of BACT for SO_2 Emissions from Diesel-Fired Boilers

The Department reviewed GVEA's proposal and finds that SO_2 emissions from the diesel-fired boilers can additionally be controlled with good combustion practices.

Step 5 - Selection of SO_2 BACT for the Diesel-Fired Boilers

The Department's finding is that BACT for SO_2 emissions from the diesel-fired boilers is as follows:

(a) SO_2 emissions from EUs 10 and 11 shall be controlled limiting the sulfur content of fuel combusted in the turbines to no more than 0.0015 percent by weight;

(b) Maintain good combustion practices by following the manufacturer's operating and maintenance procedures at all times of operation; and

(c) Compliance with the proposed fuel sulfur content limit will be demonstrated with fuel shipment receipts and/or fuel test results for sulfur content.

Table 5-9 lists the proposed SO_2 BACT determination for this facility along with those for other diesel-fired boilers rated at less than 100 MMBtu/hr in the Serious PM-2.5 nonattainment area.

Table 5-9. Comparison of SO_2 BACT for the Diesel-Fired Boilers at Nearby Power Plants

Facility	Process Description	Capacity	Limitation	Control Method
Fort Wainwright	Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Limited Operation Good Combustion Practices Ultra-Low Sulfur Diesel
	Waste Fuel-Fired Boilers		0.5 % S by weight	Good Combustion Practices
UAF	3 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel
GVEA Zehnder	2 Diesel-Fired Boilers	< 100 MMBtu/hr	15 ppmw S in fuel	Good Combustion Practices Ultra-Low Sulfur Diesel

6. BACT DETERMINATION SUMMARY

Table 6-1. Proposed NOx BACT Limits

EU ID	Description of EU	Capacity	Proposed BACT Limit	Proposed BACT Control
1	Fuel Oil-Fired Regenerative Gas Simple Cycle Gas Turbine	268 MMBtu/hr	0.044 lb/MMBtu	Selective Cayalytic Reduction Water Injection
2	Fuel Oil-Fired Regenerative Gas Simple Cycle Gas Turbine	268 MMBtu/hr	0.044 lb/MMBtu	
3	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr	10.9 g/hp-hr	Turbocharger & Aftercooler Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
4	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr	10.9 g/hp-hr	
10	Diesel-Fired Boiler	1.7 MMBtu/hr	0.15 lb/MMBtu	Good Combustion Practices
11	Diesel-Fired Boiler	1.7 MMBtu/hr	0.15 lb/MMBtu	

Table 6-2. Proposed PM-2.5 BACT Limits

EU ID	Description of EU	Capacity	Proposed BACT Limit	Proposed BACT Control
1	Fuel Oil-Fired Regenerative Gas Simple Cycle Gas Turbine	268 MMBtu/hr	0.012 lb/MMBtu	Low Ash Fuel Good Combustion Practices
2	Fuel Oil-Fired Regenerative Gas Simple Cycle Gas Turbine	268 MMBtu/hr	0.012 lb/MMBtu	
3	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr	0.32 g/hp-hr	Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
4	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr	0.32 g/hp-hr	
10	Diesel-Fired Boiler	1.7 MMBtu/hr	0.012 lb/MMBtu	Good Combustion Practices
11	Diesel-Fired Boiler	1.7 MMBtu/hr	0.012 lb/MMBtu	

Table 6-3. Proposed SO_2 BACT Limits

EU ID	Description of EU	Capacity	Proposed BACT Limit	Proposed BACT Control
1	Fuel Oil-Fired Regenerative Gas Simple Cycle Gas Turbine	268 MMBtu/hr	15 ppmw S in Fuel	Ultra Low Sulfur Diesel
2	Fuel Oil-Fired Regenerative Gas Simple Cycle Gas Turbine	268 MMBtu/hr	15 ppmw S in Fuel	
3	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr	15 ppmw S in Fuel	Ultra Low Sulfur Diesel Good Combustion Practices Limited Operation (100 hours/year each, for non-emergency operation)
4	Diesel-Fired Emergency Generator Engine	28 MMBtu/hr	15 ppmw S in Fuel	
10	Diesel-Fired Boiler	1.7 MMBtu/hr	15 ppmw S in Fuel	Ultra Low Sulfur Diesel Good Combustion Practices
11	Diesel-Fired Boiler	1.7 MMBtu/hr	15 ppmw S in Fuel	

THE STATE of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

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November 16, 2017

Naomi Knight, Environmental Officer
Golden Valley Electric Association
PO Box 71249
Fairbanks, AK 99707-1249

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum from Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility by December 22, 2017

Dear Ms. Knight:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that GVEA North Pole and Zehnder and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as GVEA North Pole and Zehnder. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analyses are a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Ms. Naomi Knight at GVEA on May 11, 2017 notifying her of the reclassification

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)
[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.
[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

to Serious and included a request for the BACT analysis to be completed by August 8, 2017. The BACT analyses from GVEA North Pole and Zehnder, which included emission units found in Operating Permits AQ0110TVP03 and AQ0109TVP03, were submitted by email to the Department on August 30, 2017.

ADEC and EPA reviewed the BACT analyses provided for GVEA North Pole and Zehnder Facilities and ADEC is requesting additional information to assist it in making a legally and practicably enforceable BACT determinations for the sources. Both the ADEC and EPA comments are enclosed in this letter. ADEC requests a response by December 22, 2017. If ADEC does not receive a response to this information request by this date, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facilities' infrastructure and without additional information may select a more stringent BACT for your facilities in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analysis before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes final BACT determinations for GVEA North Pole and Zehnder, it must include the determinations in Alaska's Serious SIP that then ultimately requires approval by EPA.[4] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 - 4 years after reclassification.[5]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from GVEA. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch, Director
Division of Air Quality

[4] https://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart4-sec7513a
[5] 40. CFR 51.1010(4)

Enclosures:

November 16, 2017	ADEC Request for Additional Information for GVEA North Pole and Zehnder BACT Analyses;
November 15, 2017	EPA GVEA BACT Analysis Review Comments
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for GVEA North Pole and Zehnder

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/Air Quality
Naomi Knight/GVEA
Tim Hamlin, EPA Region 10
Dan Brown, EPA Region 10
Zach Hedgpeth, EPA Region 10

ADEC Request for Additional Information
Golden Valley Electric Association – North Pole and Zehnder Facilities
BACT Analysis Review
August 2017

November 16, 2017

Please address the following comments by providing the additional information identified by December 22, 2017. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public review. In order to provide this additional review opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public review period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

1. Equipment Life – Page 31 of the North Pole analysis and Page 27 of the Zehnder analysis state "Because of the harsh climate, equipment in this far north location experiences more wear and tear than equipment in moderate climates. On this basis, a ten year return on the [water injection and] SCR system is assumed to be reasonable." This same assumption is made for the other control devices. ADEC identified that the EPA Air Pollution Control Cost Manual[1] uses a hypothetical example that assumes the control equipment has a useful life of ten years. However the cost analyses must use a reasonable estimate of the actual life of the control equipment for each control technology. In order to use an equipment life that is shorter than 30 years, evidence must be provided to support the claim that 10 years is a reasonable timeframe for equipment life. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as turbines.

2. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

[1] U.S. EPA OAQPS Air Pollution Control Cost Manual, 6th Edition [EPA/452/B-02-001]

3. Cost Analyses – Page 44 of the North Pole analysis indicates that EUs 1 and 2 have historically low run hours. Page 34 of the Zehnder analysis state that "GVEA believes that an economic analysis based on the actual emissions and operations of these turbines is more relevant for purposes of determining viable ways to reduce PM2.5 ambient concentrations in the Fairbanks area." However, all BACT cost effectiveness calculations must be based upon the potential to emit, and not on historic operation. Please update the cost analyses using the unrestricted potential to emit for each of the emissions units or propose operational limits (including control efficiencies associated with limited operation). Additionally, see Comments 4, 5, and 6 for additional information related to retrofit costs, baseline emissions, and factor of safety.

4. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) is required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for any difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analyses.

5. Baseline Emissions – Include the baseline emissions for all emission units included in the analyses. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and low NOx burners) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.

6. Factor of Safety – If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

7. Good Combustion Practices –For each emission unit type (oil fuel-fired turbines, combined cycle turbines, emergency generator engines, and boilers) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

8. Alternate Fuel – Page 96 of the North Pole analysis indicates that "the capital costs incurred to switch fuels [to ULSD] would include an estimated capital cost of $30,425,000 to install bulk fuel storage." Please provide a full evaluation of the fuel change impacts, fuel pricing, and bulk storage facility pricing. Based on the fuel supply information gathered for the BACM analysis for the Fairbanks Serious SIP, the Department is aware of more than one supplier of alternate fuels. Please make sure all supplier cost information is addressed for all emission units that are evaluating a fuel switch.

9. Cost Analysis Spreadsheets – The BACT analyses for North Pole and Zehnder Facilities include emissions, cost effectiveness, and incremental cost effectiveness calculations, but none of these calculations have been submitted in a spreadsheet format. Please submit the electronic versions of the spreadsheets used in determining the cost effectiveness for any control technology not selected as the highest level of control.

10. Confidential Documentation – The BACT analyses for North Pole and Zehnder Facilities have indicated that details related to costs were included in a separately submitted package under application for confidentiality of records. Please submit the supporting documentation so the Department can conduct a more detailed review of the analyses and calculations.
11. Control Technology Availability – For the North Pole Facility, include Flue Gas Recirculation in the review of NOx control technologies for diesel-fired boilers. Rank the control technologies by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of good combustion practices. Provide a numerical NOx emission limit for the diesel-fired boilers or identify the work or operational practices that will be utilized to ensure compliance with proposed limits.

GVEA – North Pole and Zehnder Power Plants
BACT Analysis Review Comments
Reports dated August 2017 – GVEA

Zach Hedgpeth, PE
EPA Region 10 – Seattle
November 15, 2017

Note: These comments represent a partial review of the BACT analyses for the GVEA North Pole and Zehnder facilities, since none of the emission calculations or cost analysis calculations have been submitted in spreadsheet format. Also, certain documents forming the basis for costs used in the analyses have not been submitted due to confidentiality concerns. EPA Region 10 will conduct a more detailed review of the analysis and calculations following submittal of this information.

1. Equipment Life – Page 31 of the North Pole analysis[1] states "a standardized ten year return on investment at seven percent interest rate is assumed". This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in this far north location experiences more wear and tear than equipment in moderate climates". The analysis includes no further information to support the assumption of a ten year equipment life, nor the underlying assertion regarding wear and tear. The analyses must use a reasonable estimate of the actual life of the control equipment for each control technology, based on the best evidence available. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as turbines.
2. Control Technology Availability – Technically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology is not available for the emission unit in question. For example, the North Pole analysis concludes that flue gas recirculation is not technically feasible for NO_X control based on the statement that "FGR is not available with the vendor-provided Low-NO_X combustor retrofit package for these boilers." Written documentation from multiple vendors must be included to support this statement.
3. Basis for Costs and Assumptions – Documents cited in the analyses which form the basis for costs used in the analyses and assumptions made in the analyses must be provided. For example, within the analysis of SCR for the North Pole facility (see page 30), many of the costs used for SCR appear to be based either on "past project experience" or "information from other projects". Detailed information forming the basis for these cost assumptions in the analysis must be submitted as part of the BACT analysis. Certain other costs are estimated based on a 1993 EPA document referred to as the "Alternative Control Techniques Document". A copy of this document must be included as an attachment to the analysis if this document forms the basis for information used in the analysis. EPA Region 10 will conduct a more detailed review of the calculations following submittal of this and other requested information.
4. EPA Cost Spreadsheets – Note that the EPA has recently updated the cost manual chapter pertaining to SCR, and developed a cost spreadsheet to be used for evaluation of this technology

[1] Golden Valley Electric Association, Voluntary $PM_{2.5}$ Serious Nonattainment Area BACT Analysis for the North Pole Facility, August 2017

for cost effectiveness[2]. The EPA spreadsheet was developed to evaluate cost effectiveness of SCR as applied to boilers, so cannot be directly applied to turbines. However, the cost analyses for SCR developed for the GVEA emission units must be consistent with the updated cost manual chapter.

5. SCR Space Constraints – The North Pole analysis includes a number of statements regarding space constraints and other installation challenges that the analysis claims complicate or possibly preclude installation of SCR on the turbines, however detailed drawings, site plans and other information have not been submitted to substantiate these claims. One aerial photo of the facility has been included, but all areas surrounding the buildings housing the emission units are marked as unavailable due to "maintenance access areas" or "fuel delivery truck route". Establishing the entire area surrounding the buildings as unavailable for control equipment based on these purposes would require substantially more detailed justification than has been provided. Additionally, in order to establish SCR as not technically feasible due to space constraints or other retrofit factors, detailed site specific information must be submitted in order to establish the basis for such a determination. Installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase cost and site specific installation cost estimate or quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor.

6. Costs Not Included – In several locations (i.e., p. 40 of the North Pole analysis), the analyses include the statement that cost estimates are "conservatively low" because they do not include the cost of support systems needed to operate the control equipment. EPA Region 10 believes these costs should be included in the analyses, based on site-specific capital and installation estimates or quotes provided by qualified control equipment vendors. Justification for inclusion of each retrofit-related cost must be included in the analyses. Development of reasonably accurate cost estimates for these retrofit projects is necessary in order to inform the BACT determination for each emission unit and pollutant.

7. Potential vs. Actual Emissions – In some places, the analyses propose BACT determinations based on use of actual emissions. All BACT cost effectiveness calculations must use potential-to-emit (PTE), regardless of the emission unit usage history or actual historical emission rates. The facility should consider operating limits in cases where certain emission units do not need to retain relatively high PTE for facility operational purposes.

[2] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

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Department of Environmental Conservation

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Return Receipt Requested

April 24, 2015

Naomi Knight, Environmental Officer
Golden Valley Electric Association
PO Box 71249
Fairbanks, AK 99707-1249

Subject: Voluntary BACT Analysis for Zehnder Facility and North Pole Power Plant

Dear Ms. Knight:

Portions of the Fairbanks North Star Borough are in nonattainment with the 24-hour National Ambient Air Quality Standard for Fine Particulate Matter (PM 2.5). The Alaska Department of Environmental Conservation (ADEC) expects that the Environmental Protection Agency (EPA) will change the nonattainment designation from a Moderate Area to a Serious Area in June 2016. Once EPA designates the area as Serious, an 18-month clock begins for submittal of an implementation plan that includes best available control technologies (BACT) analysis and determination for stationary sources with over 70 tons per year (TPY) potential to emit (PTE) for PM2.5 or its precursors.

ADEC has neither the funding nor the in depth knowledge of your facility's infrastructure to determine the most appropriate BACT for your facility. Without the information or resources necessary to conduct detailed cost analysis and produce supporting documentation, ADEC may select a more stringent BACT for your facility in order to be approvable by EPA. In addition, 18 months is likely not adequate to complete a thorough BACT analysis.

Therefore, ADEC requests that your facility voluntarily begin the BACT analysis. We request that you submit an initial BACT analysis to ADEC by December 2015 and the final BACT analysis by March 2016 to ADEC. ADEC is required to make a BACT determination for every eligible facility within the designated PM2.5 nonattainment area and final BACT determinations are ultimately reviewed by EPA and subject to federal approval as part of the federally required PM2.5 implementation plan.

<u>Background</u>
EPA required that ADEC submit a State Implementation Plan (SIP) because portions of the Fairbanks North Star Borough (FSNB) are in nonattainment with the health based 24-hour National

Ambient Air Quality Standard for PM2.5. ADEC submitted an initial, Moderate Area PM2.5 SIP for FNSB to EPA on December 31, 2014.

Unfortunately, this Moderate Area SIP was developed as an impracticable SIP because modeling was unable to demonstrate that attainment with the health standard was possible by December 30, 2015. Preliminary air monitoring results also indicate that FNSB will not demonstrate attainment in 2015. Attainment is calculated on a rolling three year average of the highest 98th percentile concentration at each monitor. When those monitoring results become final in May 2016 and an official three year design value is calculated, the FNSB non-attainment area will remain over the 24-hr PM 2.5 standard of 35 $\mu g/m^3$. The final determination of this design value will result in the FNSB non-attainment area being reclassified from a Moderate Area to a Serious Area[1] (40 CRF Parts 50, 51 and 93). This reclassification will happen by operation of law as outlined in Clean Air Act Sections 188 and 189. It is anticipated that the formal designation to Serious Area will occur in June 2016.

A Serious Area designation will result in several new, more stringent requirements, one of which is that all source categories in the nonattainment area that meet the BACT threshold of 70 TPY PTE for $PM_{2.5}$ and its precursor pollutants (NOx, SO2, VOC, NH3) must be analyzed for Best Available Control Measures (BACM). As part of BACM, a Best Available Control Technologies (BACT) analysis will be required. The Serious Area BACT trigger requires the same approach as a PSD/NSR BACT project. A Serious non-attainment area BACT limit is set using a top-down analysis on a case-by-case basis taking into account energy, environmental and economic impacts, and costs. The analysis must include all emission units at the source.

The timelines for completion of the BACT analysis, subsequent BACT determination, and the submittal of the Serious Area SIP are outlined in the preamble of the Particulate Matter 10 (PM10) rule and reconfirmed in the newly proposed $PM_{2.5}$ Implementation Rule[2]. Both rules require a completed SIP 18 months after designation to Serious. This 18 month time period does not allow enough time to thoroughly evaluate BACT, update the emission inventory, complete the modeling and allow for development and processing for a Serious Area SIP.

ADEC believes that it is best for facilities to complete the BACT analysis for their own facilities. ADEC does not have the funding to develop the analysis nor the in depth knowledge of each sources' infrastructure. ADEC would therefore base the cost analysis on the installation of control equipment without being able to factor in all the costs associated with retrofitting existing equipment. Without the detailed cost analysis and supporting documentation to support less stringent BACT options, it is doubtful that the BACT portions of the Serious SIP will be approvable without using the most stringent measures.

By requesting an early BACT analysis for facilities before the official Serious Area designation, it will help ADEC meet the following timelines and ultimately submit a Serious Area SIP to EPA by the required due date. Early analysis also has the potential to increase flexibility for each Stationary Source under the rules.

[1] 40 CFR Parts 50,51 and 93 http://www.epa.gov/airquality/particlepollution/actions.html

[2] http://www.epa.gov/airquality/particlepollution/actions.html

- Serious Area SIP inventory development starts: January, 2015
- BACT kick off meeting: March 5, 2015
- Submit initial BACT results to ADEC: December, 2015
- Submit complete/final BACT analysis to ADEC: March, 2016
- Serious Area SIP modeling by ADEC starts: March, 2016
- Serious Area designation by EPA (Expected): June, 2016
- Serious Area SIP draft: December, 2016
- Serious Area SIP public notice period: February, 2017
- Serious Area SIP submitted by ADEC to EPA: December, 2017

Meeting the BACT analysis requirements is a major component of a Serious SIP. This is a challenging issue. It is important that ADEC accurately reflect the contributions of industrial sources to the air pollution problem and the potential improvements available within this emission sector along with the other emission sources in the community.

ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

Sincerely,

Denise Koch

Denise Koch, Director
Division of Air Quality

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
John Kuterbach, ADEC/ Air Quality
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality

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Your Touchstone Energy® Cooperative

December 22, 2017

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RE: Response to request for additional information for the Best Available Control Technology Technical Memorandum from Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility.

Dear Ms. Koch,

Golden Valley Electric Association (GVEA) received a request for additional information from the Alaska Department of Environmental Conservation (ADEC) on November 16, 2017 regarding the Best Available Control Technology (BACT) analyses previously submitted for the North Pole Power Plant and Zehnder Facility. The request for additional information included a set of 11 comments from ADEC and 7 comments from EPA region 10. Listed below is each comment followed by GVEA's response.

Overall, GVEA understands from a regulatory perspective that ADEC and EPA wish to have as much information as possible available to substantiate BACT determinations, and that the highest level of engineering detail would require hundreds of thousands of dollars in engineering studies; the real studies that would identify true retrofit feasibility and true costs. In preparing the BACT analyses GVEA worked to provide a level of detail that is commonly commensurate with BACT analyses and practical to obtain. With respect to the evaluation of NOx BACT in particular, GVEA finds itself in a dilemma while waiting for the outcome of ADEC's NOx precursor demonstration, hesitant to over invest in costly engineering studies that many not be necessary.

ADEC Comments

1. Equipment Life – Page 31 of the North Pole analysis and Page 27 of the Zehnder analysis state "Because of the harsh climate, equipment in this far north location experiences more wear and tear than equipment in moderate climates. On this basis, a ten year return on the [water injection and] SCR system is assumed to be reasonable." This same assumption is made for the other control devices. ADEC identified that the EPA Air Pollution Control Cost Manual uses a hypothetical example that assumes the control equipment has a useful life of ten years. However the cost analyses must use a reasonable estimate of the actual life of the control equipment for each control technology. In order to use an equipment life that is shorter than 30 years, evidence must be provided to support the claim that 10 years is a reasonable timeframe for equipment life. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as turbines.

    GVEA response:
    The 10-year equipment life as used in the calculations for capital recover in the Zehnder Plant and North Pole Plant BACT analyses is consistent with established ADEC practice and previously approved PSD permitting BACT analyses evaluated by ADEC over the past 20 years. GVEA believes this 10-year equipment life timeframe is appropriate for equipment operated in the harsh Alaska climate and falls within the equipment lifetimes used in the EPA Air Pollution Control Cost Manual (sixth edition, EPA/452/B-02-001, Control Cost Manual) which uses equipment lifetimes between 5 and 30 years. Ten, 15, and 20-year lifespans are frequently used in the manual.

    As examples, two recent Alaskan permits with BACT analyses based on a 10-year equipment life include
    - *The BACT analysis for the Doyon Utilities JBER Electric, Gas & Sanitary Services Permit AQ0237CPT04 dated May 8, 2013. See the footnote to Table B-4 of the TAR to that permit.*
    - *The BACT analysis for the Agrium U.S. Inc. Kenai Nitrogen Operations Permit AQ0083CPT06 dated January 6, 2015. See the table on page 24 (of 171) in the TAR to that permit.*

2. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

GVEA response:

<u>BACT Limits for Normal Operation</u>

The numerical emissions limits that were proposed as BACT selections and that were provided in the Zehnder Power Plant and North Pole Power Plant BACT analyses are summarized in attached Tables 2-1 and 2-2, respectively. Averaging periods, which were inadvertently omitted from the BACT analysis reports, are also included in Tables 2-1 and 2-2.

The averaging periods provided in Tables 2-1 and 2-2 are not an indication of compliance demonstration methodology. Source testing is not an appropriate compliance demonstration methodology for the Zehnder plant and North Pole plant boilers because the units are very small, diesel-fired, and not operated continuously. Startups and shutdowns are typically unscheduled events, but source test planning and mobilization can required up to several months in Alaska because source testing teams and equipment frequently must be brought to Alaska from the Lower 48. The requirement to provide a 30 to 60 -day source test notification to ADEC and/or EPA and to prepare and obtain agency approval of a source test plan also reduces scheduling flexibility. The agency-mandated source testing protocol typically requires that three 1-hour test runs be completed for a test to be valid, while typical startups and shutdowns have a much shorter duration. As a result, retaining records demonstrating proper operation and maintenance is the appropriate compliance demonstration method. Based on the same rationale, the compliance demonstration methodology for the Zehnder plant and North Pole plant emergency diesel-fired reciprocating engines should be retaining records demonstrating proper operation and maintenance.

GVEA wishes to note that while preparing this response, one emission factor error was found in each of the Zehnder plant and North Pole plant BACT analysis reports, but in neither case is the BACT analyses affected.[1]

<u>BACT Limits for Startup, Shutdown, and Malfunction (SSM)</u>

The BACT affected emission units at the Zehnder and North Pole plants have short startup durations, normally ranging from 15 to 30 minutes. The shutdown durations are similarly short, typically less than 15 minutes for all of the BACT affected emission units. For startup, shutdown BACT available options are numerical emission limits, or duration

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[1] *Table 3-15 of the Zehnder report incorrectly lists the nitrogen oxides (NO_X) emission rate for EUs 3 and 4 as 0.0022 pounds per horsepower-hour (lb/hp-hr). The correct BACT emission rate for NO_X emissions from EUs 3 and 4 is 0.024 lb/hp-hr. The NO_X BACT analysis in Section 3 of the Zehnder plant report is based on the correct emission factor. Table 3-23 of the North Pole report incorrectly lists the NO_X emission rate for EU 7 as 0.0022 lb/hp-hr. The correct BACT emission rate for NO_X emissions from EU 7 is 0.031 lb/hp-hr. The NO_X BACT analysis in Section 3 of the North Pole plant report is based on the correct emission factor.*

limits. For malfunction BACT available options are numerical emission limits, or the expeditious return to normal operation or shut down for repairs.

For startup and shutdown, numerical emission limits are not a practical BACT selection for these emission units because demonstrating compliance with such a limit is not technically feasible as a practical matter. Specifically, the startup and shutdown periods are too short to enable performance testing using the methods provided in Appendix A to 40 Code of Federal Regulations (CFR) 60.

As an allowed alternative, the BACT limit available for all emission units and for all air pollutants is the specification of duration limits for startup and shutdown. This proposed work and operational practice is consistent with the BACT guidance and enables a practical methodology for demonstrating compliance during startup and shutdown period. Table 2-3 shows the proposed BACT startup and shutdown durations for emission units at the Zehnder Facility while Table 2-4 shows the proposed BACT startup and shutdown durations for emission units at the North Pole Plant.

For malfunctions, numerical emission limits are not a practical BACT selection for the Zehnder and North Pole emission units during a malfunction because demonstrating compliance with such a limit is not technically feasible as a practical matter. Specifically, predicting when or for how long a malfunction might occur is not possible because of the nature of malfunction events. As a result, demonstrating compliance with numerical emission limits during a malfunction is not practical using the performance testing methods provided in Appendix A to 40 CFR 60.

As an allowed alternative, the BACT limit for all air pollutants and emission units is to restore the malfunctioning emission unit to normal operation as soon as is practical or proceed with shutting down the emission unit until repairs can be made. This proposed work and operational practice is consistent with the BACT guidance and enables a practical methodology for demonstrating compliance during malfunction. Table 2-2 also shows the proposed malfunction BACT for the emission units at the Zehnder Facility and Table 2-4 shows the proposed BACT for the emission units at the North Pole Plant.

3. <u>Cost Analyses</u> – Page 44 of the North Pole analysis indicates that EUs 1 and 2 have historically low run hours. Page 34 of the Zehnder analysis state that "GVEA believes that an economic analysis based on the actual emissions and operations of these turbines is more relevant for purposes of determining viable ways to reduce PM2.5 ambient concentrations in the Fairbanks area." However, all BACT cost effectiveness calculations must be based upon the potential to emit, and not on historic operation. Please update the cost analyses using the unrestricted potential to emit for each of the emissions units or propose operational limits (including control efficiencies associated with limited operation). Additionally, see Comments 4, 5, and 6 for additional information related to retrofit costs, baseline emissions, and factor of safety.

GVEA response:
The North Pole Plant and Zehnder Plant BACT analyses reports submitted in August 2017 do provide the cost effectiveness based on potential to emit (PTE). The cost effectiveness tables and associated page numbers for each pollutant and each control evaluated are provided below in Table 3-1.

Table 3-1. Location of BACT Cost Effectiveness Based on PTE

North Pole Plant				
EU ID	**Pollutant**	**Control Cost Effectiveness Evaluated**	**Table**	**Page**
EU ID 1	NO_X	SCR with Water Injection	Table 3-5	51
EU ID 2	NO_X	SCR with Water Injection	Table 3-7	53
EU ID 1	NO_X	SCR	Table 3-9	55
EU ID 2	NO_X	SCR	Table 3-11	57
EU ID 1	NO_X	Water Injection	Table 3-13	59
EU ID 2	NO_X	Water Injection	Table 3-15	61
EU ID 1	SO_2	ULSD	Table 5-4	103
EU ID 2	SO_2	ULSD	Table 5-5	104
Zehnder Plant				
EU ID	**Pollutant**	**Control Cost Effectiveness Evaluated**	**Table**	**Page**
EU IDs 1 and 2	NO_X	SCR with Water Injection	Table 3-5	42
	NO_X	SCR	Table 3-7	44
	NO_X	Water Injection	Table 3-9	46
	SO_2	ULSD	Table 5-4	81

GVEA understands that a traditional BACT process typically evaluates control cost effectiveness based on PTE and did present those costs. GVEA also understands that BACT decisions are made on a case-by-case basis so that criteria specific to each BACT situation can be properly considered. In this case, GVEA believes that the historically low actual operating hours and associated emissions from the North Pole Plant EUs 1 and 2, and the Zehnder Plant EUs 1 and 2 are representative of the actual contribution emissions from these plants have made to the measured ambient $PM_{2.5}$ concentrations. Because the GVEA cooperative members would bear the economic burden of paying for emission controls that would in practical reality do very little to reduce regional ambient $PM_{2.5}$ concentrations, GVEA proposes that basing the BACT cost effectiveness on the historical actual operating hours is appropriate.

GVEA believes it is premature to commit to any operating limitations. Though these emission units have historically operated only a few hours on an annual basis, all of the emission units are critical to providing reliable power to our cooperative members in the event GVEA loses other generating units or is unable to receive purchased power from Southcentral Alaska. Having available generation is especially important during the coldest winter months when reliable power is critical to maintain the health and safety of *our members. Before knowing the outcome of the ADEC NO_X precursor demonstration, GVEA is uncomfortable committing to restrictions on available operating hours that may be unnecessary if the NOx precursor demonstration is successful.*

4. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) is required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for any difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analyses.

   GVEA response:
   GVEA did not use stand-alone retrofit factors in the BACT cost analyses presented in the August 2017 reports, rather vendor supplied cost information took into account the retrofit installation along with potential complications and cost increases associated with the Alaskan location.

5. Baseline Emissions – Include the baseline emissions for all emission units included in the analyses. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and low NOx burners) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.

   GVEA response:
   For both the Zehnder plant and North Pole plant analyses submitted in August 2017, baseline emissions were provided in Section 1, in Tables 1-2 through 1-5. The baseline emission rates incorporate existing emission control devices and enforceable emission and operating limits.

6. Factor of Safety – If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

   GVEA response:
   GVEA did not feel safety factors were warranted and they were not included in the BACT emission limits proposed in the BACT analysis reports submitted in August 2017.

7. Good Combustion Practices –For each emission unit type (oil fuel-fired turbines, combined cycle turbines, emergency generator engines, and boilers) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

   GVEA response:
   GVEA's current practice and proposed practice to achieve good combustion practices is the adherence to the original equipment manufacturer (OEM) recommendations for operation and maintenance of all emission units. Good combustion practices are integral to these OEM recommendations, so following the recommendations intrinsically assures compliance with good combustion practices. Set points for efficient combustion are also set into the control systems and those parameters are kept constant. For building heaters the OEM guidelines are followed for tuning and operation and O_2 balance is periodically measured.

8. Alternate Fuel – Page 96 of the North Pole analysis indicates that "the capital costs incurred to switch fuels [to ULSD] would include an estimated capital cost of $30,425,000 to install bulk fuel storage." Please provide a full evaluation of the fuel change impacts, fuel pricing, and bulk storage facility pricing. Based on the fuel supply information gathered for the BACM analysis for the Fairbanks Serious SIP, the Department is aware of more than one supplier of alternate fuels. Please make sure all supplier cost information is addressed for all emission units that are evaluating a fuel switch.

   GVEA response:
   Ensuring the resilient and economical supply of fuel for both normal and emergency operations is extremely important to GVEA and as such the evaluation of fuel vendors within Alaska and the Pacific Northwest is a normal part of strategic planning. The capital costs used in the BACT were developed with the assistance of a technical memo provided by PDC Engineers, and a summary analysis provided by an Energy Analyst with Leidos Engineering. The supporting documentation is provided in the separately submitted package under request for confidentiality.

9. Cost Analysis Spreadsheets – The BACT analyses for North Pole and Zehnder Facilities include emissions, cost effectiveness, and incremental cost effectiveness calculations, but none of these calculations have been submitted in a spreadsheet format. Please submit the electronic versions of the spreadsheets used in determining the cost effectiveness for any control technology not selected as the highest level of control.

   GVEA response:
   The enclosed disk contains the electronic versions of the spreadsheets used in determining the cost effectiveness for all control technologies evaluated.

10. Confidential Documentation – The BACT analyses for North Pole and Zehnder Facilities have indicated that details related to costs were included in a separately submitted package under application for confidentiality of records. Please submit the supporting documentation so the Department can conduct a more detailed review of the analyses and calculations.

    GVEA response:
    The supporting documentation has been submitted under separate cover dated December 22, 2017

11. Control Technology Availability – For the North Pole Facility, include Flue Gas Recirculation in the review of NOx control technologies for diesel-fired boilers. Rank the control technologies by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of good combustion practices. Provide a numerical NOx emission limit for the diesel-fired boilers or identify the work or operational practices that will be utilized to ensure compliance with proposed limits.

    GVEA response:
    Aaron Simpson of ADEC and Courtney Kimball of SLR (a GVEA consultant) discussed this question during a phone call on November 30, 2017. The North Pole facility does not have any diesel-fired boilers. Mr. Simpson indicated that the comment was meant to address the diesel-fired boilers at the Zehnder facility (EUs 10 and 11). Mr. Simpson and Ms. Kimball agreed that while Flue Gas Recirculation (FGR) is an available emission control technology, vendor information indicates that boiler efficiency would decrease as a result of FGR use. This information is provided in Section 3.2.3 of the Zehnder BACT analysis report. Upon further review of this section of the report, Mr. Simpson stated that no further response to this question was necessary.

EPA Comments

1. Equipment Life – Page 31 of the North Pole analysis states "a standardized ten year return on investment at seven percent interest rate is assumed". This assumption for the equipment life is based solely on the statement that "because of the harsh climate, equipment in this far north location experiences more wear and tear than equipment in moderate climates". The analysis includes no further information to support the assumption of a ten year equipment life, nor the underlying assertion regarding wear and tear. The analyses must use a reasonable estimate of the actual life of the control equipment for each control technology, based on the best evidence available. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as turbines.

GVEA response:
Please see response to ADEC Comment 1 above.

2. Control Technology Availability – Technically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology is not available for the emission unit in question. For example, the North Pole analysis concludes that flue gas recirculation is not technically feasible for NO_X control based on the statement that "FGR is not available with the vendor-provided Low-NO_X combustor retrofit package for these boilers." Written documentation from multiple vendors must be included to support this statement.

   GVEA response:
   Please see response to ADEC Comment 11 above, Aaron Simpson of ADEC and Courtney Kimball of SLR (a GVEA consultant) discussed flue gas recirculation during a phone call on November 30, 2017. The North Pole facility does not have any diesel-fired boilers. Mr. Simpson indicated that his comment was meant to address the diesel-fired boilers at the Zehnder facility (EUs 10 and 11). Mr. Simpson and Ms. Kimball agreed that while Flue Gas Recirculation (FGR) is an available emission control technology, vendor information indicates that boiler efficiency would decrease as a result of FGR use. This information is provided in Section 3.2.3 of the Zehnder BACT analysis report. Upon further review of this section of the report, Mr. Simpson stated that no further response to this question was necessary for ADEC Comment 11. GVEA defers to this conversation in response to this comment.

3. Basis for Costs and Assumptions – Documents cited in the analyses which form the basis for costs used in the analyses and assumptions made in the analyses must be provided. For example, within the analysis of SCR for the North Pole facility (see page 30), many of the costs used for SCR appear to be based either on "past project experience" or "information from other projects". Detailed information forming the basis for these cost assumptions in the analysis must be submitted as part of the BACT analysis. Certain other costs are estimated based on a 1993 EPA document referred to as the "Alternative Control Techniques Document". A copy of this document must be included as an attachment to the analysis if this document forms the basis for information used in the analysis. EPA Region 10 will conduct a more detailed review of the calculations following submittal of this and other requested information.

   GVEA response:
   GVEA believes providing cost estimate elements based on "past project experience" or "information from other projects" without providing detailed information is appropriate for this BACT analysis, and is commensurate with an acceptable level of engineering study and cost. Stanley Consultants Inc. (SCI), is a multi-disciplinary engineering company that has provided decades of service to the power generation industry. Services that include new plant design and upgrades and retrofits. SCI assisted in the gathering of engineering estimates, vendor estimates, and did supply information based on their previous project experience. Providing additional detail would require additional time and expense and GVEA is concerned that is may not be warranted pending results from

ADEC about the modeled impacts that NO_X emissions may or may not be having on actual ambient $PM_{2.5}$ concentrations.

The 1993 EPA Alternative Control Techniques Document is specifically cited in the References section (immediately following Section 6) of the North Pole BACT Analysis Report. The document is available on the EPA website[2] and has been supplied with other files on the included DVD-ROM

4. EPA Cost Spreadsheets – Note that the EPA has recently updated the cost manual chapter pertaining to SCR, and developed a cost spreadsheet to be used for evaluation of this technology for cost effectiveness. The EPA spreadsheet was developed to evaluate cost effectiveness of SCR as applied to boilers, so cannot be directly applied to turbines. However, the cost analyses for SCR developed for the GVEA emission units must be consistent with the updated cost manual chapter.

   GVEA response:
   The NO_X BACT analyses for SCR do not incorporate the November 2017 changes to Section 4, Chapter 2 of the EPA Control Cost Manual (which was posted to the EPA website in December 2017) because EPA issued those changes after the BACT analysis reports were submitted to ADEC. The August 2017 submittal was prepared to be consistent with the previous version. GVEA is aware that interest rates were modified and lowered from 7 percent to 4.25 percent, however in the short time allowed to prepare these responses has not modified the reports and the analyses to reflect this change.

5. SCR Space Constraints – The North Pole analysis includes a number of statements regarding space constraints and other installation challenges that the analysis claims complicate or possibly preclude installation of SCR on the turbines, however detailed drawings, site plans and other information have not been submitted to substantiate these claims. One aerial photo of the facility has been included, but all areas surrounding the buildings housing the emission units are marked as unavailable due to "maintenance access areas" or "fuel delivery truck route". Establishing the entire area surrounding the buildings as unavailable for control equipment based on these purposes would require substantially more detailed justification than has been provided. Additionally, in order to establish SCR as not technically feasible due to space constraints or other retrofit factors, detailed site specific information must be submitted in order to establish the basis for such a determination. Installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase cost and site specific installation cost estimate or quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor.

[2] https://www3.epa.gov/ttncatc1/dir1/gasturb.pdf

GVEA response:
As stated in the BACT analyses and intended to be demonstrated on the aerial photographs, GVEA is very concerned with space constraints at both the Zehnder and North Pole sites. This concern is born from our experience in operating and maintaining the units, and maneuvering on the property. The stacks for EU ID's 1 and 2 are split, each having exits on the south and north sides of the building, there is a high voltage substation to the south, and the blue lines represent the circular routes fuel tanker trucks travel to deliver fuel in the most efficient cycle. Marked maintenance areas include access locations for the use of cranes. GVEA believes it would take a very detailed and expensive engineering effort to fully determine the feasibility and cost of SCR installation on EU ID's 1 and 2, and has difficulty justifying that effort until additional information is available from ADEC about the modeled impacts that NO_X emissions may or may not be having on actual ambient $PM_{2.5}$ concentrations. It is very difficult, if not impossible, to gain detailed evaluations and site specific installation estimates from equipment vendors without significant investment.

6. Costs Not Included – In several locations (i.e., p. 40 of the North Pole analysis), the analyses include the statement that cost estimates are "conservatively low" because they do not include the cost of support systems needed to operate the control equipment. EPA Region 10 believes these costs should be included in the analyses, based on site-specific capital and installation estimates or quotes provided by qualified control equipment vendors. Justification for inclusion of each retrofit-related cost must be included in the analyses. Development of reasonably accurate cost estimates for these retrofit projects is necessary in order to inform the BACT determination for each emission unit and pollutant.

   GVEA response:
   GVEA made every effort to include as many of the support system costs as possible within the scope of this project, however without more detailed and costly engineering and vendor estimates not all equipment is estimated. When available vendor quotes were included. As presented in the separately submitted package under request for confidentiality, recent project incurred costs were apportioned to include reagent preparation equipment. As much available information as possible was gathered, balancing time and expense.

7. Potential vs. Actual Emissions – In some places, the analyses propose BACT determinations based on use of actual emissions. All BACT cost effectiveness calculations must use potential-to emit (PTE), regardless of the emission unit usage history or actual historical emission rates. The facility should consider operating limits in cases where certain emission units do not need to retain relatively high PTE for facility operational purposes.

   GVEA response:
   Please see response to ADEC Comment 3 above.

In conclusion, GVEA's mission is *to safety provide its member Oowners with quality electric service, quality customer service and innovative energy solutions at fair and reasonable prices.* GVEA is committed to being a constructive contributor to improving regional $PM_{2.5}$ concentrations with practical solutions that do not unfairly burden our cooperative members. We recognize that the ultimate path to attainment will be comprised of many smaller contributions, and appeal to ADEC and EPA to work with all stakeholders to find effective and economically viable solutions.

Sincerely,

Naomi Morton Knight, P.E.
Environmental Health & Safety Officer

Attachments/Enclosures:
Tables 2-1 through 2-4
DVD Disk

cc: Aaron Simpson, ADEC/Air Quality

Table 2-1. Zehnder Power Plant - Suggested BACT Limits Summary

Emission Unit		Fuel	NO_X BACT			$PM_{2.5}$ BACT[1]			SO_2 BACT		
ID	Description		Description	Emission Rate[2]	Averaging Period[3]	Description	Emission Rate[2]	Averaging Period[3]	Description	Fuel Sulfur Content	Averaging Period[3]
1, 2	Simple Cycle Gas Turbines	Fuel Oil	Good Combustion Practices (existing)	0.88 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	0.012 lb/MMBtu	4 hour block	Fuel Oil and Good Combustion Practices (existing)	0.5 wt. pct. S	4 hour block
3,4	Generator Engines	Diesel	Turbocharger and Aftercooler + Limited Operation (existing)	0.024 lb/hp-hr[4]	4 hour block	Limited Operation (existing)	0.1 lb/MMBtu	4 hour block	Fuel Oil and Good Combustion Practices (existing)	0.5 wt. pct. S	4 hour block
10, 11	Boilers	Diesel	Good Combustion Practices (existing)	20 lb/kgal	4 hour block	Good Combustion Practices (existing)	2.13 lb/kgal	4 hour block	ULSD	0.0015 wt. pct. S	4 hour block

Notes:

[1] GVEA provided direct $PM_{2.5}$ emissions in the analysis even though Zehnder Power Plant is not a Serious Nonattainment Area major source for direct $PM_{2.5}$ emissions.
A BACT analysis is not required for this air pollutant.

[2] Emissions are on a per unit basis.

[3] The averaging period is not an indication of compliance demonstration methodology. In some cases, compliance is adequately demonstrated using operating and maintenance records or fuel sulfur content reports.

[4] The NO_X emission factor for EUs 3 and 4 that was provided in Table 3-15 of the Zehnder BACT analysis report is incorrect. The correct NO_X emission factor is 0.024 lb/hp-hr (3.2 lb/MMBtu of fuel input), consistent with Table 1-3 of the report. The calculations in Section 3 of that report are correctly based on the NO_X emission factor of 0.024 lb/hp-hr.

Table 2-2. North Pole Power Plant - Suggested BACT Limits Summary

Emission Unit		Fuel	NO_X BACT			$PM_{2.5}$ BACT			SO_2 BACT		
ID	Description		Description	Emission Rate[1]	Averaging Period[2]	Description	Emission Rate[1]	Averaging Period[2]	Description	Emission Rate[1]	Averaging Period[2]
1	Simple Cycle Gas Turbine	Fuel Oil	Limited Operation (existing)	0.88 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	0.12 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	500 ppm S in fuel	4 hour block
2	Simple Cycle Gas Turbine	Fuel Oil	Limited Operation (existing)	0.88 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	0.12 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	500 ppm S in fuel	4 hour block
5,6	Combined Cycle Gas Turbine	LSR	Water Injection (existing)	0.24 lb/MMBtu	4 hour block	Good Combustion Practices (existing)	0.12 lb/MMBtu	4 hour block	LSR (existing)	30 ppm S in fuel	4 hour block
7	Emergency Generator Engine	Fuel Oil	Turbocharger and Aftercooler + Limited Operation (existing)	0.031 lb/hp-hr[3]	4 hour block	Limited Operation + Good Combustion Practices (existing)	0.0022 lb/hp-hr	4 hour block	Good Combustion Practices (existing)	500 ppm S in fuel	4 hour block
11,12	Boiler	Propane	Good Combustion Practices (existing)	13 lb/kgal	4 hour block	Low Sulfur Fuel (existing)	0.7 lb/kgal	4 hour block	Low Sulfur Fuel - Propane (existing)	0.0012 lb/kgal	4 hour block

Notes:

[1] Emissions are on a per unit basis.

[2] The averaging period is not an indication of compliance demonstration methodology. In some cases, compliance is adequately demonstrated using operating and maintenance records or fuel sulfur content reports.

[3] The NO_X emission factor for EU7 that was provided in Table 3-23 of the North Pole BACT analysis report is incorrect. The correct NO_X emission factor is 0.031 lb/hp-hr (4.41 lb/MMBtu of heat input), consistent with Table 1-3 of the report. The calculations in Section 3 of that report are correctly based on the NO_X emission factor of 0.031 lb/hp-hr.

Table 2-3. Zehnder Power Plant - Suggested Startup, Shutdown, and Malfunction BACT Limits Summary

Emission Unit		Startup, Shutdown, and malfunction (SSM) BACT for All Air Pollutants		
ID	Description	Startup	Shutdown	Malfunction
1, 2	Simple Cycle Gas Turbines	Reach stable operation within 30 minutes of initiating startup	Complete shutdown within 15 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
3,4	Generator Engines	Reach stable operation within 15 minutes of initiating startup	Complete shutdown within 10 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
10, 11	Boilers	Reach stable operation within 15 minutes of initiating startup	Complete shutdown within 10 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.

Table 2-4. North Pole Power Plant - Suggested Startup, Shutdown, and Malfunction BACT Limits Summary

Emission Unit		Startup, Shutdown, and malfunction (SSM) BACT for All Air Pollutants		
ID	Description	Startup	Shutdown	Malfunction
1	Simple Cycle Gas Turbine	Reach stable operation within 30 minutes of initiating startup	Complete shutdown within 15 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
2	Simple Cycle Gas Turbine	Reach stable operation within 30 minutes of initiating startup	Complete shutdown within 15 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
5,6	Combined Cycle Gas Turbine	Reach stable operation within 30 minutes of initiating startup	Complete shutdown within 15 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
7	Emergency Generator Engine	Reach stable operation within 15 minutes of initiating startup	Complete shutdown within 10 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.
11,12	Boiler	Reach stable operation within 15 minutes of initiating startup	Complete shutdown within 10 minutes of initiating shutdown procedure.	Restore emission unit to normal operation as soon as is practicable or shutdown emission unit.

EPA-453/R-93-007

Alternative Control Techniques Document— NO_x Emissions from Stationary Gas Turbines

Emission Standards Division

U. S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711
January 1993

ALTERNATIVE CONTROL TECHNIQUES DOCUMENTS

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1.0 INTRODUCTION

Congress, in the Clean Air Act Amendments of 1990 (CAAA), amended Title I of the Clean Air Act (CAA) to address ozone nonattainment areas. A new Subpart 2 was added to Part D of Section 103. Section 183(c) of the new Subpart 2 provides that:

> [w]ithin 3 years after the date of the enactment of the CAAA, the Administrator shall issue technical documents which identify alternative controls for all categories of stationary sources of...oxides of nitrogen which emit or have the potential to emit 25 tons per year or more of such air pollutant.

These documents are to be subsequently revised and updated as determined by the Administrator.

Stationary gas turbines have been identified as a category that emits more than 25 tons of nitrogen oxide (NO_x) per year. This alternative control techniques (ACT) document provides technical information for use by State and local agencies to develop and implement regulatory programs to control NO_x emissions from stationary gas turbines. Additional ACT documents are being developed for other stationary source categories.

Gas turbines are available with power outputs ranging from 1 megawatt (MW) (1,340 horsepower [hp]) to over 200 MW (268,000 hp) and are used in a broad scope of applications. It must be recognized that the alternative control techniques and the corresponding achievable NO_x emission levels presented in this document may not be applicable for every gas turbine application. The size and design of the turbine, the operating duty cycle, site conditions, and other site-specific factors must be taken into consideration, and the suitability of an alternative control technique must be determined on a case-by-case basis.

The information in this ACT document was generated through a literature search and from information provided by gas turbine manufacturers, control equipment vendors, gas turbine users, and regulatory agencies. Chapter 2.0 presents a summary of the findings of this study. Chapter 3.0 presents information on gas turbine operation and industry applications. Chapter 4.0 contains a discussion of NO_x formation and uncontrolled NO_x emission factors. Alternative control techniques and achievable controlled emission levels are included in Chapter 5.0. The cost and cost effectiveness of each control technique are presented in Chapter 6.0. Chapter 7.0 describes environmental and energy impacts associated with implementing the NO_x control techniques.

2.0 SUMMARY

This chapter summarizes the more detailed information presented in subsequent chapters of this document. It presents a summary of nitrogen oxide (NO_x) formation mechanisms and uncontrolled NO_x emission factors, available NO_x emission control techniques, achievable controlled NO_x emission levels, the costs and cost effectiveness for these NO_x control techniques applied to combustion gas turbines, and the energy and environmental impacts of these control techniques. The control techniques included in this analysis are water or steam injection, dry low-NO_x combustors, and selective catalytic reduction (SCR).

Section 2.1 includes a brief discussion of NO_x formation and a summary of uncontrolled NO_x emission factors. Section 2.2 describes the available control techniques and achievable controlled NO_x emission levels. A summary of the costs and cost-effectiveness for each control technique is presented in Section 2.3. Section 2.4 reviews the range of controlled emission levels, capital costs, and cost effectiveness. Section 2.5 discusses energy and environmental impacts.

2.1 NO_x FORMATION AND UNCONTROLLED NO_x EMISSIONS

The two primary NO_x formation mechanisms in gas turbines are thermal and fuel NO_x. In each case, nitrogen and oxygen present in the combustion process combine to form NO_x. Thermal NO_x is formed by the dissociation of atmospheric nitrogen (N_2) and oxygen (O_2) in the turbine combustor and the subsequent formation of NO_x. When fuels containing nitrogen are combusted, this additional source of nitrogen results in fuel NO_x formation. Because most turbine installations burn natural gas or light distillate oil fuels with little or no nitrogen content, thermal NO_x is the dominant source of NO_x emissions. The formation rate of thermal NO_x increases exponentially with increases in temperature. Because the flame temperature of oil fuel is higher than that of natural gas, NO_x emissions are higher for operations using oil fuel than natural gas.

Uncontrolled NO_x emission levels were provided by gas turbine manufacturers in parts per million, by volume (ppmv). Unless stated otherwise, all emission levels shown in ppmv are corrected to 15 percent O_2. These emission levels were used to calculate uncontrolled NO_x emission factors, in pounds (lb) of NO_x per million British thermal units (Btu) (lb NO_x/MMBtu). Sample calculations are shown in Appendix A. These uncontrolled emission levels and emission factors for both natural gas and oil fuel are presented in Table 2-1

TABLE 2-1. UNCONTROLLED NO_x EMISSION FACTORS FOR GAS TURBINES

Manufacturer	Model No.	Output, MW	NO_x emissions, ppmv, dry and corrected to 15% 0_2 Natural gas	Distillate oil No. 2	NO_x emissions factor, lb NO_x/MMBtu[a] Natural gas	Distillate oil No. 2
Solar	Saturn	1.1	99	150	0.397	0.551
	Centaur	3.3	130	179	0.521	0.658
	Centaur "H"	4.0	105	160	0.421	0.588
	Taurus	4.5	114	168	0.457	0.618
	Mars T12000	8.8	178	267	0.714	0.981
	Mars T14000	10.0	199	NA[b]	0.798	NA[b]
GM/Allison	501-KB5	4.0	155	231	0.622	0.849
	570-KA	4.9	101	182	0.405	0.669
	571-KA	5.9	101	182	0.405	0.669
General Electric	LM1600	12.8	144	237	0.577	0.871
	LM2500	21.8	174	345	0.698	1.27
	LM5000	33.1	185	364	0.742	1.34
	LM6000	41.5	220	417	0.882	1.53
	MS5001P	26.3	142	211	0.569	0.776
	MS6001B	38.3	148	267	0.593	0.981
	MS7001EA	83.5	154	228	0.618	0.838
	MS7001F	123	179	277	0.718	1.02
	MS9001EA	150	176	235	0.706	0.864
	MS9001F	212	176	272	0.706	1.00
Asea Brown Boveri	GT8	47.4	430	680	1.72	2.50
	GT10	22.6	150	200	0.601	0.735
	GT11N	81.6	390	560	1.56	2.06
	GT35	16.9	300	360	1.20	1.32
Westinghouse	W261B11/12	52.3	220	355	0.882	1.31
	W501D5	119	190	250	0.762	0.919
Siemens	V84.2	105	212	360	0.850	1.32
	V94.2	153	212	360	0.850	1.32
	V64.3	61.5	380	530	1.52	1.95
	V84.3	141	380	530	1.52	1.95
	V94.3	203	380	530	1.52	1.95

[a]Based on emission levels provided by gas turbine manufacturers, corresponding to rated load at ISO conditions. NO_x emissions calculations are shown in Appendix A.
[b]Not available.

. Uncontrolled NO_x emission levels range from 99 to 430 ppmv for natural gas fuel and from 150 to 680 ppmv for distillate oil fuel. Corresponding uncontrolled emission factors range from 0.397 to 1.72 lb NO_x/MMBtu and 0.551 to 2.50 lb NO_x/MMBtu for natural gas and distillate oil fuels, respectively. Because thermal NO_x is primarily a function of combustion temperature, NO_x emission rates vary with combustor design. There is no discernable correlation between turbine size and NO_x emission levels evident in Table 2-1.

2.2 CONTROL TECHNIQUES AND CONTROLLED NO_x EMISSION LEVELS

Reductions in NO_x emissions can be achieved using combustion controls or flue gas treatment. Available combustion controls are water or steam injection and dry low-NO_x combustion designs. Selective catalytic reduction is the only available flue gas treatment.

2.2.1 Combustion Controls

Combustion control using water or steam lowers combustion temperatures, which reduces thermal NO_x formation. Fuel NO_x formation is not reduced with this technique. Water or steam, treated to quality levels comparable to boiler feedwater, is injected into the combustor and acts as a heat sink to lower flame temperatures. This control technique is available for all new turbine models and can be retrofitted to most existing installations.

Although uncontrolled emission levels vary widely, the range of achievable controlled emission levels using water or steam injection is relatively small. Controlled NO_x emission levels range from 25 to 42 ppmv for natural gas fuel and from 42 to 75 ppmv for distillate oil fuel. Achievable guaranteed controlled emission levels, as provided by turbine manufacturers, are shown for individual turbine models in Figures 2-1 and 2-2

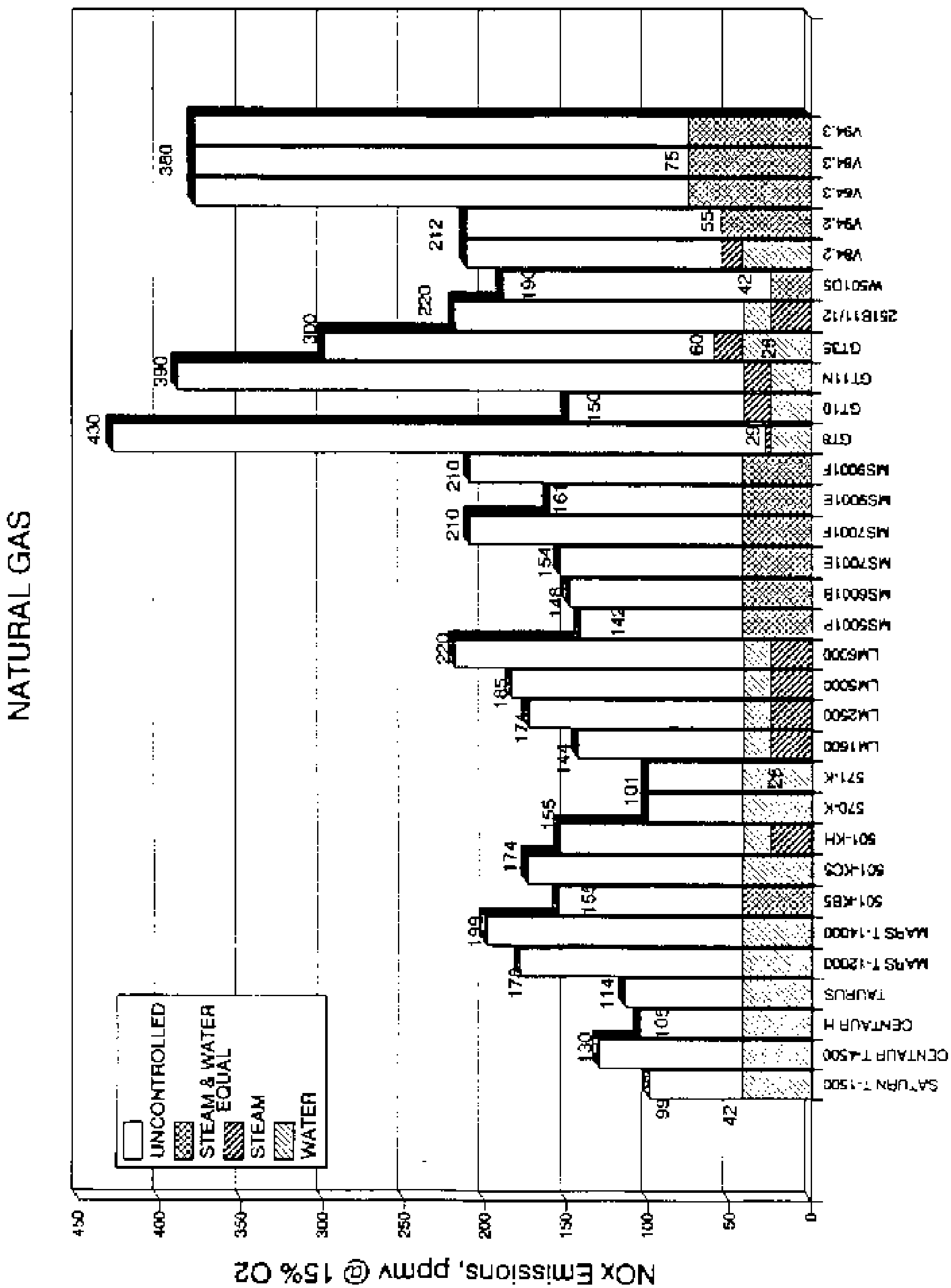


Figure 2-1. **Uncontrolled NOx emission levels and gas turbine manufacturers' guaranteed controlled levels using wet injection. Natural gas fuel.**

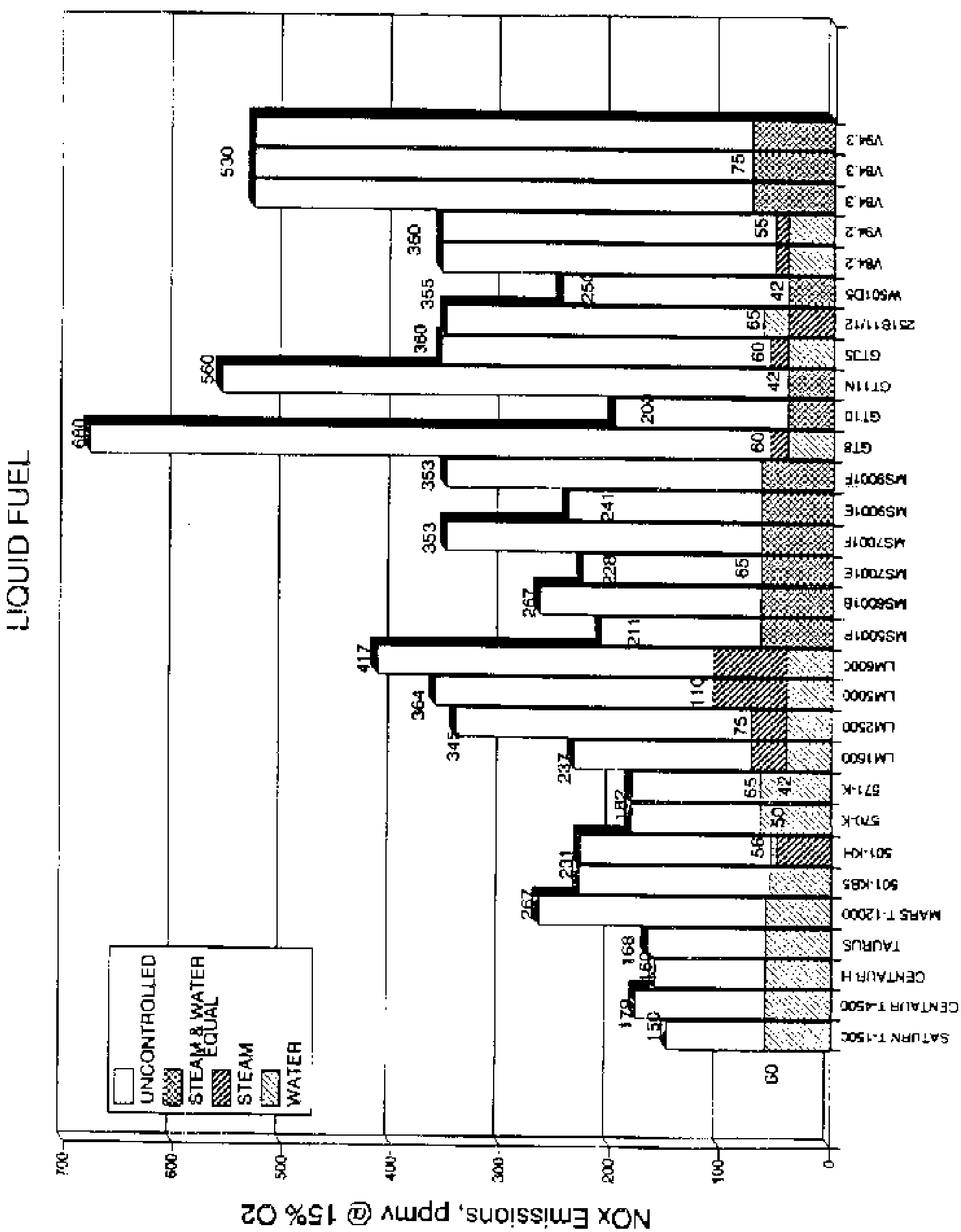


Figure 2-2. **Uncontrolled NO_x emission levels and gas turbine manufacturers' guaranteed controlled levels using wet injection. Distillate oil fuel.**

for natural gas and oil fuels, respectively.

The decision whether to use water versus steam injection for NO_x reduction depends on many factors, including the availability of steam injection nozzles and controls from the turbine manufacturer, the availability and cost of steam at the site, and turbine performance and maintenance impacts. This decision is usually driven by site-specific environmental and economic factors.

A system that allows treated water to be mixed with the fuel prior to injection is also available. Limited testing of water-in-oil emulsions injected into the turbine combustor have achieved NO_x reductions equivalent to direct water injection but at reduced water-to-fuel rates. The vendor reports a similar system is available for natural gas-fired applications.

Dry low-NO_x combustion control techniques reduce NO_x emissions without injecting water or steam. Two designs, lean premixed combustion and rich/quench/lean staged combustion have been developed.

Lean premixed combustion designs reduce combustion temperatures, thereby reducing thermal NO_x. Like wet injection, this technique is not effective in reducing fuel NO_x. In a conventional turbine combustor, the air and fuel are introduced at an approximately stoichiometric ratio and air/fuel mixing occurs simultaneously with combustion. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing results in a homogeneous air/fuel mixture, which minimizes

localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air acts as a heat sink to lower combustion temperatures, which lowers thermal NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Lean premixed combustors are currently available from several turbine manufacturers for a limited number of turbine models. Development of this technology is ongoing, and availability should increase in the coming years. All turbine manufacturers state that lean premixed combustors are designed for retrofit to existing installations.

Controlled NO_x emission levels using dry lean premixed combustion range from 9 to 42 ppmv for operation on natural gas fuel. The low end of this range (9 to 25 ppmv) has been limited to turbines above 20 megawatts (MW) (27,000 horsepower [hp]); to date, three manufacturers have guaranteed controlled NO_x emission levels of 9 ppmv at one or more installations for utility-sized turbines. Controlled NO_x emissions from smaller turbines typically range from 25 to 42 ppmv. For operation on distillate oil fuel, water or steam injection is required to achieve controlled NO_x emissions levels of approximately 65 ppmv. Development continues for oil-fueled operation in lean premixed designs, however, and one turbine manufacturer reports having achieved controlled NO_x emission levels below 50 ppmv in limited testing on oil fuel without wet injection.

A second dry low-NO_x combustion design is a rich/quench/lean staged combustor. Air and fuel are partially combusted in a fuel-rich primary stage, the combustion products are then rapidly quenched using water or air, and combustion is completed in a fuel-lean secondary stage. The fuel-rich primary stage inhibits NO_x formation due to low O_2 levels. Combustion temperatures in the fuel-lean secondary stage are below NO_x formation temperatures as a result of the quenching process and the presence of excess air. Both thermal and fuel NO_x are controlled with this design. Limited testing with fuels including natural gas and coal have achieved controlled NO_x emissions of 25 ppmv. Development of this design continues, however, and currently the rich/quench/lean combustor is not available for production turbines.

2.2.2 Selective Catalytic Reduction

This flue gas treatment technique uses an ammonia (NH_3) injection system and a catalytic reactor to reduce NO_x. An injection grid disperses NH_3 in the flue gas upstream of the catalyst, and NH_3 and NO_x are reduced to N_2 and water (H_2O) in the catalyst reactor. This control technique reduces both thermal NO_x and fuel NO_x.

Ammonia injection systems are available that use either anhydrous or aqueous NH_3. Several catalyst materials are available. To date, most SCR installations use a base-metal catalyst with an operating temperature window ranging from approximately 260° to 400°C (400° to 800°F). The exhaust temperature from the gas turbine is typically above 480°C (900°F), so the catalyst is located within a heat recovery steam generator (HRSG) where temperatures are reduced to a range compatible with the catalyst operating temperature. This operating temperature requirement has, to date, limited SCR to cogeneration or combined-cycle applications with HRSG's to reduce flue gas temperatures. High-temperature zeolite catalysts, however, are now available and have operating temperature windows of up to 600°C (1100°F), which is suitable for installation directly downstream of the turbine. This high-temperature zeolite catalyst offers the potential for SCR applications with simple cycle gas turbines.

To achieve optimum long-term NO_x reductions, SCR systems must be properly designed for each application. In addition to temperature considerations, the NH_3 injection rate must be carefully controlled to maintain an NH_3/NO_x molar ratio that effectively reduces NO_x and avoids excessive NH_3 emissions downstream of the catalyst, known as ammonia slip. The selected catalyst formulation must be resistant to potential masking and/or poisoning agents in the flue gas.

To date, most SCR systems in the United States have been installed in gas-fired turbine applications, but improvements in SCR system designs and experience on alternate fuels in Europe and Japan suggest that SCR systems are suitable for firing distillate oil and other sulfur-bearing fuels. These fuels produce sulfur dioxide (SO_2), which may oxidize to sulfite (SO_3) in the catalyst reactor. This SO_3 reacts with NH_3 slip to form ammonium salts in the low-temperature section of the HRSG and exhaust ductwork. The ammonium salts must be periodically cleaned from the affected surfaces to avoid fouling and corrosion as well as increased back-pressure on the turbine. Advances in catalyst formulations include sulfur-resistant catalysts with low SO_2 oxidation rates. By limiting ammonia slip and using these sulfur-resistant catalysts, ammonium salt formation can be minimized.

Catalyst vendors offer NO_x reduction efficiencies of 90 percent with ammonia slip levels of 10 ppmv or less. These emission levels are warranted for 2 to 3 years, and all catalyst vendors contacted accept return of spent catalyst reactors for recycle or disposal.

Controlled NO_x emission levels using SCR are typically 9 ppmv or less for gas-fueled turbine installations. With the exception of one site, all identified installations operate the SCR system in combination with combustion controls that reduce NO_x emission levels into the SCR to a range of 25 to 42 ppmv. Most continuous-duty turbine installations fire natural gas; there is limited distillate oil-fired operating experience in the United States. Several installations with SCR in the northeast United States that use distillate oil as a back-up fuel have controlled NO_x emission limits of 18 ppmv for operation on distillate oil fuel.

2.3 COSTS AND COST EFFECTIVENESS FOR NO_x CONTROL TECHNIQUES

Capital costs and cost effectiveness were developed for the available NO_x control techniques. Capital costs are presented in Section 2.3.1. Cost-effectiveness figures, in $/ton of NO_x

removed, are shown in Section 2.3.2. All costs presented are in 1990 dollars.

2.3.1 Capital Costs

Capital costs are the sum of purchased equipment costs, taxes and freight charges, and installation costs. Purchased equipment costs were estimated based on information provided by equipment manufacturers, vendors, and published sources. Taxes, freight, and installation costs were developed based on factors recommended in the Office of Air Quality and Planning and Standards Control Cost Manual (Fourth Edition). Capital costs for combustion controls and SCR are presented in Sections 2.3.1.1 and 2.3.1.2, respectively.

2.3.1.1 Combustion Controls Capital Costs. Capital costs for wet injection include a mixed bed demineralizer and reverse-osmosis water treatment system and an injection system consisting of pumps, piping and hardware, metering controls, and injection nozzles. All costs for wet injection are based on the availability of water at the site; no costs have been included for transporting water to the site. These costs apply to new installations; retrofit costs would be similar except that turbine-related injection hardware and metering controls purchased from the turbine manufacturer may be higher for retrofit applications.

The capital costs for wet injection are shown in Figure 2-3, and range from $388,000 for a 3.3 MW (4,430 hp) turbine to $4,830,000 for a 161 MW (216,000 hp) turbine.

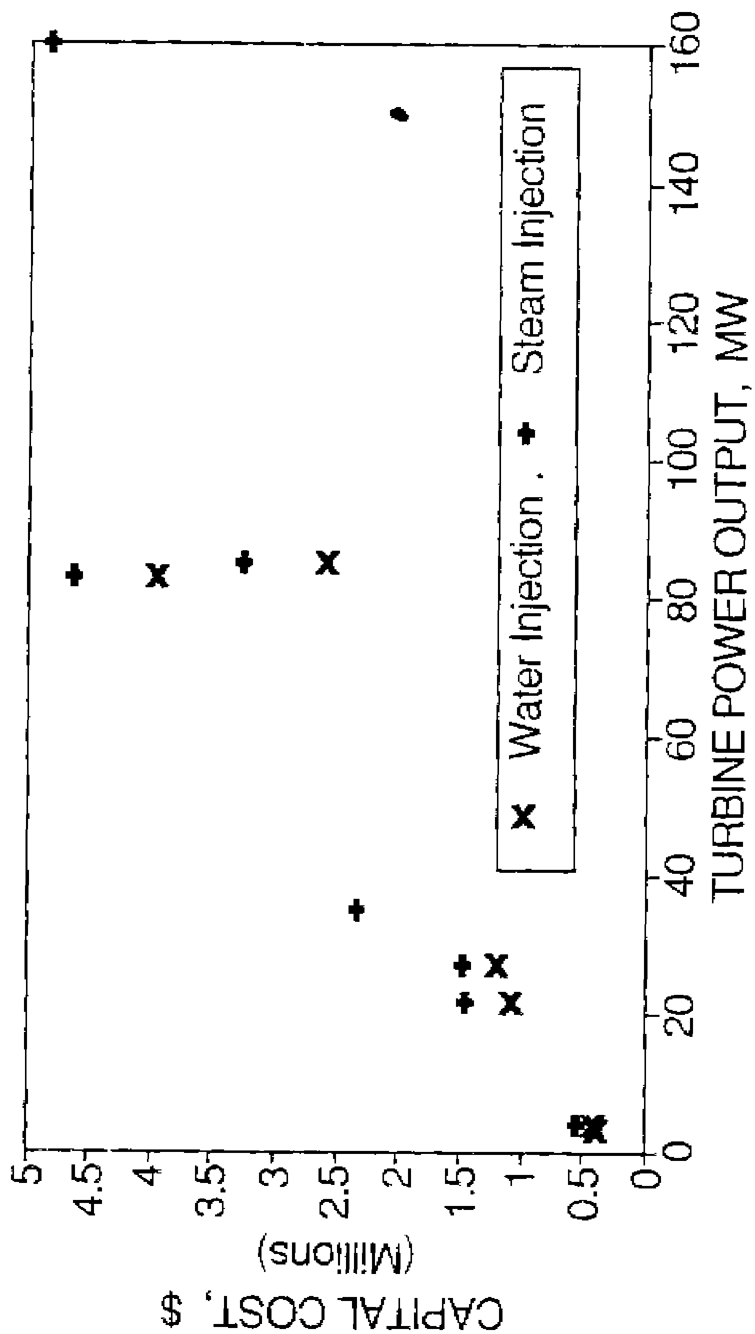


Figure 2-3. Capital costs for water or steam injection.

These capital costs include both water and steam injection systems for use with either gas or distillate oil fuel applications. Figure 2-3 shows that the capital costs for steam injection are slightly higher than those for water injection for turbines in the 3 to 25 MW (4,000 to 33,500 hp) range.

The capital costs for dry low-NO_x combustors are the incremental costs for this design over a conventional combustor and apply to new installations. Turbine manufacturers estimate retrofit costs to be approximately 40 to 60 percent higher than new equipment costs. Incremental capital costs for dry low-NO_x

combustion were provided by turbine manufacturers and are presented in Figure 2-4.

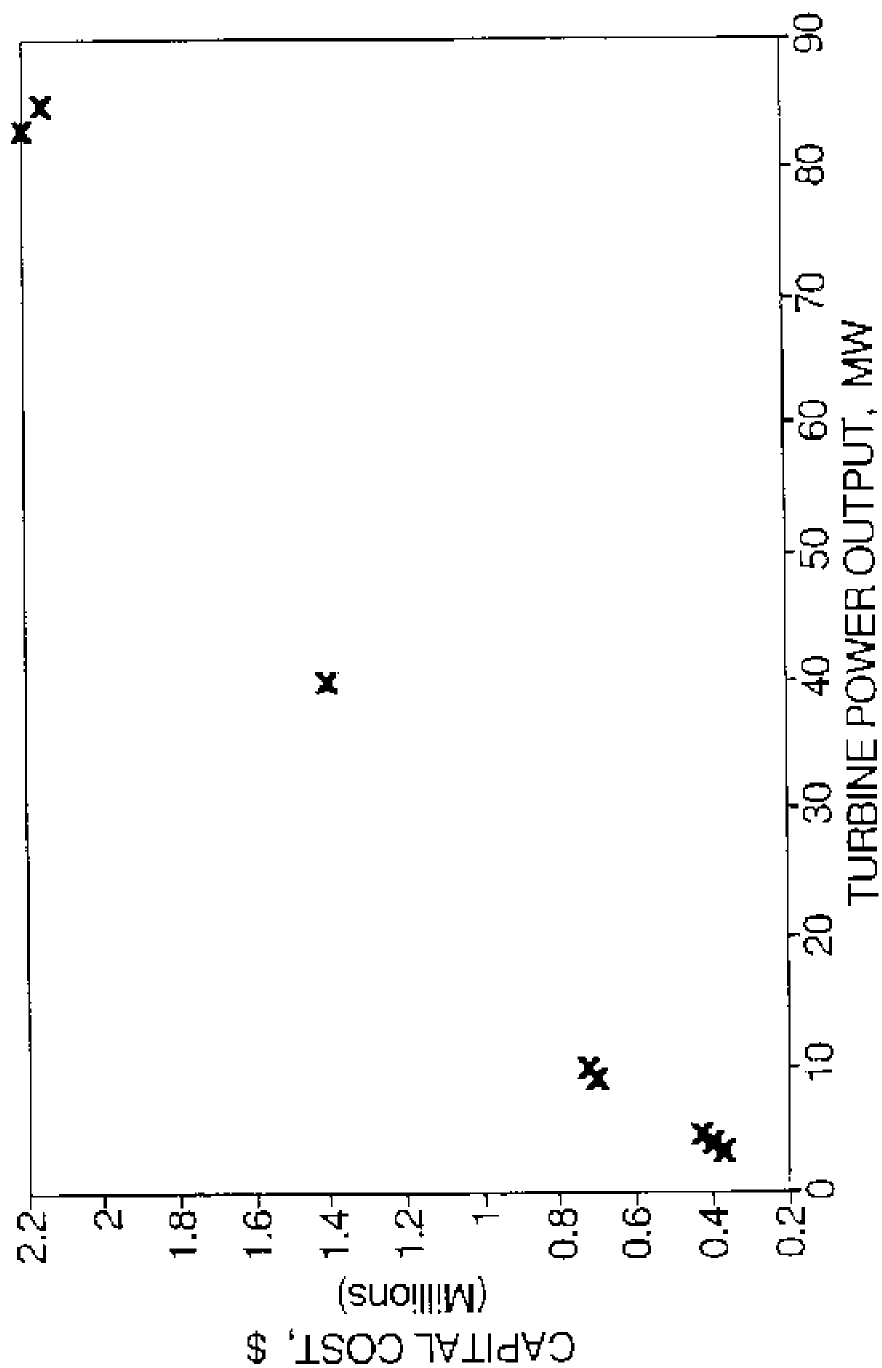


Figure 2-4. Capital costs for dry low-NO_x combustion.

The incremental capital costs range from \$375,000 for a 3.3 MW (4,430 hp) turbine to \$2.2 million for an 85 MW (114,000 hp) machine. Costs were not available for turbines above 85 MW (114,000 hp).

When evaluated on a \$/MW (\$/hp) basis, the capital costs for wet injection or dry low-NO_x combustion controls are highest for the smallest turbines and decrease exponentially with increasing turbine size. The range of capital costs for combustion controls, in \$/MW, and the effect of turbine size on capital costs are shown in Figure 2-5.

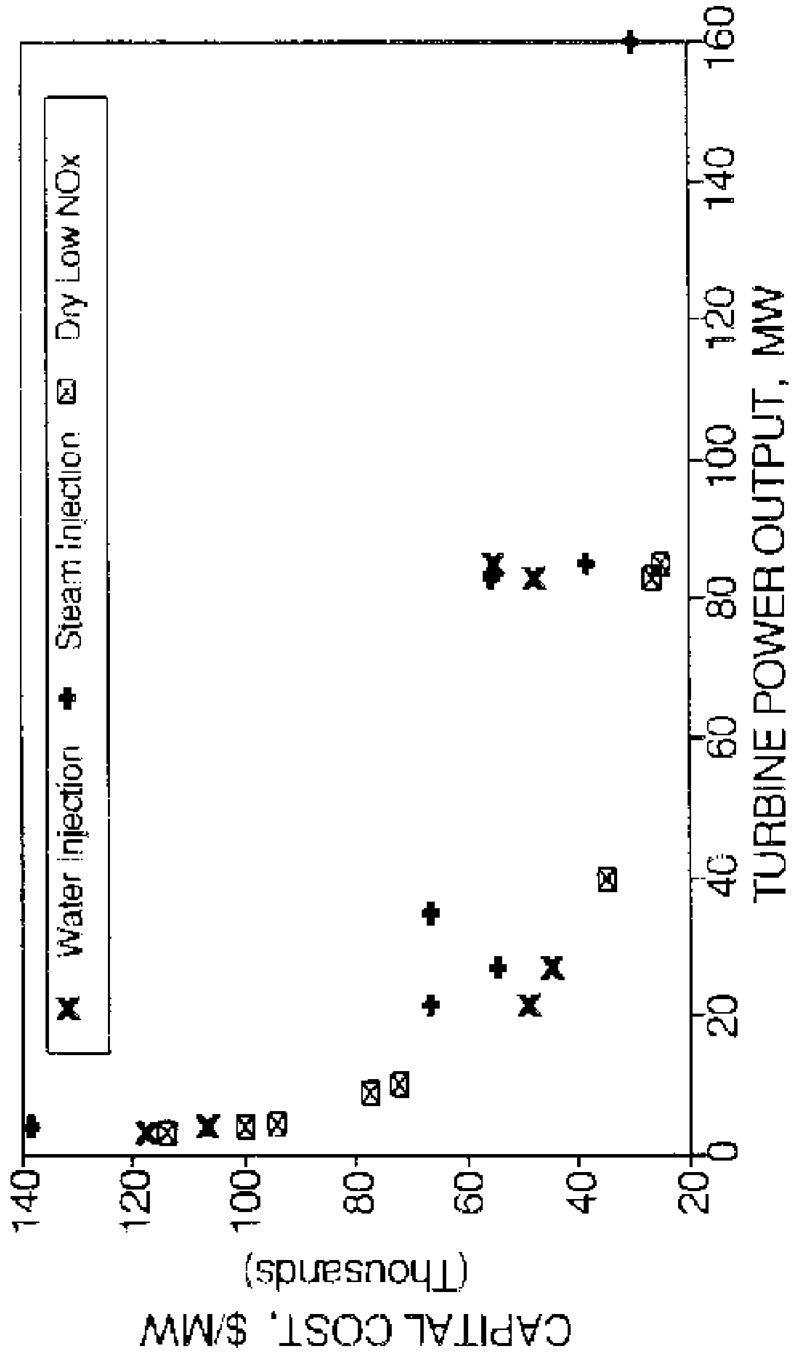


Figure 2-5. Capital costs, in $/MW, for cumbustion controls.

For wet injection, the capital costs range from a high of $138,000/MW ($103/hp) for a 3.3 MW (4,430 hp) turbine to a low of $29,000/MW ($22/hp) for a 161 MW (216,000 hp) turbine. Corresponding capital cost figures for dry low-NO_x combustion range from $114,000/MW ($85/hp) for a 3.3 MW (4,430 hp) unit to $26,000/MW ($19/hp) for an 85 MW (114,000 hp) machine.

2.3.1.2 SCR Capital Costs. Capital costs for SCR include the catalyst reactor, ammonia storage and injection system, and controls and monitoring equipment. A comparison of available cost estimates for base-metal catalyst systems and high-temperature zeolite catalyst systems indicates that the costs for these systems are similar, so a single range of costs was developed that represents all SCR systems, regardless of catalyst type or turbine cycle (i.e., simple, cogeneration, or combined cycle).

The capital costs for SCR, shown in Figure 2-6, range from $622,000 for a 3.3 MW (4,430 hp) turbine to $8.46 million for a 161 MW (216,000 hp) turbine.

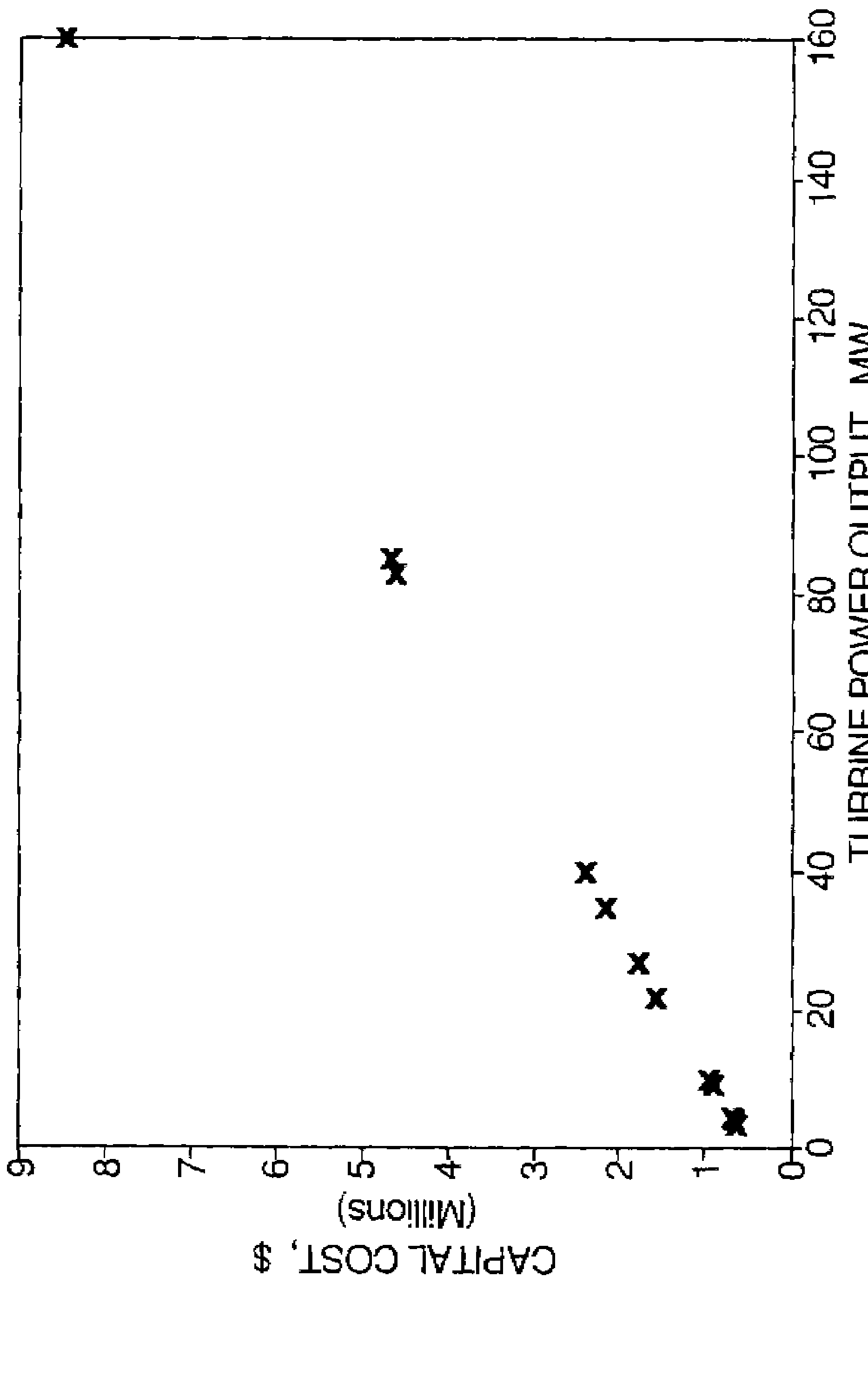


Figure 2-6. Capital costs for selective catalytic reduction.

Figure 2-7 plots capital costs on a \$/MW basis and shows that these costs are highest for the smallest turbine, at \$188,000/MW (\$140/hp) for a 3.3 MW (4,430 hp) unit, and decrease exponentially with increasing turbine size to \$52/MW (\$40/hp) for a 161 MW (216,000 hp) machine.

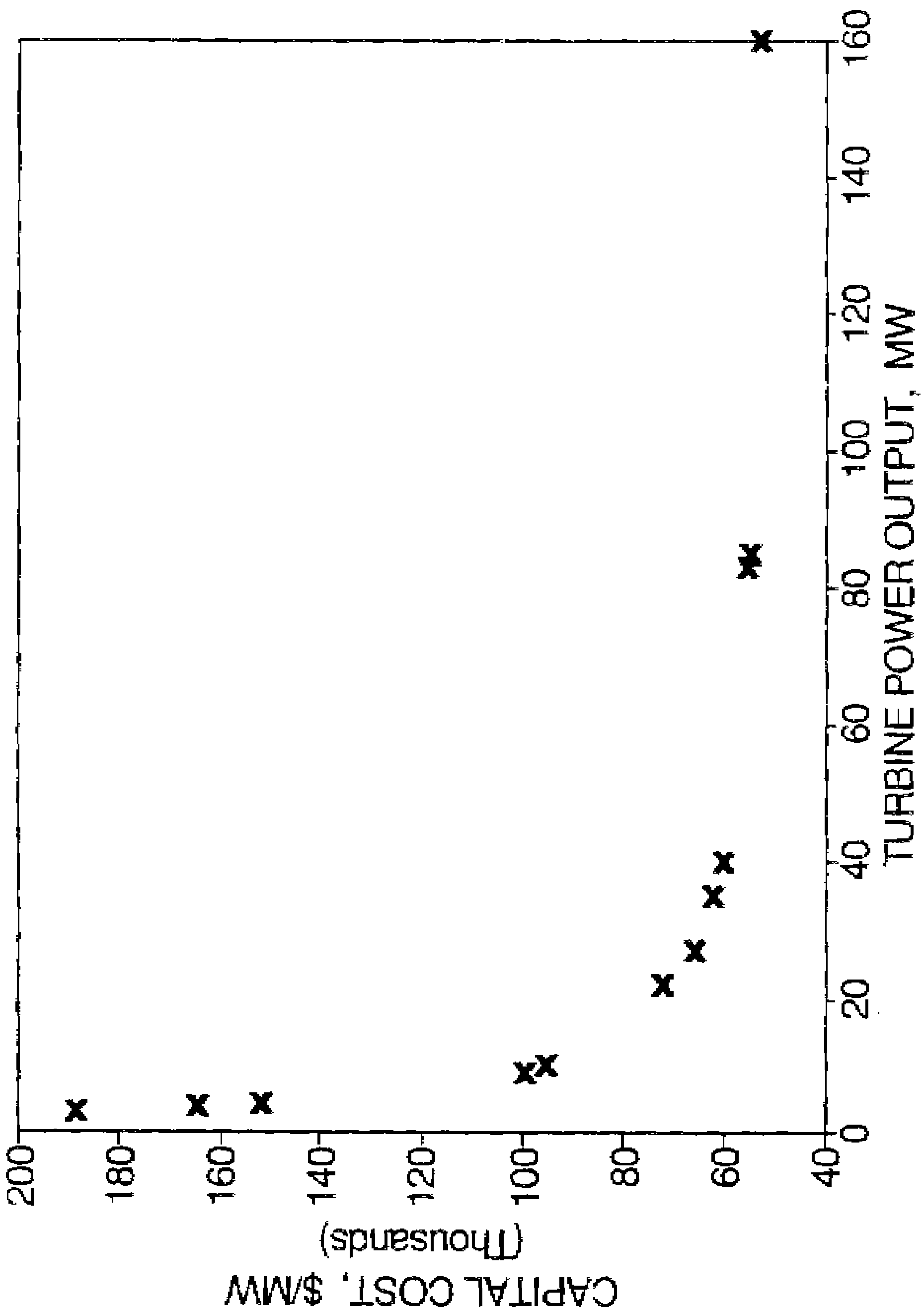


Figure 2-7. Capital costs, in $/MW, for selective catalytic reduction.

These costs apply to new installations firing natural gas as the primary fuel. No SCR sites using oil as the primary fuel were identified, and costs were not available. For this

reason, the costs for gas-fired applications were also used for oil-fired sites. Retrofit SCR costs could be considerably higher than those shown here for new installations, especially if an existing HRSG and ancillary equipment must be moved or modified to accommodate the SCR system.

2.3.2 Cost Effectiveness

The cost effectiveness, in $/ton of NO_x removed, was developed for each NO_x control technique. The cost effectiveness for a given control technique is calculated by dividing the total annual cost by the annual NO_x reduction, in tons. The cost effectiveness presented in this section correspond to 8,000 annual operating hours. Total annual costs were calculated as the sum of all annual operating costs and annualized capital costs. Annual operating costs include costs for incremental fuel, utilities, maintenance, applicable performance penalties, operating and supervisory labor, plant overhead, general and administrative, and taxes and insurance. Capital costs were annualized using the capital recovery factor method with an equipment life of 15 years and an annual interest rate of 10 percent. Cost-effectiveness figures for combustion controls and SCR are presented in Sections 2.3.2.1 and 2.3.2.2, respectively.

2.3.2.1 Combustion Controls Cost Effectiveness. Cost effectiveness for combustion controls is shown in Figure 2-8.

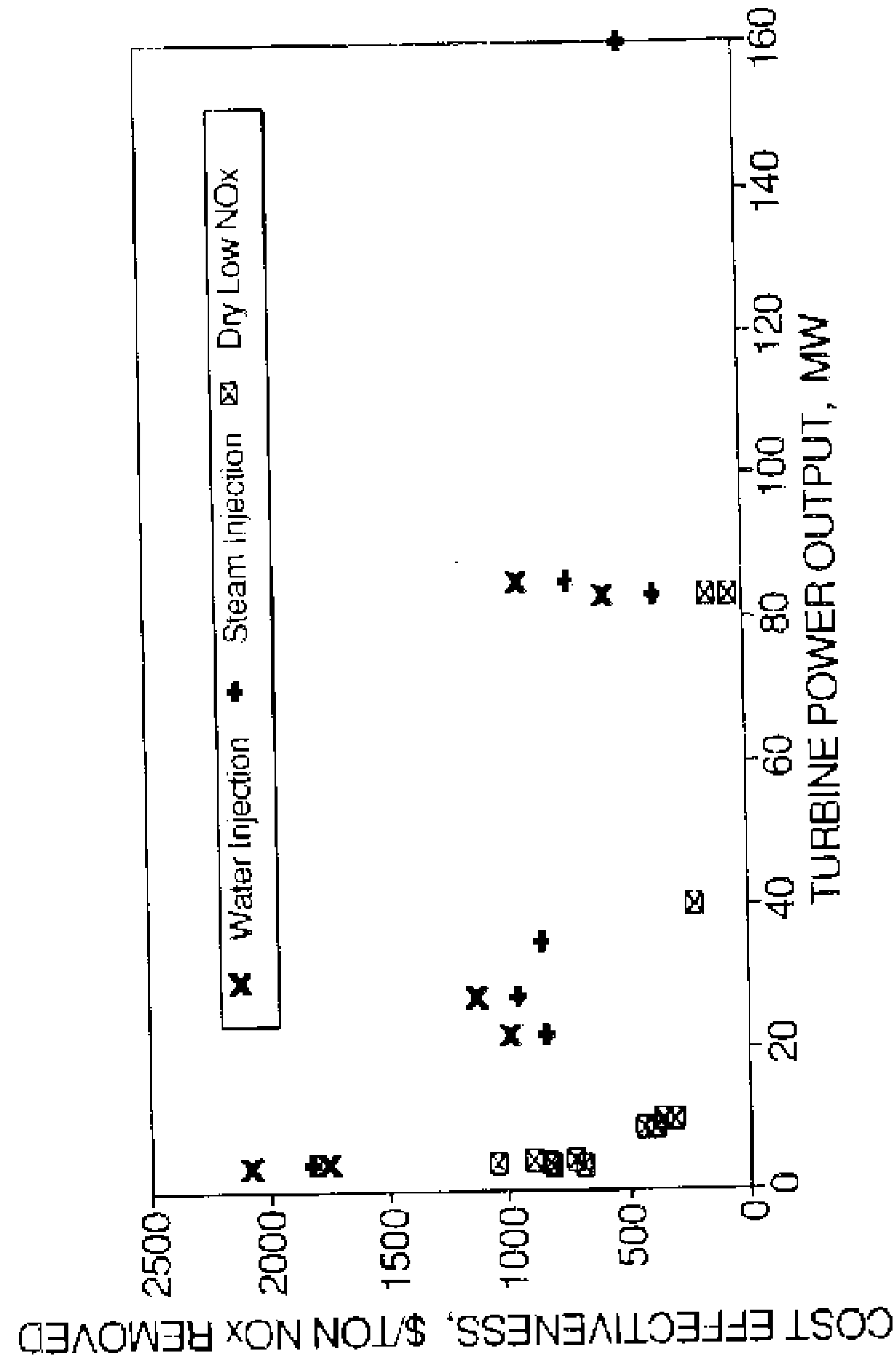


Figure 2-8. Cost effectiveness of combustion controls.

Figure 2-8 indicates that cost effectiveness for combustion controls is highest for the smallest turbines and decreases exponentially with decreasing turbine size. Figure 2-8 also shows that the range of cost effectiveness for water injection is similar to that for steam injection, primarily because the total annual costs and achievable controlled NO_x emission levels for water and steam injection are similar. The cost-effectiveness range for dry low-NO_x combustion is lower than that for wet

$_x$ levels are similar (25 to 42 ppmv), due to the lower total annual costs for dry low-NO_x combustion.

For water injection, cost effectiveness, in \$/ton of NO_x removed, ranges from \$2,080 for a 3.3 MW (4,430 hp) unit to \$575 for an 83 MW (111,000 hp) turbine and \$937 for an 85 MW (114,000 hp) turbine. For steam injection, cost effectiveness is \$1,830 for a 3.3 MW (4,430 hp), decreasing to \$375 for an 83 MW (111,000 hp) turbine, and increasing to \$478 for a 161 MW (216,000 hp) turbine. The relatively low cost effectiveness for the 83 MW (111,000 hp) turbine is due to this particular turbine's high uncontrolled NO emissions, which result in a relatively high NO_x removal efficiency and lower cost effectiveness. The cost effectiveness shown in Figure 2-8

number of oil-fired applications with water injection indicates that the cost effectiveness ranges from 70 to 85 percent of the

NO_x removal efficiency achieved in oil-fired applications.

For dry low-NO_x combustion, cost effectiveness, in \$/ton of NO_x removed, ranges from \$1,060 for a 4.0 MW (5,360 hp) turbine down to \$154 for an 85 MW (114,000 hp) machine. A cost effectiveness of \$57 was calculated for the 83 MW (111,000 hp) unit. Again, the relatively high uncontrolled NO_x emissions and the resulting high NO_x removal efficiency for this turbine model yields a relatively low cost-effectiveness figure. Current dry low-NO_x combustion designs do not achieve NO_x reductions with oil fuels, so the cost-effectiveness values shown in this section apply only to gas-fired applications.

2.3.2.2 SCR Cost Effectiveness. Cost effectiveness for SCR was calculated based on the use of combustion controls upstream of the catalyst to reduce NO_x emissions to a range of 25 to 42 ppmv at the inlet to the catalyst. This approach was used because all available SCR cost information is for SCR applications used in combination with combustion controls and all but one of the 100+ SCR installations in the United States operate in combination with combustion controls. For this cost analysis, a 5-year catalyst life and a 9 ppmv controlled NO_x emission level was used to calculate cost effectiveness for SCR.

Figure 2-9 presents SCR cost effectiveness. Figure 2-9 shows that, like combustion controls, SCR cost effectiveness is highest for the smallest turbines and decreases exponentially with decreasing turbine size.

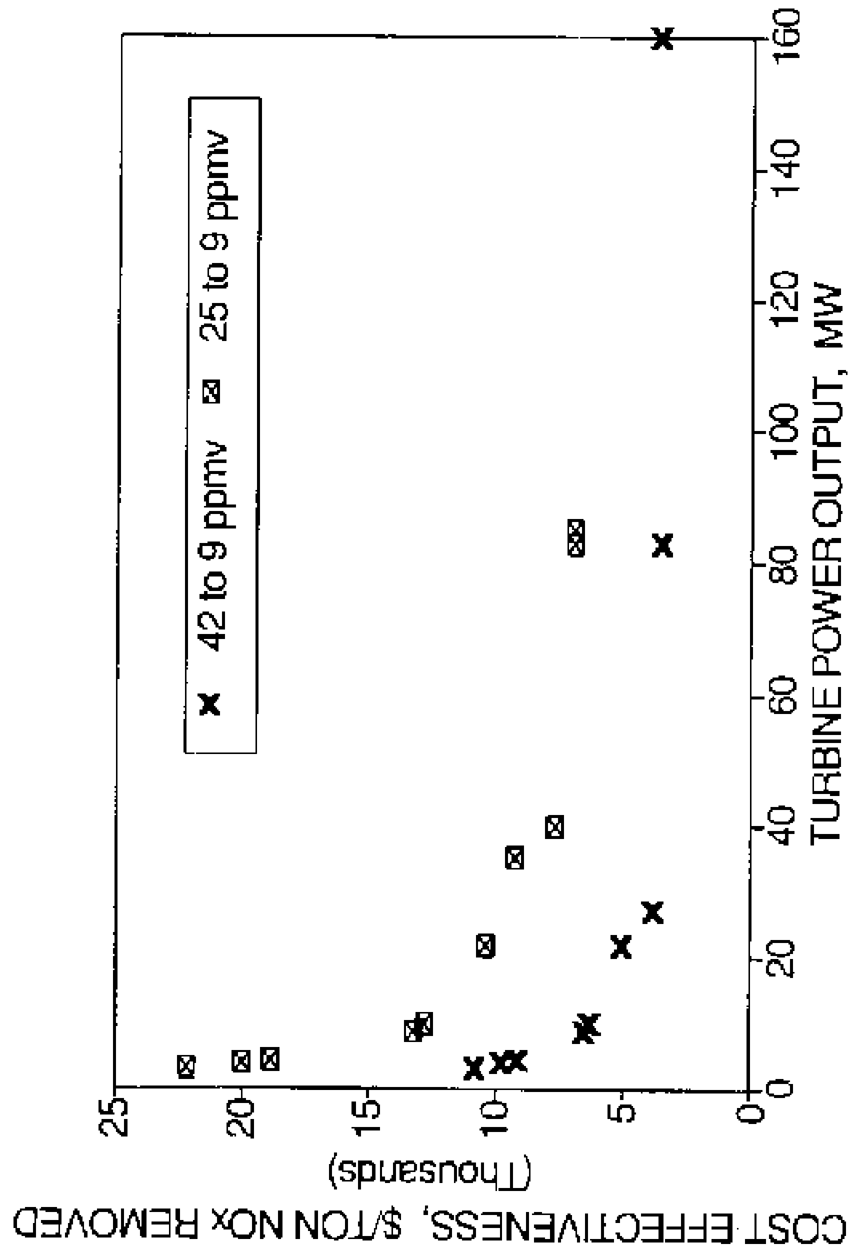


Figure 2-9. Cost effectiveness for selective catalytic reduction installed downstream of combustion controls.

Also, because this cost analysis uses a 9 ppmv controlled NO_x emission level for SCR, NO_x reduction efficiencies are higher where the NO_x emission level into the SCR is 42 ppmv than for applications with a 25 ppmv level. Cost effectiveness corresponding to an inlet NO_x emission level of 42 ppmv, in $/ton of NO_x removed, ranges from a high of $10,800 for a 3.3 MW (4430 hp) turbine to $3,580 for a 161 MW (216,000 hp) turbine. For an inlet NO_x emission level of 25 ppmv, the cost-effectiveness range shifts higher, from $22,100 for a 3.3 MW (4,430 hp) installation to $6,980 for an 83 MW (111,000 hp) site.

The range of cost effectiveness for SCR shown in Figure 2-9 applies to gas-fired applications. Cost effectiveness developed for a limited number of oil-fired installations using capital costs from gas-fired applications yields cost-effectiveness values ranging from approximately 70 to 77 percent of those for gas-fired sites. The lower cost-effectiveness figures for oil-fired applications result primarily from the greater annual NO_x reductions for oil-fired applications; the gas-fired capital costs used for these oil-fired applications may understate the actual capital costs for these removal rates and actual oil-fired cost-effectiveness figures may be higher.

Combined cost-effectiveness figures, in $/ton of NO_x removed, were calculated for the combination of combustion controls plus SCR by dividing the sum of the total annual costs by the sum of the NO_x removed for both control techniques. The controlled NO_x emission level for the combination of controls is 9 ppmv. These combined cost-effectiveness figures are presented in Figure 2-10.

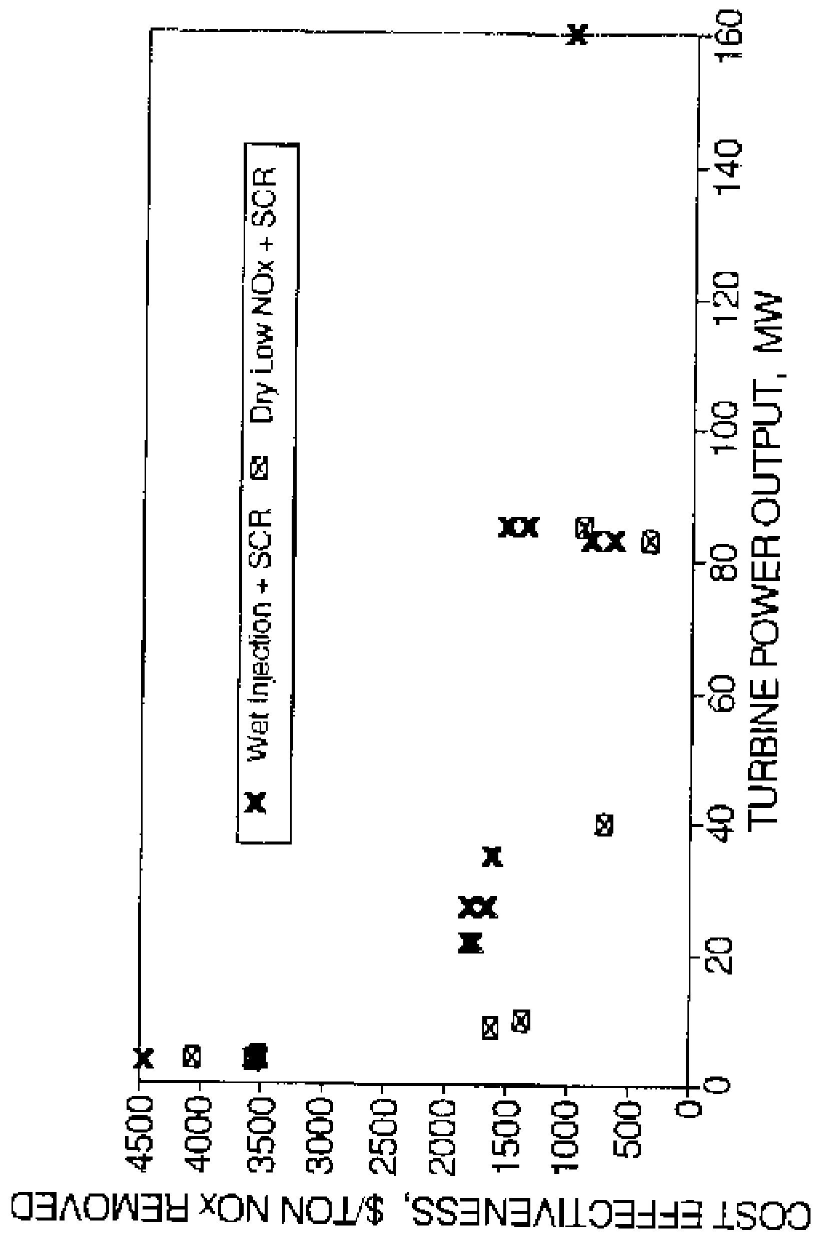


Figure 2-10. Combined cost effectiveness for combustion controls plus selective catalytic reduction.

For wet injection plus SCR, the combined cost effectiveness ranges from $4,460 for a 3.3 MW (4,430 hp) application to $988 for a 160 MW (216,000 hp) site. The $645 cost-effectiveness value for the 83 MW (111,000 hp) turbine is lower than the other turbine models shown in Figure 2-10 due to

the relatively high uncontrolled NO_x emission level for this turbine, which results in relatively high NO_x removal rates and a lower cost effectiveness. For dry low-NO_x combustion plus SCR, combined cost-effectiveness values range from $4,060 to $348 for this turbine size range.

2.4 REVIEW OF CONTROLLED NO_x EMISSION LEVELS AND COSTS

An overview of the performance and costs for available NO_x control techniques is presented in Figure 2-11.

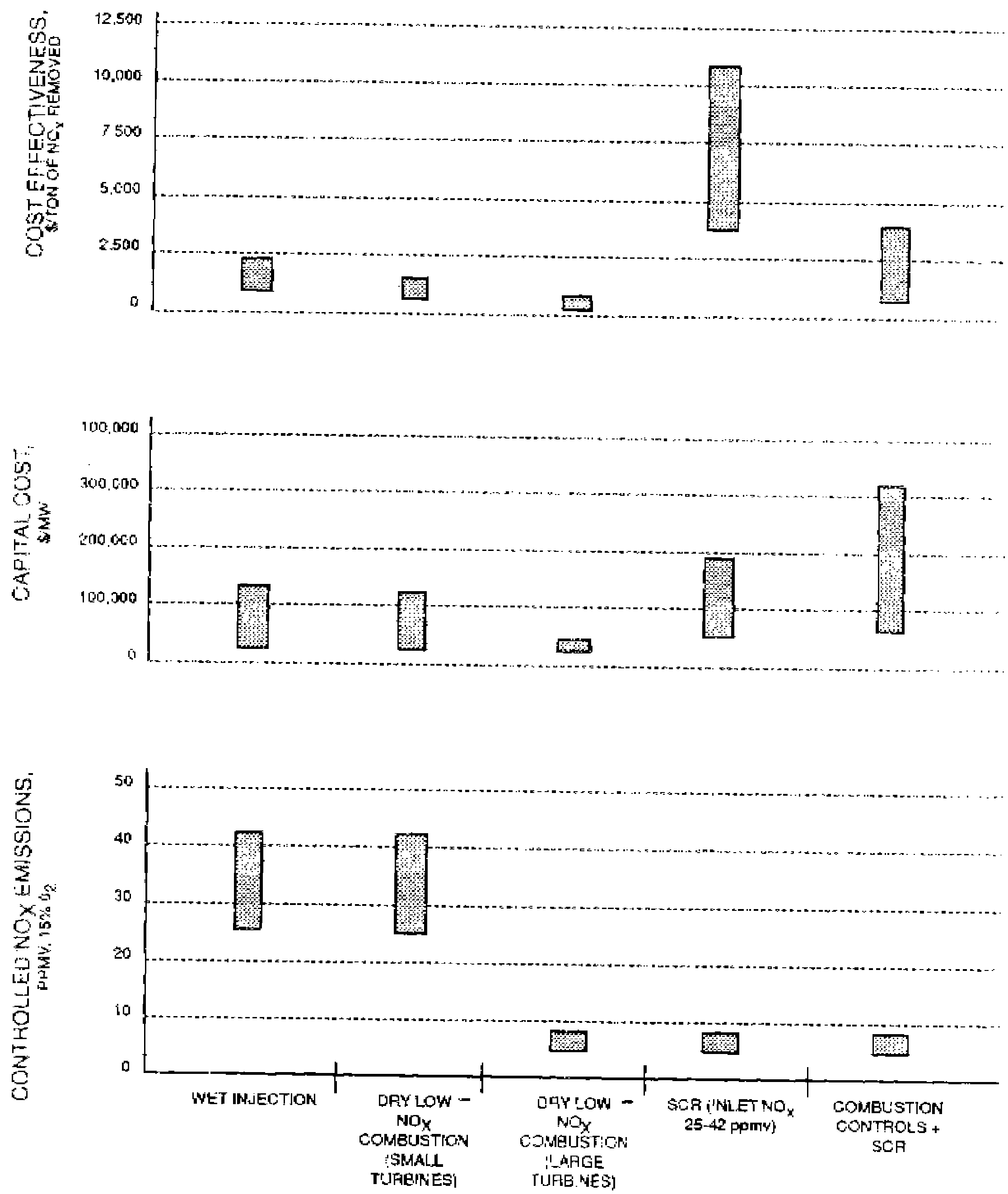


Figure 2-11. Controlled NO_x emission levels and associated capital costs and cost effectiveness for available NO_x control techniques. Natural gas fuel.

Figure 2-11 shows relative achievable controlled NO_x emission levels, capital costs, and cost effectiveness for gas-fired turbine applications. Controlled NO_x emission levels of 25 to 42 ppmv can be achieved using either wet injection or, where available, dry low-NO_x combustion. Wet injection capital costs range from $30,000 to $140,000 per MW ($22 to $104 per hp), and cost effectiveness ranges from $375 to $2,100 per ton of NO_x removed. Dry low-NO_x combustion capital costs range from $25,000 to $115,000 per MW ($19 to $86 per hp), and cost effectiveness ranges from $55 to $1,050 per ton of NO_x removed.

A controlled NO_x emission level of 9 ppmv requires the addition of SCR, except for a limited number of large turbine models for which dry low-NO_x combustion designs can achieve this level. For turbine models above 40 MW (53,600 hp), the capital costs of dry low-NO_x combustion range from $25,000 to $36,000 per MW ($25 to $27 per hp), and the cost effectiveness ranges from $55 to $138 per ton of NO_x removed. Adding SCR to reduce NO_x emission levels from 42 or 25 ppmv to 9 ppmv adds capital costs ranging from $53,000 to $190,000 per MW ($40 to $142 per hp) and yields cost-effectiveness values ranging from $3,500 to $10,500 per ton of NO_x removed. The combination of combustion controls plus SCR yields combined capital costs ranging from $78,000 to $330,000 per MW ($58 to $246 per hp) and cost-effectiveness values ranging from $350 to $4,500 per ton of NO_x removed.

2.5 ENERGY AND ENVIRONMENTAL IMPACTS OF NO_x CONTROL TECHNIQUES

The use of the NO_x control techniques described in this document may affect the turbine performance and maintenance requirements and may result in increased emissions of carbon monoxide (CO), hydrocarbons (HC), and NH_3. These potential energy and environmental impacts are discussed in this section.

Water or steam injection affects turbine performance and in some turbines also affects maintenance requirements. The increased mass flow through the turbine resulting from water or steam injection increases the available power output. The quenching effect in the combustor, however, decreases combustion efficiency, and consequently the efficiency of the turbine decreases in most applications. The efficiency reduction is greater for water than for steam injection, largely because the heat of vaporization energy cannot be recovered in the turbine. In applications where the steam can be produced from turbine exhaust heat that would otherwise be rejected to the atmosphere, the net gas turbine efficiency is increased with steam injection. Injection of water or steam into the combustor increases the maintenance requirements of the hot section of some turbine models. Water injection generally has a greater impact than steam on increased turbine maintenance. Water or steam injection has the potential to increase CO and, to a lesser extent, HC emissions, especially at water-to-fuel ratios above 0.8.

Turbine manufacturers report no significant performance impacts for lean premixed combustors. Power output and efficiency are comparable to conventional designs. No maintenance impacts are reported, although long-term operating experience is not available. Impacts on CO emissions vary for different combustor designs. Limited data from three manufacturers showed minimal or no increases in CO emissions for controlled NO_x emission levels of 25 to 42 ppmv. For a controlled NO_x level of 9 ppmv, however, CO emissions increased in from 10 to 25 ppmv in one manufacturer's combustor design.

For SCR, the catalyst reactor increases the back-pressure on the turbine, which decreases the turbine power output by approximately 0.5 percent. The addition of the SCR system and associated controls and monitoring equipment increases plant maintenance requirements, but it is expected that these maintenance requirements are consistent with maintenance schedules for other plant equipment. There is no impact on CO or HC emissions from the turbine caused by the SCR system, but ammonia slip through the catalyst reactor results in NH_3 emissions. Ammonia slip levels are typically guaranteed by SCR vendors at 10 ppmv, and operating experience indicates actual NH_3 emissions are at or below this level.

3.0 STATIONARY GAS TURBINE DESCRIPTION AND INDUSTRY APPLICATIONS

This section describes the physical components and operating cycles of gas turbines and how turbines are used in industry. Projected growth in key industries is also presented.

3.1 GENERAL DESCRIPTION OF GAS TURBINES

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. A common example of a gas turbine is the aircraft jet engine. In stationary applications, the hot combustion gases are directed through one or more fan-like turbine wheels to generate shaft horsepower rather than the thrust propulsion generated in an aircraft engine. Often the heat from the exhaust gases is recovered through an add-on heat exchanger.

Figure 3-1

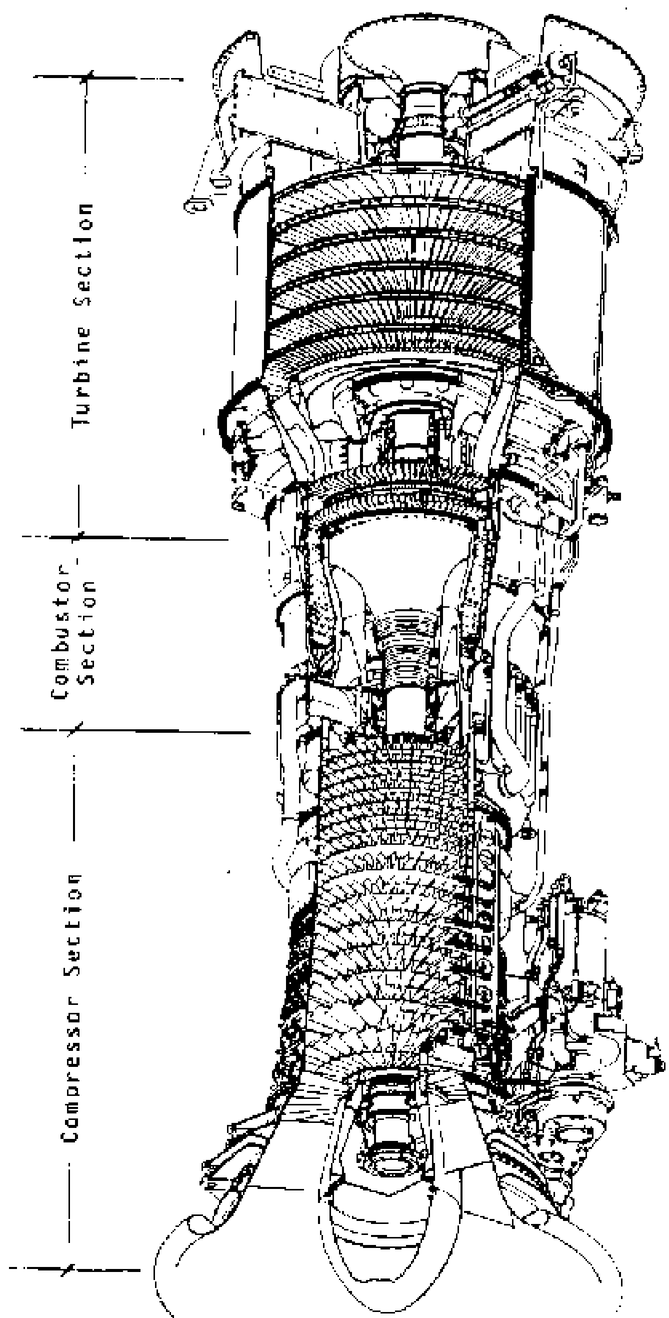
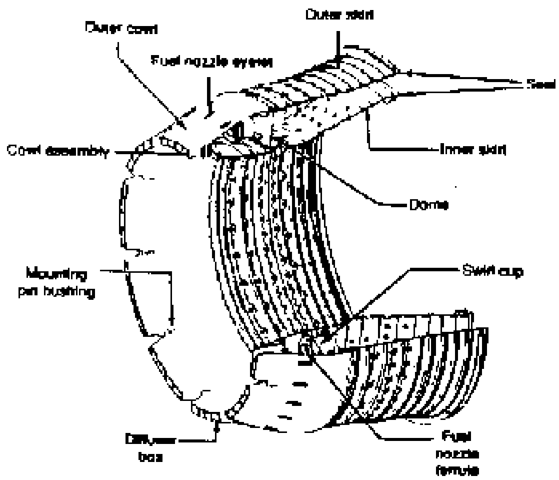


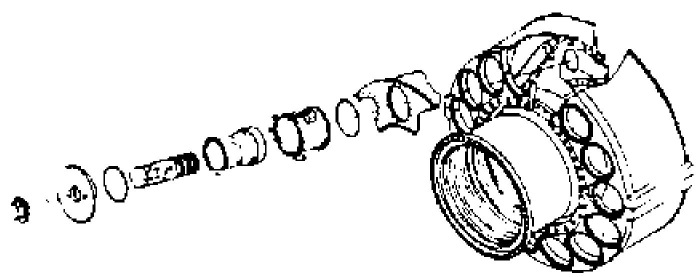
Figure 3-1. The three primary sections of a gas turbine.[1]

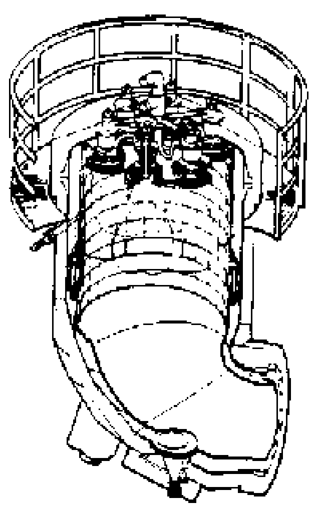
presents a cutaway view showing the three primary sections of a gas turbine: the compressor, the combustor, and the turbine.[1] The compressor draws in ambient air and compresses it by a pressure ratio of up to 30 times ambient pressure.[2] The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. There are three types of combustors: annular, can-annular, and silo. An annular combustor is a single continuous chamber roughly the shape of a doughnut that rings the turbine in a plane perpendicular to the air flow. The can-annular type uses a similar configuration but is a series of can-shaped chambers rather than a single continuous chamber. The silo combustor type is one or more chambers mounted external to the gas turbine body. These three combustor types are shown in Figure 3-2



Annular

Can-annular





Silo

Figure 3-2. Types of gas turbine combustors.[3-5]

; further discussion of combustors is found in Chapter 5.[3-5]
Flame temperatures in the combustor can reach 2000°C (3600°F).[6]
The hot combustion gases

are then diluted with additional cool air from the compressor section and directed to the turbine section at temperatures up to 1285°C (2350°F).[6] Energy is recovered in the turbine section in the form of shaft horsepower, of which typically greater than 50 percent is required to drive the internal compressor section.[7] The balance of the recovered shaft energy is available to drive the external load unit.

The compressor and turbine sections can each be a single fan-like wheel assembly, or stage, but are usually made up of a series of stages. In a single-shaft gas turbine, shown in Figure 3-3

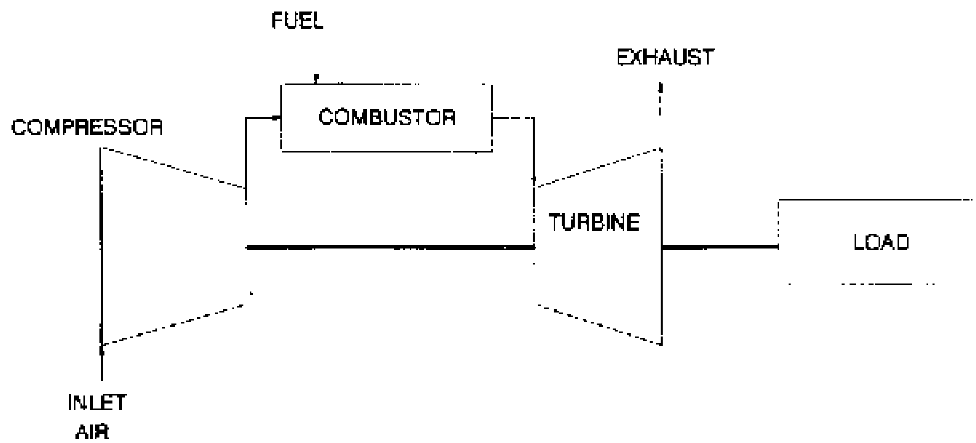


Figure 3-3. Single-shaft gas turbine.

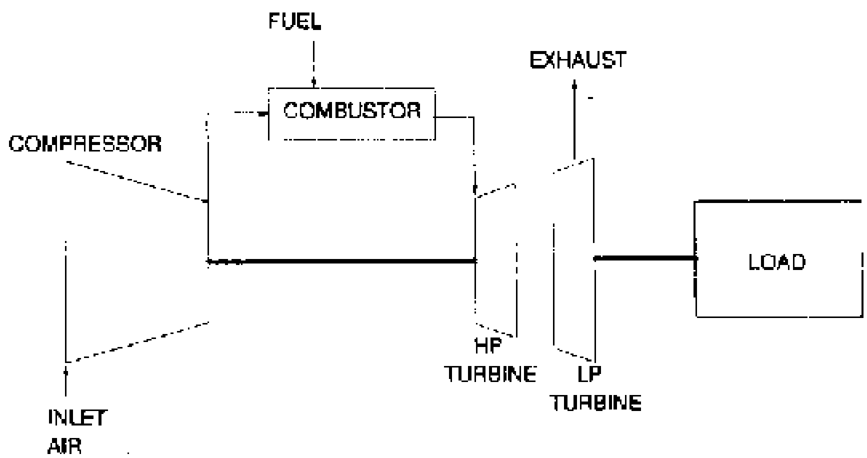


Figure 3-4. Two-shaft gas turbine.

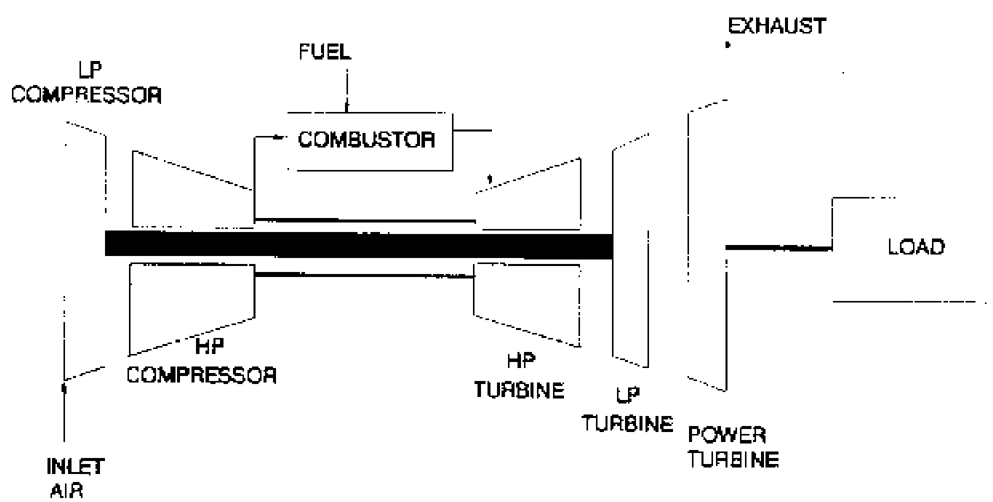


Figure 3-5. Three-shaft gas turbine.

, all compressor and turbine stages are fixed to a single, continuous shaft and operate at the same speed. A single-shaft gas turbine is typically used to drive electric generators where there is little speed variation.

A two-shaft gas turbine is shown in Figure 3-4. In this design, the turbine section is divided into a high-pressure and low-pressure arrangement, where the high-pressure turbine is mechanically tied to the compressor section by one shaft, while the low-pressure turbine, or power turbine, has its own shaft and is connected to the external load unit. This configuration allows the high-pressure turbine/compressor shaft assembly, or rotor, to operate at or near optimum design speeds, while the power turbine rotor speed can vary over as wide a range as is required by most external-load units in mechanical drive applications (i.e., compressors and pumps).

A third configuration is a three-shaft gas turbine. As shown in Figure 3-5, the compressor section is divided into a low-pressure and high-pressure configuration. The low-pressure compressor stages are mechanically tied to the low-pressure turbine stages, and the high-pressure compressor stages are similarly connected to the high-pressure turbine stages in a concentric shaft arrangement. These low-pressure and high-pressure rotors operate at optimum design speeds independent of each other. The power turbine stages are mounted on a third independent shaft and form the power turbine rotor, the speed of which can vary over as wide a range as is necessary for mechanical drive applications.

Gas turbines can burn a variety of fuels. Most burn natural gas, waste process gases, or liquid fuels such as distillate oils (primarily No. 2 fuel oil). Some gas turbines are capable of burning lower-grade residual or even crude oil with minimal processing. Coal-derived gases can be burned in some turbines.

The capacity of individual gas turbines ranges from approximately 0.08 to over 200 megawatts (MW) (107 to 268,000 horsepower [hp]).[2] Manufacturers continue to increase the horsepower of individual gas turbines, and frequently they are "ganged," or installed in groups so that the total horsepower output from one location can meet virtually any installation's power requirements.

Several characteristics of gas turbines make them attractive power sources. These characteristics include a high horsepower-to-size ratio, which allows for efficient space utilization, and a short time from order placement to on-line operation. Many suppliers offer the gas turbine, load unit, and all accessories as a fully assembled package that can be performance tested at the supplier's facility. This packaging is cost effective and saves substantial installation time. Other advantages of gas turbines are:

1. Low vibration;
2. High reliability;
3. No requirement for cooling water;
4. Suitability for remote operation;
5. Lower capital costs than reciprocating engines; and
6. Lower capital costs than boiler/steam turbine-based electric power generating plants.[8]

3.2 OPERATING CYCLES

The four basic operating cycles for gas turbines are simple, regenerative, cogeneration, and combined cycles. Each of these cycles is described separately below.

3.2.1 Simple Cycle

The simple cycle is the most basic operating cycle of a gas turbine. In a simple cycle application, a gas turbine functions with only the three primary sections described in Section 3.1, as depicted in Figure 3-6.

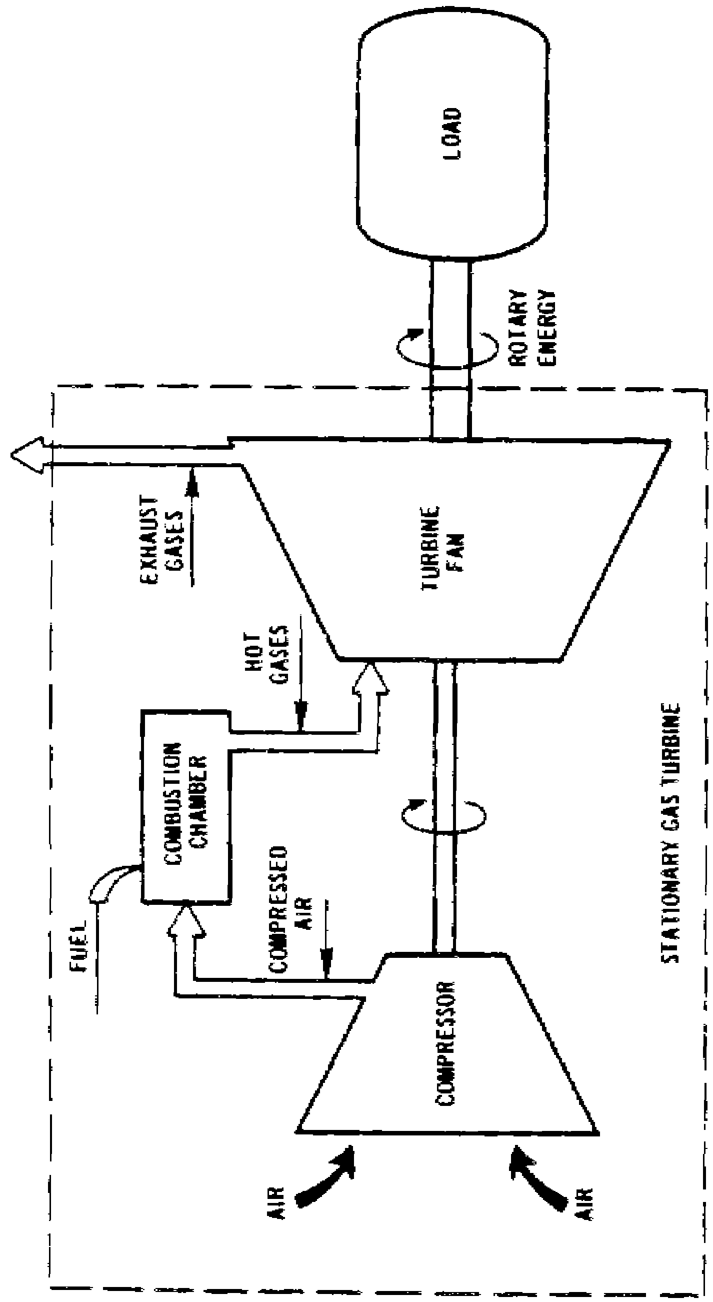


Figure 3-6. Simple cycle gas turbine appplication.[10]

[10] Cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is typically in the 30 to 35 percent range, although one manufacturer states an efficiency of 40 percent for an engine recently introduced to the market.[9] In addition to shaft energy output, 1 to 2 percent of the fuel input energy can be attributed to mechanical losses; the balance is exhausted from the turbine in the form of heat.[7] Simple cycle operation is typically used when there is a requirement for shaft horsepower without recovery of the exhaust heat. This cycle offers the lowest installed capital cost but also provides the least efficient use of fuel and therefore the highest operating cost.

3.2.2 Regenerative Cycle

The regenerative cycle gas turbine is essentially a simple cycle gas turbine with an added heat exchanger, called a regenerator or recuperator, to preheat the combustion air. In the regenerative cycle, thermal energy from the exhaust gases is transferred to the compressor discharge air prior to being introduced into the combustor. A diagram of this cycle is depicted in Figure 3-7

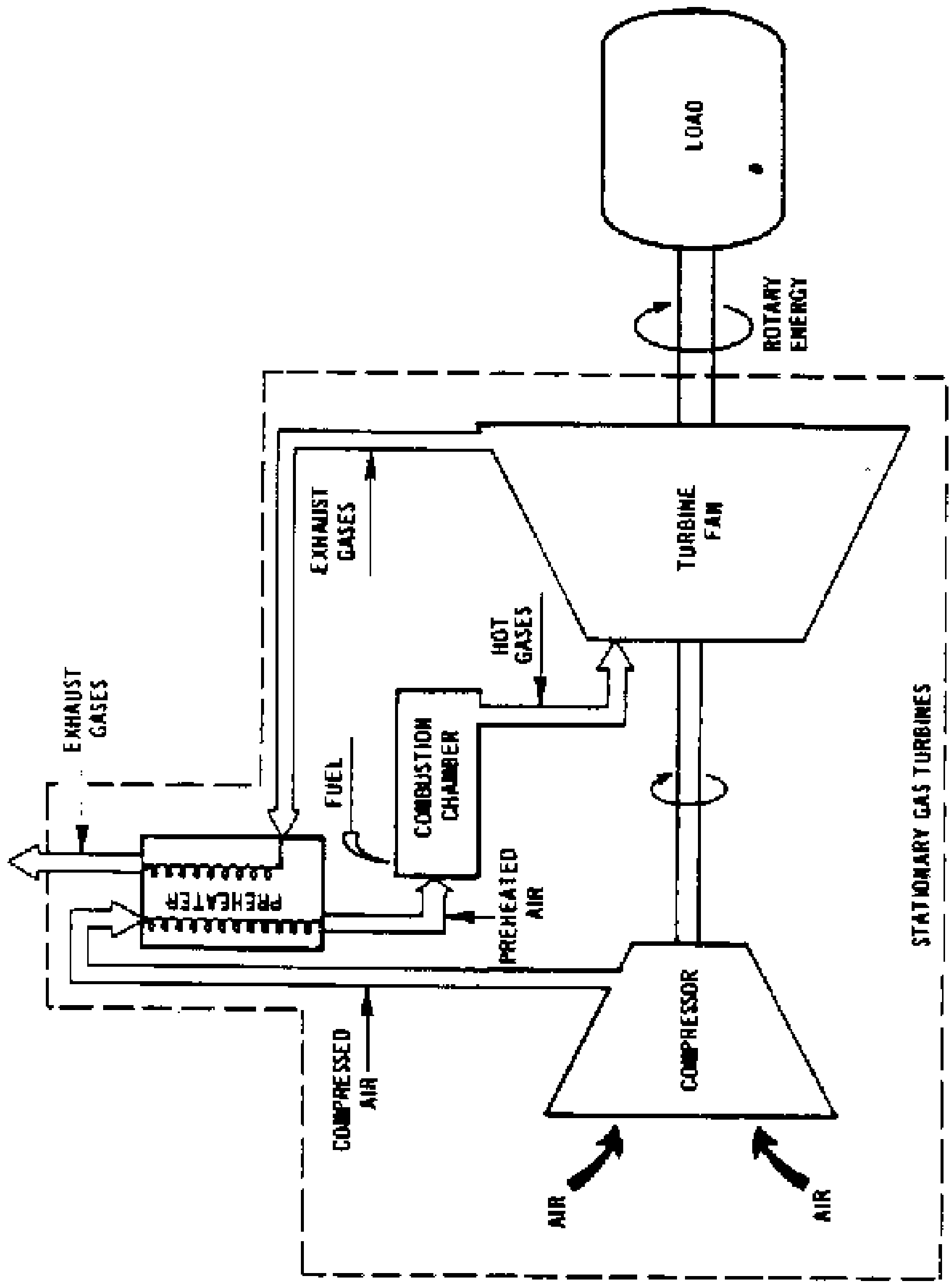


Figure 3-7. Regenerative cycle gas turbine.[11]

.[11] Preheating the combustion air reduces the amount of fuel required to reach design combustor temperatures and therefore improves the overall cycle efficiency over that of simple cycle operation. The efficiency gain is directly proportional to the differential temperature between the exhaust gases and compressor discharge air. Since the compressor discharge air temperature increases with an increase in pressure ratio, higher regenerative cycle efficiency gains are realized from lower compressor pressure ratios typically found in older gas turbine models.[7] Most new or updated gas turbine models with high compressor pressure ratios render regenerative cycle operation economically unattractive because the capital cost of the regenerator cannot be justified by the marginal fuel savings.

3.2.3 Cogeneration Cycle

A gas turbine used in a cogeneration cycle application is essentially a simple cycle gas turbine with an added exhaust heat exchanger, called a heat recovery steam generator (HRSG). This configuration is shown in Figure 3-8

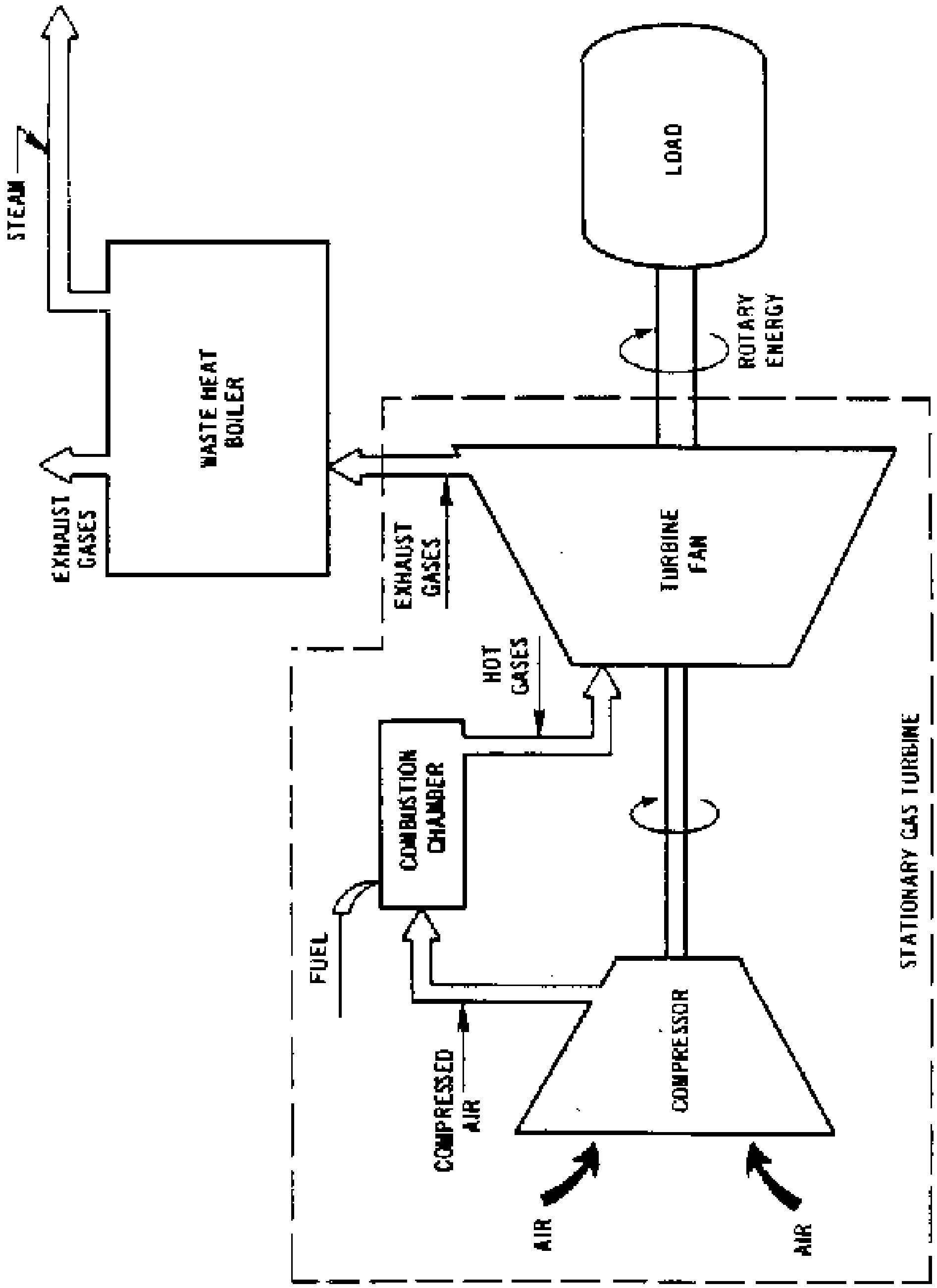


Figure 3-8. Cogeneration cycle gas turbine application.[12]

.[12] The steam generated by the exhaust heat can be delivered at a variety of pressure and temperature conditions to meet site thermal process requirements. Where the exhaust heat is not sufficient to meet site requirements, a supplementary burner, or duct burner, can be placed in the exhaust duct upstream of the HRSG to increase the exhaust heat energy. Adding the HRSG equipment increases the capital cost, but recovering the exhaust heat increases the overall cycle efficiency to as high as 75 percent.[13]

3.2.4 Combined Cycle

A combined cycle is the terminology commonly used for a gas turbine/HRSG configuration as applied at an electric utility. This cycle, shown in Figure 3-9

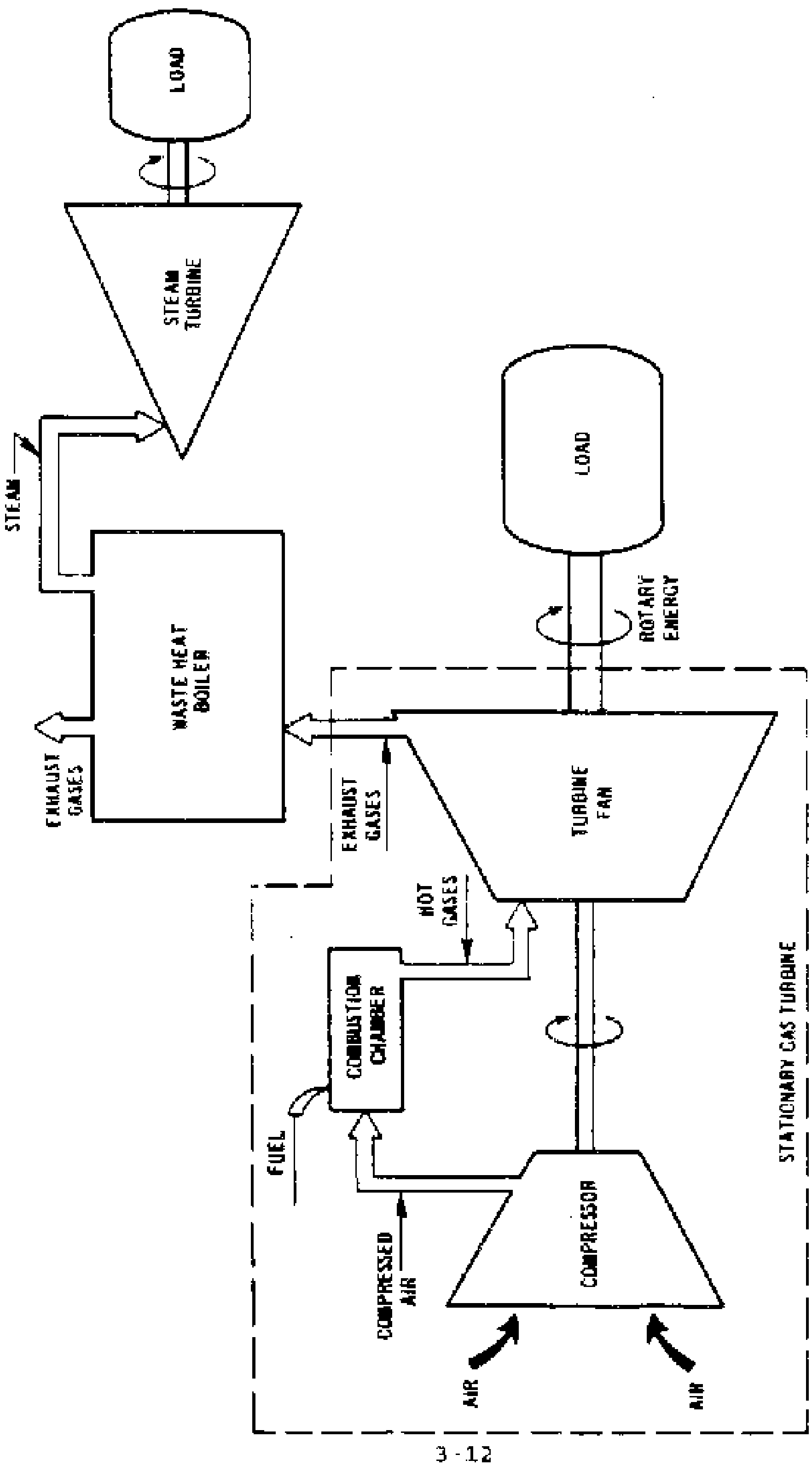


Figure 3-9. Combined cycle gas turbine application.[12]

, is used to generate electric power.[12] The gas turbine drives an electric generator, and the steam produced in the HRSG is delivered to a steam turbine, which also drives an electric generator. The boiler may be supplementary-fired to increase the steam production where desired. Cycle efficiencies can exceed 50 percent.

3.3 INDUSTRY APPLICATIONS

Gas turbines are used by industry in both mechanical and electrical drive applications. Compressors and pumps are most often the driven load unit in mechanical drive applications, and electric generators are driven in electrical drive installations. Few sites have gas/air compression or fluid pumping requirements that exceed 15 MW (20,100 hp), and for this reason mechanical drive applications generally use gas turbines in the 0.08- to 15.0-MW (107- to 20,100-hp) range.[14] Electric power requirements range over the entire available range of gas turbines, however, and all sizes can be found in electrical drive applications, from 0.08 to greater than 200 MW (107 to 268,000 hp).[15]

The primary applications for gas turbines can be divided into five broad categories: the oil and gas industry,

stand-by/emergency electric power generation, independent electric power producers, electric utilities, and other industrial applications.[16] Where a facility has a requirement for mechanical shaft power only, the installation is typically simple or regenerative cycle. For facilities where either electric power or mechanical shaft power and steam generation are required, the installation is often cogeneration or combined cycle to capitalize on these cycles' higher efficiencies.

3.3.1 Oil and Gas Industry

The bulk of mechanical drive applications are in the oil and gas industry. Gas turbines in the oil and gas industry are used primarily to provide shaft horsepower for oil and gas extraction and transmission equipment, although they are also used in downstream refinery operations. Most gas turbines found in this industry are in the 0.08- to 15.0-MW (107- to 20,100-hp) range.

Gas turbines are particularly well suited to this industry, as they can be fueled by a wide range of gaseous and liquid fuels often available at the site. Natural gas and distillate oil are the most common fuels. Many turbines can burn waste process gases, and some turbines can burn residual oils and even crude oil. In addition, gas turbines are suitable for remote installation sites and unattended operation. Most turbines used in this industry operate continuously, 8,000+ hours per year, unless the installation is a pipeline transmission application with seasonal operation.

Competition from reciprocating engines in this industry is significant. Although gas turbines have a considerable capital cost advantage, reciprocating engines require less fuel to produce the same horsepower and consequently have a lower operating cost.[17] Selection of gas turbines vs. reciprocating engines is generally determined by site-specific criteria such as installed capital costs, costs for any required emissions control equipment, fuel costs and availability, annual operating hours, installation and structural considerations, compatibility with existing equipment, and operating experience.

3.3.2 Stand-By/Emergency Electric Power Generation

Small electric generator sets make up a considerable number of all gas turbine sales under 3.7 MW (5,000 hp). The majority of these installations provide backup or emergency power to critical networks or equipment and use liquid fuel. Telephone companies are a principal user, and hospitals and small municipalities also are included in this market. These turbines operate on an as-needed basis, which typically is between 75 and 200 hours per year.

Gas turbines offer reliable starting, low weight, small size, low vibration, and relatively low maintenance, which are important criteria for this application. Gas turbines in this size range have a relatively high capital cost, however, and reciprocating engines dominate this market, especially for applications under 2,000 kW (2,700 hp).[18,19]

3.3.3 Independent Electrical Power Producers

Large industrial complexes and refining facilities consume considerable amounts of electricity, and many sites choose to generate their own power. Gas turbines can be used to drive electric generators in simple cycle operation, or an HRSG system may be added to yield a more efficient cogeneration cycle. The vast majority of cogeneration installations operate in a combined cycle capacity, using a steam turbine to provide additional electric power. The Public Utility Regulatory Policies Act (PURPA) of 1978 encourages independent cogenerators to generate electric power by requiring electric utilities to (1) purchase electricity from qualifying producers at a price equal to the cost the utility can avoid by not having to otherwise supply that power (avoided cost) and (2) provide backup power to the cogenerator at reasonable rates. Between 1980 and 1986, approximately 20,000 MW of gas turbine-produced electrical generating capacity was certified as qualifying for PURPA benefits. This installed capacity by private industry power generators is more than the sum of all utility gas turbine orders for all types of central power plants during this period.[20] The Department of Energy (DOE) expects an additional 27,000 MW capacity to be purchased by private industry in the next 10 years.[21]

Gas turbines installed in this market range in power from 1 to over 100 MW (1,340 to 134,000 hp) and operate typically between 4,000 and 8,000 hours per year. While reciprocating engines compete with the gas turbine at the lower end of this market (under approximately 7.5 MW [10,000 hp]), the advantages of lower installed costs, high reliability, and low maintenance requirements make gas turbines a strong competitor.

3.3.4 Electric Utilities

Electric utilities are the largest user of gas turbines on an installed horsepower basis. They have traditionally installed these turbines for use as peaking units to meet the electric power demand peaks typically imposed by large commercial and industrial users on a daily or seasonal basis; consequently, gas turbines in this application operate less than 2,000 hours per year.[22] The power range used by the utility market is 15 MW to over 150 MW (20,100 to 201,000 hp). Peaking units typically operate in simple cycle.

The demand for gas turbines from the utility market was flat through the late 1970's and 1980's as the cost of fuel increased and the supplies of gas and oil became unpredictable. There are signs, however, that the utility market is poised to again purchase considerable generating capacity. The capacity margin, which is the utility industry's measure of excess generation capacity, peaked at 30 percent in 1982. By 1990, the capacity margin had dropped to approximately 20 percent, and, based on current construction plans, will reach the industry rule-of-thumb minimum of 15 percent by 1995.[21] The utility industry is adding new capacity and repowering existing older plants, and gas turbines are expected to play a considerable role.

Many utilities are now installing gas turbine-based combined cycle installations with provisions for burning coal-derived gas fuel at some future date. This application is known as integrated coal gasification combined cycle (IGCC). At least five power plant projects have been announced, and several more are being negotiated. Capital costs for these plants are in many cases higher than comparable natural gas-fueled applications, but future price increases for natural gas could make IGCC an attractive option for the future.[23]

Utility orders for gas turbines have doubled in each of the last 2 years. The DOE says that electric utilities will need to add an additional 73,000 MW to capacity to meet demand by the year 2000, and as Figure 3-10

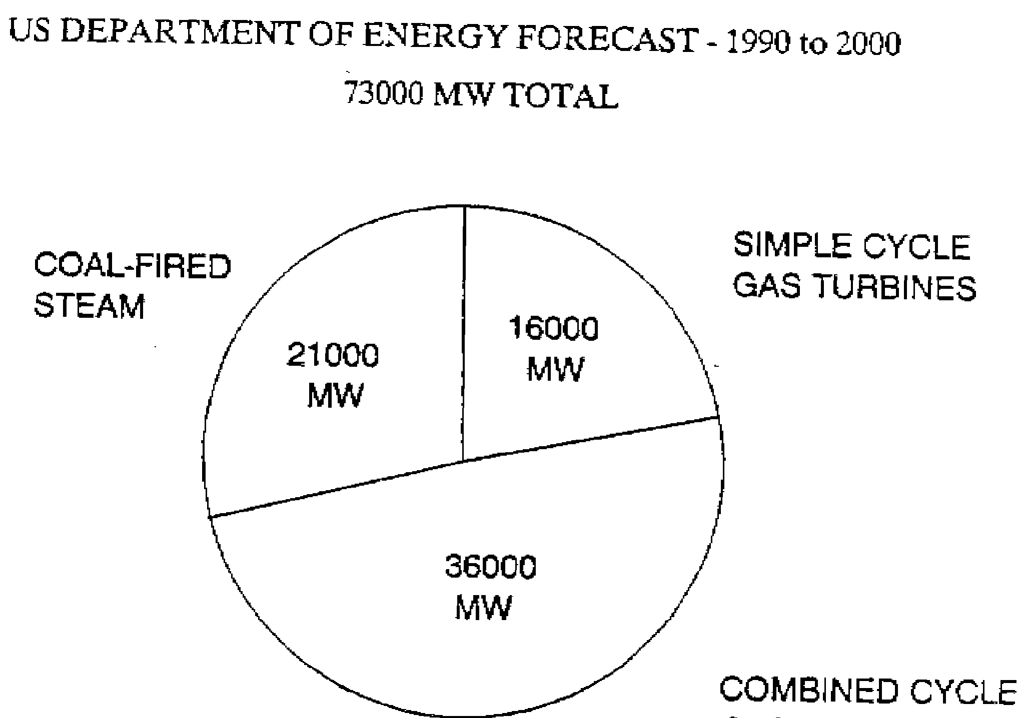


Figure 3-10. Total capacity to be purchased by the utility industry.[21]

shows, DOE expects 36,000 MW of combined cycle and 16,000 MW of simple cycle gas turbines to be purchased. This renewed interest in gas turbines is a result of:

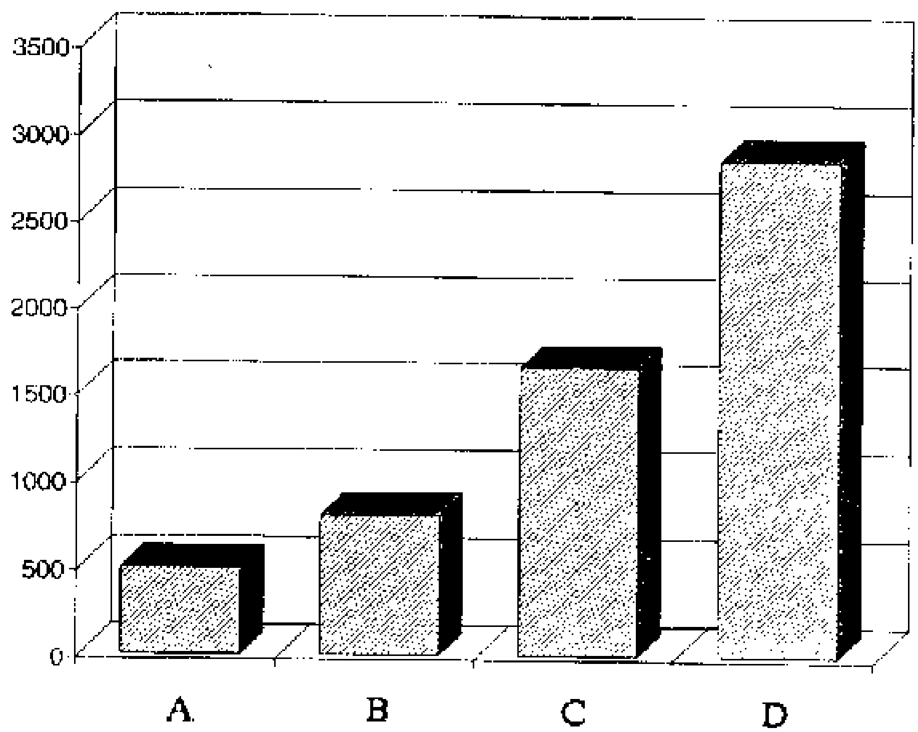
1. The introduction of new, larger, more efficient gas turbines;

2. Lower natural gas prices and proven reserves to meet current demand levels for more than 100 years;

3. Shorter lead times than those of competing equipment; and

4. Lower capital costs for gas turbines.[21]

Utility capital cost estimates, as shown in Figure 3-11



A - Repower existing plant using combined cycle gas turbines
B - New plant using combined cycle gas turbines
C - New plant using coal fired boilers
D - New plant using nuclear power

Figure 3-11. Capital costs for electric utility plants.[24]

, are (1) $500 per KW for repowering existing plants with combined cycle gas turbines, (2) $800 per KW for new combined cycle plants, (3) $1,650 per KW for new coal-fired plants, and (4) $2,850 per KW for new nuclear-powered plants.[24]

Gas turbines are also an alternative to displace planned or existing nuclear facilities. A total of 1,020 MW of gas turbine-generated electric power was recently commissioned in Michigan at a plant where initial design and construction had begun for a nuclear plant. Four additional idle nuclear sites are considering switching to gas turbine-based power production due to the legal, regulatory, financial, and public obstacles facing nuclear facilities.[24]

3.3.5 Other Industrial Applications

Industrial applications for gas turbines include various types of mechanical drive and air compression equipment. These applications peaked in the late 1960's and declined through the 1970's.[25] With the promulgation of PURPA in 1978 (see Section 3.3.3), many industrial facilities have found it

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economically feasible to install a combined cycle gas turbine to meet power and steam requirements. Review of editions of Gas Turbine World over the last several years shows that a broad range of industries (e.g., pulp and paper, chemical, and food processing) have installed combined cycle gas turbines to meet their energy requirements.

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4.0 CHARACTERIZATION OF NO_x EMISSIONS

This section presents the principles of NO_x formation, the types of NO_x emitted (i.e., thermal NO_x, prompt NO_x, and fuel NO_x), and how they are generated in a gas turbine combustion process. Estimated NO_x emission factors for gas turbines and the bases for the estimates are also presented.

4.1 THE FORMATION OF NO_x

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of nitrogen (N_2) and oxygen (O_2) into N and O, respectively. Reactions following this dissociation result in seven known oxides of nitrogen: NO, NO_2, NO_3, N_2O, N_2O_3, N_2O_4, and N_2O_5. Of these, nitric oxide (NO) and nitrogen dioxide (NO_2) are formed in sufficient quantities to be significant in atmospheric pollution.[1] In this document, "NO_x" refers to either or both of these gaseous oxides of nitrogen.

Virtually all NO_x emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO_2 molecule.[2] There are two mechanisms by which NO_x is formed in turbine combustors: (1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_x and prompt NO_x) and (2) the conversion of nitrogen chemically bound in the fuel (fuel NO_x). These mechanisms are discussed below.

4.1.1 Formation of Thermal and Prompt NO_x

Thermal NO_x is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen.

The major contributing chemical reactions are known as the Zeldovich mechanism and take place in the high temperature area of the gas turbine combustor.[3] Simply stated, the Zeldovich mechanism postulates that thermal NO_x formation increases exponentially with increases in temperature and linearly with increases in residence time.[4]

Flame temperature is dependent upon the equivalence ratio, which is the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.[5] An equivalence ratio of 1.0 corresponds to the stoichiometric ratio and is the point at which a flame burns at its highest theoretical temperature.[5] Figure 4-1

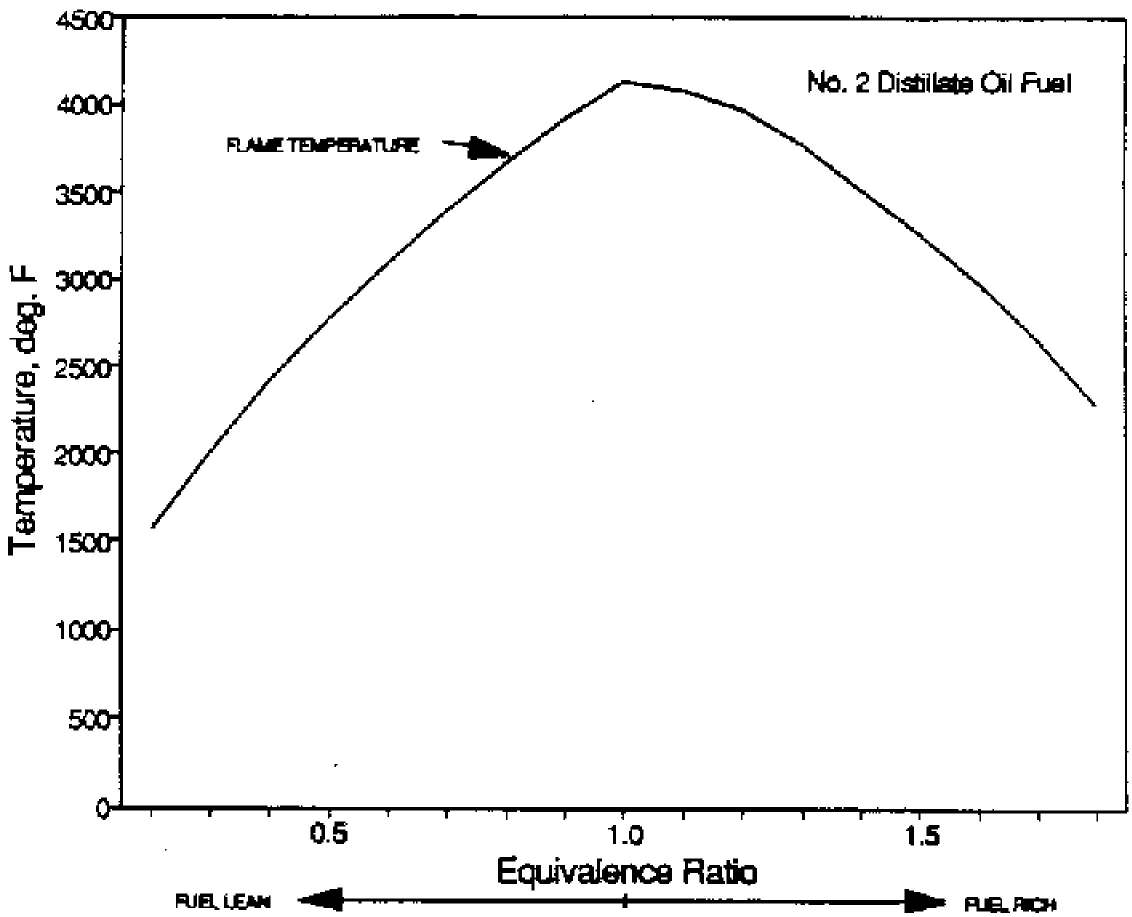

Figure 4-1. Influence of equivalence ratio on flame temperature.[4]

shows the flame temperature and equivalence ratio relationship for combustion using No. 2 distillate fuel oil (DF-2).[4]

The series of chemical reactions that form thermal NO_x according to the Zeldovich mechanism are presented below.[3]

1. $O_2 \rightleftharpoons 2O$;

2. $N_2 \rightleftharpoons 2N$;

3. $N + O \rightleftharpoons NO$;

4. $N + O_2 \rightleftharpoons NO + O$; and

5. $O + N_2 \rightleftharpoons NO + N$.

This series of equations applies to a fuel-lean combustion process. Combustion is said to be fuel-lean when there is excess oxygen available (equivalence ratio <1.0). Conversely, combustion is fuel-rich if insufficient oxygen is present to burn all of the available fuel (equivalence ratio >1.0). Additional equations have been developed that apply to fuel-rich combustion. These equations are an expansion of the above series to add an intermediate hydroxide molecule (OH):[3]

6. $N + OH \rightleftharpoons NO + H$,

and further to include an intermediate product, hydrogen cyanide (HCN), in the formation process:[3]

7. $N_2 + CH \rightleftharpoons HCN + N$ and

8. $N + OH \rightleftharpoons H + NO$.

The overall equivalence ratio for gases exiting the gas turbine combustor is less than 1.0.[4] Fuel-rich areas do exist in the overall fuel-lean environment, however, due to less-than-ideal fuel/air mixing prior to combustion. This being the case, the above equations for both fuel-lean and fuel-rich combustion apply for thermal NO_x formation in gas turbines.

Prompt NO_x is formed in the proximity of the flame front as intermediate combustion products such as HCN, N, and NH are oxidized to form NO_x as shown in the following equations:

1. $CH + N_2 \rightleftharpoons HCN + N$;

2. $CH_2 + N_2 \rightleftharpoons HCN + NH$; and

3. $HCN, N, NH + O_x \rightleftharpoons NO + ...$[6]

Prompt NO_x is formed in both fuel-rich flame zones and fuel-lean premixed combustion zones. The contribution of prompt NO_x to overall NO_x emissions is relatively small in conventional near-stoichiometric combustors, but this contribution increases with decreases in the equivalence ratio (fuel-lean mixtures). For this reason, prompt NO_x becomes an important consideration for the low-NO_x combustor designs described in Chapter 5 and establishes a minimum NO_x level attainable in lean mixtures.[7]

4.1.2 Formation of Fuel NO_x

Fuel NO_x (also known as organic NO_x) is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as

N_2 in some natural gas, does not contribute significantly to fuel NO_x formation.[8] However, nitrogen compounds are present in coal and petroleum fuels as pyridine-like (C_5H_5N) structures that tend to concentrate in the heavy resin and asphalt fractions upon distillation. Some low-British thermal unit (Btu) synthetic fuels contain nitrogen in the form of ammonia (NH_3), and other low-Btu fuels such as sewage and process waste-stream gases also contain nitrogen. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_x.[9] With excess air, the degree of fuel NO_x formation is primarily a function of the nitrogen content in the fuel. The fraction of fuel-bound nitrogen (FBN) converted to fuel NO_x decreases with increasing nitrogen content, although the absolute magnitude of fuel NO_x increases. For example, a fuel with 0.01 percent nitrogen may have 100 percent of its FBN converted to fuel NO_x, whereas a fuel with a 1.0 percent FBN may have only a 40 percent fuel NO_x conversion rate. The low-percentage FBN fuel has a 100 percent conversion rate, but its overall NO_x emission level would be lower than that of the high-percentage FBN fuel with a 40 percent conversion rate.[10]

Nitrogen content varies from 0.1 to 0.5 percent in most residual oils and from 0.5 to 2 percent for most U.S. coals.[11] Traditionally, most light distillate oils have had less than 0.015 percent nitrogen content by weight. However, today many distillate oils are produced from poorer-quality crudes, especially in the northeastern United States, and these distillate oils may contain percentages of nitrogen exceeding the 0.015 threshold; this higher nitrogen content can increase fuel NO_x formation.[4] At least one gas turbine installation burning coal-derived fuel is in commercial operation in the United States.[12]

Most gas turbines that operate in a continuous duty cycle are fueled by natural gas that typically contains little or no FBN. As a result, when compared to thermal NO_x, fuel NO_x is not currently a major contributor to overall NO_x emissions from stationary gas turbines.

4.2 UNCONTROLLED NO_x EMISSIONS

The NO_x emissions from gas turbines are generated entirely in the combustor section and are released into the atmosphere via the stack. In the case of simple and regenerative cycle operation, the combustor is the only source of NO_x emissions. In cogeneration and combined cycle applications, a duct burner may be placed in the exhaust ducting between the gas turbine and the heat recovery steam generator (HRSG); this burner also generates NO_x emissions. (Gas turbine operating cycles are discussed in Section 3.2.) The amount of NO_x formed in the combustion zone is "frozen" at this level regardless of any temperature reductions that occur at the downstream end of the combustor and is released to the atmosphere at this level.[1]

4.2.1 Parameters Influencing Uncontrolled NO_x Emissions

The level of NO_x formation in a gas turbine, and hence the NO_x emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO_x generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output level as a percentage of the rated full power output of the turbine. These factors are discussed below.

4.2.1.1 Combustor Design. The design of the combustor is the most important factor influencing the formation of NO_x. Design considerations are presented here and discussed further in Chapter 5.

Thermal NO_x formation, as discussed in Section 4.1.1, is influenced primarily by flame temperature and residence time. Design parameters controlling equivalence ratios and the introduction of cooling air into the combustor strongly influence thermal NO_x formation. The extent of fuel/air mixing prior to combustion also affects NO_x formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NO_x production takes place.[13] The dependence of thermal NO_x formation on flame temperature and equivalence ratio is shown in Figure 4-2

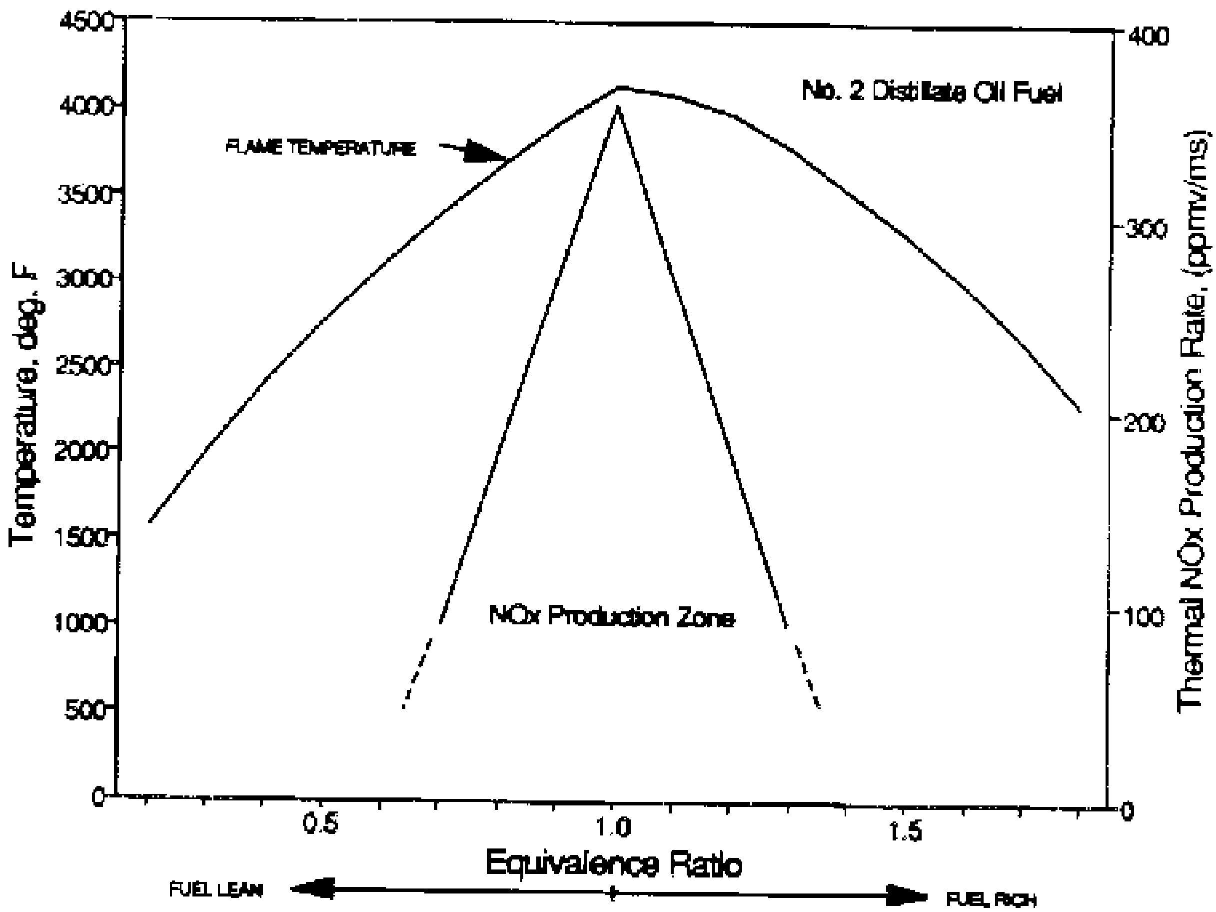

Figure 4-2. Thermal NO_x production as a function of flame temperature and equivalence ratio.[4]

for DF-2.[4] Conversely, prompt NO_x is largely insensitive to changes in temperature and pressure.[7]

Fuel NO_x formation, as discussed in Section 4.1.2, is formed when FBN is released during combustion and oxidizes to form NO_x. Design parameters that control equivalence ratio and residence time influence fuel NO_x formation.[14]

4.2.1.2 Type of Fuel. The level of NO_x emissions varies for different fuels. In the case of thermal NO_x, this level increases with flame temperature. For gaseous fuels, the constituents in the gas can significantly affect NO_x emissions levels. Gaseous fuel mixtures containing hydrocarbons with molecular weights higher than that of methane (e.g., ethane, propane, and butane) burn at higher flame temperatures and as a result can increase NO_x emissions greater than 50 percent over NO_x levels for methane gas fuel. Refinery gases and some unprocessed field gases contain significant levels of these higher molecular weight hydrocarbons. Conversely, gas fuels that contain significant inert gases, such as CO_2, generally produce lower NO_x emissions. These inert gases serve to absorb heat during combustion, thereby lowering flame temperatures and reducing NO_x emissions. Examples of this type of gas fuel are air-blown gasifier fuels and some field gases.[15] Combustion of hydrogen also results in high flame temperatures, and gases with significant hydrogen content produce relatively high NO_x emissions. Refinery gases can have hydrogen contents exceeding 50 percent.[16]

As is shown in Figure 4-3

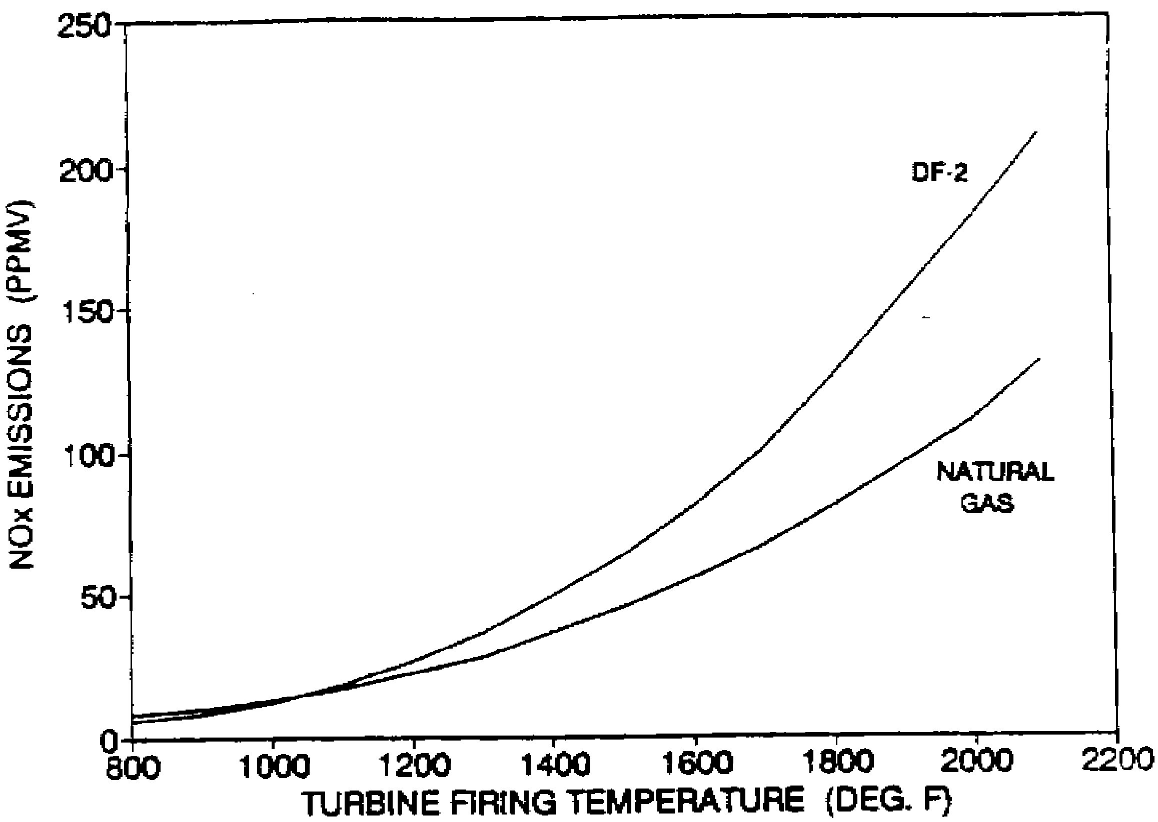

Figure 4-3. Influence of firing temperature on thermal NO_x formation.[17]

, DF-2 burns at a flame temperature that is approximately 75°C (100°F) higher than that of natural gas, and as a result, NO_x emissions are higher when burning DF-2 than they are when burning natural gas.[17] Low-Btu fuels such as coal gas burn with lower flame temperatures, which result in

substantially lower thermal NO_x emissions than natural gas or DF-2.[18] For fuels containing FBN, the fuel NO_x production increases with increasing levels of FBN.

4.2.1.3 Ambient Conditions. Ambient conditions that affect NO_x formation are humidity, temperature, and pressure. Of these ambient conditions, humidity has the greatest effect on NO_x formation.[19] The energy required to heat the airborne water vapor has a quenching effect on combustion temperatures, which reduces thermal NO_x formation. At low humidity levels, NO_x emissions increase with increases in ambient temperature. At high humidity levels, the effect of changes in ambient temperature on NO_x formation varies. At high humidity levels and low ambient temperatures, NO_x emissions increase with increasing temperature. Conversely, at high humidity levels and ambient temperatures above 10°C (50°F), NO_x emissions decrease with increasing temperature.

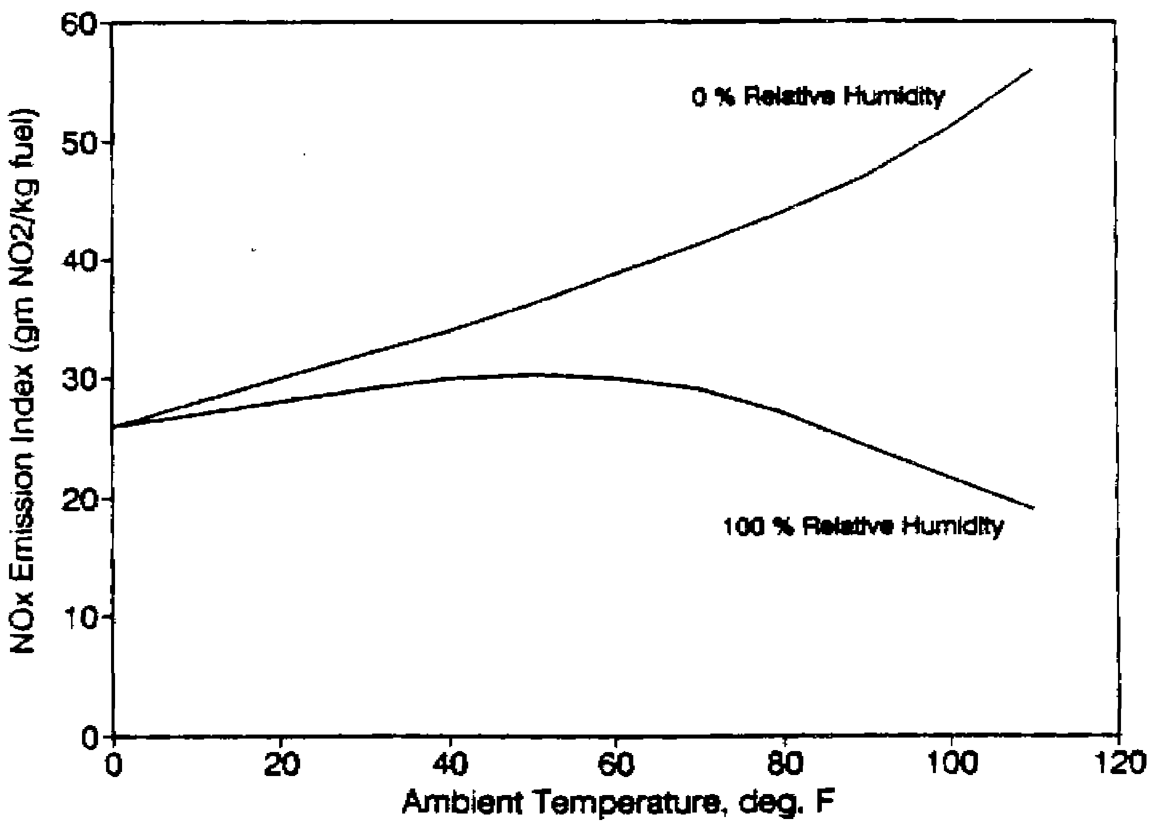

Figure 4-4. Influence of relative humidity and ambient temperature on NO_x formation.[19]

This effect of humidity and temperature on NO_x formation is shown in Figure 4-4. A rise in ambient pressure results in higher pressure and temperature levels entering the combustor and so No_x production levels increase with increases in ambient pressure.[19]

The influence of ambient conditions on measured NO_x emission levels can be corrected using the following equation:[20]

$$NO_x = (NO_{xo})(P_r/P_o)^{0.5} e^{19(Ho-0.00633)} (288°K/T_a)^{1.53}$$

where:

NO_x = emission rate of NO_x at 15 percent O_2 and International Standards Organization (ISO) ambient conditions, volume percent;

NO_{xo} = observed NO_x concentration, parts per million by volume (ppmv) referenced to 15 percent O_2;

P_r = reference compressor inlet absolute pressure at 101.3 kilopascals ambient pressure, millimeters mercury (mm Hg);

P_o = observed compressor inlet absolute pressure at test, mm Hg;

H_o = observed humidity of ambient air, g H_2O/g air;

e = transcendental constant, 2.718; and

T_a = ambient temperature, K.

At least two manufacturers state that this equation does not accurately correct NO_x emissions for their turbine models.[8,12] It is expected that these turbine manufacturers could provide corrections to this equation that would more accurately correct NO_x emissions for the effects of ambient conditions based on test data for their turbine models.

4.2.1.4 Operating Cycles. Emissions from identical turbines used in simple and cogeneration cycles have similar NO_x emissions levels, provided no duct burner is used in heat recovery applications. The NO_x emissions are similar because, as stated in Section 4.2, NO_x is formed only in the turbine combustor and remains at this level regardless of downstream temperature reductions. A turbine operated in a regenerative cycle produces higher NO_x levels, however, due to increased combustor inlet temperatures present in regenerative cycle applications.[21]

4.2.1.5 Power Output Level. The power output level of a gas turbine is directly related to the firing temperature, which is directly related to flame temperature. Each gas turbine has a base-rated power level and corresponding NO_x level. At power outputs below this base-rated level, the flame temperature is lower, so NO_x emissions are lower. Conversely, at peak power outputs above the base rating, NO_x emissions are higher due to higher flame temperature. The NO_x emissions for a range of firing temperatures are shown in Figure 4-3 for one manufacturer's gas turbine.[17]

4.2.2 NO_x Emissions From Duct Burners

In some cogeneration and combined cycle applications, the exhaust heat from the gas turbine is not sufficient to produce the desired quantity of steam from the HRSG, and a supplemental burner, or duct burner, is placed in the exhaust duct between the gas turbine and HRSG to increase temperatures to sufficient levels. In addition to providing additional steam capacity, this burner also increases the overall system efficiency since essentially all energy added by the duct burner can be recovered in the HRSG.[22]

The level of NO_x produced by a duct burner is approximately 0.1 pound per million Btu (lb/MMBtu) of fuel burned. The ppmv level depends upon the flowrate of gas turbine exhaust gases in which the duct burner is operating and thus varies with the size of the turbine.[23]

Typical NO_x production levels added by a duct burner operating on natural gas fuel are:[23]

Gas turbine output, megawatts (MW)	Duct burner NO_x, ppmv, referenced to 15 percent O_2
3 to 50	10 to 30
50+	5 to 10

4.3 UNCONTROLLED EMISSION FACTORS

TABLE 4-1. UNCONTROLLED NO_x EMISSIONS FACTORS FOR GAS TURBINES AND DUCT BURNERS[8,12,15,24-29]

Manufacturer	Model No.	Output, MW	NO_x emissions, ppmv, dry and corrected to 15% 0_2 Natural gas	Distillate oil No. 2	NO_x emissions factor, lb NO_x/MMBtu[a] Natural gas	Distillate oil No. 2
Solar	Saturn	1.1	99	150	0.397	0.551
	Centaur	3.3	130	179	0.521	0.658
	Centaur "H"	4.0	105	160	0.421	0.588
	Taurus	4.5	114	168	0.457	0.618
	Mars T12000	8.8	178	267	0.714	0.981
	Mars T14000	10.0	199	NA[b]	0.798	NA[b]
GM/Allison	501-KB5	4.0	155	231	0.622	0.849
	570-KA	4.9	101	182	0.405	0.669
	571-KA	5.9	101	182	0.405	0.669
General Electric	LM1600	12.8	144	237	0.577	0.871
	LM2500	21.8	174	345	0.698	1.27
	LM5000	33.1	185	364	0.742	1.34
	LM6000	41.5	220	417	0.882	1.53
	MS5001P	26.3	142	211	0.569	0.776
	MS6001B	38.3	148	267	0.593	0.981
	MS7001EA	83.5	154	228	0.618	0.838
	MS7001F	123	179	277	0.718	1.02
	MS9001EA	150	176	235	0.706	0.864
	MS9001F	212	176	272	0.706	1.00
Asea Brown Boveri	GT8	47.4	430	680	1.72	2.50
	GT10	22.6	150	200	0.601	0.735
	GT11N	81.6	390	560	1.56	2.06
	GT35	16.9	300	360	1.20	1.32
Westinghouse	W261B11/12	52.3	220	355	0.882	1.31
	W501D5	119	190	250	0.762	0.919
Siemens	V84.2	105	212	360	0.850	1.32
	V94.2	153	212	360	0.850	1.32
	V64.3	61.5	380	530	1.52	1.95
	V84.3	141	380	530	1.52	1.95
	V94.3	203	380	530	1.52	1.95
Duct burners	All	NA[c]	$\leq$30	NA[b]	<0.100[d]	NA[b]

[a]Based on emission levels provided by gas turbine manufacturers, corresponding to rated load at ISO conditions. NO_x emissions calculations are shown in Appendix A.
[b]Not available.
[c]Not applicable.
[d]References 16 and 22.

Uncontrolled emission factors are presented in Table 4-1. These factors are based on uncontrolled emission levels provided by manufacturers in ppmv, dry, and corrected to 15 percent O_2, corresponding to 100 percent output load and International Standards Organization (ISO) conditions of 15°C (59°F) and 1 atmosphere (14.7 psia). Sample calculations are given in Appendix A. The uncontrolled emissions factors range from 0.397 to 1.72 lb/MMBtu (99 to 430 ppmv) for natural gas and 0.551 to 2.50 lb/MMBtu (150 to 680 ppmv) for DF-2.

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5.0 NO_x CONTROL TECHNIQUES

Nationwide NO_x emission limits have been established for stationary gas turbines in the new source performance standards (NSPS) promulgated in 1979.[1] This standard, summarized in Table 5-1

TABLE 5-1. NO_x EMISSION LIMITS AS ESTABLISHED BY THE NEW SOURCE PERFORMANCE STANDARDS FOR GAS TURBINES[1]

Fuel input MMBtu/hr	Size, MW	Application(s)	NO_x limit, ppmv at 15% O_2, dry[a b]
<10	1[c]	All	None
10-100	1-10[c]	All	150
>100	10+[c] <30[c] >30[c]	Utility[d] Nonutility Nonutility	75 150 None
<100	10[c]	Regenerative cycle	None
All	All	e	None

[a]Based on thermal efficiency of 25 percent. This limit may be increased for higher efficiencies by multiplying the limit in the table by 14.4/actual heat rate, in kJ/watt-hr.
[b]A fuel-bound nitrogen allowance may be added to the limits listed in the table according to the table listed below:

Fuel-bound nitrogen (N), percent by weight	Allowable increase, ppmv
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	400 x N
$0.1 < N \leq 0.25$	40 + [6.7 x (N - 0.1)]
$N > 0.25$	50

[c]Based on gas turbine heat rate of 10,000 Btu/kW-hr.
[d]An installation is considered a utility if more than 1/3 of its potential electrical output is sold.
[e]Emergency/stand-by, military (except garrison facilities), military training, research and development, firefighting, and emergency fuel operation applications are exempt from NO_x emission limits.

, effectively sets a limit for new, modified, or reconstructed gas turbines greater than 10.7 gigajoules per hour (approximately 3,800 horsepower [hp]) of 75 or 150 parts per million by volume (ppmv), corrected to 15 percent oxygen (O_2) on a dry basis, depending upon the size and application of the turbine. State and regional regulatory agencies may set more restrictive limits, and two organizations have established limits as low as 9 ppmv: the South Coast Air Quality Management District (SCAQMD) has defined limits as listed in Table 5-2

TABLE 5-2. NO_x COMPLIANCE LIMITS AS ESTABLISHED BY THE SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT (SCAQMD) FOR EXISTING TURBINES. RULE 1134. ADOPTED AUGUST 1989.[a,2]

Unit size, megawatt rating (MW)	NO_x limit, ppmv, 15% O_2 dry[b]
0.3 to <2.9 MW	25
2.9 to <10.0 MW	9
2.9 to <10.0 MW No SCR	15
10.0 MW and over	9
10.0 MW and over No SCR	12
60 MW and over Combined cycle No SCR	15
60 MW and over Combined cycle	9
Compliance limit = Reference limit X EFF/25 percent	
where:	
$EFF = \frac{3{,}413 \times 100\%}{\text{Actual heat rate at HHV of fuel (Btu/kW-hr)}}$	
or	
EFF^c = (Manufacturer's rated efficiency at LHV) x $\frac{LHV}{HHV}$	

[a]The NO_x reference limits to be effective by December 31, 1995.
[b]Averaged over 15 consecutive minutes.
[c]EFF = the demonstrated percent efficiency of the gas turbine only as calculated without consideration of any down-stream energy recovery from the actual heat rate (Btu/kW-hr), or 1.34 (Btu/hp-hr); corrected to the higher heating value (HHV) of the fuel and ISO conditions, as measured at peak load for that facility; or the manufacturer's continuous rated percent efficiency (manufacturer's rated efficiency) of the gas turbine after correction from lower heating value (LHV) to the HHV of the fuel, whichever efficiency is higher. The value of EFF shall not be less than 25 percent. Gas turbines with lower efficiencies will be assigned a 25 percent efficiency for this calculation.

; and the Northeast States for Coordinated Air Use Management (NESCAUM) has recommended limits as listed in Table 5-3.

5-34

TABLE 5-3. NO_x EMISSION LIMITS RECOMMENDED BY THE NORTHEAST STATES FOR COORDINATED AIR USE MANAGEMENT (NESCAUM)

NEW TURBINES[3]

Fuel input, MMBtu/hr	Size, MW[a]	Fuel type	NO_x limit, ppmv[b]
1-100	1-10	Gas Oil	42 65
>100	10+	Gas Oil Gas/oil back-up	9[c] 9[c] 9[c]/18[c d]

[a]Based on gas turbine heat rate of 10,000 Btu/kW-hr.
[b]Dry basis, corrected to 15 percent oxygen.
[c]Based on use of selective catalytic reduction (SCR). Limits for operation without SCR, where permitted, should be the turbine manufacturer's lowest guaranteed NO_x limit.
[d]Based on the use of SCR and a fuel-bound nitrogen content of 600 ppm or less.

EXISTING TURBINES[4]

Operating cycle	Fuel	NO_x emission limit, ppmv, 15 percent O_2
Simple	Gas, no oil back-up	55
	Oil	75
	Gas, with oil back-up	55 (Gas fuel) 75 (Oil fuel)
Combined	Gas, no oil back-up	42
	Oil	65
	Gas, with oil back-up	42 (Gas fuel) 65 (Oil fuel)

Note: Applies to existing turbines rated at 25 MMBtu/hr or above (maximum heat input rate).

This chapter discusses the control techniques that are available to reduce NO_x emissions for stationary turbines, the use of duct burners, the use of alternate fuels to lower NO_x emissions, and the applicability of NO_x control techniques to offshore applications. Each control technique is structured into categories to discuss the process description, applicability, factors that affect performance, and achievable controlled NO_x emission levels. Where information for a technique is limited, one or more categories may be combined. Section 5.1 describes wet controls, including water and steam injection. Section 5.2 describes combustion controls, including lean and staged combustion. Selective catalytic reduction (SCR), a postcombustion technique, is described in Section 5.3, and the combination of SCR with other control techniques is described in

Section 5.4. Emissions from duct burners and their impact on total NO_x emissions are described in Section 5.5. Section 5.6 describes NO_x emission impacts when using alternate fuels. Two control techniques that show potential for future use, selective noncatalytic reduction (SNCR) and catalytic combustion, are described in Sections 5.7 and 5.8, respectively. Control technologies for offshore oil platforms are described in Section 5.9. Finally, references for Chapter 5 are found in Section 5.10.

5.1 WET CONTROLS

The injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_x formation. This control technique is available from all gas turbine manufacturers contacted for this study.[5-11]

The process description, applicability, factors affecting performance, emissions data and manufacturers' guarantees, impacts on other emissions, and gas turbine performance and maintenance impacts are discussed in this section.

5.1.1 Process Description

Injecting water into the flame area of a turbine combustor provides a heat sink that lowers the flame temperature and thereby reduces thermal NO_x formation. Injection rates for both water and steam are usually described by a water-to-fuel ratio (WFR) and are usually given on a weight basis (e.g., lb water to lb fuel).

A water injection system consists of a water treatment system, pump(s), water metering valves and instrumentation, turbine-mounted injection nozzles, and the necessary interconnecting piping. Water purity is essential to prevent or mitigate erosion and/or the formation of deposits in the hot section of the turbine; Table 5-4

TABLE 5-4. WATER QUALITY SPECIFICATIONS OF SELECTED GAS TURBINE MANUFACTURERS FOR WATER INJECTION SYSTEMS[11-18]

	Turbine Manufacturer							
Element	A	B	C	D	E	F	G	H
Total solids, ppm (dissolved and nondissolved)	5	5	1	a	0.1 gram/gallon	15	5	8
Total alkali metals, ppm	0.1	0.5 (HD) 0.1 (AD)[d]	0.1	--	0.5	0.1[b]5	[c]<0.05	--
Calcium, ppm	5	--	--	--	--	--	<1.0	--
Sulfates, ppm	--	--	--	--	--	--	--	0.5
Silica, ppm	0.02	--	0.02	--	--	0.1	<0.02	0.1
Silicon, ppm	--	--	--	18.0	--	--	--	--
Sulfur, ppm	0.1	--	--	--	--	1.0	--	--
Chlorides, ppm	--	--	--	6.0	--	1.0	--	0.5
Iron and copper, ppm	--	--	--	0.1	--	--	--	--
Sodium and potassium, ppm	--	--	--	--	--	--	--	0.1
Particle size, microns	10	--	10	--	5	--	--	20
Total hardness, ppm	--	--	--	--	--	0.2	--	--
Oxygen[f]	--	--	--	--	--	--	--	--
Acidity, pH	7.0-8.5	6.5-7.5	7.0-8.5	7.5-8.0	--	6.5-7.5	6.5-7.0	6.0-8.0

[a]Determined by local regulations for particulates exhausted from combustion process.
[b]HD - heavy-duty turbine.
[c]Including vanadium and lead.
[d]AD - aeroderivative turbine.
[e]90 percent of 0.1 gram particles shall be less than 5 microns.

summarizes the water quality specifications for eight gas turbine manufacturers.

In a steam injection system, steam replaces water as the injected fluid. The injection system is similar to that for water injection, but the pump is replaced by a steam-producing boiler. This boiler is usually a heat recovery steam generator

(HRSG) that recovers the gas turbine exhaust heat and generates steam. The balance of the steam system is similar to the water injection system. The water treatment required for boiler feed water to the HRSG yields a steam quality that is suitable for injection into the turbine. The additional steam requirement for NO_x control, however, may require that additional capacity be added to the boiler feed water treatment system.

Another technique that is commercially available for oil-fired aeroderivative and industrial turbines uses a water-in-oil emulsion to reduce NO_x emissions. This technique introduces water into the combustion process by emulsifying water in the fuel oil prior to injection. This emulsion has a water content of 20 to 50 percent by volume and is finely dispersed and chemically stabilized in the oil phase. The principle of NO_x control is similar to conventional water injection, but the uniform dispersion of the water in the oil provides greater NO_x reduction than conventional water injection at similar WFR's.[19]

A water-in-oil emulsion injection system consists of mechanical emulsification equipment, chemical stabilizer injection equipment, water metering valves, chemical storage and metering valves, and instrumentation. In most cases the emulsifying system can be retrofitted to the existing fuel delivery system, which eliminates the requirement for a separate delivery system for water injection. At multiunit installations, one emulsion system can be used to supply emulsified fuel to several turbines. For dual fuel turbines, the emulsion can be injected through the oil fuel system to control NO_x emissions.[19]

Data provided by the vendor for this technique indicates that testing has been performed on oil-fired turbines operating in peaking duty. Long-term testing has not been completed at this point to quantify the long-term effects of the emulsifier on the operation and maintenance of the turbine.

5.1.2 Applicability of Wet Controls

Wet controls have been applied effectively to both aeroderivative and heavy-duty gas turbines and to all configurations except regenerative cycle applications.[20] It is expected that wet controls can be used with regenerative cycle turbines, but no such installations were identified. All manufacturers contacted have water injection control systems available for their gas turbine models; many also offer steam injection control systems. Where both systems are available, the decision of which control to use depends upon steam availability and economic factors specific to each site.

Wet controls can be added as a retrofit to most gas turbine installations. In the case of water injection, one limitation is the possible unavailability of injection nozzles for turbines operating in dual fuel applications. In this application, the injection nozzle as designed by the manufacturer may not physically accommodate a third injection port for water injection. This limitation also applies to steam injection. In addition, steam injection is not an available control option from some gas turbine manufacturers.

5.1.3 Factors Affecting the Performance of Wet Controls

The WFR is the most important factor affecting the performance of wet controls. Other factors affecting performance are the combustor geometry and injection nozzle(s) design and the fuel-bound nitrogen (FBN) content. These factors are discussed below.

The WFR has a significant impact on NO_x emissions. Tables 5-5 and 5-6 provide NO_x reduction and WFRs for natural gas and

TABLE 5-5. MANUFACTURER'S GUARANTEED NO_x REDUCTION EFFICIENCIES AND ESTIMATED WATER-TO-FUEL RATIOS FOR NATURAL GAS FUEL OPERATION[5-11,21-24]

	NO_x emission levels, ppmv at 15% O_2/NO_x percent reduction			Water-to-fuel ratio (lb water to lb fuel)	
Manufacturer/model	Uncontrolled	Water injection	Steam injection	Water injection	Steam injection
General Electric					
LM1600	133	42[a]/68	25/81	0.61	1.49
LM2500	174	42[a]/76	25/86	0.73	1.46
LM5000	185	42[a]/77	25/87	0.63	1.67
LM6000	220	42[a]/81	25/89	0.68	1.67
MS5001P	142	42/70	42/70	0.72	1.08
MS6001B	148	42/72	42/72	0.77	1.16
MS7001E	154	42/73	42/73	0.81	1.22
MS7001F	210	42/80	42/80	0.79	1.34
MS9001E	161	42/74	42/74	0.78	1.18
MS9001F	210	42/86	42/80	NA[b]	NA[b]
Asea Brown Boveri					
GT10	150	25/83	42/72	0.93	1.07
GT8	430	25/94	29/93	1.86	2.48
GT11N	390	25/94	25/94	1.76	2.47
GT35	300	42/86	60/80	1.00	1.20
Solar Turbines, Inc.					
T-1500 Saturn	99	42/58	NA[c]/NA[c]	0.33	NA[c]
T-4500 Centaur	130	42/68	NA[c]/NA[c]	0.61	NA[c]
Type H Centaur	105	42/60	NA[c]/NA[c]	0.70	NA[c]
Taurus	114	42/63	NA[c]/NA[c]	0.79	NA[c]
T-12000 Mars	178	42/76	NA[c]/NA[c]	0.91	NA[c]
T-14000 Mars	199	42/79	NA[c]/NA[c]	1.14	NA[c]
Allison/GM					
501-KB5	155	42/73	42/73	0.80	1.53
501-KC5	174	42/76	NA[c]/NA[c]	NA[b]	NA[c]
501-KH	155	42/73	25/84	NA[b]	NA[b]
570-K	101	42/58	NA[c]/NA[c]	NA[b]	NA[c]
571-K	101	42/58	NA[c]/NA[c]	0.80	NA[c]
Westinghouse					
251B11/12	220	42/81	25/89	1.0	1.8
501D5	190	25/87	25/87	1.6	1.6
Siemens					
V84.2	212	42/80	55/74	2.0	2.0
V94.2	212	55/74	55/74	1.6	1.6
V64.3	380	75/80	75/80	1.6	1.4
V84.3	380	75/80	75/80	1.6	1.4
V94.3	380	75/80	75/80	1.6	1.4

[a]A NO_x emissions level of 25 ppmv can be achieved, but turbine maintenance requirements increase over those required for 42 ppmv.

TABLE 5-6. MANUFACTURER'S GUARANTEED NO_x REDUCTION EFFICIENCIES AND ESTIMATED WATER-TO-FUEL RATIOS FOR DISTILLATE OIL FUEL OPERATION[5-11,21-24]

	NO_x emissions level, ppmv at 15% O_2/NO_x percent reduction			Water-to-fuel ratio (lb water to lb fuel)	
Manufacturer/model	Uncontrolled	Water injection	Steam injection	Water injection	Steam injection
General Electric					
LM1600	237	42/82	75/70	NA[a]	NA[a]
LM2500	345	42/88	75/78	0.99	NA[a]
LM5000	364	42/88	110/70	NA[a]	NA[a]
LM6000	417	42/90	110/74	NA[a]	NA[a]
MS5001P	211	65/69	65/69	0.79	1.06
MS6001B	267	65/76	65/76	0.73	1.20
MS7001E	228	65/72	65/72	0.67	1.19
MS7001F	353	65/82	65/77	0.72	1.35
MS9001E	241	65/73	65/72	0.65	1.16
MS9001F	353	65/82	65/76	NA[a]	NA[a]
Asea Brown Boveri					
GT10	200	42/79	42/79	0.75	1.25
GT8	680	42/94	60/91	1.62	2.15
GT11N	560	42/88	42/93	1.50	2.28
GT35	360	42/88	60/83	1.00	1.20
Solar Turbines, Inc.					
T-1500 Saturn	150	60/60	NA[b]/NA[b]	0.46	NA[b]
T-4500 Centaur	179	60/66	NA[b]/NA[b]	0.60	NA[b]
Type H Centaur	160	60/63	NA[b]/NA[b]	0.72	NA[b]
Taurus	168	60/64	NA[b]/NA[b]	0.96	NA[b]
T-12000 Mars	267	60/78	NA[b]/NA[b]	1.00	NA[b]
T-14000 Mars	NA[a]	60/NA[a]	NA[b]/NA[b]	NA[a]	NA[b]
Allison/GM					
501-KB5	231	56/76	NA[b]/NA[b]	NA[a]	NA[b]
501-KC5	NA[a]	NA[a]/NA[a]	NA[b]/NA[b]	NA[a]	NA[b]
501-KH	231	56/76[a]	50/78	NA[a]	NA[a]
570-K	182	65/64[a]	NA[b]/NA[b]	NA[a]	NA[b]
571-K	182	65/64[a]	NA[b]/NA[b]	NA[a]	NA[b]
Westinghouse					
251B11/12	355	65/82	42/88	1.0	1.8
501D5	250	42/83	42/83	1.0	1.6
Siemens					
V84.2	360	42/88	55/85	1.4	2.0
V94.2	360	42/88	55/85	1.4	1.6
V64.3	530	75/86	75/86	1.2	1.4
V84.3	530	75/86	75/86	1.2	1.4
V94.3	530	75/86	75/86	1.2	1.4

[a]Data not available.

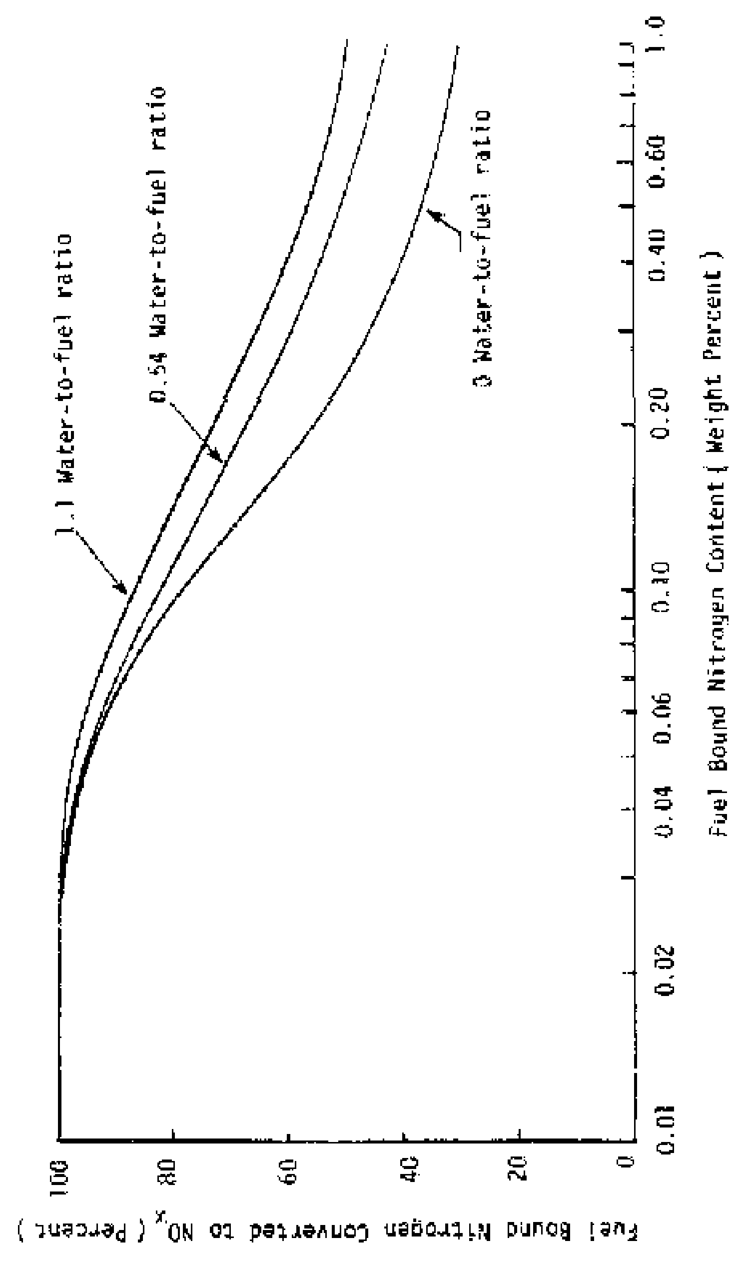
distillate oil fuels, respectively, based on information provided by gas turbine manufacturers. For natural gas fuel, WFR's for water or steam injection range from 0.33 to 2.48 to achieve controlled NO_x emission levels ranging from 25 to 75 ppmv, corrected to 15 percent oxygen. For oil fuel, WFR's range from 0.46 to 2.28 to achieve controlled NO_x emission levels ranging from 42 to 110 ppmv, corrected to 15 percent oxygen. Nitrogen oxide reduction efficiency increases as the WFR

increases. As shown in Tables 5-5 and 5-6, reduction efficiencies of 70 to 90 percent are common. Note that, in general, the WFR's for steam are higher than for water injection because water acts as a better heat sink than steam due to the heat absorbed by vaporization; therefore, higher levels of steam than water must be injected for a given reduction level.

The combustor geometry and injection nozzle design and location also affect the performance of wet controls. For maximum NO_x reduction efficiency, the water must be atomized and injected in a spray pattern that provides a homogeneous mixture of water droplets and fuel in the combustor. Failure to achieve this mixing yields localized hot spots in the combustor that produce increased NO_x emissions.

The type of fuel affects the performance of wet controls. In general, lower controlled NO_x emission levels can be achieved with gaseous fuels than with oil fuels. The FBN content also affects the performance of wet controls. Those fuels with relatively high nitrogen content, such as coal-derived liquids, shale oil, and residual oils, result in significant fuel NO_x formation. Natural gas and most distillate oils are low-nitrogen fuels. Consequently, fuel NO_x formation is minimal when these fuels are burned.

Wet controls serve only to lower the flame temperature and therefore are an effective control only for thermal NO_x formation; water injection may in fact increase the rate of fuel NO_x formation, as shown in Figure 5-1.[25] The mechanisms responsible for this potential increase were not identified.


1.1 Water-to-fuel ratio
0.54 Water-to-fuel ratio
0 Water-to-fuel ratio
100
80
60
40
20
0
Fuel Bound Nitrogen Converted to NO_x (Percent)
0.01
0.02
0.04
0.06
0.10
0.20
0.40
0.60
1.0
Fuel Bound Nitrogen Content (Weight Percent)

5.1.4 Achievable NO_x Emissions Levels Using Wet Controls

This section presents the achievable controlled NO_x emission levels for wet injection, as guaranteed by gas turbine manufacturers. Emission test data, obtained using EPA Test Method 20 or equivalent, are also presented.

Guaranteed NO_x emission levels as provided by gas turbine manufacturers for wet controls are shown in Figures 5-2 and

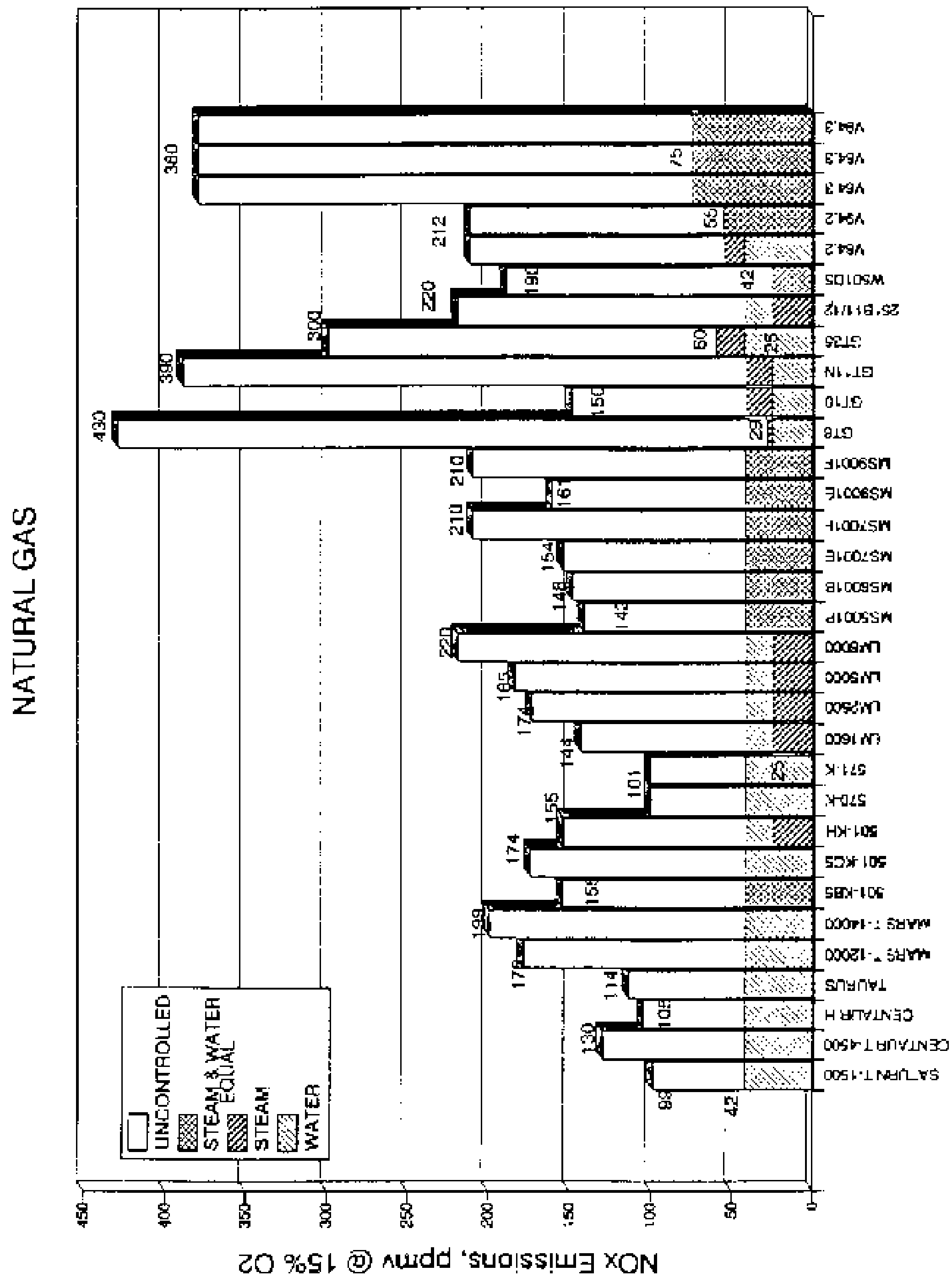


Figure 5-1. Percentage of fuel-bound nitrogen converted to NO_x versus the fuel-bound nitrogen content and the water-to-fuel ratio for a turbine firing temperature of 1000°C (1840°F).[25,26]

Figure 5-2. Uncontrolled NO_x emissions and gas turbine manufacturers' guaranteed controlled levels using wet injection. Natural gas fuel.[6-11,17,18,23]

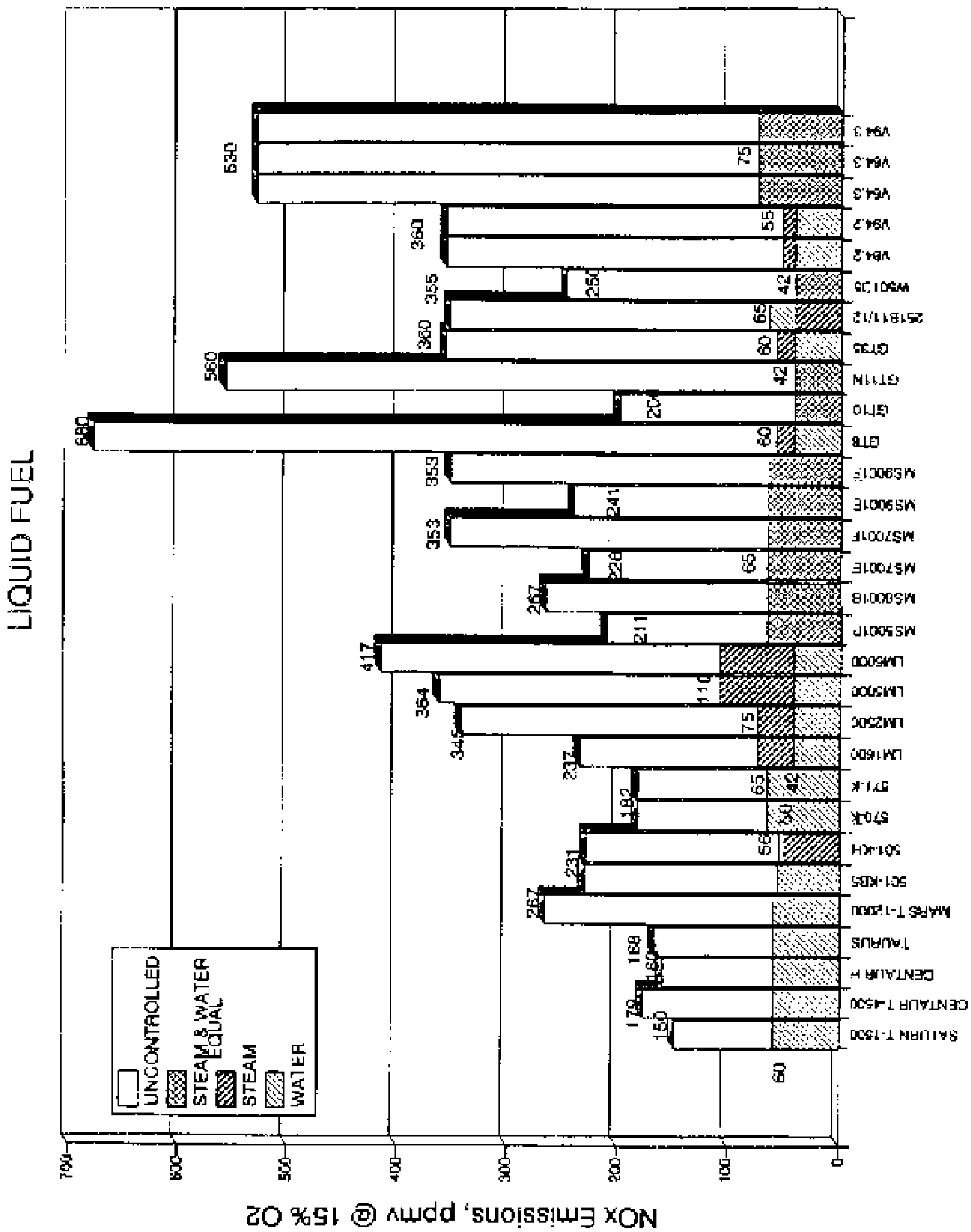


Figure 5-3. **Uncontrolled NO_x emissions and gas turbine manufacturers' guaranteed controlled levels using wet injection. Distillate-oil fuel.**[6-11,17,18,23]

5-3. These figures show manufacturers' guaranteed NO_x emission levels of 42 ppmv for most natural gas-fired turbines, and from 42 to

75 ppmv for most oil-fired turbines. The percent reduction in NO_x emissions varies for each turbine, ranging from 60 to 94 percent depending upon each model's uncontrolled emission level and whether water or steam is injected.

Emissions data for water and steam injection are presented to show the effects of wet injection on NO_x emissions. These data show:

1. That NO_x emissions decrease with increasing WFR's; and
2. That NO_x emissions are higher for oil fuel than for natural gas.

From the available data, reduction efficiencies of 70 to over 85 percent were achieved. The emission data and WFRs shown for specific turbine models may not reflect the emission levels of current production models, since manufacturers periodically update or otherwise modify their turbines, thereby altering specific emissions levels.

Each emission test in the following figures consists of one or more data points. Where data points were obtained under similar conditions, they are grouped together and presented as a single test. For these cases, each data point, along with the arithmetic average of all of the data points, is shown.

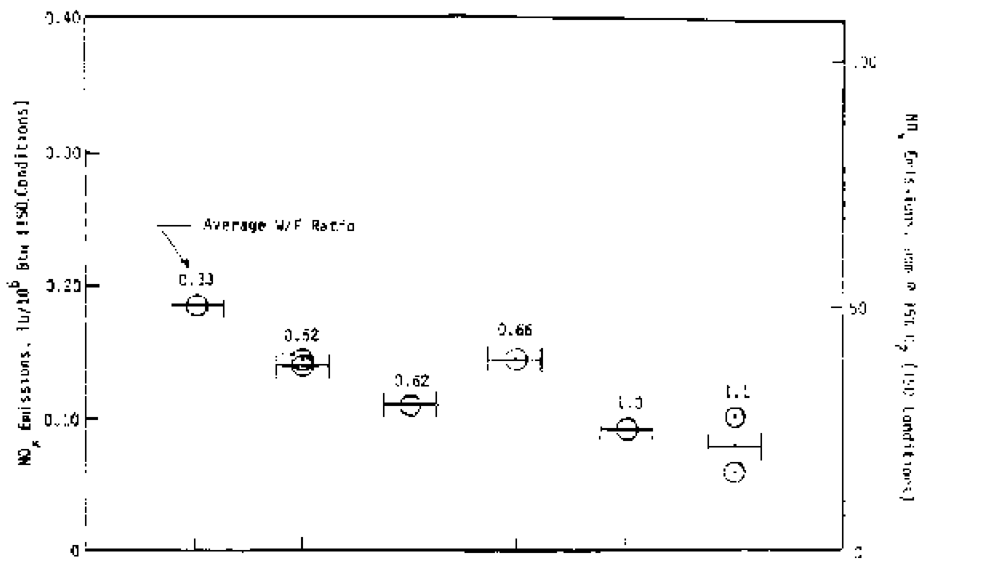
The nomenclature used to identify the tests consists of two letters followed by a number. The first letter of the two-letter designator specifies the turbine type. These types are as follows:

Letter	Turbine type
A	Aircraft-derivative turbine
H	Heavy-duty turbine
T	Small and low-efficiency turbine (less than 7.5 MW output, less than 30 percent simple-cycle efficiency)

The second letter identifies the facility. The number identifies the number of tests performed at the facility. Tests performed at the same facility on different turbines or at different times have the same two-letter designator but are followed by different test numbers. The short horizontal lines represent the average of the test data.

Also presented are the available data on the turbine, wet controls, uncontrolled NO_x emissions, percent NO_x reduction, and fuel type. All of the data shown are representative of the performance of wet controls when the turbine is operated at base load or peak load. These loads represent the worst-case conditions for NO_x emission reduction. Information on the WFR, turbine model, efficiency, control type, and fuel are included with the emission test data.

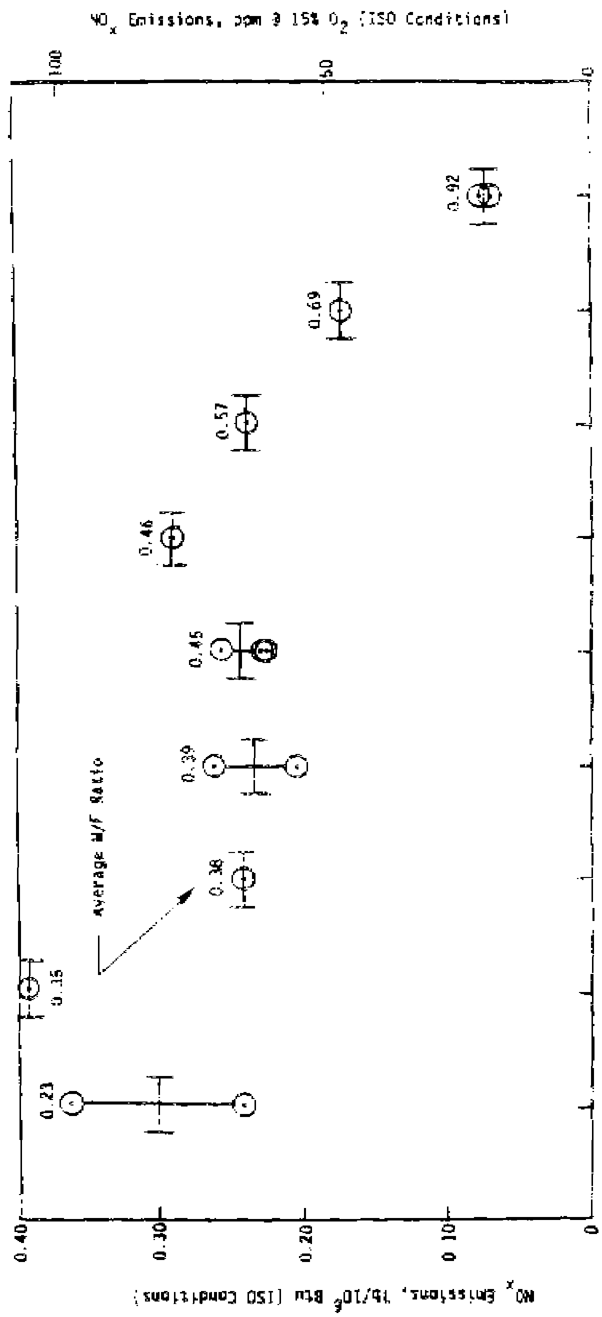
Figures 5-4, 5-5, and 5-6 present the emission test data



Test No.	TL1	TA2	TA4	TL2	TL3	TA1
Turbine Model	501KB	Centaur	Centaur	501KB	501KB	Centaur
Efficiency (%)	28	25	25	28	28	25
Combustor Type	CA	A	A	CA	CA	A
Baseload Rating (MW)	2.5	2.8	2.8	2.5	2.5	2.8
Type of Fuel	NG	NG	NG	NG	NG	NG
Load	Base	Base	Base	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.33	0.49-0.55	0.62	0.66	1.0	0.86-1.32
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	0.394	0.486	0.486	0.394	0.394	0.486
NO_x Reduction (%)	54.0	71.4	76.7	63.4	76.1	81.7

Notation.
NG = Natural Gas
CA = Can-annular
A = Annular

Figure 5-4. Nitrogen oxide emission test data for small, low-efficiency gas turbines with water injection firing natural gas.[27]



Test No.	AE2	AS1	AR2	AE1	AP1	AS2	AS3	AS4	AH1
Turbine Model	FT4C-1	LM5000	FT4C-3	FT4C-1	LM2500	LM5000	LM5000	LM5000	SK-30
Efficiency (%)	32	38	32	32	37	38	38	38	31
Combustor Type	A	A	CA	A	A	A	A	A	CA
Baseload Rating (MW)	26	37	25	26	19	37	37	37	28
Type of Fuel	NG	NG	NG	NG	NG	NG	NG	NG	NG
Load	Base	Base	Base	Base	Base	Base	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.21-0.25	0.35	0.38	0.36-0.42	0.44-0.45	0.46	0.57	0.69	0.87-0.96
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	0.424	0.930	NA	0.424	0.680	0.930	0.930	0.930	0.285
NO_x Reduction (%)	28.8	58.1	NA	44.6	64.3	68.7	74.3	81.2	74.0

Notation:
NG - Natural Gas
CA - Can-annular
A - Annular
NA = Not Available

Figure 5-5. Nitrogen oxide emission test data for aircraft-derivative gas turbines with water injection firing natural gas.[27]

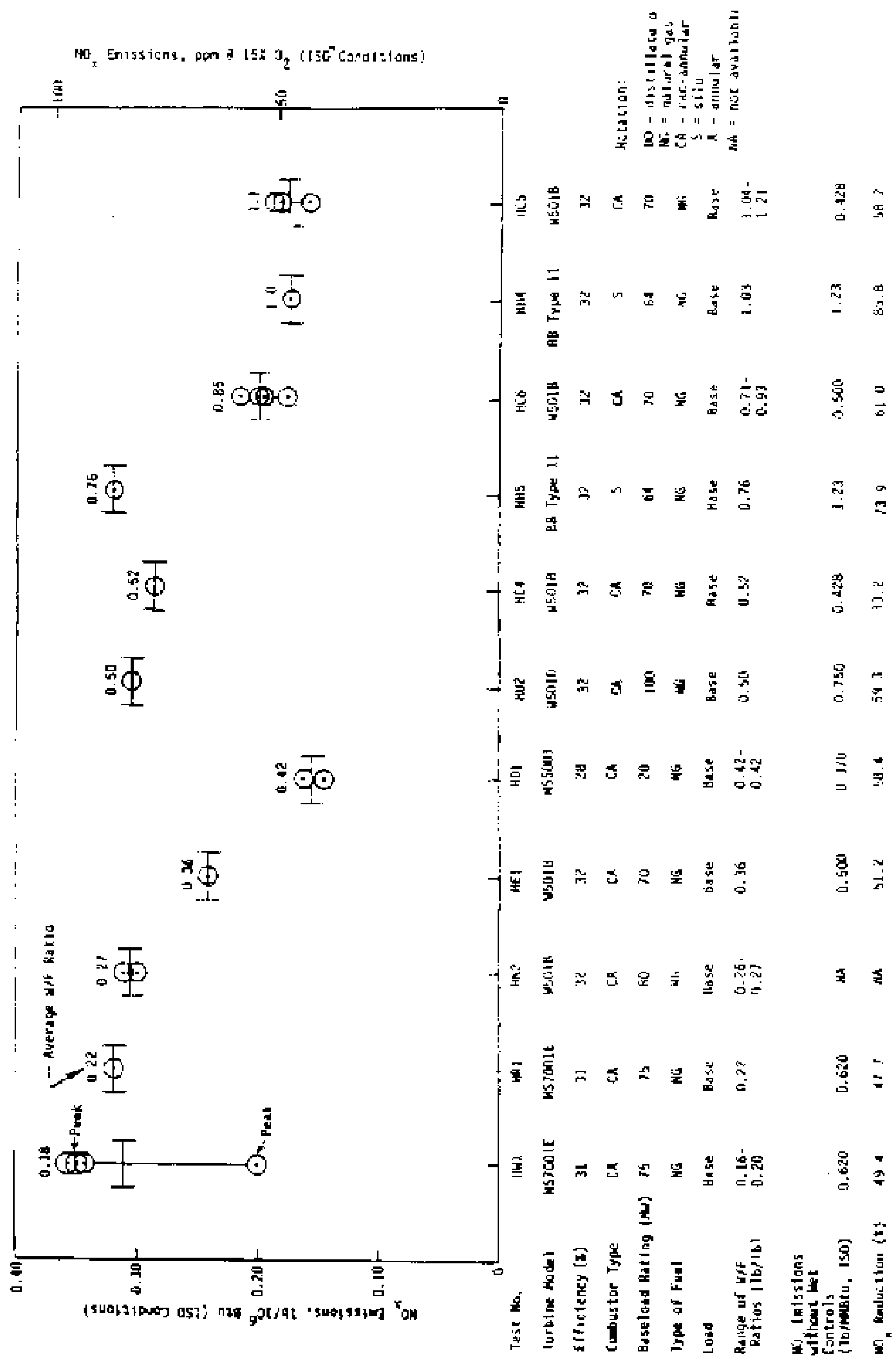
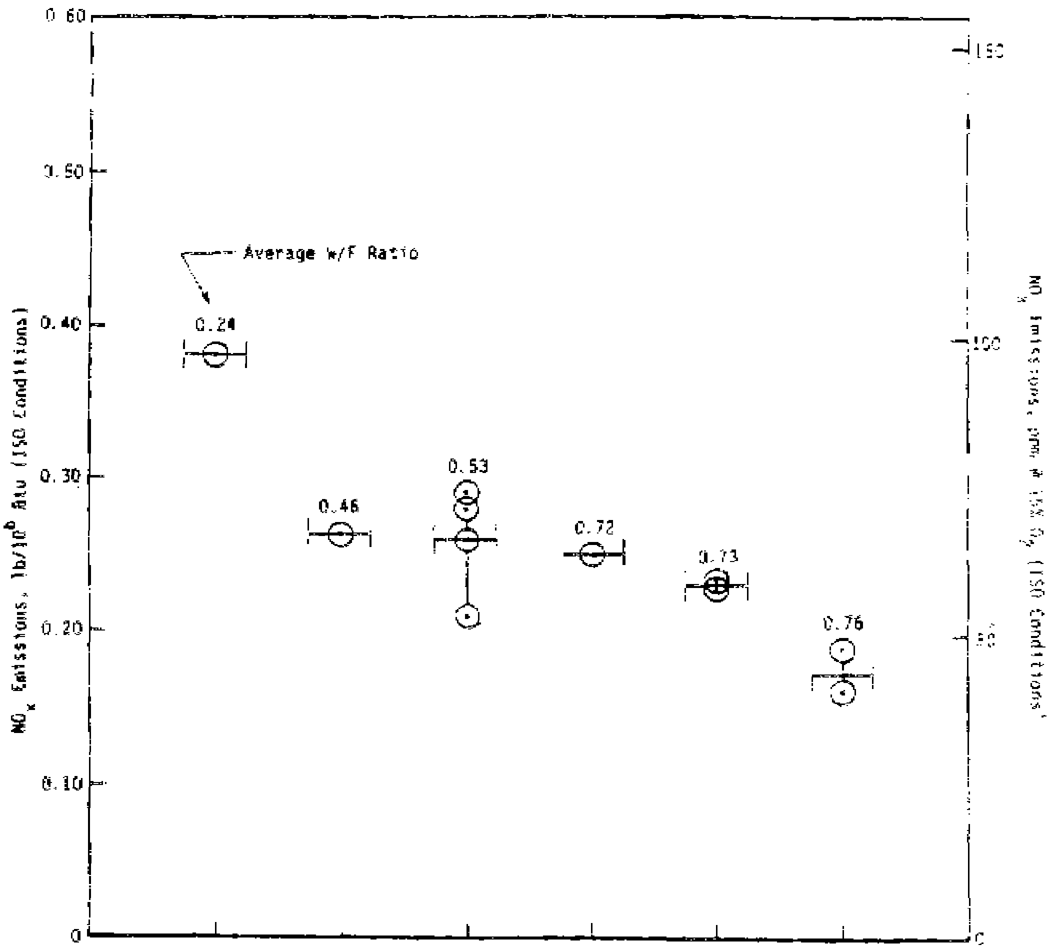


Figure 5-6. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection firing natural gas.[27]

for water injection on turbines fired with natural gas. These turbines have NO_x emissions ranging from approximately 20 to 105 ppm with WFR's ranging from 0.16 to 1.32. Turbine sizes range from 2.8 to 97 MW. Based on these data, water injection is effective on all types of gas turbines and NO_x emission levels decrease as the WFR increases. However, some turbines require a higher WFR to meet a specific emission level. For example, the gas turbines at sites HH and HC (Figure 5-6) require much higher WFR's to achieve NO_x emission levels similar to the other gas turbine models shown. This particular gas turbine also has the highest uncontrolled NO_x emission levels. Conversely, the gas turbine at site AH, shown in Figure 5-5, has the lowest uncontrolled NO_x emission level and requires the least amount of water to achieve a given emission level. Uncontrolled NO_x emission levels vary for different turbine models depending upon design factors such as efficiency, firing temperature, and the extent of combustion controls incorporated in the combustor design (see Section 4.2.1.1). In general, aircraft-derivative and heavy-duty gas turbines require similar WFR's to achieve a specific emission level. Small, low-efficiency gas turbines require less water to achieve a specific emission level.

The NO_x emissions for turbines firing distillate oil are shown in Figures 5-7, 5-8, and 5-9. The data range from



Test No.	AH4	AH3	AE3	AR1	AP2	AH2
Turbine Model	SK-30	SK-30	FT4C-1	FT4C-3F	LM2500	SK-30
Efficiency (percent)	31	31	32	32	37	31
Combustor Type	CA	CA	CA	CA	A	CA
Base Load Rating (MW)	28	28	26	25	20	28
Type of Fuel	DO	DO	DO	DO	DO	DO
Load	Base	Base	Base	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.24	0.46	0.51-0.55	0.72	0.73-0.73	0.68-0.84
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	0.559	0.559	0.787	0.840	1.37	0.559
NO_x Reduction (%)	32.0	52.8	66.8	70.5	83.4	58.9

Notation:
DO = distillate oil
NG = natural gas
CA = can-annular
A = annular

Figure 5-7. Nitrogen oxide emission test data for aircraft-derivative gas turbines with water injection firing distillate oil.[27]

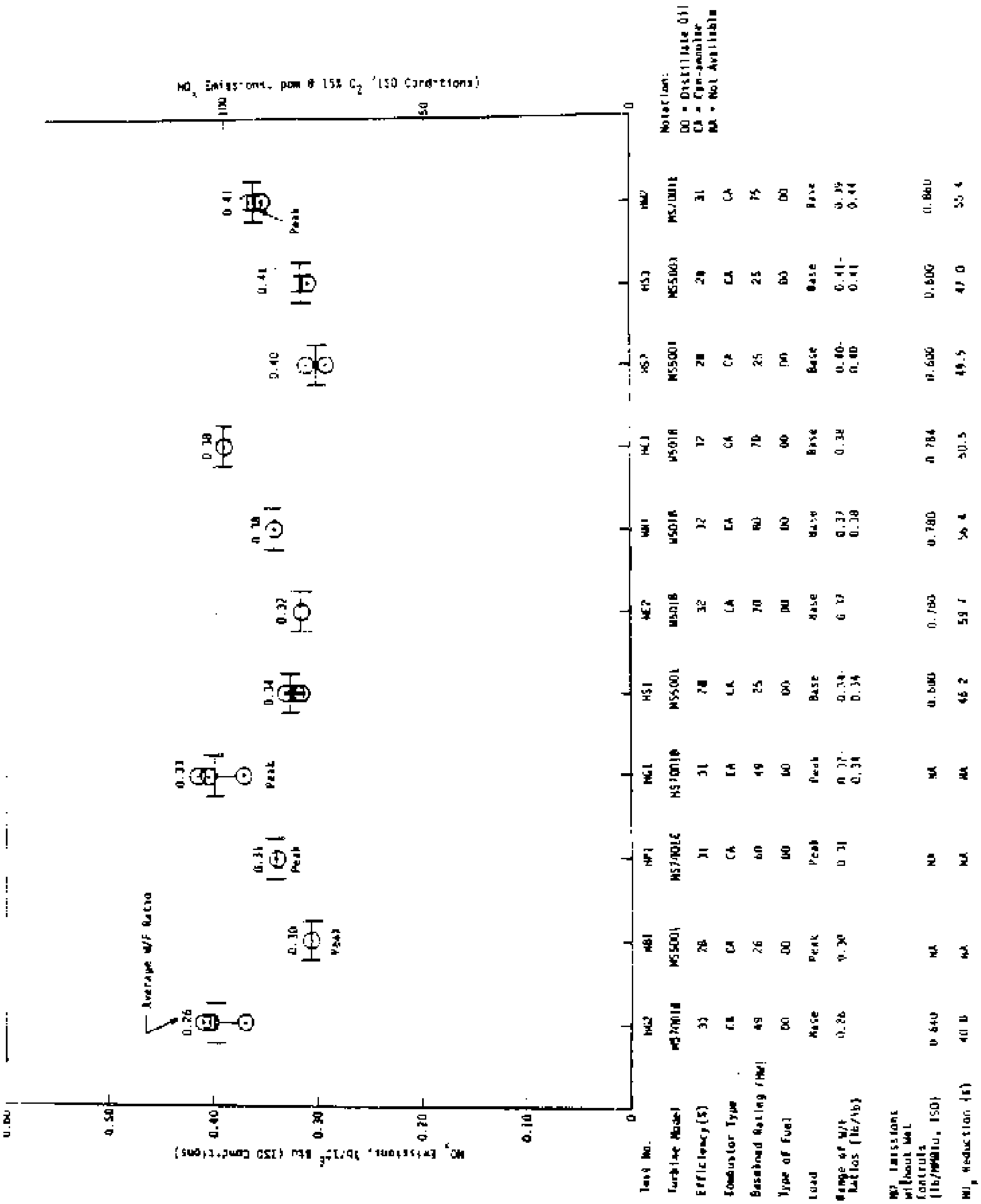


Figure 5-8. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection and WFRs less than 0.5 and firing distillate oil.[27]

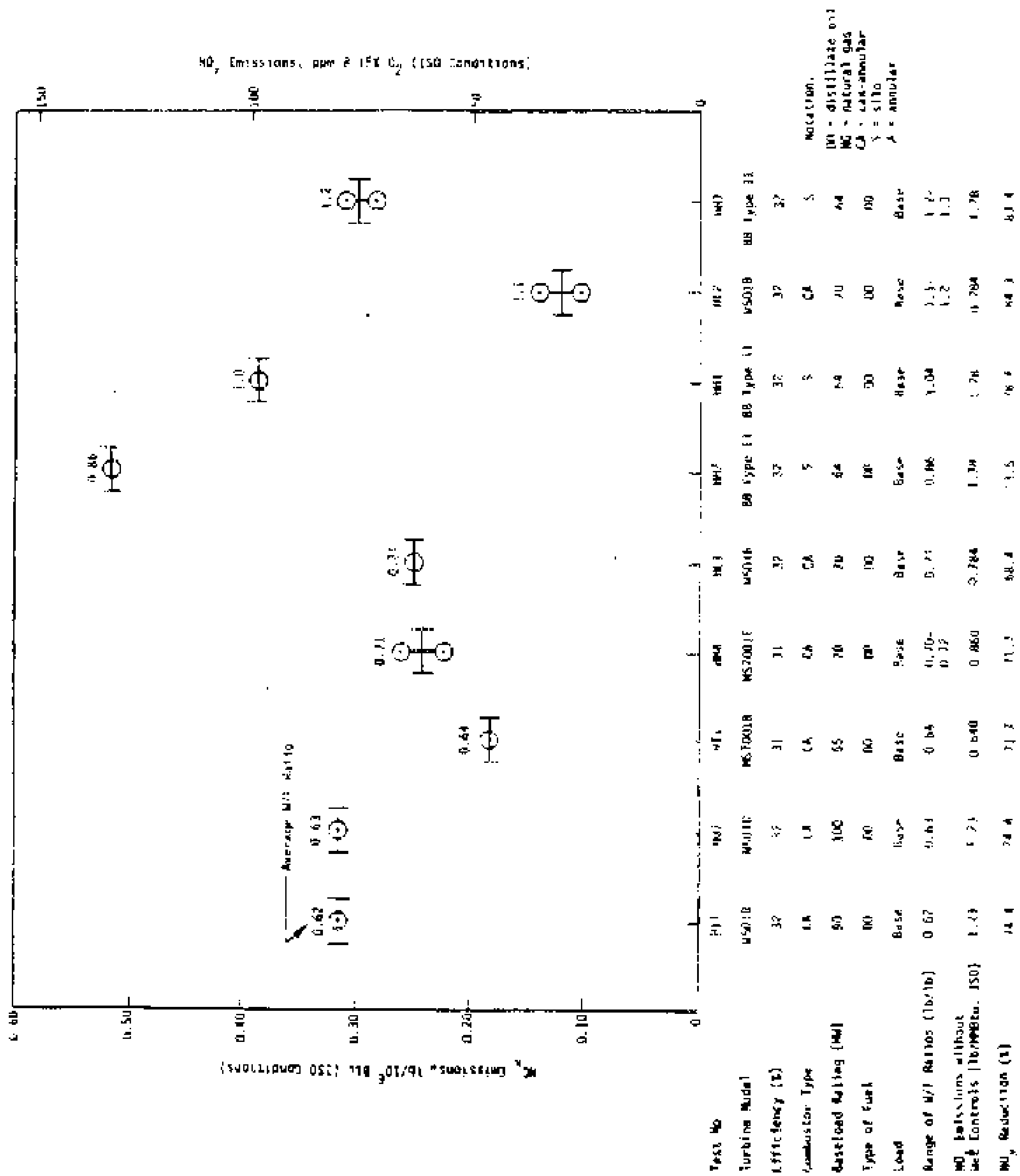
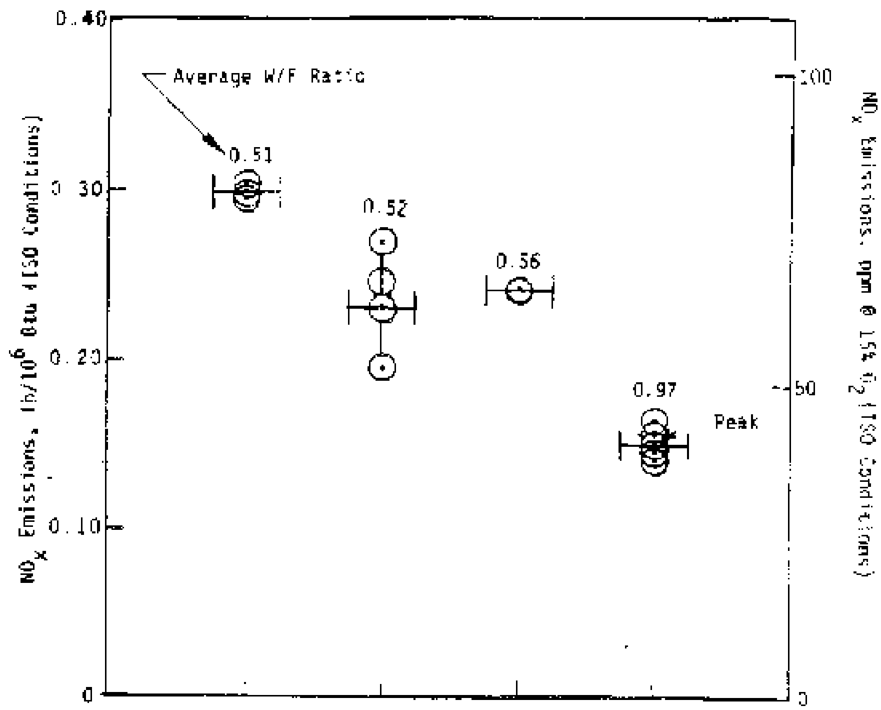


Figure 5-9. Nitrogen oxide emission test data for heavy-duty gas turbines with water injection and WFRs greater than 0.5 and firing distillate oil.[27]

approximately 30 to 135 ppm, with WFR's ranging from 0.24 to 1.31. The gas turbine sizes range from 19 to 95 MW. The data for distillate oil-fired turbines show the same general trends as the data for natural gas-fired turbines. Site HH (Figure 5-9)

again shows that higher WFR's are required due to the high uncontrolled NO_x emissions from this gas turbine. Also, by comparing the emission data for the distillate oil-fired turbines and natural gas-fired turbines, the data show that burning distillate oil requires higher WFR's than does burning natural gas for a given level of NO_x emissions. Higher WFR's are required because distillate oil produces higher uncontrolled NO_x levels than does natural gas (see Section 4.2.1.2).

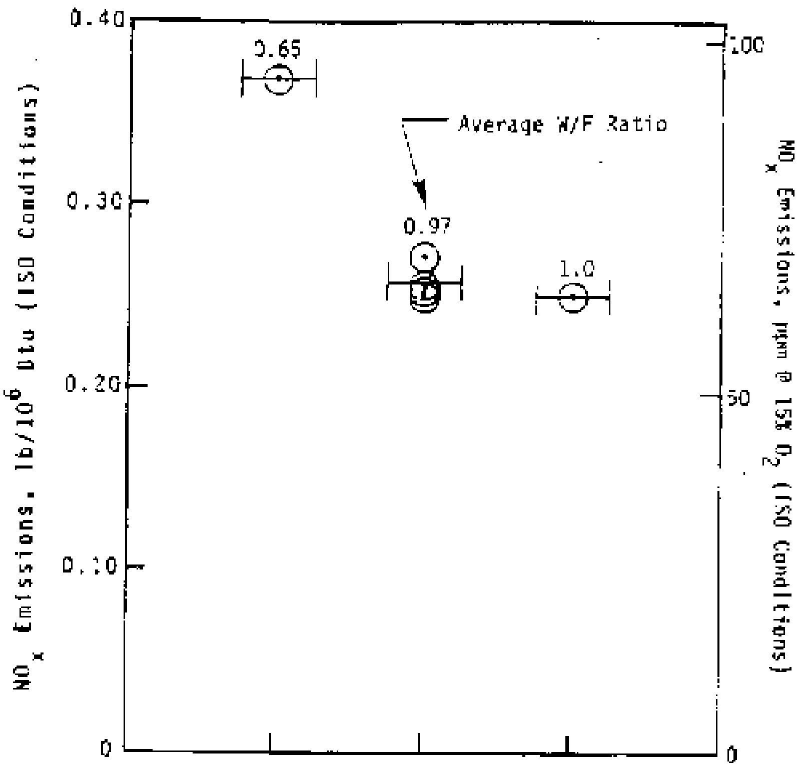
The NO_x emission test data for steam injection are presented in Figures 5-10



Test No.	HV1	HZ1	HM1	HZ2
Turbine Model	89 Type 9	MS6001B	MS7001E	MS6001B
Efficiency (percent)	29	31	32	31
Combustor Type	S	CA	CA	CA
Base Load Rating (Mw)	30	36	70	36
Type of Fuel	NG	NG	NG	NG
Load	Base	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.50-0.51	0.42-0.69	0.56	0.94-1.02
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	NA	0.423	0.620	0.423
NO_x Reduction (%)	NA	44.9	61.1	64.3

Notation:
DO = distillate oil
NG = natural gas
CA = can-annular
A = annular
S = silo
NA = not available

Figure 5-10. Nitrogen oxide emission test data for gas turbines with steam injection firing natural gas.[27]



Test No.	HM2	HM3	HZ3
Turbine Model	MS7001E	MS7001E	MS6001B
Efficiency (percent)	32	32	31
Combustor Type	CA	CA	CA
Base Load Rating, MW	70	70	36
Fuel	DO	DO	DO
Load	Base	Base	Base
Range of W/F Ratios (lb/lb)	0.65	0.91-0.99	1.01
NO_x Emissions without Wet Controls (lb/MMBtu, ISO)	0.860	0.860	0.749
NO_x Reduction (%)	56.5	70.2	66.6

Notation:

DO = distillate oil
NG = natural gas
CA = can-annular
S = silo
A = annular

Figure 5-11. Nitrogen oxide emission test data for gas turbines with steam injection firing distillate oil.[27]

and 5-11 for natural gas-fired turbines and distillate oil-fired turbines, respectively. The turbines firing natural gas have NO_x emissions ranging from approximately 40 to 80 ppm, with WFR's ranging from 0.50 to 1.02. The gas turbine sizes range from 30 to 70 MW.

The NO_x emissions for turbines firing distillate oil range from approximately 65 to 95 ppm, with WFR's ranging from 0.65 to 1.01, and the gas turbine sizes tested were 36 and 70 MW. Fewer data points are available for steam injection than for water injection. However, the available data for both distillate oil-fired and natural gas-fired turbines show that NO_x emissions decrease as the steam-to-fuel ratio increases.

Reductions in NO_x emissions similar to water injection with oil-fired turbines have been achieved using water-in-oil emulsions. Results of emission tests for four turbines are shown in Table 5-7

TABLE 5-7. ACHIEVABLE GAS TURBINE NO_x EMISSION REDUCTIONS FOR OIL-FIRED TURBINES USING WATER-IN-OIL EMULSIONS[19]

				NO_x emissions, ppmv at 15 percent O_2		
Turbine manufacturer	Turbine model	Power output, MW	Water-to-fuel ratio	Uncontrolled	Controlled	Percent reduction
Turbo Power and Marine	A4	35	0.65	184	53	68
	A9	33	0.55	150	50	66
	A9	33	0.92	126	29	77
General Electric	MS5001	15	0.49	131	60	54

. The controlled NO_x emissions range from 29 to 60 ppmv, corresponding to NO_x reductions of 54 to 77 percent.[19] The controlled NO_x emission levels and percent reduction are consistent with those achieved using conventional water injection. Limited testing has shown that the emulsion achieves a given NO_x reduction level with a lower WFR than does a separate water injection arrangement. Test data for one oil-fired turbine showing a comparison of the WFR's for a water-in-oil emulsion versus a separate water injection system are shown in Figure 5-12

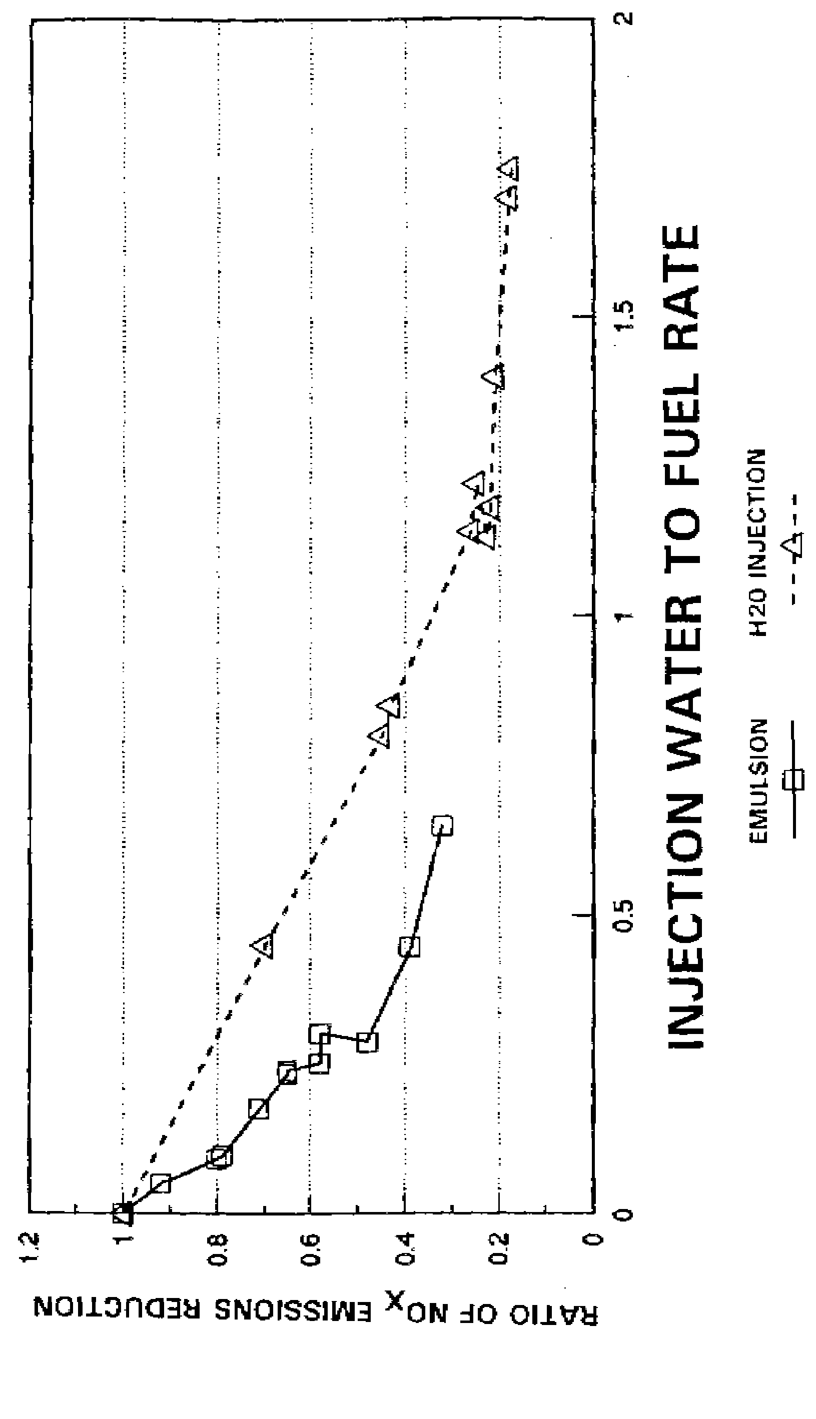


Figure 5-12. Comparison of the WFR requirement for water-in-oil emulsion versus separate water injection for an oil-fired turbine.[28]

. As shown here, NO_x reductions achieved by a water injection system at a WFR of 1.0 can be achieved by a water-in-oil emulsion at a WFR of 0.6.

On a mass basis, the reduction in NO_x emissions using water injection is shown in Table 5-8

TABLE 5-8. UNCONTROLLED NO_x EMISSIONS AND POTENTIAL NO_x REDUCTIONS FOR GAS TURBINES USING WATER INJECTION

		NO_x emissions					
		Uncontrolled		Controlled		NO_x reduction	
Gas turbine model	Power output, MW[a]	Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, tons/yr[c]	Oil fuel, tons/yr[c]
Saturn	1.1	6.4	9.9	2.8	4.1	14.3	23.3
Centaur	3.3	22.0	31.2	7.4	10.8	58.5	81.5
Centaur "H"	4.0	20.8	32.6	8.6	12.7	48.6	79.8
Taurus	4.5	24.7	37.6	9.4	13.9	61.1	94.9
Mars T-12000	8.8	69.4	107	17.0	24.9	210	329
Mars T-14000	10.0	85.4	NA[d]	18.7	NA[d]	267	NA[d]
501-KB5	4.0	31.6	48.5	8.9	12.2	90.9	145
570-K	4.9	22.7	41.0	9.8	15.2	51.8	103
571-K	5.9	24.2	44.0	10.4	16.3	55.1	111
LM1600	14.0	74.1	127	22.4	23.2	207	414
LM2500	22.7	146	301	36.4	37.9	438	1,050
LM5000	34.5	232	474	54.5	56.6	710	1,670
LM6000	43.0	310	609	61.3	63.5	996	2,180
MS5001P	26.8	181	274	55.5	87.4	503	747
MS6001B	39.0	250	459	73.2	116	704	1,370
MS7001E	84.7	544	822	154	243	1,560	2,320
MS7001F	161	1,290	2,190	267	417	4,090	7,090
MS9001E	125	810	1,320	219	369	2,370	3,820
MS9001F	229	1,850	3,150	382	600	5,850	10,200
GT8	47.4	899	1,440	54.1	92.3	3,380	5,410
GT10	22.6	143	196	24.6	42.6	472	614
GT11N	83.3	1,350	1,990	99.0	154	5,060	7,334
GT35	16.9	214	264	30.9	31.9	730	929
251B11/12	49.2	453	741	89.5	141	1,450	2,400
501D5	109	843	1,120	115	196	2,910	3,710
V84.2	105	858	1,570	176	190	2,730	5,520
V94.2	153	1,250	2,290	335	276	3,650	8,050
V64.3	61.5	859	1,290	176	188	2,740	4,390
V84.3	141	1,930	2,910	395	426	6,150	9,920
V94.3	204	2,790	4,170	571	611	8,890	14,200

[a]Power output at ISO conditions, without wet injection, with natural gas fuel.
[b]Based on ppmv levels shown in Tables 5-5 and 5-6. See Appendix A for conversion from ppmv to lb/hr.
[c]Based on 8,000 hours operation per year.
[d]Data not available.

; Table 5-9 shows corresponding reductions for steam injection.

TABLE 5-9. UNCONTROLLED NO_x EMISSIONS AND POTENTIAL NO_x REDUCTIONS FOR GAS TURBINES USING STEAM INJECTION

		NO_x emissions					
		Uncontrolled		Controlled		NO_x reduction	
Gas turbine model	Power output, MW[a]	Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, lb/hr[b]	Oil fuel, lb/hr[b]	Gas fuel, tons/yr[c d]	Oil fuel, tons/yr[c d]
Saturn	1.1	6.4	9.9	6.4	9.9	0	0
Centaur	3.3	22.0	31.2	22.0	31.2	0	0
Centaur "H"	4.0	20.8	32.6	20.8	32.6	0	0
Taurus	4.5	24.7	37.6	24.7	37.6	0	0
Mars T-12000	8.8	69.4	107	69.4	107	0	0
501-KB5	4.0	31.6	48.5	8.6	48.5	194	0
570-K	4.9	22.7	41.0	22.7	41.0	0	0
571-K	5.9	24.2	44.0	24.2	44.0	0	0
LM1600	14.0	74.1	127	13.0	40.5	245	345
LM2500	22.7	146	301	21.2	66.0	499	938
LM5000	34.5	232	474	31.7	145	802	1,320
LM6000	43.0	310	609	35.6	162	1,100	1,790
MS5001P	26.8	181	274	54.1	85.3	508	755
MS6001B	39.0	250	459	71.4	113	711	1,380
MS7001E	84.7	544	822	150	237	1,580	2,340
MS7001F	161	1,290	2,190	260	407	4,110	7,130
MS9001E	125	810	1,320	214	360	2,390	3,850
MS9001F	229	1,850	3,150	373	585	5,890	10,200
GT8	47.4	899	1,440	61.2	129	3,350	5,260
GT10	22.6	143	196	40.4	41.6	410	618
GT11N	83.3	1,350	1,990	147	151	4,830	7,350
GT35	16.9	214	264	43.1	44.4	681	878
251B11/12	49.2	453	741	52.0	88.6	1,600	2,610
501D5	109	843	1,120	112	191	2,920	3,730
V84.2	105	858	1,570	225	242	2,530	5,310
V94.2	153	1,250	3,290	327	353	3,690	7,740
V64.3	61.5	859	1,290	171	184	2,750	4,410
V84.3	141	1,930	2,910	386	415	6,190	9,960
V94.3	204	2,790	4,170	557	596	8,940	14,300

[a]Power output at ISO conditions, without wet injection, with natural gas fuel.
[b]Based on ppmv levels shown in Tables 5-5 and 5-6. See Appendix A for conversion from ppmv to lb/hr.

As an example, a 21.8 MW turbine burning natural gas fuel can reduce NO_x emissions by 452 tons/yr (8,000 hours operation) using water injection and 511 tons/yr using steam injection. This same turbine burning oil fuel will reduce annual NO_x emissions by 1,040 tons using water injection and by 925 tons using steam injection.

5.1.5 Impacts of Wet Controls on CO and HC Emissions

While carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines, water injection may increase these emissions. Figure 5-13

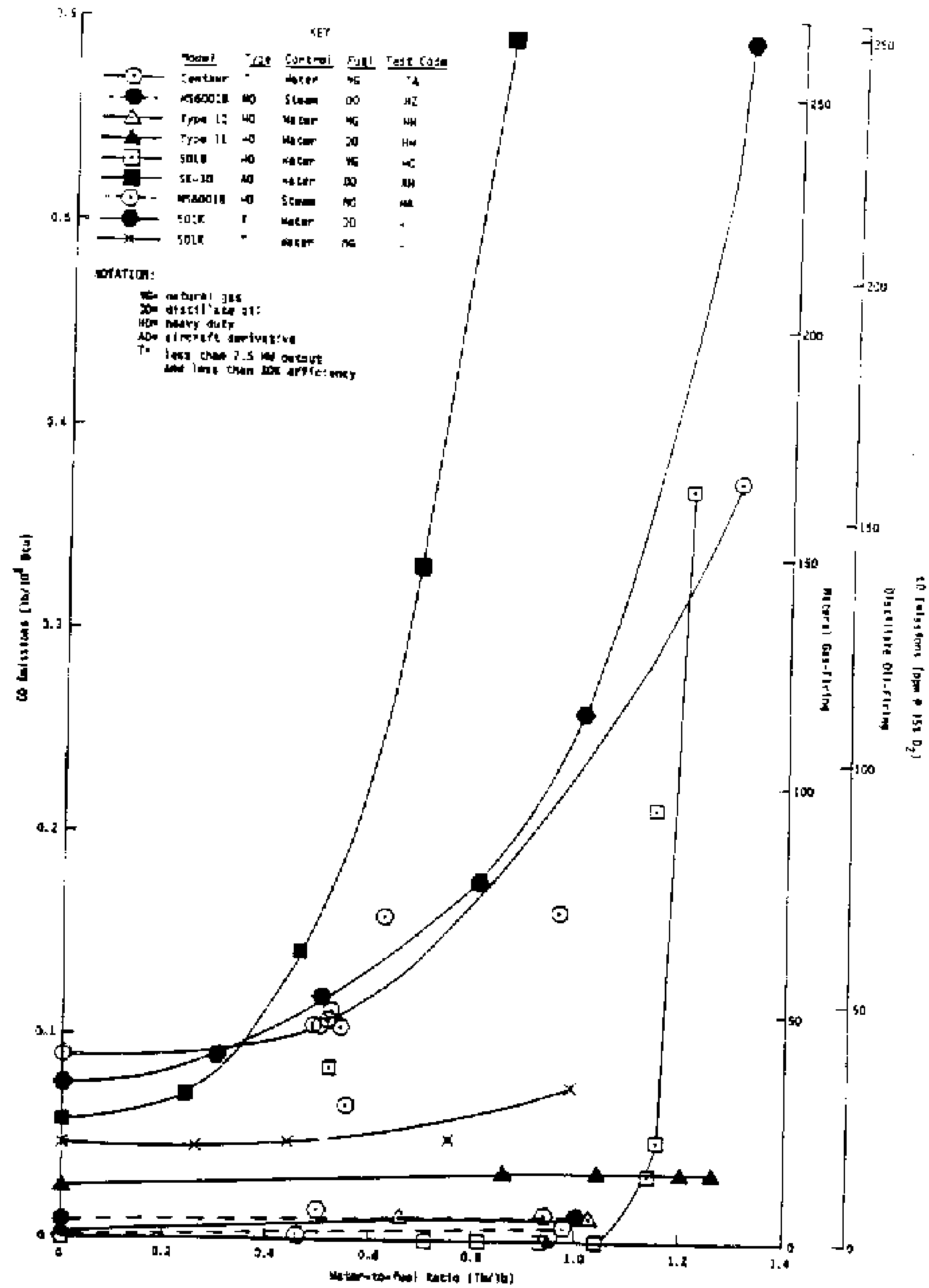


Figure 5-13. Effect of wet injection on CO emissions.[29]

shows the impact of water injection on CO emissions for several production gas turbines. In many turbines, CO emissions increase as the WFR increases, especially at WFR's above 0.8. Steam injection also increases CO emissions at relatively high WFR's, but the impact is less than that of water injection.[29,30]

Water and steam injection also increase HC emissions, but to a lesser extent than CO emissions.[29,30] The effect of water injection on HC emissions for one turbine is shown in

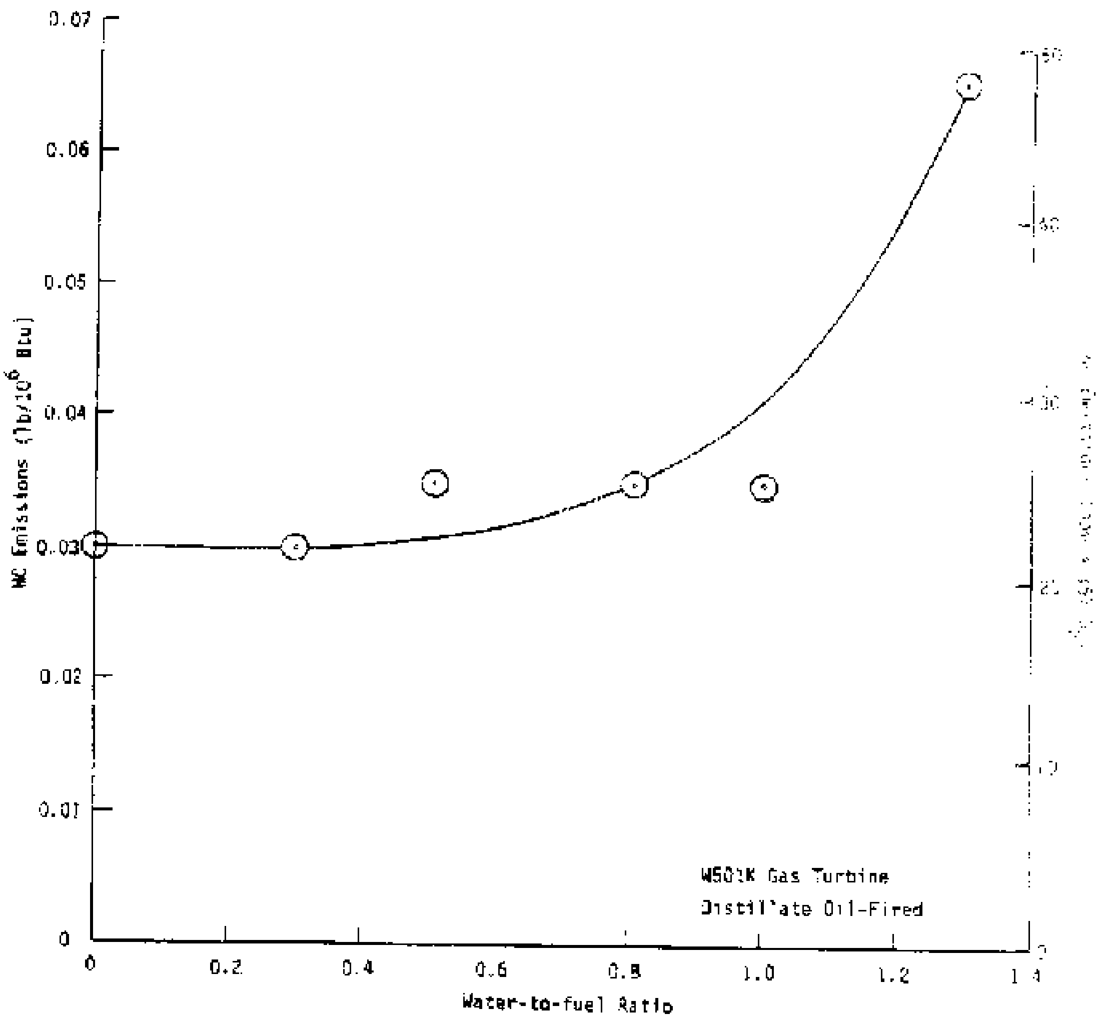


Figure 5-14. Effect of water injection on HC emissions for one turbine model.[29]

Figure 5-14. Like CO emissions, hydrocarbon emissions increase at WFR's above 0.8.

For applications where the water or steam injection rates required for NO_x emission reductions result in excess CO and/or HC emissions, it may be possible to select an alternative turbine and/or fuel with a relatively flat CO curve, as indicated in Figure 5-13. Another alternative is an oxidation catalyst to reduce these emissions. This oxidation catalyst is an add-on control device that is placed in the turbine exhaust duct or HRSG and serves to oxidize CO and HC to H_2O and CO_2. The catalyst material is usually a precious metal (platinum, palladium, or rhodium), and oxidation efficiencies of 90 percent or higher can be achieved. The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the flue gas stream.[31]

5.1.6 Impacts of Wet Controls on Gas Turbine Performance

Wet controls affect gas turbine performance in two ways: power output increases and efficiency decreases. The energy from the added mass flow and heat capacity of the injected water or steam can be recovered in the turbine, which results in an increase in power output. For water injection, the fuel energy required to vaporize the water in the turbine combustor, however, results in a net penalty to the overall efficiency of the turbine. For steam injection, there is an energy penalty associated with generating the steam, which results in a net penalty to the overall cycle efficiency. Where the steam source is exhaust heat, which would otherwise be exhausted to the atmosphere, the heat recovery results in a net gain in gas turbine efficiency.[32] The actual efficiency reduction associated with wet controls is specific to each turbine and the actual WFR required to meet a specific NO_x reduction. The overall efficiency penalty increases with increasing WFR and is usually higher for water injection than for steam injection due to the heat of vaporization associated with water. The impacts on output and efficiency for one manufacturer's gas turbines are shown in Table 5-10.

TABLE 5-10. REPRESENTATIVE WATER/STEAM INJECTION IMPACTS ON GAS TURBINE PERFORMANCE FOR ONE MANUFACTURER'S HEAVY-DUTY TURBINES[33]

No_x level, ppmv	Water/fuel ratio	Percent overall efficiency change	Percent output change[a]	Remarks
75 NSPS	0.5	-1.8	+3	Oil-fired, simple cycle, water injection
42	1.0	<-3	+5	Natural gas, simple cycle, water injection
42	1.2	-2	+5	Natural gas, combined cycle, steam injection
25	1.2	-4	+6	Natural gas, water injection, multinozzle combustor
25	1.3	-3	+5.5	Natural gas, steam injection, combined cycle (Frame 6 turbine model)

[a]Compared with no injection.

5.1.7 Impacts of Wet Controls on Gas Turbine Maintenance

Water injection increases dynamic pressure oscillation activity in the turbine combustor.[33] This activity can, in some turbine models, increase erosion and wear in the hot section of the turbine, thereby increasing maintenance requirements. As a result, the turbine must be removed from service more frequently for inspection and repairs to the hot section components. A summary of the maintenance impacts as provided by manufacturers is shown in Table 5-11.

TABLE 5-11. IMPACTS OF WET CONTROLS ON GAS TURBINE MAINTENANCE USING NATURAL GAS FUEL[5-11,17,24]

Manufacturer/Model	NO_x emissions, ppmv @ 15% O_2			Inspection interval, hours		
	Standard combustor	Water injection	Steam injection	Standard	Water injection	Steam injection
General Electric						
LM1600	133	42/25	25	25,000	16,000[a]	25,000
LM2500	174	42/25	25	25,000	16,000[a]	25,000
LM5000	185	42/25	25	25,000	16,000[a]	25,000
LM6000	220	42/25	25	25,000	16,000[a]	25,000
MS5001P	142	42	42	12,000	6,000	6,000
MS6001B	148	42	42	12,000	6,000	8,000
MS7001E	154	42	42	8,000	6,500	8,000
MS7001F	179	42	42	8,000	8,000	8,000
MS9001E	176	42	42	8,000	6,500	8,000
MS9001F	176	42	42	8,000	8,000	8,000
Asea Brown Boveri						
GT10	150	25	42	80,000[b]	80,000[b]	80,000[b]
GT8	430	25	29	24,000	24,000	24,000
GT11N	400	25	25	24,000	24,000	24,000
GT35	300	42	60	80,000[b]	80,000[b]	80,000[b]
Siemens Power Corp.						
V84.2	212	42	55	25,000	25,000	25,000
V94.2	212	55	55	25,000	25,000	25,000
V64.3	380	75	75	25,000	25,000	25,000
V84.3	380	75	75	25,000	25,000	25,000
V94.3	380	75	75	25,000	25,000	25,000
Solar Turbines, Inc.						
T-1500 Saturn	99	42	NA[c]	NA[d]	NA[d]	NA[c]
T-4500 Centaur	150	42	NA[c]	NA[d]	NA[d]	NA[c]
Type H Centaur	105	42	NA[c]	NA[d]	NA[d]	NA[c]
Taurus	114	42	NA[c]	NA[d]	NA[d]	NA[c]
T-12000 Mars	178	42	NA[c]	NA[d]	NA[d]	NA[c]
T-14000 Mars	199	42	NA[c]	NA[d]	NA[d]	NA[c]
Allison/General Motors						
501-KB5	155	42	NA[c]	25,000	17,000	NA[d]
501-KC5	174	42	NA[c]	30,000	22,000	NA[d]
501-KH	155	42	25	25,000	17,000	20,000
570-K	101	42	NA[c]	20,000	12,000	NA[d]
571-K	101	42	NA[c]	20,000	12,000	NA
Westinghouse						
251B11/12	220	42	25	8,000	8,000	8,000
501D5	190	25	25	8,000	8,000	8,000

[a]Applies only to 25 ppmv level. No impact for 42 ppmv.
[b]This interval applies to time between overhaul (TBO).
[c]Steam injection is not available for this model.
[d]Data not available.

As this table shows, the maintenance impact, if any, varies from manufacturer to manufacturer and model to model. Some manufacturers stated that there is no impact on maintenance intervals associated with water or steam injection for their turbine models. Data were provided only for operation with natural gas.

5.2 COMBUSTION CONTROLS

The formation of both thermal NO_x and fuel NO_x depends upon combustion conditions, so modification of these conditions affects NO_x formation. The following combustion modifications are used to control NO_x emission levels:

1. Lean combustion;
2. Reduced combustor residence time;
3. Lean premixed combustion; and
4. Two-stage rich/lean combustion.

These combustion modifications can be applied singly or in combination to control NO_x emissions.

The mechanisms by which each of these techniques reduce NO_x formation, their applicability to new gas turbines, and the design or operating factors that influence NO_x reduction performance are discussed below by control technique.

5.2.1 Lean Combustion and Reduced Combustor Residence Time

5.2.1.1 Process Description. Gas turbine combustors were originally designed to operate with a primary zone equivalence ratio of approximately 1.0. (An equivalence ratio of 1.0 indicates a stoichiometric ratio of fuel and air. Equivalence ratios below 1.0 indicate fuel-lean conditions, and ratios above 1.0 indicate fuel-rich conditions.) With lean combustion, the additional excess air cools the flame, which reduces the peak flame temperature and reduces the rate of thermal NO_x formation.[34]

In all gas turbine combustor designs, the high-temperature combustion gases are cooled with dilution air to an acceptable temperature prior to entering the turbine. This dilution air rapidly cools the hot gases to temperatures below those required for thermal NO_x formation. With reduced residence time combustors, dilution air is added sooner than with standard combustors. Because the combustion gases are at a high temperature for a shorter time, the amount of thermal NO_x formed decreases.[34]

Shortening the residence time of the combustion products at high temperatures may result in increased CO and HC emissions if no other changes are made in the combustor. In order to avoid increases in CO and HC emissions, combustors with reduced residence time also incorporate design changes in the air distribution ports to promote turbulence, which improves fuel/air mixing and reduces the time required for the combustion process to be completed. These designs may also incorporate fuel/air premixing chambers. Therefore, the differences between reduced residence time combustors and standard combustors are the placement of the air ports, the design of the circulation flow patterns in the combustor, and a shorter combustor length.[34]

5.2.1.2 Applicability. Lean primary zone combustion and reduced residence time combustion have been applied to annular, can-annular, and silo combustor designs.[35-37] Almost all gas turbines presently being manufactured incorporate lean combustion and/or reduced residence time to some extent in their combustor designs, incorporating these features into production models since 1975.[38,39] However, the varying uncontrolled NO_x emission levels of gas turbines shown in Figures 5-2 and 5-3 indicate that these controls are not incorporated to the same degree in every gas turbine and may be limited in some turbines by the quantity of dilution air available for lean combustion.

Lean primary zone and reduced residence time are most applicable to low-nitrogen fuels, such as natural gas and distillate oil fuels. These modifications are not effective in reducing fuel NO_x.[40]

5.2.1.3 Factors Affecting Performance. For a given combustor, the performance of lean combustion is directly affected by the primary zone equivalence ratio. As shown in Figure 4-2, the further the equivalence ratio is reduced below 1.0, the greater the reduction in NO_x emissions. However, if the equivalence ratio is reduced too far, CO emissions increase and flame stability problems occur.[41] This emissions tradeoff effectively limits the amount of NO_x reduction that can be achieved by lean combustion alone.

For combustors with reduced residence time, the amount of NO_x emission reduction achieved is directly related to the decrease in residence time in the high-temperature flame zone.

5.2.1.4 Achievable NO_x Emission Levels Using Lean Combustion and Reduced Residence Time Combustors. Lean combustion reduces NO_x emissions, and when used in combination with reduced residence time, NO_x emissions are further reduced. Figure 5-1

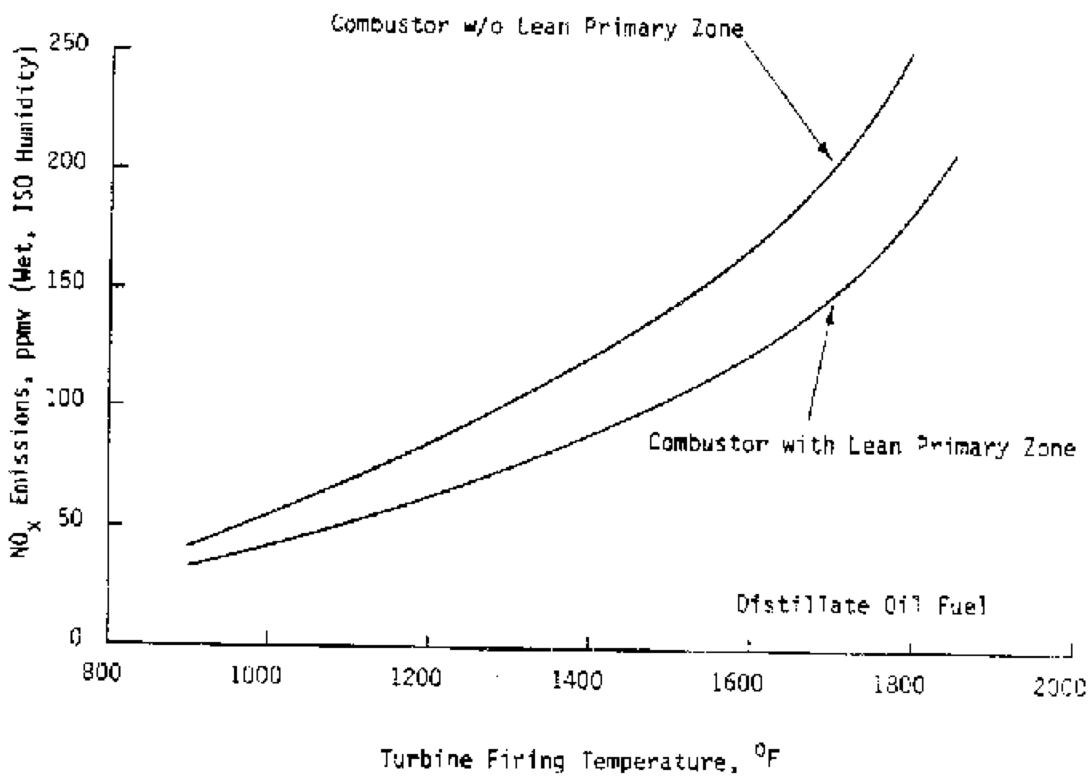


Figure 5-15. Nitrogen oxide emissions versus turbine firing temperature for combustors with and without a lean primary zone.[42]

5 shows a comparison of NO_x emissions from a combustor with a lean primary zone and NO_x emissions from the same combustor without a lean primary zone. At the same firing temperature, NO_x emissions reductions of up to 30 percent are achieved using lean primary zone combustion without increasing CO emissions. Reducing the residence time at elevated temperatures reduces NO_x emissions. One test at 1065°C (1950°F) yielded a reduction in NO_x emissions of 40 percent by reducing the residence time. Carbon monoxide emissions increased from less than 10 to approximately 30 ppm.[42-45]

5.2.2 Lean Premixed Combustors

5.2.2.1 Process Description. In a conventional combustor, the fuel and air are introduced directly into the combustion zone and fuel/air mixing and combustion take place simultaneously. Wide variations in the air-to-fuel ratio (A/F) exist, and combustion of localized fuel-rich pockets produces significant levels of NO_x emissions. In a lean premixed combustor design, the air and fuel is premixed at very lean A/F's prior to introduction into the combustion zone. The excess air in the lean mixture acts as a heat sink, which lowers combustion temperatures. Premixing results in a homogeneous mixture, which minimizes localized fuel-rich zones. The resultant uniform, fuel-lean mixture results in greatly reduced NO_x formation rates.[17]

To achieve NO_x levels below 50 ppmv, referenced to 15 percent O_2, the design A/F approaches the lean flammability limit. To stabilize the flame, ensure complete combustion, and minimize CO emissions, a pilot flame is incorporated into the combustor or burner design. In most designs, the relatively small amount of air and fuel supplied to this pilot flame is not premixed and the A/F is nearly stoichiometric, so the pilot flame temperature is relatively high. As a result, NO_x emissions from the pilot flame are higher than from the lean premixed combustion.[46]

Virtually all gas turbine manufacturers have implemented lean premixed combustion development programs. Three manufacturers' designs that are available in production turbines are described below.

The first design uses a can-annular combustor and is shown in Figure 5-16

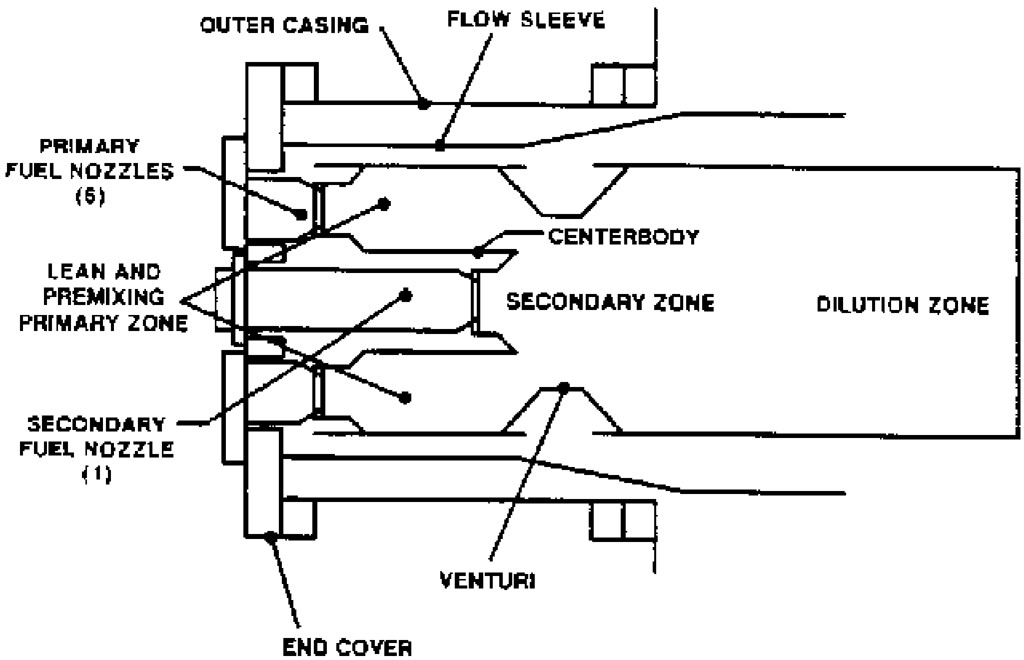


Figure 5-6. Cross-section of a lean premixed can-annular combustor.[47]

. This is a two-stage premixed combustor: the first stage is the portion of the combustor upstream of the venturi section and includes the six primary fuel nozzles; the second stage is the balance of the combustor and includes the single secondary fuel nozzle.[33]

The operating modes for this combustor design are shown in Figure 5-17. For ignition, warmup, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor.

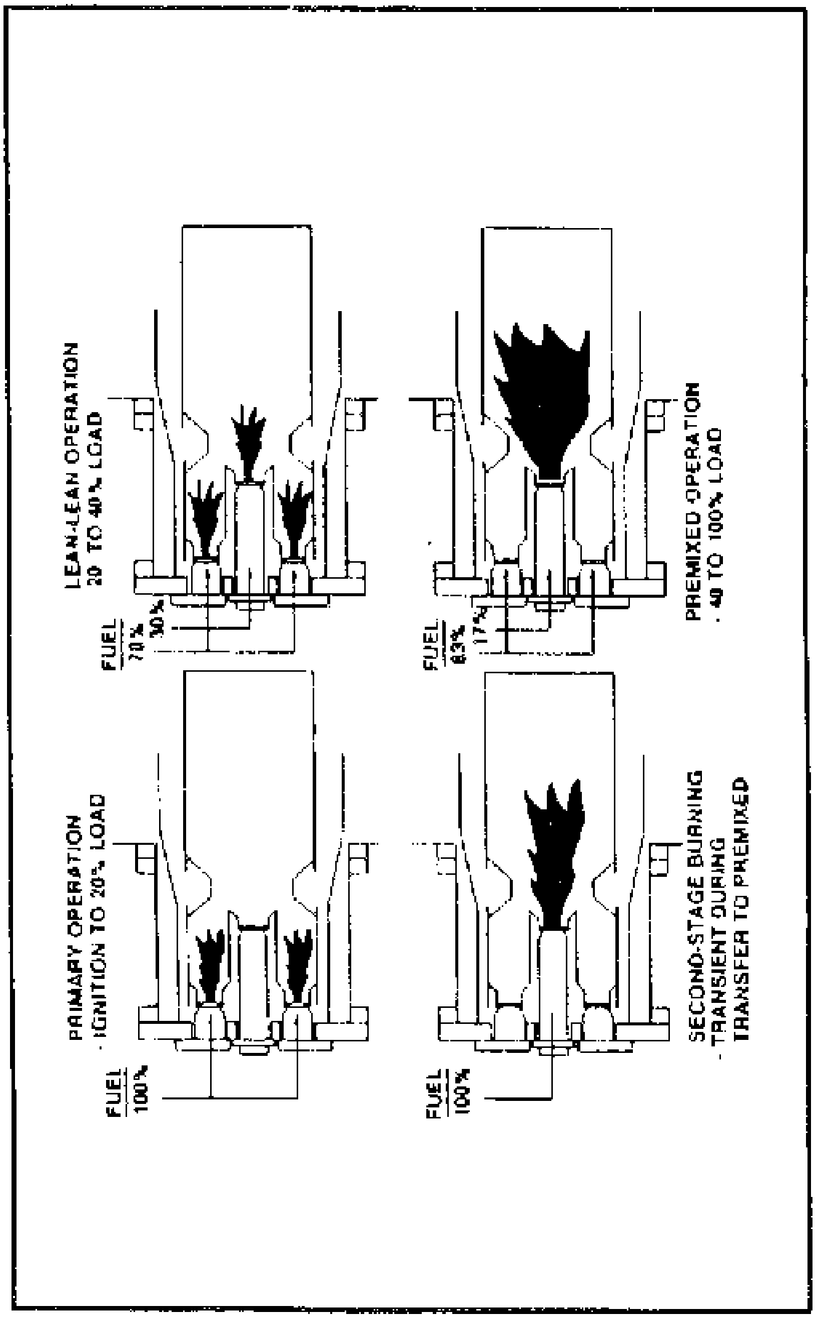


Figure 5-17. Operating modes for a lean premixed can-annular combustor.[33]

Flame is present only in the first stage, and the equivalence ratio is kept as low as stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. Again, the equivalence ratio is kept as low as possible in both stages to minimize NO_x emissions. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.[33]

For operation on distillate oil, fuel is introduced and burned only in the first stage for ignition and for loads up to approximately 50 percent. For loads greater than 50 percent, fuel is introduced and burned in both stages.[33]

Figure 5-18 shows a lean premixed combustor design used by another manufacturer for an annular combustor.

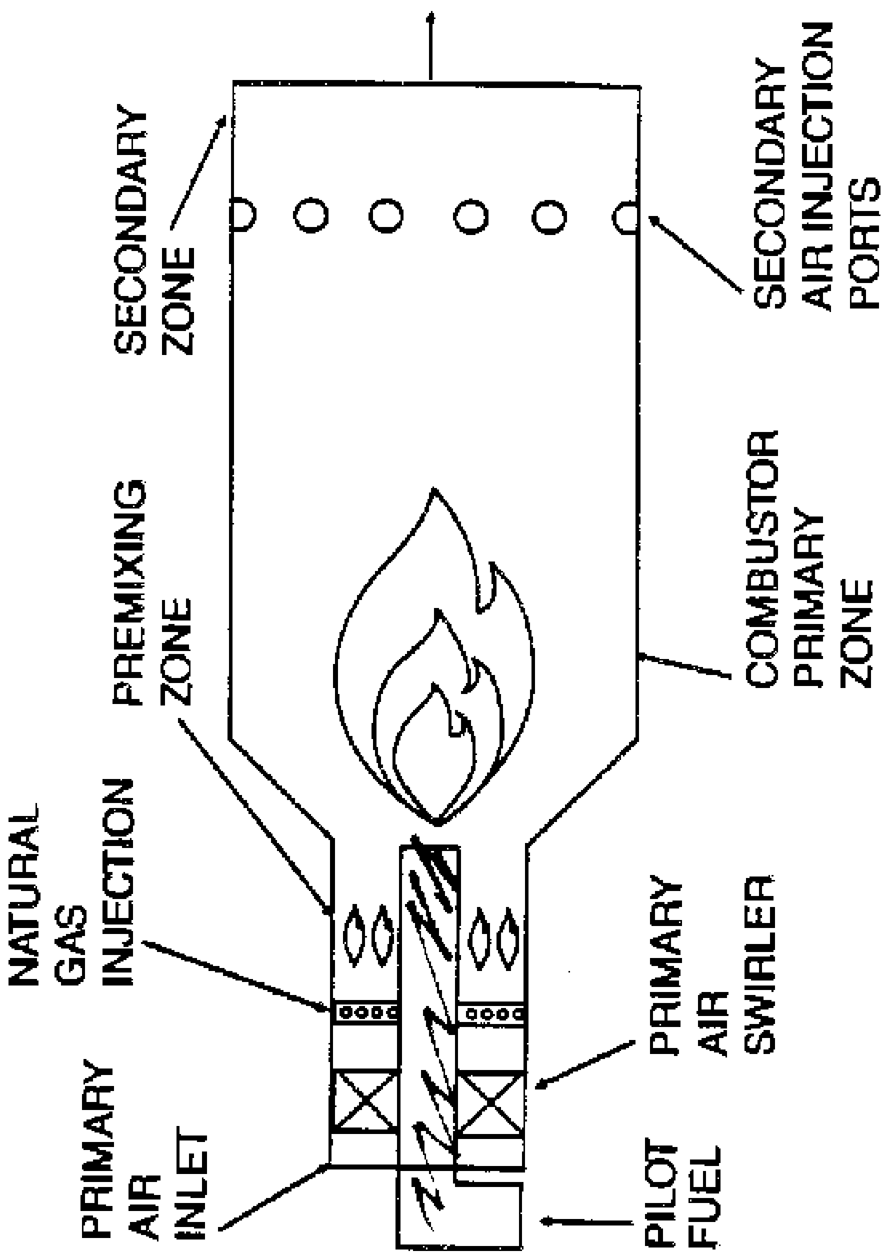


Figure 5-18. Cross-section of lean premixed annular combustion design.[47]

The air and fuel are premixed using a very lean A/F, and the resultant uniform mixture is delivered to the primary combustion zone where combustion is stabilized using a pilot flame. Using one or more mechanical systems to regulate the airflow delivered to the combustor, the premix mode is operable for output loads between 50 and 100 percent. Below 50 percent load, only the pilot flame is operating, and NO_x emissions levels are similar to those for conventional combustors.[46]

Another manufacturer's production low-NO_x design uses a silo combustor. Unlike the can-annular and annular designs, the silo combustor is mounted externally to the turbine and can therefore be modified without significantly affecting the rest of the turbine design, provided the mounting flange to the turbine is unchanged. In addition, this large combustion chamber is fitted with a ceramic lining that shields the metal surfaces from peak flame temperatures. This lining reduces the requirement for cooling air, so more air is available for the combustion process.[17]

This silo low-NO_x combustor design uses six burners, as shown in Figure 5-19

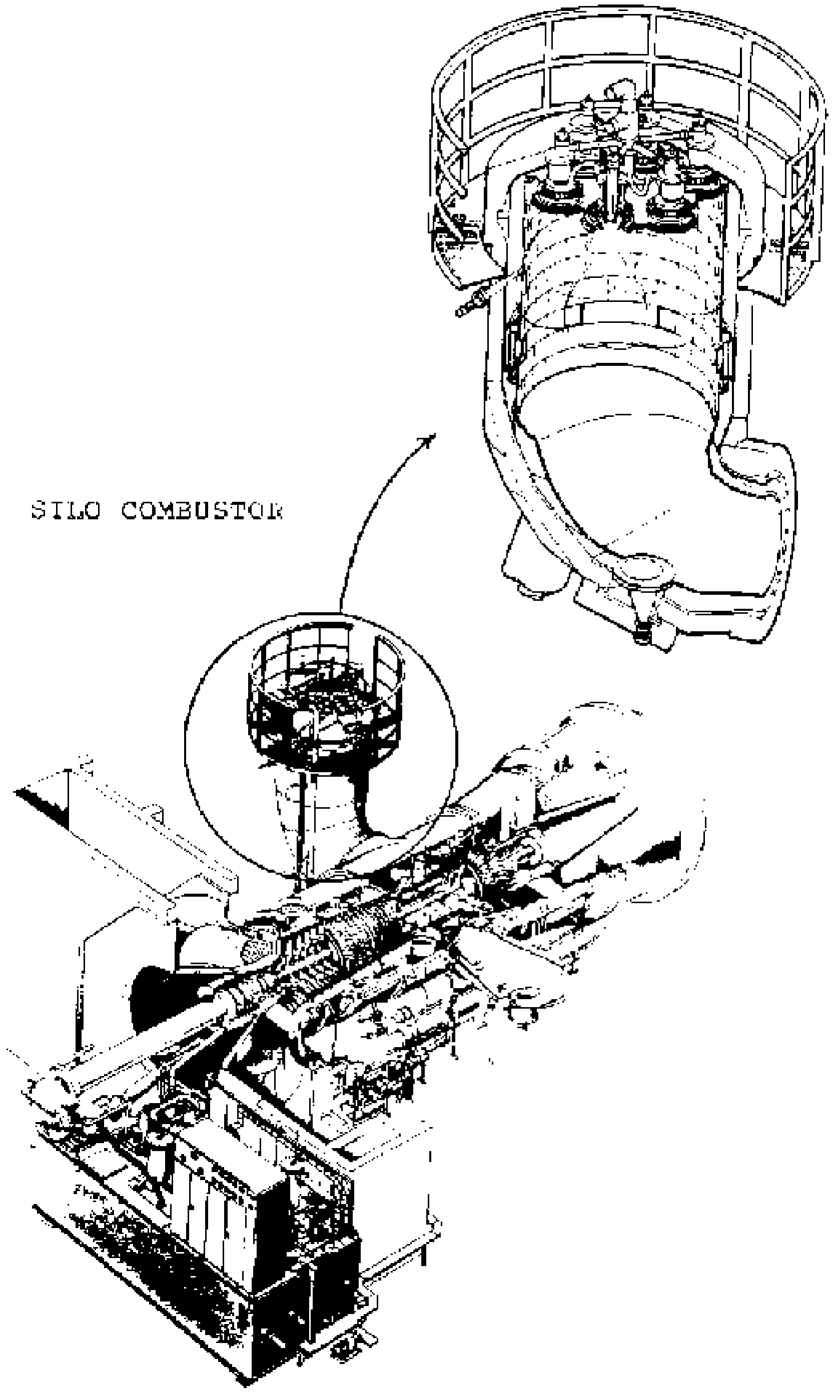


Figure 5-19. Cross-section of a low NO_x silo combustor.[35,48]

. For operation on natural gas, each burner serves to premix the air and fuel to deliver a lean and uniform mixture to the combustion zone. To achieve the lowest possible NO_x emissions, the A/F of the premixed gases is kept very near the lean flammability limit and a pilot flame is used to stabilize the overall combustion process. This burner design is shown in Figure 5-20

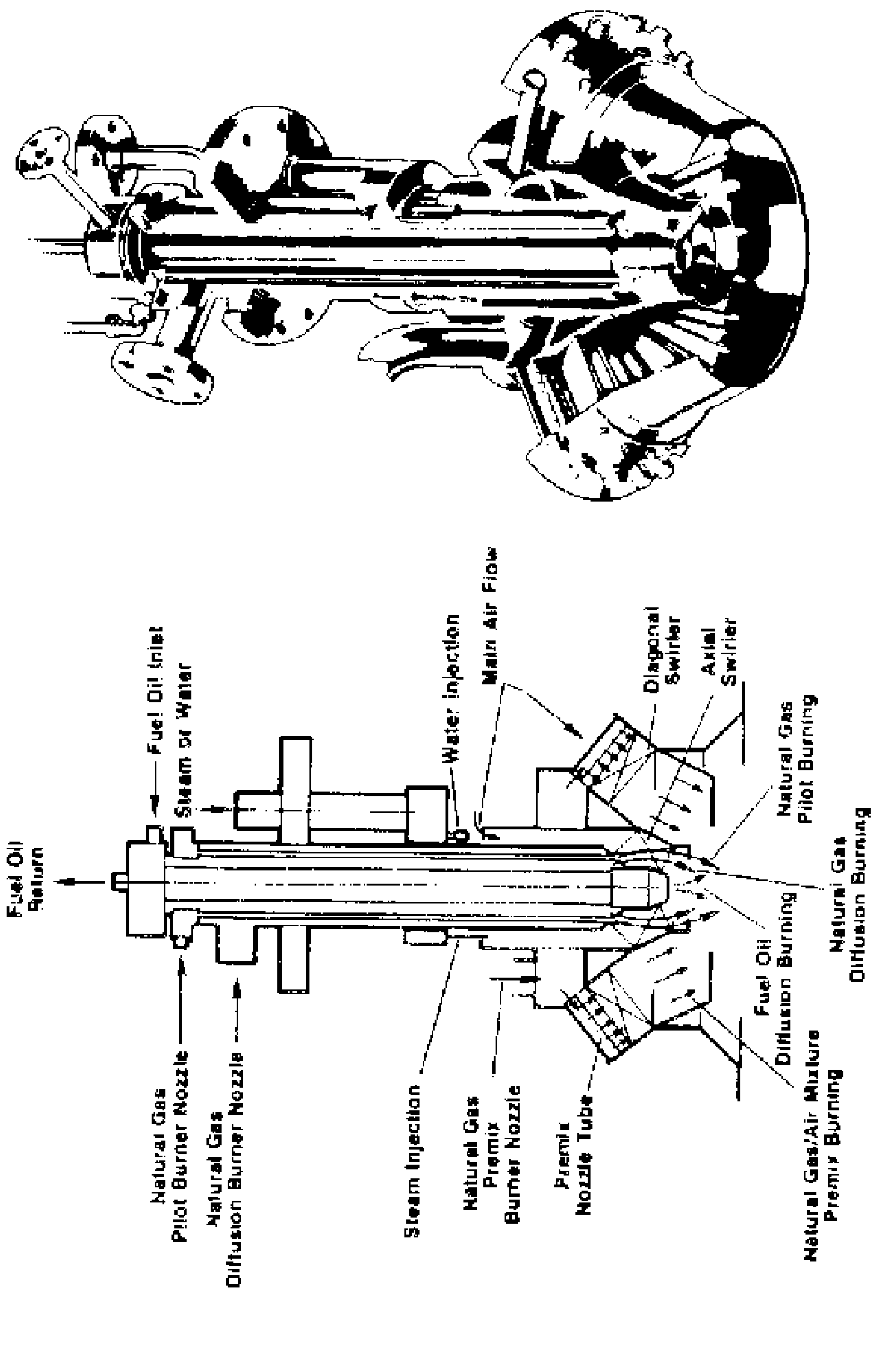


Figure 5-20. Low-NO_x burner for a silo combustor.[48]

. Like the can-annular design, the burner in the silo combustor cannot operate over the full power range of the gas turbine in the premix mode due to inability of the premix mode to deliver suitable A/F's at low power output levels. For this reason, the burners are designed to operate in a conventional diffusion burning mode at startup and low power outputs and switch to a premix burning mode at higher power output levels.

For operation on distillate oil with the current burner design, combustion occurs only in a diffusion mode and there is no premixing of air and fuel.

5.2.2.2 Applicability. As discussed in Section 5.2.2.1, lean premixed combustors apply to can-annular, annular, and silo combustors. This combustion modification is effective in reducing thermal NO_x emissions for both natural gas and distillate oil but is not effective on fuel NO_x. Therefore, lean premixed combustion is not as effective in reducing NO_x levels if high-nitrogen fuels are fired.[49]

The multiple operating modes associated with the percent operating load results in "stepped" NO_x emission levels. To date, low NO_x emission levels occur only at loads greater than 40 to 75 percent.

Lean premixed combustors currently are available for limited models from three manufacturers contacted for this study.[6,17,24] Two additional manufacturers project an availability date of 1993 or 1994 for lean premixed combustors for some turbine models.[11,50] All of these manufacturers state that these lean premixed combustors will be available for retrofit applications.

5.2.2.3 Factors Affecting Performance. The primary factors affecting the performance of lean, premixed combustors are A/F and the type of fuel. To achieve low NO_x emission levels, the A/F must be maintained in a narrow range near the lean flammability limit of the mixture. Lean premixed combustors are designed to maintain this A/F at rated load. At reduced load conditions, the fuel input requirement decreases. To avoid combustion instability and excessive CO emissions that would occur as the A/F reaches the lean flammability limit, all manufacturers' lean premixed combustors switch to a diffusion-type combustion mode at reduced load conditions, typically between 40 and 60 percent load. This switchover to a diffusion combustion mode results in higher NO_x emissions.

Natural gas produces lower NO_x levels than do oil fuels. The reasons for this are the lower flame temperature of natural gas and the ability to premix this fuel with air prior to delivery into the second combustion stage. For operation on liquid fuels, currently available lean premixed combustor designs require water injection to achieve appreciable NO_x reduction.

5.2.2.4 Achievable NO_x Emission Levels. The achievable controlled NO_x emission levels for lean premixed combustors vary depending upon the manufacturer. At least three manufacturers currently guarantee NO_x emission levels of 25 ppmv, corrected to 15 percent O_2 for most or all of their gas turbines for operation on natural gas fuel without wet injection.[6,17,24] Each of these three manufacturers has achieved controlled NO_x emission levels of less than 10 ppmv at one or more installations in the United States and/or Europe and guarantee this NO_x level for a limited number of their gas turbine models.[51] All three manufacturers offer gas turbines in the 10+ MW (13,400 hp+) range and anticipate that guaranteed NO_x emission levels of 10 ppmv or less will be available for all of their gas turbines for operation on natural gas fuel in the next few years. These low-NO_x combustor designs apply to new turbines and existing installation retrofits.

For gas turbines in the range of 10 MW (13,400 hp) and under, one gas turbine manufacturer offers a guarantee for its lean premixed combustor, without wet injection, of 42 ppmv using natural gas fuel for two of its turbine models for 1994 delivery. This manufacturer states that a controlled NO_x emission level of 25 ppmv has been achieved by in-house testing, and this 25 ppmv level firing natural gas fuel is the goal for all of its gas turbine models, for both new equipment and retrofit applications.[50]

These controlled NO_x emission levels of 9 to 42 ppmv correspond to full output load; at reduced loads, the NO_x levels increase, often in "stepped" fashion in accordance with changes in combustor operation from premixed mode to conventional or diffusion-mode operation (see Section 5.2.2.3). Figure 5-21

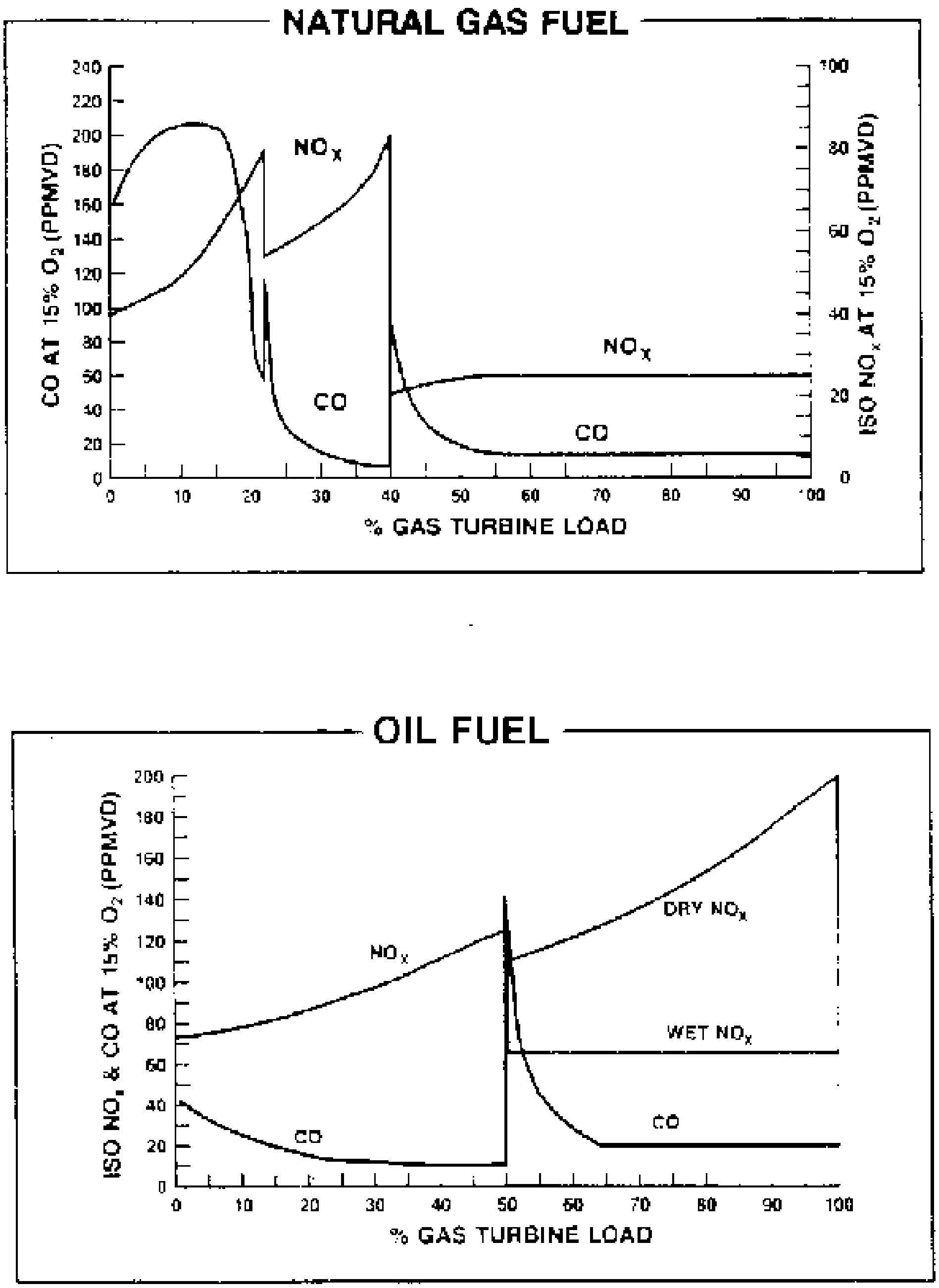


Figure 5-21. "Stepped" NO_x and CO emissions for a low-NO_x can-annular combustor burning natural gas and distillate oil fuels.[47]

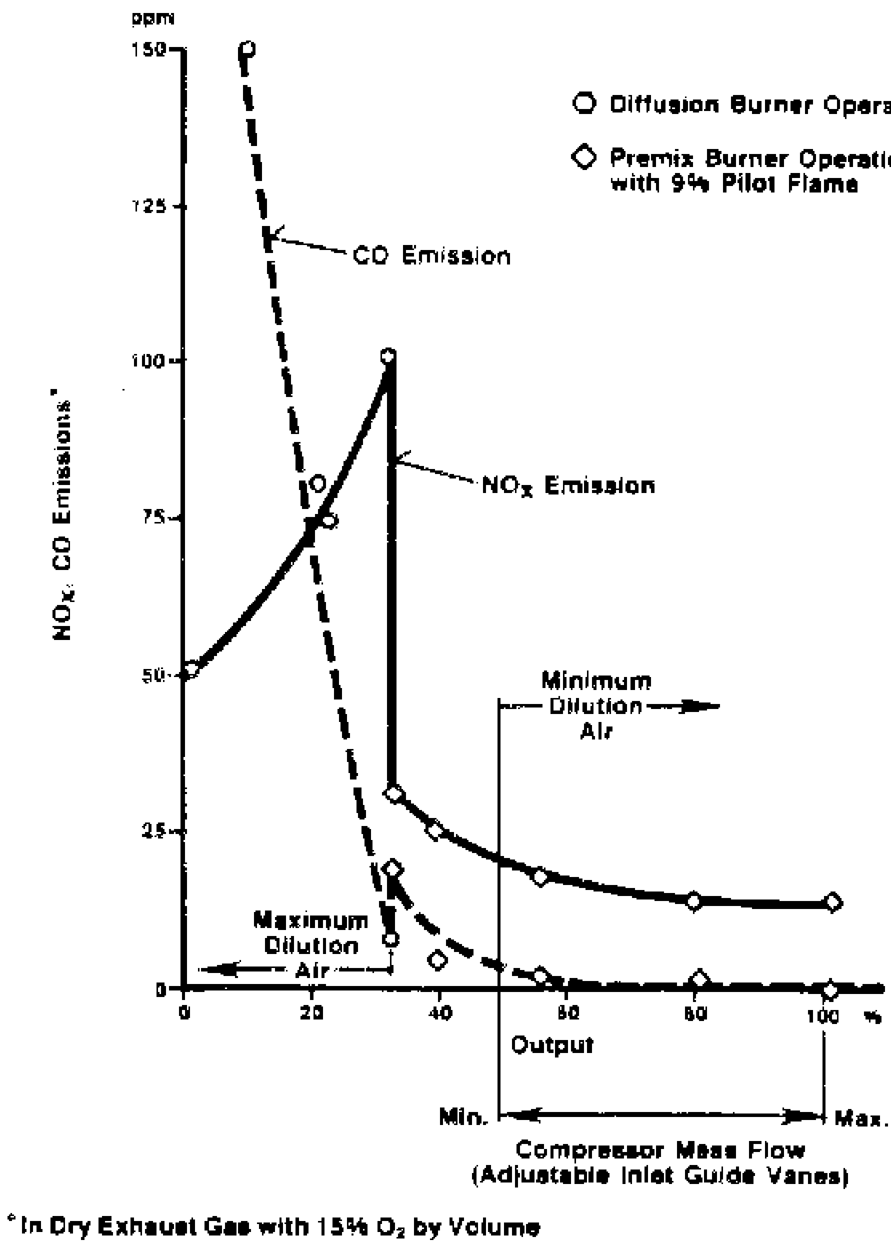


Figure 5-22. "Stepped" NO_x and CO emissions for a low-NO_x silo combustor burning natural gas.[35]

shows these stepped NO_x emissions levels for a can-annular combustor for natural gas and oil fuel operation. Figure 5-22

shows the emissions for a silo combustor operating on natural gas only.

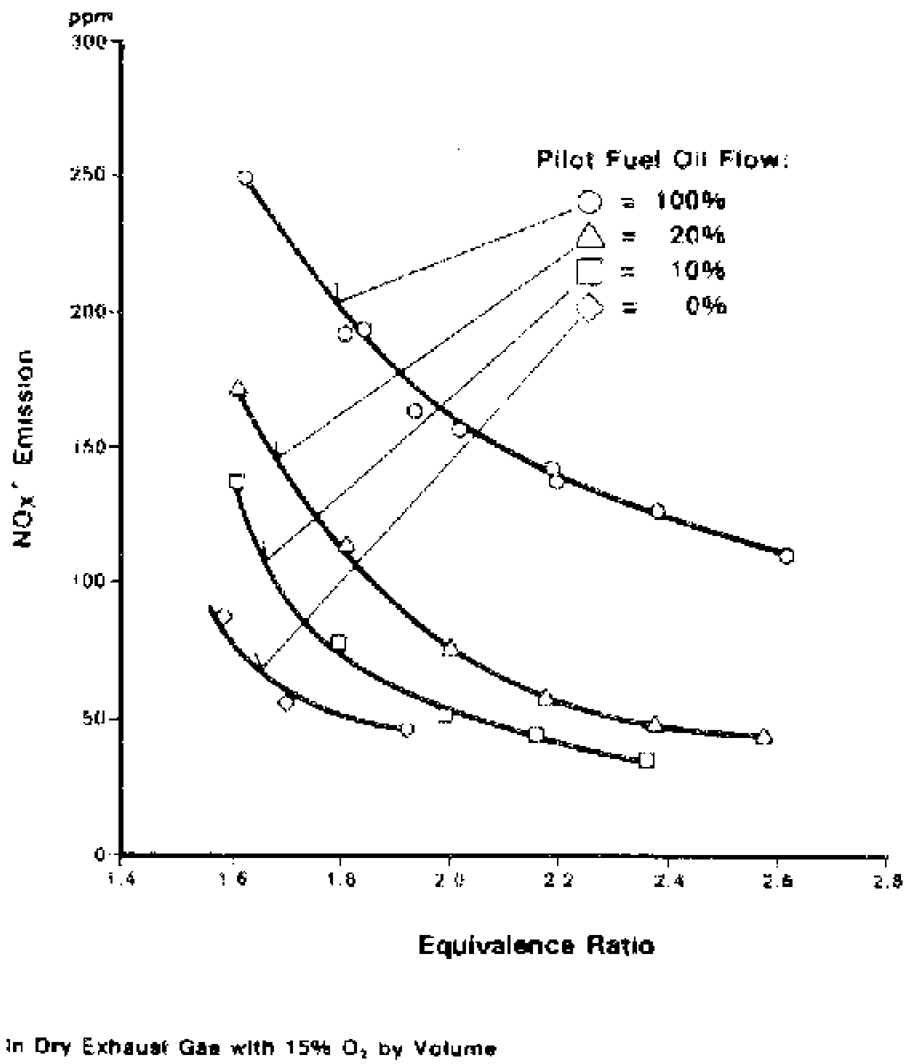


Figure 5-23. **Nitrogen oxide emission text results from a lean premix silo combustor firing fuel oil without wet injection.[53]**

The emission levels shown in Figures 5-21 and 5-22 correspond to full-scale production turbines currently available from the manufacturers.

Reduced NO_x emissions when burning oil fuel in currently available lean premixed combustor designs have been achieved only with water or steam injection. With water or steam injection, a 65 ppmv NO_x level can be achieved in the turbine with a can-annular combustor design; a 65 ppmv level can also be met with water injection in the turbine with a silo combustor at a WFR of 1.4.[48,52] This 65 ppmv level for lean premixed combustors is higher than the controlled NO_x levels achieved with water injection in oil-fired turbines using a conventional combustor design.

Modification of the existing burner design used in the silo combustor to allow premixing of the oil fuel with air prior to combustion is under development. Tests performed using a 12 MW (16,200 hp) turbine achieved NO_x emission levels below 50 ppmv without wet injection, corrected to 15 percent O_2, compared to uncontrolled levels of 150 ppmv or higher. The NO_x levels, without wet injection, as a function of equivalence ratio are shown in Figure 5-23. The design equivalence ratio at rated load is approximately 2.1. As shown in this figure, NO_x emissions below 50 ppmv were achieved at rated power output at pilot fuel flow levels of 10 percent of the total fuel input.[52]

Site test data for two turbines using silo-type lean premixed combustors, as reported by the manufacturer, are shown in Table 5-12. As this table shows, NO_x emission levels as low as 16.5 ppmv were recorded for using natural gas fuel without

TABLE 5-12. MEASURED NO_x EMISSIONS FOR COMPLIANCE TESTS OF A NATURAL GAS-FUELED LEAN PREMIXED COMBUSTOR WITHOUT WATER INJECTION[22]

Turbine No.	Output, percent of baseline	NO_x emission level, ppmv[a]
1	107	17.7
1	100	16.5
2	100	24.1
2	75	20.4
1	50	22.3
2	50	22.2

[a]In dry exhaust with 15 percent O_2, by volume.

water injection. Subsequent emission tests have achieved levels below 10 ppmv.[51] Corresponding data for operation on oil fuel using only the pilot (diffusion) stage for combustion, and with water injection, is shown in Table 5-13. Levels of NO_x emissions

TABLE 5-13. MEASURED NO_x EMISSIONS FOR OPERATION OF A LEAN PREMIXED COMBUSTOR DESIGN OPERATING IN DIFFUSION MODE ON OIL FUEL WITH WATER INJECTION[22]

Turbine No.	Output, percent of baseload	NO_x emission level, ppmv[a]
1	Peak	69.3
2	Peak	53.6
1	100	59.9
2	100	51.6
1	75	54.3
2	75	49.2
2	50	54.8

[a]In dry exhaust with 15 percent O_2, by volume.

at base load for No. 2 fuel oil are between 50 and 60 ppmv.

Based on information provided by turbine manufacturers, the potential NO_x reductions using currently available lean premixed

combustors are shown in Table 5-14. As this table indicates, NO_x emission reductions range from 14.7 tons/yr for a 1.1 MW (1,480 hp) turbine to 10,400 tons/yr

TABLE 5-14. POTENTIAL NO_x REDUCTIONS FOR GAS TURBINES USING LEAN PREMIXED COMBUSTORS

Turbine model	Power output, MW	NO_x emissions					
		Uncontrolled		Controlled		NO_x reduction	
		Gas fuel, ppmv	Oil fuel, ppvm	Gas fuel, ppmv	Oil fuel, ppmv	Gas fuel, tons/yr[a]	Oil fuel, tons/yr[a b]
Saturn[c]	1.1	99	150	42	NA[d]	14.7	NA[d]
Centaur T-4500[c]	3.3	130	179	42	NA[d]	59.5	NA[d]
Centaur "H"[c]	4.0	105	160	42	NA[d]	49.8	NA[d]
Taurus[c]	4.5	114	168	42	NA[d]	62.4	NA[d]
Mars T-12000[c]	8.8	178	267	42	NA[d]	212	NA[d]
Mars T-14000[c]	10.0	199	NA[d]	42	NA[d]	270	NA[d]
MS6001B	39.0	148	267	25/9[e]	65	829/937	1,139
MS7001E	84.7	154	228	25/9[e]	65	1,820/2,050	2,360
MS7001F	161	210	353	25	65	4,540	5,190
MS9001E	125	161	241	25/9[e]	65	2,740/3,060	3,490
MS9001F	229	210	353	25	65	6,500	7,250
GT10	22.6	150	200	25	42	476	620
GT11N	83.3	390	560	25/9[e]	42	5,070/5,290	7,360
V84.2	105	212	360	25/9[e]	NA[f]	3,030/3,290	NA[f]
V94.2	153	212	360	9[e]	NA[f]	4,410/4,780	NA[f]
V64.3	61.5	380	530	42	NA[d]	3,210	NA[d]
V84.3[c]	141	380	530	42	NA[d]	7,230	NA[d]
V94.3[e]	204	380	530	42	NA[d]	10,400	NA[d]

[a]Based on 8,000 hours operation per year.
[b]Requires water or steam injection.
[c]Scheduled availability is 1994 for natural gas fuel.
[d]NA = Data not available.
[e]Standard NO_x guarantee is 25 ppmv. Manufacturers offer guaranteed NO_x levels as low as 9 ppmv for these turbines.
[f]Scheduled availability 1993 for oil fuel without water injection. Reference 17.

for a 204 MW (274,000 hp) turbine for operation on natural gas without wet injection. Corresponding NO_x emission reductions for operation on oil fuel, with water injection, range from 620 tons/yr for a 22.6 MW (30,300 hp) turbine to 7,360 tons/yr for an 83.3 MW (112,000 hp) turbine.

Limited data from two manufacturers showing the impact of lean premixed combustor designs on CO emissions are shown in Table 5-15.

TABLE 5-15. COMPARISON OF NO_x AND CO EMISSIONS FOR STANDARD VERSUS LEAN PREMIXED COMBUSTORS FOR TWO MANUFACTURERS' TURBINES[46,54]

		Emissions, ppmv, referenced to 15 percent O_2[a]			
		Standard combustor		Lean premixed combustor	
GT Model	Power output, MW	NO_x	CO	NO_x	CO
Centaur H	4.0	105	15	25-42	50[b]
Mars T-14000	10.0	199	5.5	25-42	50[b]
MS6001B	39.0	148	10	9	25
MS7001E	84.7	154	10	9	25
MS9001E	125	161	10	9	25
MS7001F	161	210	25	25	15
MS9001F	229	210	25	25	15

[a]For operation at ISO conditions using natural gas fuel.

[b]Maximum design goal for CO emissions. Most in-house test configurations have achieved CO emission levels between 5 and 25 ppmv.

For natural gas-fueled turbines with rated outputs of 10 MW (13,400 hp) or less, controlled NO_x emission levels of 25 to 42 ppmv result in a rise in CO emission levels from 25 ppmv or less to as high as 50 ppmv.[43] For turbines above 10 MW (13,400 hp), controlled NO_x emission levels of 9 ppmv result in a rise in CO emissions from 10 to 25 ppmv for natural gas fuel. Conversely, for controlled NO_x emission levels of 25 ppmv, the CO emissions drop from 25 to 15 ppmv.[51] For one manufacturer's lean premixed silo combustor design, CO emissions at rated load are less than 5 ppmv, as shown previously in Figure 5-21. This limited data suggest that the effect of lean premixed combustors on CO emissions depends upon the specific combustor design and the controlled NO_x emission level.

The emission levels shown in Table 5-15 correspond to rated power output. Like NO_x emission levels, CO emissions change with changes in combustor operating mode at reduced power output. The "stepped" effect on CO emissions is shown in Figures 5-21 and 5-22, shown previously.

Operation on oil fuel with wet injection, shown previously in Figure 5-21, shows CO emission levels of 20 ppmv. Additional CO emission data were not available for operation on oil fuel with water injection in lean premixed combustors. Developmental tests for operation on oil fuel without wet injection in a silo combustor are presented in Figure 5-24

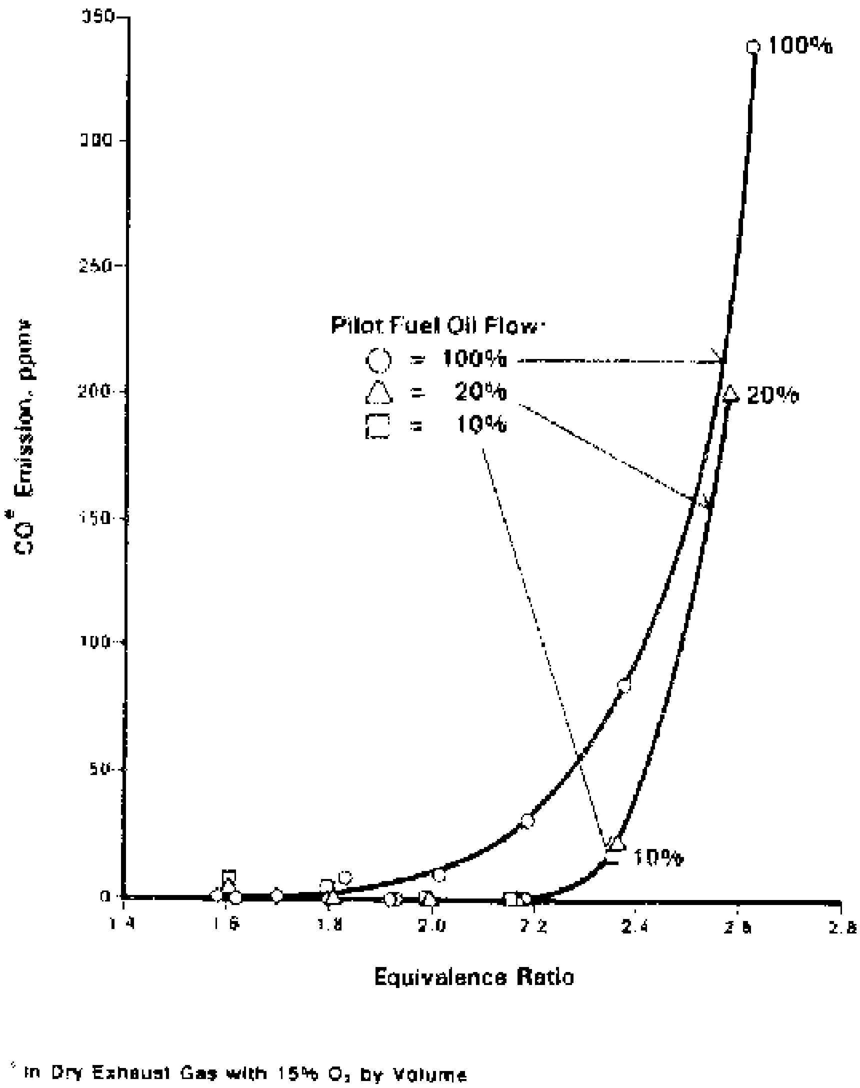


Figure 5-24. The CO emission test results from a lean premix silo combustor firing fuel oil without wet injection.

. At rated load, shown in this figure at an equivalence ratio of approximately 2.1, CO emissions are less than 10 ppmv, corrected to 15 percent $O_{2,}$

5-143

and are in the range of 0 to 2 ppmv for a pilot oil fuel flow of 10 percent (representing 10 percent of the total fuel flow).[53] This 10 percent pilot fuel flow corresponds to controlled NO_x emission levels below 50 ppmv, as shown previously in Figure 5-22. No data for HC emissions were available for lean premixed burner designs.

5.2.3 Rich/Quench/Lean Combustion

5.2.3.1 Process Description. Rich/quench/lean (RQL) combustors burn fuel-rich in the primary zone and fuel-lean in the secondary zone. Incomplete combustion under fuel-rich conditions in the primary zone produces an atmosphere with a high concentration of CO and hydrogen (H_2). The CO and H_2 replace some of the oxygen normally available for NO_x formation and also act as reducing agents for any NO_x formed in the primary zone. Thus, fuel nitrogen is released with minimal conversion to NO_x. The lower peak flame temperatures due to partial combustion also reduce the formation of thermal NO_x.[55]

As the combustion products leave the primary zone, they pass through a low-residence-time quench zone where the combustion products are rapidly diluted with additional combustion air or water. This rapid dilution cools the combustion products and at the same time produces a lean A/F. Combustion is then completed under fuel-lean conditions. This secondary lean combustion step minimally contributes to the formation of fuel NO_x because most of the fuel nitrogen will have been converted to N_2 prior to the lean combustion phase. Thermal NO_x is minimized during lean combustion due to the low flame temperature.[55]

5.2.3.2 Applicability. The RQL combustion concept applies to all types of gas turbines. None of the manufacturers contacted for this study, however, currently have this design available for their production turbines. This may be due to lack of demand for this design due to the current limited use of high-nitrogen-content fuels in gas turbines.

5.2.3.3 Factors Affecting Performance. The NO_x emissions from RQL combustors are affected primarily by the equivalence ratio in the primary combustion zone and the quench airflow rate.

Careful selection of equivalence ratios in the fuel-rich zone will minimize both thermal and fuel NO_x formation. Further NO_x reduction is achieved with increasing quench airflow rates, which serve to reduce the equivalence ratio in the secondary (lean) combustion stage.

5.2.3.4 Achievable NO_x Emissions Levels Using Rich/Quench/Lean Combustion. The RQL staged combustion has been demonstrated in rig tests to be effective in reducing both thermal NO_x and fuel NO_x. As shown in Figure 5-25, NO_x emissions are reduced by 40 to 50 percent in a test rig burning diesel fuel.

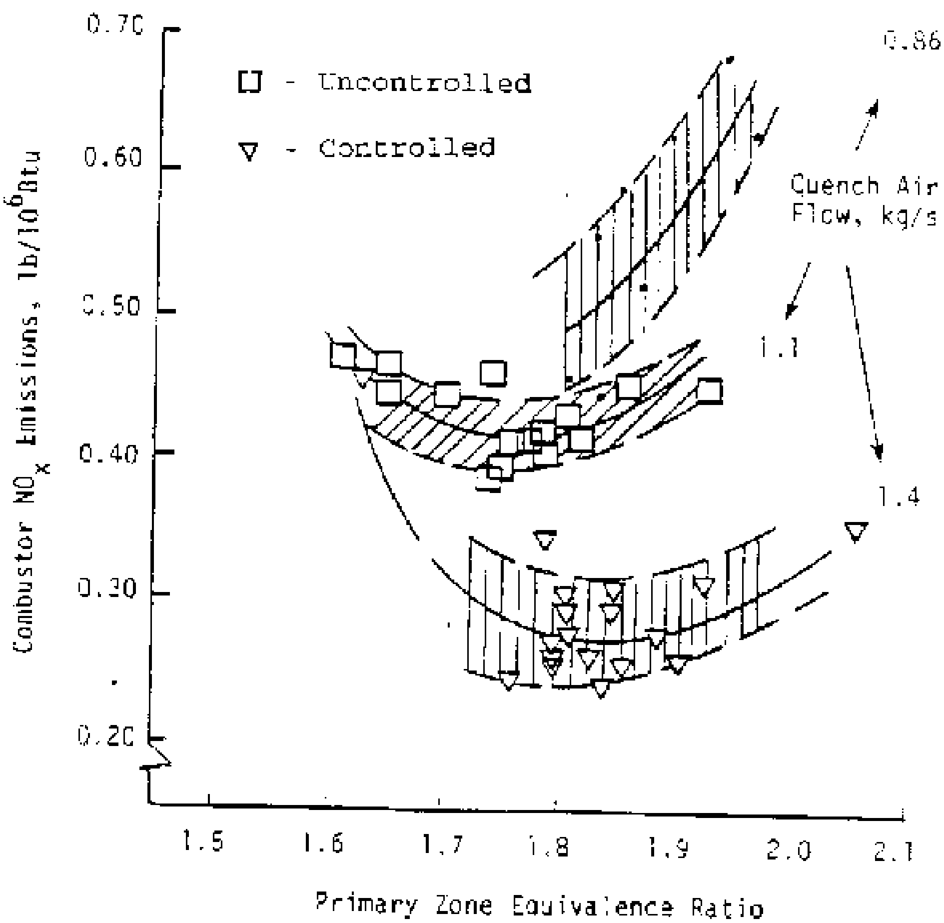


Figure 5-25. Nitrogen oxide emissions versus primary zone equivalence ratio for a rich/quench/lean combustor firing distillate oil.[56]

At an equivalence ratio of 1.8, the NO_x emissions can be reduced from 0.50 to 0.27 lb/MMBtu by increasing the quench airflow from 0.86 to 1.4 kg/sec. Data were not available to convert the NO_x emissions figures to ppmv. The effectiveness of rich/lean staged combustion in reducing fuel NO_x when firing high-FBN fuels is shown in Figure 5-26.

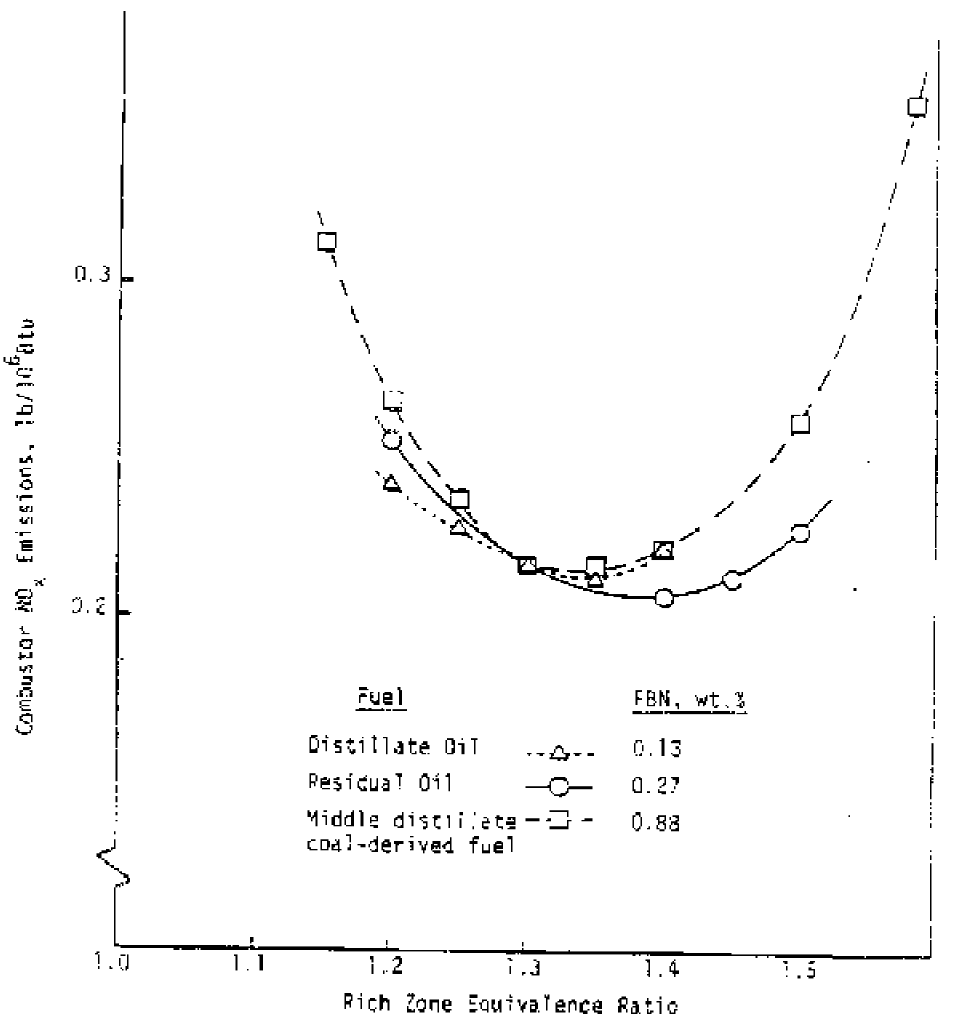


Figure 5-26. Effects of fuel bound nitrogen (FBN) content of NO_x emissions for a rich/quench/lean combustor.[57]

Increasing the FBN content from 0.13 to 0.88 percent has little impact on the total NO_x formation at an operating equivalence ratio of 1.3 to 1.4. Tests on other rich/lean combustors indicate fuel nitrogen conversions to NO_x of about 7 to 20 percent.[58,59] These fuel nitrogen conversions represent a fuel NO_x emission reduction of approximately 50 to 80 percent.

One manufacturer has tested an RQL combustor design in a 4 MW (5,360 hp) gas turbine fueled with a finely ground coal and water mixture. The coal partially combusts in a fuel-rich zone at temperatures of 1650°C (3000°F), with low O_2 levels and an extremely short residence time. The partially combusted products are then rapidly quenched with water, cooling combustion temperatures to inhibit thermal NO_x formation. Additional combustion air is then introduced, and combustion is completed under fuel-lean conditions. In tests at the manufacturer's plant, cosponsored by the U. S. Department of Energy, a NO_x emission level of 25 ppmv at 15 percent O_2 was achieved. This combustor design can also be used with natural gas and oil fuels. Single-digit NO_x emission levels are reported for operation on

natural gas fuel. This combustor design is not yet available for production turbines.[60]

5.3 SELECTIVE CATALYTIC REDUCTION

Selective catalytic reduction (SCR) is an add-on NO_x control technique that is placed in the exhaust stream following the gas turbine. Over 100 gas turbine installations use SCR in the United States.[61] An SCR process description, the applicability of SCR for gas turbines, the factors affecting SCR performance, and the achievable NO_x reduction efficiencies are discussed in this section.

5.3.1 Process Description

The SCR process reduces NO_x emissions by injecting ammonia into the flue gas. The ammonia reacts with NO_x in the presence of a catalyst to form water and nitrogen. In the catalyst unit, the ammonia reacts with NO_x primarily by the following equations:[62]

$$NH_3 + NO + 1/4\ O_2 \rightarrow N_2 + 3/2\ H_2O;\ \text{and}$$

$$NH_3 + 1/2\ NO_2 + 1/4\ O_2 \rightarrow 3/2\ N_2 + 3/2\ H_2O.$$

The catalyst's active surface is usually either a noble metal, base metal (titanium or vanadium) oxide, or a zeolite-based material. Metal-based catalysts are usually applied as a coating over a metal or ceramic substrate. Zeolite catalysts are typically a homogenous material that forms both the active surface and the substrate. The geometric configuration of the catalyst body is designed for maximum surface area and minimum obstruction of the flue gas flow path to maximize conversion efficiency and minimize back-pressure on the gas turbine. The most common catalyst body configuration is a monolith, "honeycomb" design, as shown in Figure 5-27.

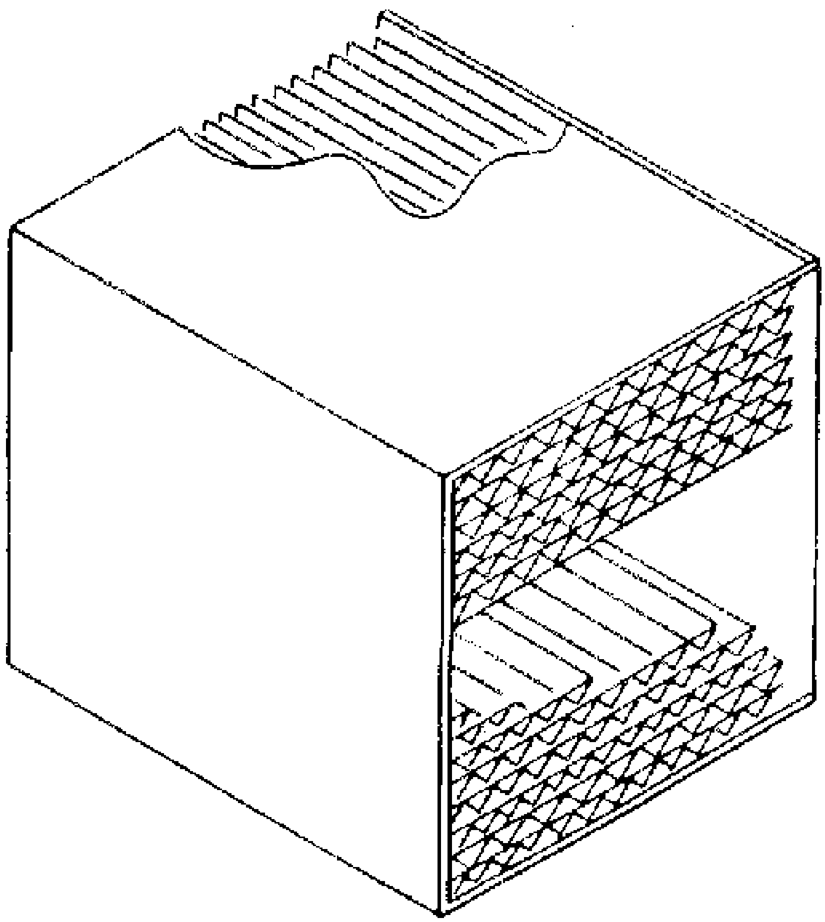


Figure 5-27. Cutaway view of a typical monolith catalyst body with honeycomb configuration.[62]

An ammonia injection grid is located upstream of the catalyst body and is designed to disperse the ammonia uniformly throughout the exhaust flow before it enters the catalyst unit. In a typical ammonia injection system, anhydrous ammonia is drawn from a storage tank and evaporated using a steam- or electric-heated vaporizer. The vapor is mixed with a pressurized carrier gas to provide both sufficient momentum through the injection nozzles and effective mixing of the ammonia with the flue gases. The carrier gas is usually compressed air or steam, and the ammonia concentration in the carrier gas is about 5 percent.[62]

An alternative to using the anhydrous ammonia/carrier gas system is to inject an a aqueous ammonia solution. This system is currently not as common but removes the potential safety hazards associated with transporting and storing anhydrous ammonia and is often used in installations with close proximity to populated areas.[61,62]

The NH_3/NO_x ratio can be varied to achieve the desired level of NO_x reduction. As indicated by the chemical reaction equations listed above, it takes one mole of NH_3 to reduce one mole of NO, and two moles of NH_3 to reduce one mole of NO_2. The NO_x composition in the flue gas from a gas turbine is over 85 percent NO, and SCR systems generally operate with a molar NH_3/NO_x ratio of approximately 1.0.[63] Increasing this ratio will further reduce NO_x emissions but will also result in increased unreacted ammonia passing through the catalyst and into the atmosphere. This unreacted ammonia is known as ammonia slip.

5.3.2 Applicability of SCR for Gas Turbines

Selective catalytic reduction applies to all gas turbine types and is equally effective in reducing both thermal and fuel NO_x emissions. There are, however, factors that may limit the applicability of SCR.

An important factor that affects the performance of SCR is operating temperature. Gas turbines that operate in simple cycle have exhaust gas temperatures ranging from approximately 450° to 540°C (850° to 1000°F). Base-metal catalysts have an operating temperature window for clean fuel applications of approximately 260° to 400°C (400° to 800°F). For sulfur-bearing fuels that produce greater than 1 ppm SO_3 in the flue gas, the catalyst operating temperature range narrows to 315° to 400°C (600° to 800°F). The upper range of this temperature window can be increased using a zeolite catalyst to a maximum of 590°C (1100°F).[64]

Base metal catalysts are most commonly used in gas turbine SCR applications, accounting for approximately 80 percent of all U.S. installations, and operate in cogeneration or combined cycle applications. The catalyst is installed within the HRSG, where the heat recovery process reduces exhaust gas temperatures to the proper operating range for the catalyst. The specific location of the SCR within the HRSG is application-specific; Figure 5-28 shows two possible SCR locations.

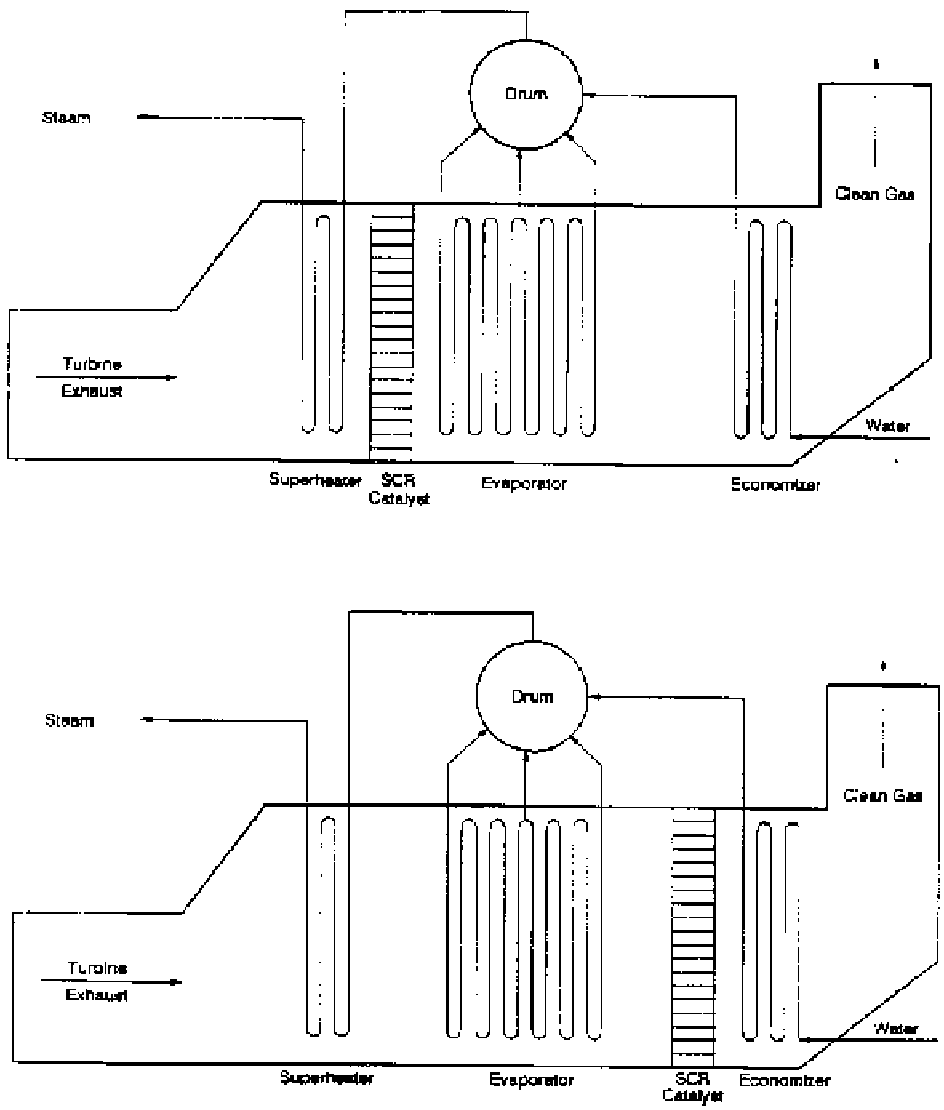


Figure 5-28. Possible locations for SCR unit in HRSG.[62]

In addition to the locations shown, the catalyst may also be located within the evaporator section of the HRSG.

As noted above, zeolite catalysts have a maximum operating temperature range of up to 590°C (1100°F), which is compatible with simple cycle turbine exhaust temperatures. To date, however, there is only one SCR installation operating with a zeolite catalyst directly downstream of the turbine. This catalyst, commissioned in December 1989, has an operating range of 260° to 515°C (500° to 960°F) and operates approximately 90 percent of the time at temperatures above 500°C (930°F).[65]

Another consideration in determining the applicability of SCR is complications arising from sulfur-bearing fuels. The sulfur content in pipeline quality natural gas is negligible, but distillate and residual oils as well as some low-Btu fuel gases such as coal gas have sulfur contents that present problems when used with SCR systems. Combustion of sulfur-bearing fuels produces SO_2 and SO_3 emissions. A portion of the SO_2 oxidizes to SO_3 as it passes through the HRSG, and base metal catalysts have an SO_2-to-SO_3 oxidation rate of up to five percent.[64] In addition, oxidation catalysts, when used to reduce CO emissions, will also oxidize SO_2 to SO_3 at rates of up to 50 percent.[66]

Unreacted ammonia passing through the catalyst reacts with SO_3 to form ammonium bisulfate (NH_4HSO_4) and ammonium sulfate [$(NH_4)_2 SO_4$] in the low-temperature section of the HRSG. The rate of ammonium salt formation increases with increasing levels of SO_3 and NH_3, and the formation rate increases with decreasing temperature. Below 200°C (400°F), ammonium salt formation occurs with single-digit ppmv levels of SO_3 and NH_3.[66]

The exhaust temperature exiting the HRSG is typically in the range of 150° to 175°C (300° to 350°F), so ammonium salt formation typically occurs in the low-temperature section of the HRSG.[66] Ammonium bisulfate is a sticky substance that over time corrodes the HRSG boiler tubes. Additionally, it deposits on both the boiler and catalyst bed surfaces, leading to fouling and plugging of these surfaces. These deposits result in increased back pressure on the turbine and reduced heat transfer efficiency in the HRSG. This requires that the HRSG be removed from service periodically to water-wash the affected surfaces. Ammonium sulfate is not corrosive, but like ammonium bisulfate, it deposits on the HRSG surfaces and contributes to plugging and fouling of the heat transfer system.[33]

Formation of ammonium salts can be avoided by limiting the sulfur content of the fuel and/or limiting the ammonia slip. Low SO_2-to-SO_3 oxidizing catalysts are also available. Base metal catalysts are available with oxidation rates of less than 1 percent, but these low oxidation formulas also have lower NO_x reduction activity per unit volume and therefore require a greater catalyst volume to achieve a given NO_x reduction level. Zeolite catalysts are reported to have intrinsic SO_2-to-SO_3 oxidation rates of less than 1 percent.[64,66] As stated above, pipeline-quality natural gas has negligible sulfur content, but some sources of natural gas contain H_2S, which may contribute to ammonium salt formation. For oil fuels, even the lowest-sulfur distillate oil or liquid aviation fuel contains sulfur levels that can produce ammonium salts. According to catalyst vendors, SCR systems can be designed for 90 percent NO_x reduction and 10 ppm or lower NH_3 slip for sulfur-bearing fuels up to 0.3 percent by weight.[64] Continuous emission monitoring equipment has been developed for NH_3, and may be instrumental in regulating ammonia injection to minimize slip.[67]

To date, there is limited operating experience using SCR with oil-fired gas turbine installations. One combined cycle installation using oil fuel, a United Airlines facility in San Francisco installed in 1985, experienced fuel-related catalyst problems and now uses only natural gas fuel.[33] In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available, however, and catalyst formulation improvements have proven effective in resisting performance degradation with oil fuels in Europe and Japan, where catalyst life in excess of 4 to 6 years has been achieved, versus 8 to 10 years with natural gas fuel.[64] A zeolite catalyst installed on a 5 MW (6710 hp) dual fuel reciprocating engine in the northeastern United States has operated for over 3 years and burned approximately 600,000 gallons of diesel fuel while maintaining a NO_x reduction efficiency of greater than 90 percent.[3]

In its guidance to member states, NESCAUM recommends that SCR be considered for NO_x reduction in dual-fueled turbine applications. There are four combined cycle gas turbines installations operating with SCR in the northeast United States burning natural gas as the primary fuel with oil fuel as a back-up.[3] These installations, listed in Table 5-16,

TABLE 5-16. GAS TURBINE INSTALLATIONS IN THE NORTHEASTERN UNITED STATES WITH SCR AND PERMITTED FOR BOTH NATURAL GAS AND OIL FUELS[3]

Installation	State	Gas turbine model	Output, MW[a]	NO_x emissions, ppmv (gas fuel/oil fuel)		
				Uncontrolled[b]	Wet injection[b]	Wet injection + SCR[c]
Altresco-Pittsfield	MA	MS6001	38.3	148/267	42/65	9/18[d e]
Cogen Technologies	NJ	MS6001	38.3	148/267	42/65	15/65[f]
Ocean State Power	RI	MS7001E	83.5	154/277	42/65	9/42[f]
Pawtucket Power	RI	MS6001	38.3	148/267	42/65	9/18[d]

[a]Power output for a single gas turbine. Installation power output is higher due to multiple units and/or combined cycle operation.

[b]Per manufacturer at ISO conditions.

[c]Operating permit limits.

[d]This installation requires the SCR system to be operational when burning oil fuel.

[e]This installation operated 185 hours on oil fuel in 1991, burning approximately 354,000 gallons of oil fuel.

[f]Ammonia injection is shut down during operation on oil fuel.

began operating recently and have limited hours of operation on oil fuel. As indicated in the table, two of these installations shut down the ammonia injection when operating on oil fuel to prevent potential operating problems arising from sulfur-bearing fuels. Permits issued more recently in this region for other dual-fuel installations, however, require that the SCR system be operational on either fuel.[3]

A final consideration for SCR is catalyst masking or poisoning agents. Natural gas is considered clean and free of contaminants, but other fuels may contain agents that can degrade catalyst performance. For refinery, field, or digester gas fuel applications, it is important to have an analysis of the fuel and properly design the catalyst for any identified contaminants. Arsenic, iron, and silica may be present in field gases, along with zinc and phosphorus. Catalyst life with these fuels depends upon the content of the gas and is a function of the initial design parameters. With oil fuels, in addition to the potential for ammonium salt formation, it is important to be aware of heavy metal content. Particulates in the flue gas can also mask the catalyst.[64]

Selective catalytic reduction may not be readily applicable to gas turbines firing fuels that produce high ash loadings or high levels of contaminants because these elements can lead to fouling and poisoning of the catalyst bed. However, because gas turbines are also subject to damage from these elements, fuels with high levels of ash or contaminants typically are not used.

Coal, while not currently a common fuel for turbines, has a number of potential catalyst deactivators. High dust concentrations, alkali, earth metals, alkaline heavy metals, calcium sulfate, and chlorides all can produce a masking or blinding effect on the catalyst. High dust can also erode the catalyst. Erosion commonly occurs only on the leading face of the catalyst. Airflow deflectors and dummy layers of catalyst can be used to straighten out the airflow and reduce erosion. There is currently no commercial U.S. experience with coal. In Japan, which burns low-sulfur coal with moderate dust levels, catalyst life has been 5 years or more without replacement. In Germany, with high dust loadings, the experience has also been 5 years or more.[64]

Masking agents deposit on the surface of the catalyst, forming a barrier between the active catalyst surface and the exhaust gas, inhibiting catalytic activity. Poisoning agents chemically react with the catalyst and render the affected area inactive. Masking agents can be removed by vacuuming or by using soot blowers or superheated steam. Catalysts cleaned in this manner can recover greater than 90 percent of the original reduction activity. The effects of poisoning agents, however, are permanent and the affected catalyst surface cannot be regenerated.[64]

Retrofit applications for SCR may require the addition of a heat exchanger for simple cycle installations, and replacement or extensive modification of the existing HRSG in cogeneration and combined cycle applications to accommodate the catalyst body. For these reasons, retrofit applications for SCR could involve high capital costs.

5.3.3 Factors Affecting SCR Performance

The NO_x reduction efficiency for an SCR system is influenced by catalyst material and condition, reactor temperature, space velocity, and the NH_3/NO_x ratio.[63] These design and operating variables are discussed below.

Several catalyst materials are available, and each has an optimum NO_x removal efficiency range corresponding to a specific temperature range. Proprietary formulations containing titanium dioxide, vanadium pentoxide, platinum, or zeolite are available to meet a wide spectrum of operating temperatures. The NO_x removal efficiencies for these catalysts are typically between 80 and 90 percent when new. The NO_x removal efficiency gradually decreases over the operating life of the catalyst due to deterioration from masking, poisoning, or sintering.[63] The rate of catalyst performance degradation depends upon operating conditions and is therefore site-specific.

The space velocity (volumetric flue gas flow divided by the catalyst volume) is an indicator of gas residence time in the catalyst unit. The lower the space velocity, the higher the residence time, and the higher the potential for increased NO_x reduction. Because the gas flow is a constant determined by the gas turbine, the space velocity depends upon the catalyst volume, or total active surface area. The distance across the opening between plates or cells in the catalyst, referred to as the pitch, affects the overall size of the catalyst body. The smaller the pitch, the greater the number of rows or cells that can be placed in a given volume. Therefore, for a given catalyst body size, the smaller the pitch, the larger the catalyst volume and the lower the space velocity. For natural gas applications the catalyst pitch is typically 2.5 millimeters (mm) (0.10 inch [in.]), increasing to 5 to 7 mm (0.20 to 0.28 in.) for coal-fuel applications.[64]

As discussed in Section 5.3.1, the NH_3/NO_x ratio can be varied to achieve the desired level of NO_x reduction. Increasing this ratio increases the level of NO_x reduction but may also result in higher ammonia slip levels.

5.3.4 Achievable NO_x Emission Reduction Efficiency Using SCR

Most SCR systems operating in the United States have a space velocity of about 30,000/hr, a NH_3/NO_x ratio of about 1.0, and ammonia slip levels of approximately 10 ppm. The resulting NO_x reduction efficiency is about 90 percent.[41] Reduction efficiency is the level of NO_x removed as a percentage of the level of NO_x entering the SCR unit. Only one gas turbine installation in the United States was identified using only SCR to reduce NO_x emissions. This installation has two natural gas-fired 8.5 MW gas turbines, each with its own HRSG in which is installed an SCR system. A summary of emission testing at this site lists NO_x emissions at the inlet to the SCR catalyst at 130 ppmv. Controlled NO_x emissions downstream of the catalyst were 18 ppmv, indicating a NO_x reduction efficiency of 86 percent. Maximum ammonia slip levels were listed at 35 ppmv.[68]

All other gas turbine installations identified as using SCR in the United States use this control method in combination with wet injection and/or low-NO_x combustors. The emission levels that can be achieved by this combination of controls are found in Section 5.4.

5.3.5 Disposal Considerations for SCR

The SCR catalyst material has a finite life, and disposal can pose a problem. The guaranteed catalyst life offered by catalyst suppliers ranges from 2 to 3 years.[64] In Japan, where SCR systems have been in operation since 1980, experience shows that many catalysts in operation with natural gas-fired boilers have performed well for 7 years or longer.[63,64] In any case, at some point the catalyst must be replaced, and those units containing heavy metal oxides such as vanadium or titanium potentially could be considered hazardous wastes. While the amount of hazardous material in the catalyst is relatively small, the volume of the catalyst body can be quite large, and disposal of this waste could be costly. Some suppliers provide for the removal and disposal of spent catalyst. Precious metal and zeolite catalysts do not contain hazardous wastes.

5.4 CONTROLS USED IN COMBINATION WITH SCR

With but one exception, SCR units installed in the United States are used in combination with wet controls or combustion controls described in Sections 5.1 and 5.2. Wet controls yield NO_x emission levels of 25 to 42 ppmv for natural gas and 42 to 110 ppmv for distillate oil, based on the data provided by gas turbine manufacturers and shown in Figures 5-10 and 5-11. A carefully designed SCR system can achieve NO_x reduction efficiencies as high as 90 percent, with ammonia slip levels of 10 ppmv or less for natural gas and low-sulfur (<0.3 percent by weight) fuel applications.[64]

As discussed for wet injection in Sections 5.1.4 and 5.2.2.4, controlled NO_x emission levels for natural gas range from 25 to 42 ppmv for natural gas fuel and from 42 to 110 ppmv for oil fuel. Applying a 90 percent reduction efficiency for SCR, NO_x levels can be theoretically reduced to 2.5 to 4.2 and 4.2 to 11.0 ppmv for natural gas and oil fuels, respectively. For oil fuels and other sulfur-bearing fuels, a reduction efficiency of 90 percent requires special design considerations to address potential operational problems caused by the sulfur content in the fuel. This subject is discussed in Section 5.3.2. The final controlled NO_x emission level depends upon the NO_x level exiting the turbine and the achievable SCR reduction efficiency.

Test reports provided by SCAQMD include three gas turbine combined cycle installations fired with natural gas that have achieved NO_x emission levels of 3.4 to 7.2 ppmv, referenced to 15 percent oxygen. The NO_x and CO emissions reported for these tests are shown in Table 5-17

TABLE 5-17. EMISSIONS TESTS RESULTS FOR GAS TURBINES USING STEAM INJECTION PLUS SCR[69-71]

				NO_x emissions, ppmv (lb/hr)			
Test No.	Gas turbine model	Output, MW	Fuel	Uncontrolled	Wet injection	Wet injection + SCR	CO, ppmv
1	MS7001E	82.8	Natural gas + refinery gas mixture	154	42	5.66 (25.2)	<2.00
2	MS7001E	79.7	Natural gas + refinery gas + butane mixture	148	42	7.17 (31.7)	<2.00
3	MS6001B	33.8	LPG + refinery gas mixture	148	42	3.36 (5.82)	<2.00

TABLE 5-18. SUMMARY OF SCR NO_x EMISSION REDUCTIONS AND AMMONIA SLIP LEVELS FOR NATURAL GAS-FIRED TURBINES[68]

Ammonia slip levels were not reported. Ammonia slip levels

Site	Gas turbine		Power output, MW	SCR operating temperature, °F	Maximum permit level for injection, NH_3/NO_x molar ratio	NO_x emissions, ppmv at 15% O_2			Compliance test NH_3 slip, ppmv at 15% O_2 [a]
	Manufacturer	Model				SCR in	SCR out	Percent reduction	
A	GE	LM2500	22	730	1.0	50	9.0	82	10
B	GE	MS5001	18	645	1.0	45	4.5	90	2
C	GE	LM2500	22	685	1.1	37	8.9	76	20
D	ABB	Type 8	44	760	1.2	27	4	85	9
E	GE	LM2500	22	680	1.0	60	12.6	79	7
F	GE	MS7001E	80	630	1.0	28	8.4	70	4.1
G	GE	LM2500	22	625	0.9	68	13.6	80	1
H	Allison	501-KB	3.5	650	1.1	25	1.0	96	10
I	Solar	Mars	8.5	580	1.6	130	18.2	86	35
J	GE	LM2500	22	750	1.0	37	14.8	60	11
K	GE	MS7001E	80	754	1.0	40	6.0	85	2
L	GE	MS6001	37	650	1.0	47	8.9	81	4
M	GE	MS6001	37	700	NA	33	3.3	90	8

[a]Calculated from ppmv entering the SCR and percent reduction figures.
[b]NH_3 permit limit. Test emission level not available.
[c]Test was run at less than permit NH_3/NO_x ratio of 1.1. SCR designed for exhaust from total of 5 turbines. Only one turbine operating during test.
[d]This site does not use wet injection for gas turbine NO_x reduction.
[e]NH_3 compliance test not required. NH_3 level from NH_3 monitor testing.

were reported, however, in a summary of emission tests for 13 SCR installations and are presented in Table 5-18.[68] For these sites, operating on natural gas fuel, the NO_x reduction efficiency of the catalyst ranges

from 60 to 96 percent, with most reduction efficiencies between 80 and 90 percent. Ammonia slip levels range from 1 to 35 ppmv. The site with the 35 ppmv ammonia slip level is unique in that it is the only site identified in the United States that uses only SCR rather than a combination of SCR and wet injection to reduce NO_x emissions. With the exception of this site, all NH_3 slip levels in Table 5-18 that are based on test data are less than 10 ppmv. Based on information received from catalyst vendors, it is expected that an SCR system operating downstream of a gas turbine without wet injection could be designed to limit ammonia slip levels to 10 ppmv or less.[64] No test data are available for SCR operation on gas turbines fired with distillate oil fuels.

5.5 EFFECT OF ADDING A DUCT BURNER IN HRSG APPLICATIONS

A duct burner is often added in cogeneration and combined cycle applications to increase the steam capacity of the HRSG (see Section 4.2.2). Duct burners in gas turbine exhaust streams consist of pipes or small burners that are placed in the exhaust gas stream to allow firing of additional fuel, usually natural gas. Duct burners can raise gas turbine exhaust temperatures to 1000°C (2000°F), but a more common temperature is 760°C (1400°F). The gas turbine exhaust is the source of oxygen for the duct burner.

Figure 5-29 shows a typical natural gas-fired duct burner

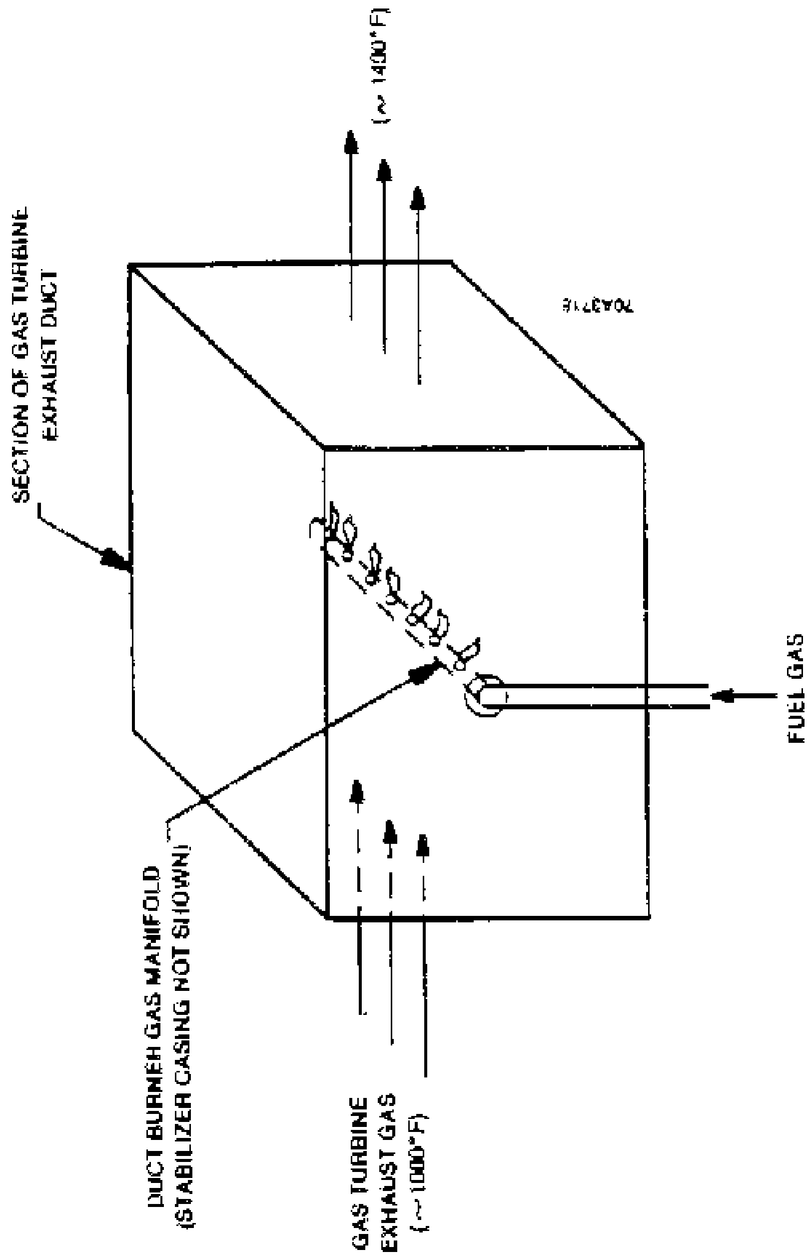


Figure 5-29. Typical duct burner for gas turbine exhaust application.[72]

installation. Figure 5-30 is a cross-sectional view of one style

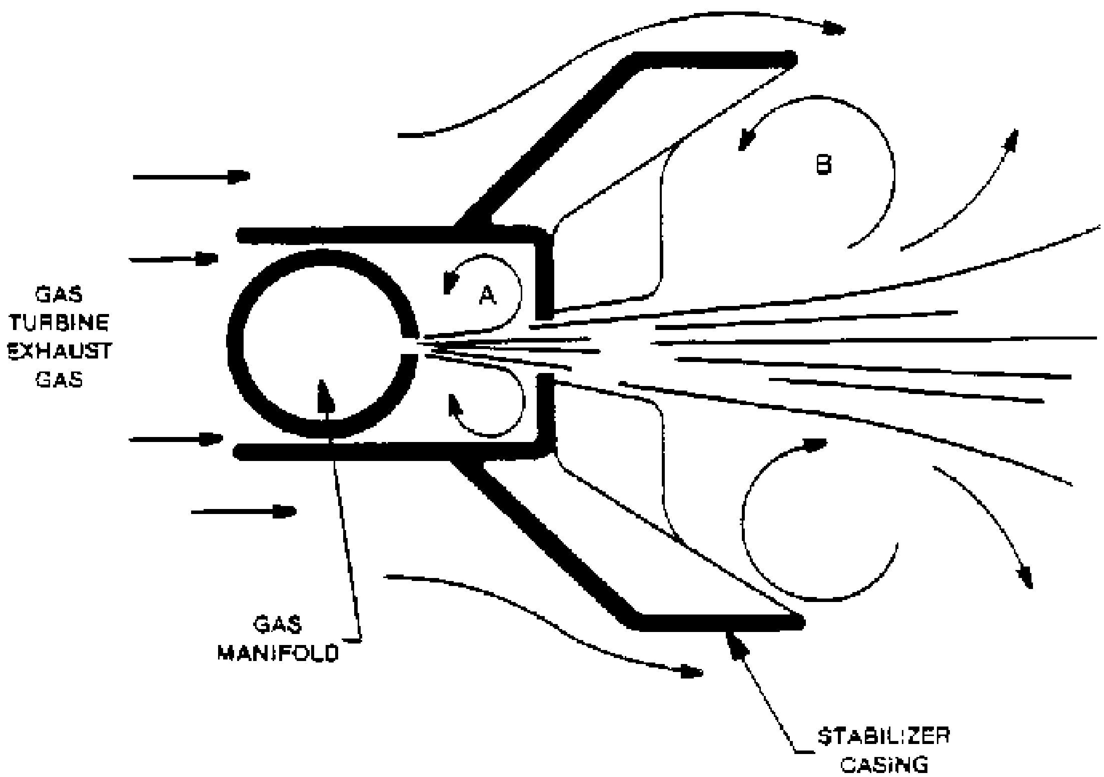


Figure 5-30. Cross-sectional view of a low-NO_x duct burner.[73,74]

of duct burner that incorporates design features to reduce NO_x. In this low-NO_x design, natural gas exits the orifice in the manifold and mixes with the gas turbine exhaust entering through a small slot between the casing and the gas manifold. This mixture forms a jet diffusion flame that causes the recirculation shown in Zone "A." Due to the limited amount of turbine exhaust that can enter Zone A, combustion in this zone is fuel-rich. As the burning gas jet exits into Zone "B," it mixes with combustion products that are recirculated by the flow eddies behind the wings of the stabilizer casing. The flame then expands into the turbine exhaust gas stream, where combustion is completed.

For oil-fired burners, the design principles of the burner are the same. However, the physical layout is slightly different, as shown in

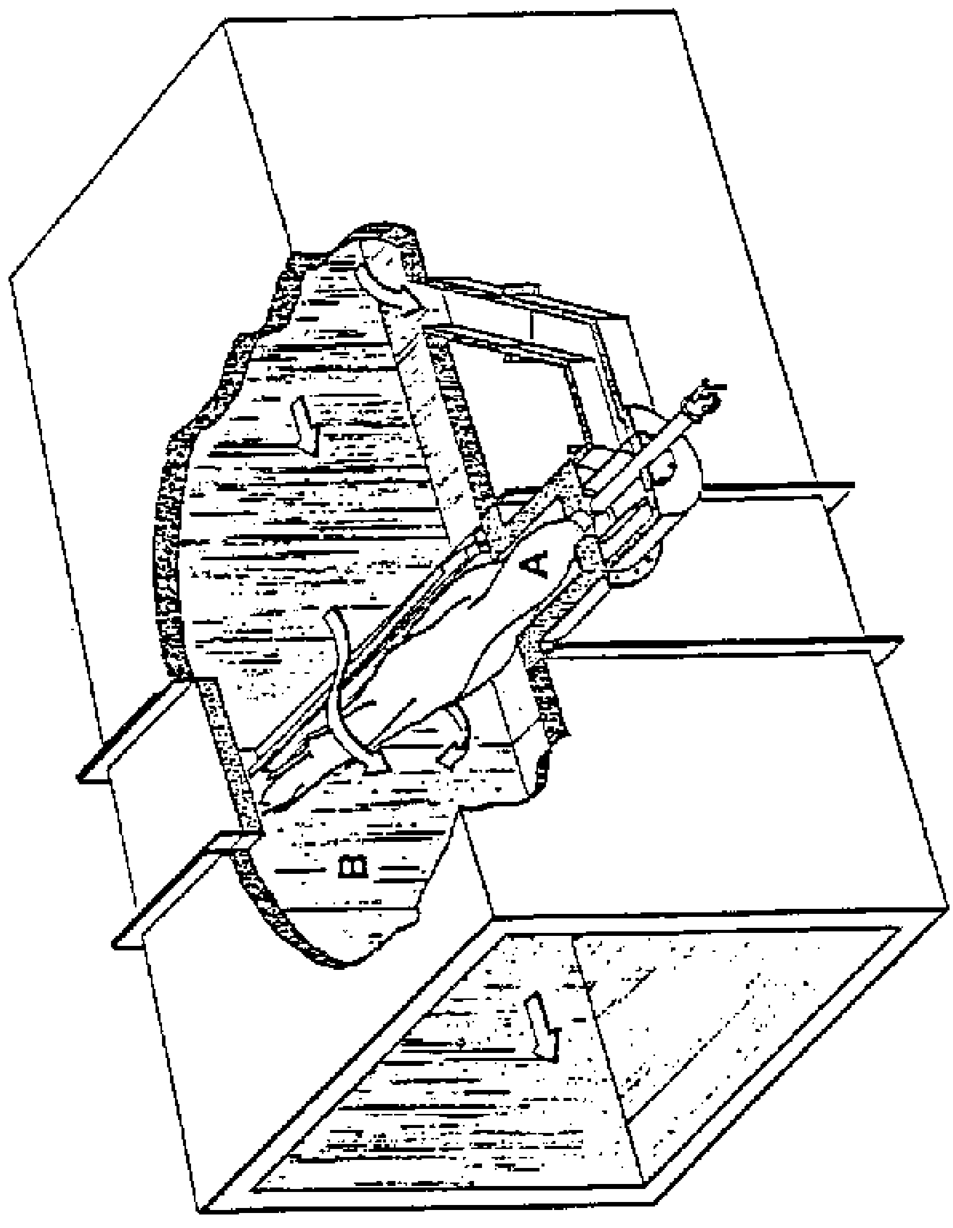


Figure 5-31. Low-NO_x duct burner designed for oil firing.[73,75]

Figure 5-31. Turbine exhaust gas is supplied in substoichiometric quantities by a slip stream duct to the burner. This slip stream supplies the combustion air for the fuel-rich Zone A. The flame shield produces the flow eddies, which recirculate the combustion products into Zone B.[76]

Most duct burners now in service fire natural gas. In all cases, a duct burner will produce a relatively small level of NO_x emissions during operation (See Section 4.2.2), but the net impact on total exhaust emissions (i.e., the gas turbine plus the duct burner) varies with operating conditions, and in some cases may even reduce the overall NO_x emissions. Table 5-19 shows the NO_x emissions measured at one site upstream and downstream of a duct burner. This table shows that NO_x emissions are reduced across the duct burner in five of the eight test runs.

TABLE 5-19. NO_x EMISSIONS MEASURED BEFORE AND AFTER A DUCT BURNER[77]

Gas turbine operation parameters			Duct burner operating parameters		Duct burner inlet		Duct burner outlet		Change across duct burner	
Test No.	Load, MW	Steam/fuel injection ratio, lb/lb	Heat input, MM Btu/hr	Load, percent	NO_x, lb/MM Btu	NO_x, lb/hr	NO_x, lb/MM Btu	NO_x, lb/hr	NO_x, lb/MM Btu	NO_x, lb/hr
1	33.8	0.94	133.8	82.1	0.149	61.4	0.097	55.7	-0.043	-5.7
2	35.0	0.97	93.3	57.3	0.142	58.8	0.113	58.9	0.001	0.1
3	34.5	0.95	40.8	25.0	0.134	57.5	0.118	58.7	0.029	1.2
4	32.0	0.50	137.5	84.4	0.207	85.8	0.151	83.9	-0.014	-1.9
5	32.8	0.46	43.8	26.8	0.228	95.2	0.192	94.0	-0.027	-1.2
6	31.5	0.00	136.7	83.9	0.392	159.7	0.270	156.2	-0.026	-3.5
7	33.0	0.00	42.0	25.8	0.384	166.7	0.313	156.7	-0.238	-10.0
8	11.1	0.00	140.9	86.5	0.157	29.1	0.132	42.1	0.092	13.0

The reason for this net NO_x reduction is not known, but it is believed to be a result of the reburning process in which the intermediate combustion products from the duct burner interact with the NO_x already present in the gas turbine exhaust. The manufacturer of the burner whose emission test results are shown in Table 5-19 states that the following conditions are necessary for reburning to occur:

1. The burner flame must produce a high temperature in a fuel-rich zone;

2. A portion of the turbine exhaust containing NO_x must be introduced into the localized fuel-rich zone with a residence time sufficient for the reburning process to convert the turbine NO_x to N_2 and O_2; and

3. The burner fuel should contain no FBN.[78]

In general, sites using a high degree of supplementary firing have the highest potential for a significant amount of reburning. In practice, only a limited number of sites achieve these reburning conditions due to specific plant operating requirements.[78]

5.6 ALTERNATE FUELS

Because thermal NO_x production is an exponential function of flame temperature (see Section 4.1.1), it follows that using fuels with flame temperatures lower than those of natural gas or distillate oils results in lower thermal NO_x emissions. Coal-derived gas and methanol have demonstrated lower NO_x emissions than more conventional natural gas or oil fuels. For applications using fuels with high FBN contents, switching to a fuel with a lower FBN content will reduce thermal NO_x formation and thereby lower total NO_x emissions.

5.6.1 Coal-Derived Gas

Combustor rig tests have demonstrated that burning coal-derived gas (coal gas) that has been treated to remove FBN produces approximately 30 percent of the NO_x emission levels experienced when burning natural gas. This is because coal gas has a low heat energy level of around 300 Btu or less, which results in a flame temperature lower than that of natural gas.[79] The cost associated with producing coal gas suitable for combustion in a gas turbine has made this alternative economically unattractive, but recent advances in coal gasification technology have renewed interest in this fuel.

A coal gas-fueled power plant is currently operating in the United States at a Dow Chemical plant in Placquemine, Louisiana. This facility operates with a subsidy from the Federal Government, which compensates for the price difference between coal gas and conventional fuels. Several commercial projects have been recently announced using technology developed by Texaco, Shell, Dow Chemical, and the U.S. Department of Energy. Facilities have been permitted for construction in Massachusetts and Delaware.[80]

A demonstration facility, known as Cool Water, operated using coal gas for 5 years in Southern California in the early 1980's. The NO_x emissions were reported at 0.07 lb/MMBtu.[80] Fuel analysis data is not available to convert this NO_x emission level to a ppmv figure. No other emissions data are available.

5.6.2 Methanol

Methanol has a flame temperature of 1925°C (3500°F) versus 2015°C (3660°F) for natural gas and greater than 2100°C (3800°F) for distillate oils. As a result, the NO_x emission levels when burning methanol are lower than those for either natural gas or distillate oils.

Table 5-20 presents NO_x emission data for a full-scale turbine firing methanol.

TABLE 5-20. NO_x EMISSIONS TEST DATA FOR A GAS TURBINE FIRING METHANOL AT BASELOAD[a,81]

Test	W/F ratio, lb/lb	NO_x emissions ISO conditions, ppm at 15% O_2	NO_x reduction, percent[b]
A	0	41	0
B	0	45	0
C	0	48	0
D	0	49	0
E	0	60	0
F	0	47	0
G	0	53	0
H	0	48	0
I	0	51	0
J	0	52	0
K	0	41	0
L	0	47	0
M	0	48	0
AVERAGE		49	
N	0.11	28	42.2
O	0.23	17	65.2
P	0.23	18	62.7
Q	0.24	18	62.7

[a]Baseload = 25 MW output
[b]Calculated using the average of the uncontrolled emissions.

The NO_x emissions from firing methanol without water injection ranged from 41 to 60 ppmv and averaged 49 ppmv. This test also indicated that methanol increases turbine output due to the higher mass flows that result from methanol firing. Methanol firing increased CO and HC emissions slightly compared to the same turbine's firing distillate oil with water injection. All other aspects of turbine performance were as good when firing methanol as when the turbine fired natural gas or distillate oil.[82] Turbine maintenance requirements were estimated to be lower and turbine life was estimated to be longer on methanol fuel than on distillate oil fuel because methanol produced fewer deposits in the combustor and power turbine.

Table 5-20 also presents NO_x emission data for methanol firing with water injection. At water-to-fuel ratios from 0.11 to 0.24, NO_x emissions when firing methanol range from 17 to 28 ppmv, a reduction of 42 to 65 percent.

In a study conducted at an existing 3.2 MW gas turbine installation in 1984, a gas turbine was modified to burn methanol. This study was conducted at the University of California at Davis and was sponsored by the California Energy Commission. A new fuel delivery system for methanol was required, but the only major modifications required for the turbine used in this study were new fuel manifolds and nozzles. Tests conducted burning methanol showed no visible smoke emissions, and only minor increases in CO emissions. Figure 5-32 shows the NO_x emissions measured while burning

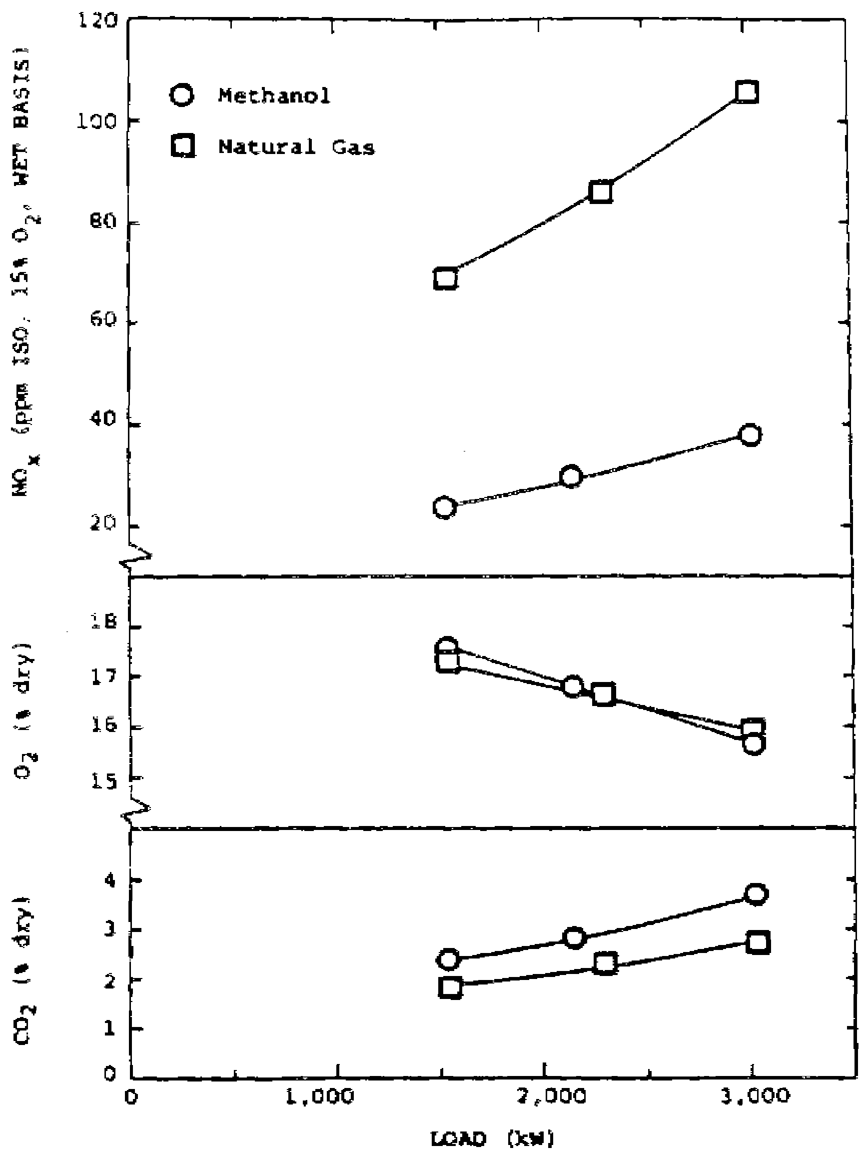


Figure 5-32. Influence of load on NO_x, and CO_2 emissions for methanol and natural gas.[83]

methanol and natural gas. Reductions of up to 65 percent were achieved, as NO_x emissions were 22 to 38 ppm when burning methanol versus

62 to 100 ppm for natural gas. In addition to the intrinsically lower NO_x production, water can be readily mixed with methanol prior to delivery to the turbine to obtain the additional NO_x reduction levels achievable with wet injection. Gas turbine performance characteristics, including startup, acceleration, load changes, and full load power, were all deemed acceptable by the turbine manufacturer.[83]

The current economics of using methanol as a primary fuel are not attractive. There are no confirmed commercial methanol-fueled gas turbine installations in the United States.

5.7 SELECTIVE NONCATALYTIC REDUCTION

Selective noncatalytic reduction (SNCR) is an add-on technology that reduces NO_x using ammonia or urea injection similar to SCR but operates at a higher temperature. At this higher operating temperature of 870° to 1200°C (1600° to 2200°F), the following reaction occurs:[84]

$$NO_x + NH_3 + O_2 + H_2O + (H_2) \rightarrow N_2 + H_2O.$$

This reaction occurs without requiring a catalyst, effectively reducing NO_x to nitrogen and water. The operating temperature can be lowered from 870°C (1600°F) to 700°C (1300°F) by injecting hydrogen (H_2) with the ammonia, as is shown in the above equation.

Above the upper temperature limit, the following reaction occurs:[84]

$$NH_3 + O_2 \rightarrow NO_x + H_2O.$$

Levels of NO_x emissions increase when injecting ammonia or urea into the flue gas at temperatures above the upper temperature limits of 1200°C (2200°F).

Since SNCR does not require a catalyst, this process is more attractive than SCR from an economic standpoint. The operating temperature window, however, is not compatible with gas turbine exhaust temperatures, which do not exceed 600°C (1100°F). Additionally, the residence time required for the reaction is approximately 100 milliseconds, which is relatively slow for gas turbine operating flow velocities.[85]

It may be feasible, however, to initiate this reaction in the gas turbine where operating temperatures fall within the reaction window, if suitable gas turbine modifications and injection systems can be developed.[85] This control technology has not been applied to gas turbines to date.

5.8 CATALYTIC COMBUSTION

5.8.1 Process Description

In a catalytic combustor, fuel and air are premixed into a fuel-lean mixture (fuel/air ratio of approximately 0.02) and then pass into a catalyst bed. In the bed, the mixture oxidizes without forming a high-temperature flame front. Peak combustion temperatures can be limited to below 1540°C (2800°F), which is below the temperature at which significant amounts of thermal NO_x begin to form.[86] An example of a lean catalytic combustor is shown in Figure 5-33.

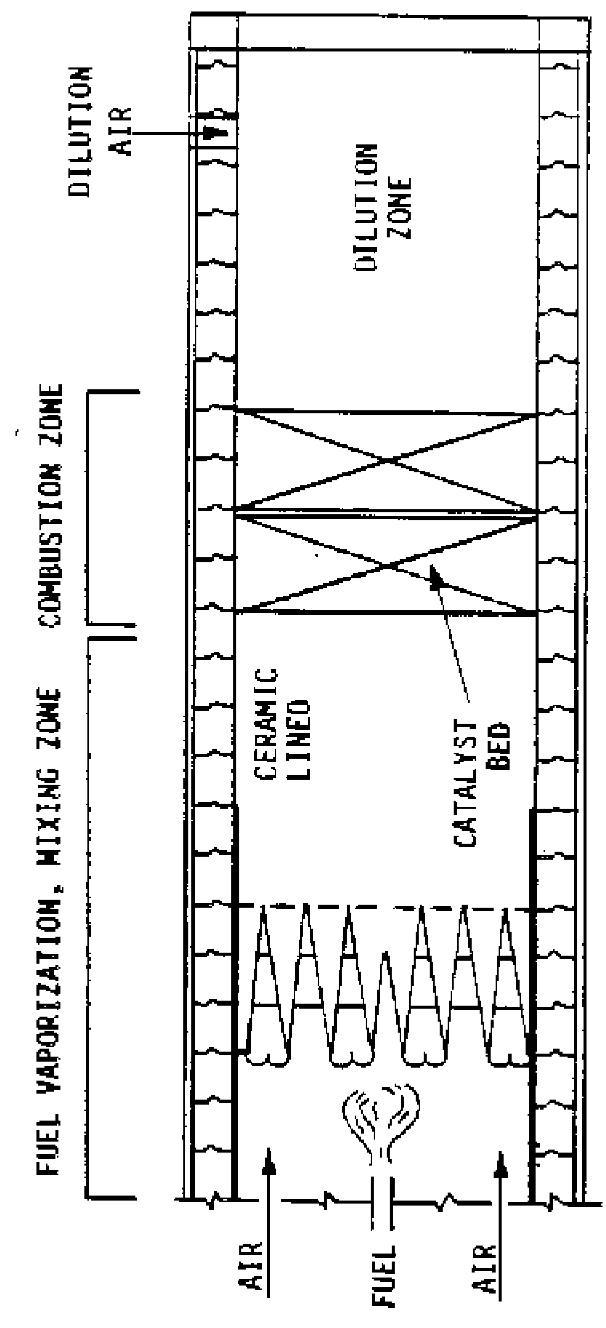


Figure 5-33. A lean catalytic combustor.87

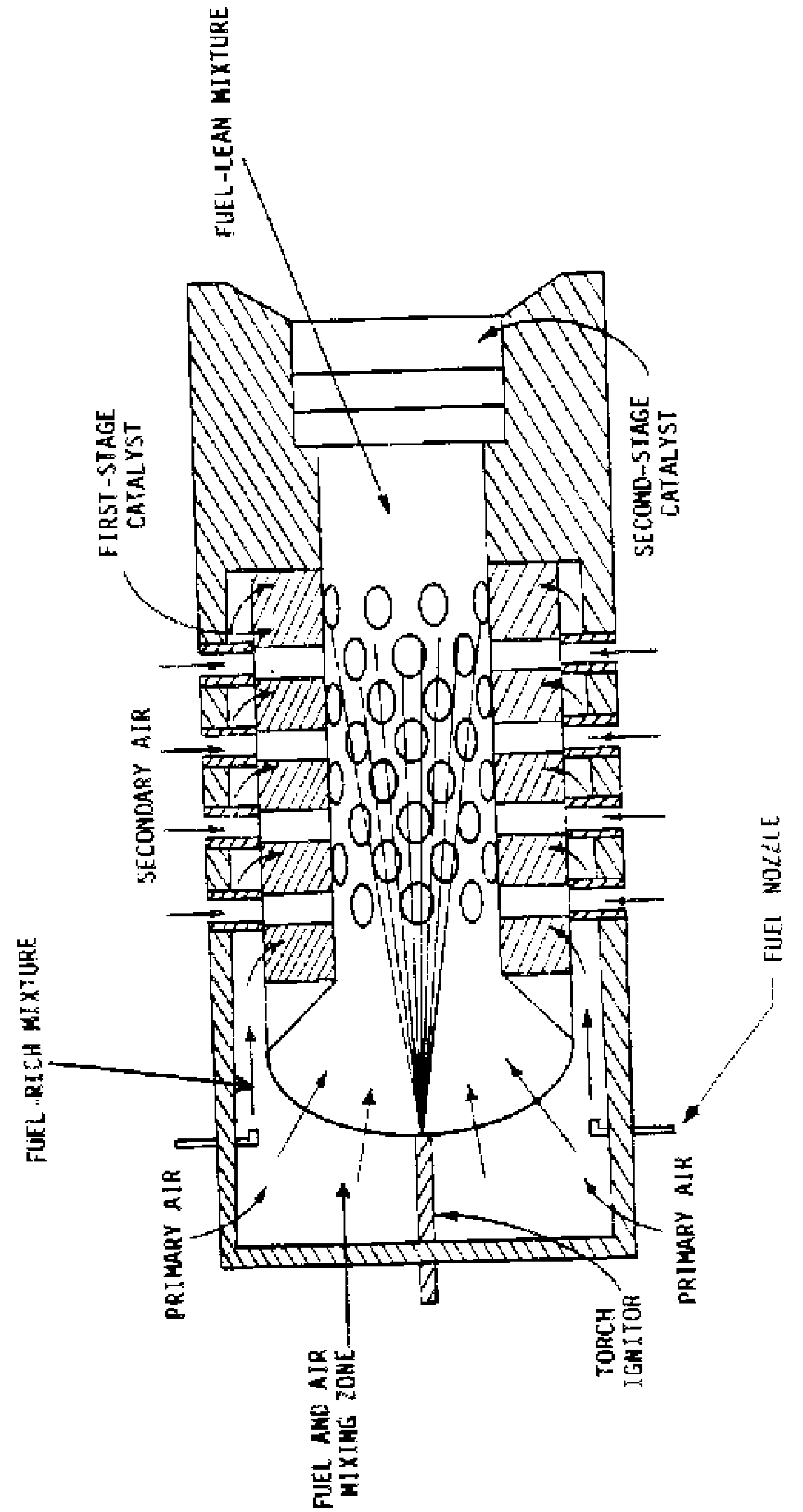


Figure 5-34. A rich/lean catalytic combustor.[89]

Catalytic combustors can also be designed to operate in a rich/lean configuration, as shown in Figure 5-34. In this configuration, the air and fuel are premixed to form a fuel-rich mixture, which passes through a first stage catalyst where combustion begins. Secondary air is then added to produce a lean mixture, and combustion is completed in a second stage catalyst bed.[89]

5.8.2 Applicability

Catalytic combustion techniques apply to all combustor types and are effective on both distillate oil- and natural gas-fired turbines. Because of the limited operating temperature range, catalytic combustors may not be easily applied to gas turbines subject to rapid load changes (such as utility peaking turbines).[90] Gas turbines that operate continuously at base load (such as industrial cogeneration applications) would not be as adversely affected by any limits on load following capability.[91]

5.8.3 Development Status

Presently, the development of catalytic combustors has been limited to bench-scale tests of prototype combustors. The major problem is the development of a catalyst that will have an acceptable life in the high-temperature and -pressure environment

of gas turbine combustors. Additional problems that must be solved are combustor ignition and how to design the catalyst to operate over the full gas turbine operating range (idle to full load).[92]

5.9 OFFSHORE OIL PLATFORM APPLICATIONS

Gas turbines are used on offshore platforms to meet compression and electrical power requirements. This application presents unique challenges for NO_x emissions control due to the duty cycle, lack of a potable water source for wet injection, and limited space and weight considerations. The duty cycle for electric power applications of offshore platforms is unique. This duty cycle is subject to frequent load changes that can instantaneously increase or decrease by as much as a factor of 10.[93] Fluctuating loads result in substantial swings in turbine exhaust gas temperatures and flow rates. This presents a problem for SCR applications because the NO_x reduction efficiency depends upon temperature and space velocity (see Section 5.3.3).

The lack of a potable water supply means that water must be shipped to the platform or sea water must be desalinated and treated. The limited space and weight requirements associated with an SCR system may also have an impact on capital costs of the platform.

A 4-year study is underway for the Santa Barbara County Air Pollution Control Board to evaluate suitable NO_x control techniques for offshore applications. The goals of the study are to reduce turbine NO_x emissions at full load to 9 ppmv, corrected to 15 percent O_2, firing platform gas fuel and to achieve part load reductions of 50 percent. The study consists of two phases. The first phase, an engineering evaluation of available and emerging emission control technologies, is completed. The second phase will select the final control technologies and develop these technologies for offshore platform applications. Phase I of this study concludes that the technologies with the highest estimated probability for success in offshore applications are:

- Water injection plus SCR (80 percent);
- Methanol fuel plus SCR (70 percent);
- Lean premixed combustion plus SCR (65 percent); and
- Steam dilution of fuel prior to combustion plus SCR (65 percent).

A key conclusion drawn from Phase I of this study is that none of the above technologies or combination of technologies in offshore platform applications currently has a high probability of successfully achieving the NO_x emission reduction goals of this study without substantial cost and impacts to platform and turbine operations, added safety considerations, and other environmental concerns. These issues will be further studied in Phase II for the above control technologies.

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6.0 CONTROL COSTS

Capital and annual costs are presented in this chapter for the nitrogen oxide (NO_x) control techniques described in Chapter 5.0. These control techniques are water and steam injection, low-NO_x combustion, and selective catalytic reduction (SCR) used in combination with these controls. Model plants were developed to evaluate the control techniques for a range of gas turbine sizes, fuel types, and annual operating hours. The gas turbines chosen for these model plants range in size from 1.1 to 160 megawatts (MW) (1,500 to 215,000 horsepower [hp]) and include both aeroderivative and heavy-duty turbines. Model plants were developed for both natural gas and distillate oil fuels. For offshore oil production platforms, cost information was available only for one turbine model.

The life of the control equipment depends upon many factors, including application, operating environment, maintenance practices, and materials of construction. For this study, a 15-year life was chosen.

Both new and retrofit costs are presented in this chapter. For water and steam injection, these costs were assumed to be the same because most of the water treatment system installation can be completed while the plant is operating and because gas turbine nozzle replacement and piping connections to the treated water supply can be performed during a scheduled downtime for maintenance. Estimated costs are provided for both new and retrofit low-NO_x combustion applications. No SCR retrofit applications were identified, and costs for SCR retrofit applications were not available. The cost to retrofit an existing gas turbine installation with SCR would be considerably higher than the costs shown for a new installation, especially for combined cycle and cogeneration installations where the heat-recovery steam generator (HRSG) would have to be modified or replaced to accommodate the catalyst reactor.

This chapter is organized into five sections. Water and steam injection costs are described in Section 6.1. Low-NO_x combustor costs are summarized in Section 6.2. Costs for SCR used in combination with water or steam injection or low-NO_x combustion are described in Section 6.3. Water injection and SCR costs for offshore gas turbines are presented in Section 6.4, and references are listed in Section 6.5.

a. WATER AND STEAM INJECTION AND OIL-IN-WATER EMULSION

Ten gas turbines models were selected, and from these turbines 24 model plants were developed using water or steam injection or water-in-oil emulsion to control NO_x emissions. These 24 models, shown in Table 6-1

TABLE 6-1. GAS TURBINE MODEL PLANTS FOR NO_x CONTROL TECHNIQUES

Model plant[a]	GT model	Turbine output, MW	Annual operating hours	Fuel, natural gas or oil	Type of emission control	Aeroderivative (AD) or heavy-duty (HD) turbine
CON-G-W-3.3	Centaur T4500	3.3	8,000	Gas	Water	HD
CON-G-W-4.0	501-KB5	4.0	8,000	Gas	Water	AD
CON-G-W-22.7	LM2500	22.7	8,000	Gas	Water	AD
CON-G-W-26.8	MS5001P	26.8	8,000	Gas	Water	HD
CON-G-W-83.3	ABB GT11N	83.3	8,000	Gas	Water	HD
CON-G-W-84.7	MS7001E	84.7	8,000	Gas	Water	HD
CON-G-S-4.0	501-KB5	4.0	8,000	Gas	Steam	AD
CON-G-S-22.7	LM2500	22.7	8,000	Gas	Steam	AD
CON-G-S-26.8	MS5001P	26.8	8,000	Gas	Steam	HD
CON-G-S-34.4	LM5000	34.5	8,000	Gas	Steam	AD
CON-G-S-83.3	ABB GT11N	83.3	8,000	Gas	Steam	HD
CON-G-S-84.7	MS7001E	84.7	8,000	Gas	Steam	HD
CON-G-S-161	MS7001F	161	8,000	Gas	Steam	HD
CON-O-W-3.3	Centaur T4500	3.3	8,000	Oil	Water	HD
CON-O-W-26.3	MS5001P	26.3	8,000	Oil	Water	HD
CON-O-W-83.3	MS7001E	83.3	8,000	Oil	Water	HD
PKR-G-W-3.3	Centaur T4500	3.3	2,000	Gas	Water	HD
PKR-G-W-26.8	MS5001P	26.8	2,000	Gas	Water	HD
PKR-G-W-84.7	MS7001E	84.7	2,000	Gas	Water	HD
PKR-O-W-3.3	Centaur T4500	3.3	2,000	Oil	Water	HD
PKR-O-W-26.3	MS5001P	26.3	2,000	Oil	Water	HD
PKR-O-W-84.7	MS7001E	84.7	2,000	Oil	Water	HD
STD-O-W-1.1	Saturn T1500	1.0	1,000	Oil	Water	HD
STD-O-E-28.0	TPM FT4	28.0	1,000	Oil	Water-in-oil emulsion	AD

[a]Model plant legend:

First entry: annual operating hours
CON--continuous duty, 8,000 hours
PKR--peaking duty, 2,000 hours
STD--stand-by duty, 1,000 hours

Second entry: fuel type
G = natural gas fuel
O = oil fuel

Third entry: control type
W = water injection
S = steam injection
E = water-in-oil emulsion

Fourth entry: power output in MW

For example, CON-G-W-3.3 designates that the model plant is continuous-duty, uses natural gas fuel, has water injection, and has a power output of 3.3 MW.

, characterize variations in existing units with respect to turbine size, type (i.e., aero-derivative vs. heavy duty), operating hours, and type of fuel. A total of 24 model plants were developed; 16 of these were continuous-duty (8,000 hours per year) and 8 were intermittent-duty (2,000 or 1,000 hours per year). Thirteen of the continuous-duty model plants burn natural gas fuel; 6 of the 13 use water injection, and 7 use steam injection to reduce NO_x emissions. The three remaining continuous-duty model plants burn distillate oil fuel and use water injection to reduce NO_x emissions. Of the eight intermittent-duty model plants, six operate 2,000 hours per year (three natural gas-fueled and three distillate oil-fueled), and two operate 1,000 hours per year (both distillate oil-fueled). All intermittent-duty model plants use water rather than steam for NO_x reduction because it was assumed that the additional capital costs associated with steam-generating equipment could not be justified for intermittent service.

Costs were available for applying water-in-oil emulsion technology to only one gas turbine, and insufficient data were available to develop costs for a similar water-injected model plant for this turbine. As a result, the costs and cost effectiveness for the water-in-oil emulsion model plant should not be compared to those of water-injected model plants.

Capital costs are described in Section 6.1.1, annual costs are described in Section 6.1.2, and emission reductions and the cost effectiveness of wet injection controls are discussed in Section 6.1.3. Additional discussion of the cost methodology and details about some of the cost estimating procedures are provided in Appendix B.

Fuel rates and water flow rates were calculated for each model plant using published design power output and efficiency, expressed as heat rate, in British thermal units per kilowatt-hour (Btu/kWh).[1] The values for these parameters are presented in Table 6-2

TABLE 6-2. FUEL AND WATER FLOW RATES FOR WATER AND STEAM INJECTION (1990 $)

Model plant	GT model	Turbine output, kW	Heat rate (HR), Btu/kW-hr	Fuel flow lb/hr[a]	Fuel flow MMBtu/yr[b]	Estimated WFR, lb water/lb fuel	Water flow, gal/min[c]	Treatment system capacity, gal/min[d]
CON-G-W-3.3	Centaur T4500	3,270	12,900	2,050	337,000	0.61	2.50	4.20
CON-G-W-4.0	501-KB5	4,000	12,700	2,460	406,000	0.80	3.94	6.60
CON-G-W-22.7	LM2500	22,670	9,220	10,100	1,670,000	0.73	14.8	24.7
CON-G-W-26.8	MS5001P	26,800	11,870	15,400	2,540,000	0.72	22.2	37.2
CON-G-W-83.3	ABB GT11N	83,300	10,400	42,000	6,930,000	1.83	154	258
CON-G-W-84.7	MS7001E	84,700	10,400	42,700	7,050,000	0.81	69.2	116
CON-G-S-4.0	501-KB5	4,000	12,700	2,460	406,000	1.50	7.38	12.4
CON-G-S-22.7	LM2500	22,670	9,220	10,100	1,670,000	1.46	29.5	49.5
CON-G-S-26.8	MS5001P	26,800	11,870	15,400	2,540,000	1.08	33.3	55.8
CON-G-S-34.4	LM5000	34,450	9,080	15,200	2,500,000	1.67	50.8	85.2
CON-G-S-83.3	ABB GT11N	83,300	10,400	42,000	6,930,000	2.12	178	299
CON-G-S-84.7	MS7001E	84,700	10,400	42,700	7,050,000	1.22	104	175
CON-G-S-161	MS7001F	161,000	9,500	74,200	12,240,000	1.34	199	334
CON-O-W-3.3	Centaur T4500	3,270	12,900	2,300	337,000	0.60	2.76	4.63
CON-O-W-26.3	MS5001P	26,300	11,950	17,100	2,510,000	0.79	27.0	45.3
CON-O-W-83.3	MS7001E	83,300	10,470	47,600	6,980,000	0.67	63.8	107
PKR-G-W-3.3	Centaur T4500	3,270	12,900	2,050	84,400	0.61	2.50	4.20
PKR-G-W-26.8	MS5001P	26,800	11,870	15,400	640,000	0.72	22.2	37.2
PKR-G-W-84.7	MS7001E	84,700	10,400	42,700	1,760,000	0.81	69.2	116
PKR-O-W-3.3	Centaur T4500	3,270	12,900	2,300	84,000	0.60	2.76	4.63
PKR-O-W-26.3	MS5001P	26,300	11,950	17,100	630,000	0.79	27.0	45.3
PKR-O-W-84.7	MS7001E	83,300	10,470	47,600	1,740,000	0.67	63.8	107
STD-O-W-1.1	Saturn T1500	1,130	14,200	875	16,000	0.46	0.81	1.35
STD-O-F-28.0	TPM FT4	28,000	14,500	19,700	406,000	0.55	21.7	36.4

[a]Natural gas: lb/hr = HR x kW x (lb/20,610 Btu). Diesel oil: lb/hr = HR x kW x (lb/18,330 Btu).
[b]MMBtu/yr = HR x kW x (MM/10^6) x (operating hours/year).
[c]Water (or steam) flow, gal/min = Fuel flow (lb/hr) x (1 hr/60 min) x (1 gal/8.33, lb. H_2O) x WFR.
[d]A 30 percent design factor has been included per discussion with system supplier, and the waste stream from the water treatment system is calculated to be 29 percent. The design capacity is therefore Water Flow x 1.3 x 1.29.

for each model plant. Fuel rates were estimated based on the heat rates, the design output, and the lower heating value (LHV) of the fuel. The LHV's used in this analysis for natural gas and diesel fuel are 20,610 Btu per pound (Btu/lb) and 18,330 Btu/lb, respectively, as shown in Table 6-3

TABLE 6-3. FUEL PROPERTIES AND UTILITY AND LABOR RATES[a]

Fuel properties	Factor	Units	Reference
Natural gas	20,610	Btu/lb	Ref. 3
	930	Btu/scf[c] (LHV)	Ref. 3
Diesel fuel	18,330	Btu/lb (LHV)	Ref. 2
	7.21	lb/gal	Ref. 2
Utility rates			
Natural gas[b]	3.88	$/scf	Ref. 4
Diesel fuel	0.77	$/gal	Ref. 5
Electricity	0.06	$/kW-hr	Ref.'s 6 and 7
Raw water	0.384	$/1,000 gal	Ref. 2, escalated @ 5% per year
Water treatment	1.97	$/1,000 gal	Ref. 2, escalated @ 5% per year
Waste disposal	3.82	$/1,000 gal	Ref. 2, escalated @ 5% per year
Labor rate			
Operating	25.60	$/hr	Ref. 2, escalated @ 5% per year
Maintenance	31.20	$/hr	Ref. 2, escalated @ 5% per year

[a]All costs are average costs in 1990 dollars.
[b]Natural gas and electricity costs from Reference 4 are the average of the costs for industrial and commercial customers.
[c]scf = standard cubic foot.

.[2] Water (or steam) injection rates were calculated based on published fuel rates and water-to-fuel ratios (WFR) provided by manufacturers.[8-12] According to a water treatment system supplier, treatment facilities are designed with a capacity factor of 1.3.[13] An additional 29 percent of the treated water flow rate is discarded as wastewater.[2] Consequently, the water treatment facility design capacity is 68 percent (1.30 x 1.29) greater than the water (or steam) injection rate.

i. Capital Costs

The capital costs for each model plant are presented in Table 6-4

TABLE 6-4. CAPITAL COSTS FOR WET INJECTION IN THOUSAND OF DOLLARS [a]

Model plant	GT model	Injection system (IS)[b]	Water treatment system (WTS)[c]	Total system (TS) = (IS + WTS)	Taxes and freight (TF) = (8% of TS)	Direct install. costs (DC) = (45% [TS + TF])	Indirect install. costs (IC)=(33% of [TS + TF +DC] + 5,000)	Contingency (C) = (20% of [TS + TF + DC + IC])	Total capital cost (TCC) = [TS + TF + DC + IC + C]
CON-G-W-3.3	Centaur T4500	113	89.9	203	16.2	50.0[d]	53.8[e]	64.6	388
CON-G-W-4.0	501-KB5	115	113	228	18.2	50.0[d]	59.2[e]	71.0	426
CON-G-W-22.7	LM2500	212	218	430	34.4	209	227	180	1,080
CON-G-W-26.8	MS5001P	215	268	483	38.6	235	254	202	1,210
CON-G-W-83.3	ABB GT11N	874	705	1,580	126	768	822	659	3,950
CON-G-W-84.7	MS7001E	562	473	1,030	82.4	501	537	430	2,580
CON-G-S-4.0	501-KB5	154	154	308	24.7	50.0	76.6	92.0	552
CON-G-S-22.7	LM2500	278	309	587	46.9	285	308	245	1,470
CON-G-S-26.8	MS5001P	262	328	590	47.2	287	310	247	1,480
CON-G-S-34.4	LM5000	530	405	935	74.8	454	488	391	2,340
CON-G-S-83.3	ABB GT11N	1,090	759	1,850	148	899	961	772	4,630
CON-G-S-84.7	MS7001E	715	580	1,300	104	632	677	543	3,260
CON-G-S-161	MS7001F	1,130	802	1,930	154	938	1,000	804	4,830
CON-O-W-3.3	Centaur T4500	114	94.5	208	16.7	50.0[d]	55.0[e]	66.0	396
CON-O-W-26.3	MS5001P	231	296	527	42.1	256	277	220	1,320
CON-O-W-83.3	MS7001E	532	454	986	78.9	479	515	412	2,470
PKR-G-W-3.3	Centaur T4500	113	89.9	203	16.2	50.0[d]	53.8[e]	64.6	388
PKR-G-W-26.8	MS5001P	215	268	483	38.6	235	254	202	1,210
PKR-G-W-84.7	MS7001E	562	473	1,030	82.4	501	537	430	2,580
PKR-O-W-3.3	Centaur T4500	114	94.5	208	16.7	50.0[d]	55.0[e]	66.0	396
PKR-O-W-26.3	MS5001P	231	296	527	42.1	256	277	220	1,320
PKR-O-W-84.7	MS7001E	532	454	986	78.9	479	515	412	2,470
STD-O-W-1.1	Saturn T1500	71.9	51.0	123	9.83	50.0	36.6	43.9	263
STD-O-F-28.0	TPM FT4	128	NA[f]	128	10.2	62.2	71.1	54.3	326

[a]All costs in 1990 dollars.
[b]Injection nozzle costs provided by manufacturers. Balance of water injection system calculated at a cost of \$4,200 x GPM.
[c]WTS = 43,900 x (design capacity, gal/min)$^{0.5}$
[d]Direct installation cost is estimated at \$50,000 for model plants rated at 5 MW or less.
[e]Indirect installation cost factor of 33 percent is reduced to 20 percent for model plants rated at 5 MW or less.
[f]NA = cost calculations based on using a portable demineralizer systems during turbine operating periods. Cost for system usage is included in Table 6-5.

. These costs were developed based on methodology in Reference 2, which is presented in this section. The capital costs include purchased equipment costs, direct and indirect installation costs, and contingency costs.

(1) Purchased Equipment Costs. Purchased equipment costs consist of the injection system, the water treatment system, taxes, and freight. All costs are presented in 1990 dollars.

(a) Water injection system. The injection system delivers water from the treatment system to the combustor. This system includes the turbine-mounted injection nozzles, the flow metering controls, pumps, and hardware and interconnecting piping from the treatment system to the turbine. On-engine hardware (the injection nozzles) costs were provided by turbine manufacturers.[9,14-17] Flow metering controls and hardware, pumps, and interconnecting piping costs for all turbines were calculated using data provided by General Electric for four heavy-duty turbine models.[17] No relationship between costs and either turbine output or water flow was evident, so the sum of the four costs was divided by the sum of the water flow requirements for the four turbines. This process yielded a cost of $4,200 per gallon per minute (gal/min), and this cost, added to the on-engine hardware costs, was used for all model plants.

(b) Water treatment system. The water treatment process, and hence the treatment system components, varies according to the degree to which the water at a given site must be treated. For this cost analysis, the water treatment system includes a reverse osmosis and mixed-bed demineralizer system. The water treatment system capital cost for each model plant was estimated based on an equation developed in Reference 2:

$$WTS = 43{,}900 \times (G)^{0.50}$$

where

WTS = water treatment system capital cost, $; and

G = water treatment system design capacity, gal/min.

This equation yields costs that are generally consistent with the range of costs presented in Reference 18.

(c) Taxes and freight. This cost covers applicable sales taxes and shipment to the site for the injection and water treatment systems. A figure of 8 percent of the total system cost was used.[2,7]

(2) Direct Installation Costs. This cost includes the labor and material costs associated with installing the foundation and supports, erecting and handling equipment, electrical work, piping, insulation, and painting. For smaller

turbines, the water treatment system is typically skid-mounted and is shipped to the site as a packaged unit, which minimizes field assembly and interconnections. The cost to install a skid-mounted water treatment skid is typically $50,000, and this cost is used for the direct installation cost for model plants less than 5 MW (6700 hp).[19] For larger turbines, it is expected that the water treatment system must be field-assembled and the direct installation costs were calculated as 45 percent of the injection and water treatment systems, including taxes and freight.[2]

(3) Indirect Installation Costs. This cost covers the indirect costs (engineering, supervisory personnel, office personnel, temporary offices, etc.) associated with installing the equipment. The cost was taken to be 33 percent of the systems' costs, taxes and freight, and direct costs, plus $5,000 for model plants above 5 MW (6,700 hp).[2] The indirect installation costs for skid-mounted water treatment systems are expected to be less than for field-assembled systems; therefore, for model plants with an output of less than 5 MW (6,700 hp), the cost percentage factor was reduced from 33 to 20 percent.

(4) Contingency Cost. This cost is a catch-all meant to cover unforeseen costs such as equipment redesign/ modification, cost escalations, and delays encountered in startup. This cost was estimated as 20 percent of the sum of the systems, taxes and freight, and direct and indirect costs.[2]

ii. Annual Costs

The annual costs are summarized in Table 6-5

TABLE 6-5. ANNUAL COSTS FOR WATER AND STEAM INJECTION (1990 $)

Model plant	GT model	Fuel penalty (FP)[a]	Electricity (E)[b]	Added maintenance cost (M)[c]	Water treatment (WT)[d]					Plant overhead (PO) = (30% of M)	G&A taxes, insurance (GATI)[i]	Capital recovery (CR)[j]	Total annual cost (TAC)[k]
					Raw water[e]	Treat-ment[f]	Labor[g]	Disposal[h]	Total cost (TW)				
CON-G-W-3.3	Centaur T4500	30,000	193	16,000	595	3,050	1,080	1,330	6,050	4,800	15,500	51,000	124,000
CON-G-W-4.0	501-KB5	47,400	304	24,000	936	4,800	1,710	2,090	9,540	7,200	17,100	56,100	162,000
CON-G-W-22.7	LM2500	178,000	1,140	28,000	3,510	18,000	6,390	7,840	35,700	8,400	43,200	142,000	436,000
CON-G-W-26.8	MS5001P	267,000	1,714	33,000	5,270	27,100	9,620	11,800	53,800	9,900	48,400	159,000	573,000
CON-G-W-83.3	ABB GT11N	1,852,000	11,884	0	36,600	188,000	66,700	81,800	373,000	0	158,000	519,000	2,910,000
CON-G-W-84.7	MS7001E	834,000	5,348	25,700	16,500	84,400	30,000	36,800	168,000	7,710	103,000	339,000	1,480,000
CON-G-S-4.0	501-KB5	25,400	571	24,000	1,760	9,010	1,600	3,930	16,300	7,200	22,100	72,600	168,000
CON-G-S-22.7	LM2500	102,000	2,280	0	7,020	36,000	6,390	15,700	65,100	0	58,800	193,000	421,000
CON-G-S-26.8	MS5001P	114,000	2,572	33,000	7,910	40,600	7,210	17,700	73,400	9,900	59,200	195,000	487,000
CON-G-S-34.4	LM5000	174,000	3,925	0	12,100	62,000	11,000	27,000	112,000	0	93,600	308,000	692,000
CON-G-S-83.3	ABB GT11N	613,000	13,768	0	42,400	217,000	38,600	94,700	393,000	0	185,000	609,000	1,810,000
CON-G-S-84.7	MS7001E	359,000	8,055	0	24,800	127,000	22,600	55,400	230,000	0	130,000	429,000	1,160,000
CON-G-S-161	MS7001F	684,000	15,374	0	47,300	243,000	43,100	106,000	439,000	0	193,000	635,000	1,970,000
CON-O-W-3.3	Centaur T4500	41,200	213	20,800	657	3,370	1,200	1,470	6,700	6,240	15,800	52,100	143,000
CON-O-W-26.3	MS5001P	404,000	2,089	42,900	6,430	33,000	11,700	14,400	65,500	12,900	52,800	174,000	754,00
CON-O-W-83.3	MS7001E	954,000	4,931	33,400	15,200	77,800	27,700	33,900	155,000	10,020	98,800	325,000	1,580,000
PKR-G-W-3.3	Centaur T4500	7,500	48.3	4,000	149	760	270	330	1,510	1,200	15,500	51,000	80,800
PKR-G-W-26.8	MS5001P	67,000	429	8,250	1,320	6,770	2,400	2,950	13,400	2,500	48,400	159,000	299,000
PKR-G-W-84.7	MS7001E	208,000	1,337	6,430	4,110	21,100	7,500	9,200	41,900	1,929	103,000	339,000	702,000
PKR-O-W-3.3	Centaur T4500	10,300	53.3	5,200	164	840	300	370	1,670	1,560	15,800	52,100	86,700
PKR-O-W-26.3	MS5001P	101,000	522	10,725	1,610	8,240	2,930	3,590	16,400	3,200	52,800	174,000	359,000
PKR-O-W-84.7	MS7001E	238,000	1,233	8,350	3,790	19,500	6,910	8,480	38,700	2,505	99,000	325,000	713,000
STD-O-W-1.1	Saturn T1500	1,500	7.78	1,300	23.9	123	43.7	53.6	244	390	10,530	34,600	48,600
STD-O-E-28.0	TPM FT4	45,500	209	0	644	51,100	1,170	1,440	54,400	0	13,000	42,900	156,000

[a]FP for water = 0.035 x WFR x (MMBtu/yr) x (ft^3/940 Btu) x ($3.88/1,000 ft^3) x (10^6/MM).
[b]E = Water flow rate (gal/min) x 0.161 x operating hours x ($0.06/kWH).
[c]Maintenance costs for the Centaur and Allison 501 turbines were obtained from the manufacturers. Costs for the MS5001 and MS7001 were estimated based on information about inspections and parts replacement presented in Appendix B. Maintenance for turbines that use diesel fuel are 30 percent higher than costs for comparable turbines using natural gas. No additional maintenance costs were assessed for steam injection.
[d]WT includes treatment chemicals, raw water, waste disposal, and operating labor.
[e]Raw Water Cost = Water Flow (gal/min) x ($0.384/1,000 gal) x (60 min/hour) x operating hours x 1.29.

[f]Treatment Cost = Water Flow (gal/min) x ($1.97/1,000 gal) x (60 min/hour) x operating hours x 1.29.
[g]Labor Cost for water = Water Flow (gal/min) x ($.70/1,000 gal) x (60 min/hour) x operating hours x 1.29.
Labor Cost for steam = Water Flow (gal/min) x ($.70/1,000 gal) x (60 min/hour) x operating hours x 1.29 x 0.5.
[h]Disposal Cost = Water Flow (gal/min) x ($3.82/1,000 gal) x (60 min/hour) x operating hours x 0.29.
[i]GATI = 0.04 x TCC (TCC is shown in Table 6-4).
[j]CR = 0.1315 x TCC based on an equipment life of 15 years and a 10 percent interest rate.

for each model plant. Annual costs include the fuel penalty; electricity; maintenance requirements; water treatment; overhead, general and administrative, taxes, and insurance; and capital recovery, as discussed in this section.

(1) <u>Fuel Penalty</u>. The reduction in efficiency associated with water injection varies for each turbine model. Based on data in Reference 2, it was estimated that a WFR of 1.0 corresponds to a fuel penalty of 3.5 percent for water injection and 1.0 percent for steam injection. This percentage was multiplied by the actual WFR and the annual fuel cost to

determine the fuel penalty for each model plant. The fuel flow was multiplied by the unit fuel costs to determine the annual fuel costs. As shown in Table 6-3, the natural gas cost is \$3.88/1,000 standard cubic feet (scf) and the diesel fuel cost is \$0.77/gal.[4,5]

An increase in output from the turbine accompanies the decrease in efficiency. This increase was not considered, however, because not all sites have a demand for the available excess power. In applications such as electric power generation, where the excess power can be used at the site or added to utility power sales, this additional output would serve to decrease or offset the fuel penalty impact.

(2) Electricity Cost. The electricity costs shown in Table 6-5 apply to the feedwater pump(s) for water or steam injection. The pump power requirements are estimated from the pump head (ft) and the water flow rate as shown in the following equation:[2]

$$\text{power pump } (kW_e) = \frac{FR}{3{,}960} \times H \times (S.G.) \times \frac{1}{0.6} \times \frac{0.7457\ kW}{hp} \times \frac{1}{0.9}$$

where:

FR = feedwater flow rate, gal/min (from Table 6-2);
H = total pump head (ft);
S.G. = specific gravity of the feed water;
0.6 = pump efficiency of 60 percent;
0.9 = electric motor efficiency of 90 percent;
3,960 = factor to correct units in FR and H to hp; and
0.7457 = factor to convert hp to kW.

For water injection, the feedwater pump(s) supply treated water to the gas turbine injection system. For steam injection, the feedwater pump(s) supply treated water to the boiler for steam generation. This cost analysis uses a feedwater temperature of 55°C (130°F) with a density of 61.6 lb/ft^3 and a total pump head requirement of 200 pounds per square inch, gauge (psig)

(468 ft).[2] Based on these values, the pump electrical demand for either water or steam injection is calculated as follows:

$$\text{pump power } (kW_e) = \frac{FR \times 468}{3{,}960} \times \frac{61.6}{62.4} \times \frac{1}{0.6} \times 0.7457 \times \frac{1}{0.9}$$

$$= 0.161 \times FR$$

The electrical cost for each model plant is the product of the pump electrical demand, the annual hours of operation, and the unit cost of electricity. The unit cost of electricity, shown in Table 6-3, is $0.06/kWH.[6,7]

Maintenance costs were developed based on information from manufacturers, and water treatment labor costs were estimated based on information from a water treatment vendor. Other costs were developed based on the methodology presented in Reference 2.

No backup steam or electricity costs were developed for water or steam injection because it was assumed that no additional downtime would be required for scheduled inspections and repairs. Maintenance intervals could be scheduled to coincide with the 760 hr/yr of downtime that are currently allocated for scheduled maintenance. If this were done, the annual utilization of the backup source would not increase.

(3) <u>Added Maintenance Costs</u>. Based on discussions with gas turbine manufacturers, additional maintenance is required for some gas turbines with water injection. The analysis procedures used to develop the incremental maintenance costs are presented in Appendix B.

The incremental maintenance cost associated with water injection for natural gas-fueled turbines was provided by the gas turbine manufacturers.[10,20-24] All gas turbine manufacturers contacted stated that there were no incremental maintenance costs for operation with steam injection. Two manufacturers provided maintenance costs for natural gas and oil fuel operation without water injection.[10,20] Using an average of these costs, incremental maintenance costs for water injection are 30 percent higher for plants that use diesel fuel instead of natural gas. Costs were prorated for model plants that operate less than 8,000 hr/yr.

(4) Water Treatment Costs. Water treatment operating costs include the cost of treatment (e.g., for chemicals and media filters), operating labor, raw water, and wastewater disposal. The raw water flow rate is equal to the treated water flow rate (the water or steam injection rate) plus the flow rate of the wastewater generated in the treatment plant. As noted in Section 6.1, the wastewater flow rate is equal to 29 percent of the injection flow rate. The annual raw water, treated water, and wastewater flow rates were multiplied by the appropriate unit costs in Table 6-3 to determine the annual costs. Water treatment labor costs were calculated at $0.70/1,000 gal for water injection.[25] This cost was multiplied by the total annual treated water flow rate to determine the annual water treatment labor cost for water injection. Labor costs for steam injection were assumed to be half as much as the costs for water injection because it was assumed that the facility already has a water treatment plant for the boiler feedwater. Therefore, the operator requirements would be only those associated with the increase in capacity of the existing treatment plant.

(5) Plant Overhead. This cost is the overhead associated with the additional maintenance effort required for water injection. The cost was calculated as 30 percent of the added maintenance cost from Section 6.1.2.3.[2]

(6) General and Administrative, Taxes, and Insurance Costs (GATI). This cost covers those expenses for administrative overhead, property taxes, and insurance and was calculated as 4 percent of the total capital cost.[2]

(7) Capital Recovery. A capital recovery factor (CRF) was multiplied by the total capital investment to estimate uniform end-of-year payments necessary to repay the investment. The CRF used in this analysis is 0.1315, which is based on an equipment life of 15 years and an interest rate of 10 percent.

(8) Total Annual Cost. This cost is the sum of the annual costs presented in Sections 6.1.2.1 through 6.1.2.7 and is the

total cost that must be paid each year to install and operate water or steam injection NO_x emissions control for a gas turbine.

iii. Emission Reduction and Cost-Effectiveness Summary for Water and Steam Injection

TABLE 6-6. COST-EFFECTIVENESS SUMMARY FOR WATER AND STEAM INJECTION (1990 $)

Model plant	GT model	NO_X emissions[a]				Total NO_x removed, tons/yr	Total annual cost, $	Cost effectiveness, $/tón
		Uncontrolled NO_x		Controlled NO_x				
		ppmv[b]	tons/yr	ppmv	[b] tons/yr			
CON-G-W-3.3	Centaur T4500	130	88.1	42	28.5	59.6	124,000	2,080
CON-G-W-4.0	501-KB5	155	126	42	34.2	91.9	162,000	1,760
CON-G-W-22.7	LM2500	174	581	42	140	441	436,000	989
CON-G-W-26.8	MS5001P	142	723	42	214	509	573,000	1,130
CON-G-W-83.3	ABB GT11N	390	5,410	25	347	5,060	2,910,000	575
CON-G-W-84.7	MS7001E	154	2,170	42	593	1,580	1,480,000	937
CON-G-S-4.0	501-KB5	155	126	42	34.2	91.9	168,000	1,830
CON-G-S-22.7	LM2500	174	581	25	83.5	497	421,000	846
CON-G-S-26.8	MS5001P	142	723	42	214	509	487,000	957
CON-G-S-34.4	LM5000	185	930	25	126	804	692,000	861
CON-G-S-83.3	ABB GT11N	390	5,410	42	583	4,830	1,810,000	375
CON-G-S-84.7	MS7001E	154	2,170	42	593	1,580	1,160,000	734
CON-G-S-161	MS7001F	210	5,150	42	1,030	4,120	1,970,000	478
CON-O-W-3.3	Centaur T4500	179	125	60	41.8	82.9	143,000	1,720
CON-O-W-26.3	MS5001P	211	1,090	65	337	753	754,000	1,000
CON-O-W-83.3	MS7001E	228	3,290	65	938	2,350	1,580,000	672
PKR-G-W-3.3	Centaur T4500	130	22.0	42	7.12	14.9	80,800	5,420
PKR-G-W-26.8	MS5001P	142	181	42	53.5	127	299,000	2,350
PKR-G-W-84.7	MS7001E	154	543	42	148	395	702,000	1,780
PKR-O-W-3.3	Centaur T4500	179	31.2	60	10.5	20.7	86,700	4,180
PKR-O-W-26.3	MS5001P	211	273	65	84.2	189	359,000	1,900
PKR-O-W-84.7	MS7001E	228	822	65	234	588	713,000	1,210
STD-O-W-1.1	Saturn T1500	150	4.97	60	1.99	2.98	48,600	16,300
STD-O-E-28.0	TPM FT4	150	122	50	37.3	84.7	156,000	1,840

[a]Example NO_x emission calculations are given in Appendix A.
[b]Referenced to 15 percent oxygen.
[c]From Table 6-5.

The uncontrolled and controlled NO_x emissions and the annual emission reductions for the model plants are shown in Table 6-6. The emissions, in tons per year (tons/yr), were calculated as shown in Appendix A.

The total annual cost was divided by the annual emission reductions to determine the cost effectiveness for each model plant. For continuous-duty natural gas-fired model plants, the cost-effectiveness figures range from approximately $600 to $2,100 per ton of NO_x removed for water injection, and decrease to approximately $400 to $1,850 per ton for steam injection. The lower range of cost-effectiveness figures for steam injection is primarily due to the greater NO_x reduction achieved with steam injection. For continuous-duty oil-fired model plants, the cost effectiveness ranges from approximately $675 to $1,750 per ton of NO_x removed, which is comparable to figures for gas-fired model plants. The cost-effectiveness figures are higher for gas turbines with lower power outputs because the fixed capital costs associated with wet injection system installation have the greatest impact on the smaller gas turbines.

Cost-effectiveness figures increase as annual operating hours decrease. For turbines operating 2,000 hr/yr, the cost-effectiveness figures are two to nearly three times higher than those for continuous-duty model plants, and increase further for model plants operating 1,000 hr/yr. For the oil-in-water emulsion model plant, the cost effectiveness corresponding to 1,000 annual operating hours is $1,840/ton of NO_x removed. No data were available to prepare a conventional water injection model plant for this turbine to compare the relative cost-effectiveness values.

b. LOW-NO_x COMBUSTORS

Incremental capital costs for low-NO_x combustors relative to standard designs for new applications were provided by three manufacturers for several turbines.[3,14,26] Based on information from the manufacturers, the performance and maintenance requirements for a low-NO_x combustor are expected to be the same as for a standard combustor, and so the only annual cost associated with low-NO_x combustors is the capital recovery. The capital recovery factor is 0.1315, assuming a life of 15 years and an interest rate of 10 percent.

Table 6-7

TABLE 6-7. COST-EFFECTIVENESS SUMMARY FOR DRY LOW-NO_x COMBUSTORS USING NATURAL GAS FUEL (1990 $)

Model plant[a]	GT model	Power output, MW	Annual operating hours	NO_x emissions[b] Uncontrolled NO_x ppmv[c]	Uncontrolled NO_x Tons/yr	Controlled NO_x ppmv	Controlled NO_x Tons/yr	NO_x removed, tons/yr	Incremental capital cost,$[d]	Annual cost, $[e]	Cost effectiveness, $/ton NO_x removed
CON-L-3.3-42	Centaur T4500	3.3	8,000	130	88.1	42.0	28.5	59.6	375,000	49,300	827
CON-L-4.0-42	Centaur 'H'	4.0	8,000	105	83.0	42.0	33.2	49.8	400,000	52,600	1,060
CON-L-4.5-42	Taurus	4.5	8,000	114	98.7	42.0	36.4	62.4	425,000	55,900	896
CON-L-8.8-42	Mars T12000	8.8	8,000	178	278	42.0	65.5	212	700,000	92,100	434
CON-L-10-42	Mars T14000	10.0	8,000	199	341	42.0	72.1	269	725,000	95,300	354
CON-L-3.3-25	Centaur T4500	3.3	8,000	130	88.1	25.0[f]	16.9	71.2	375,000	49,300	693
CON-L-4.0-25	Centaur 'H'	4.0	8,000	105	83.0	25.0[f]	19.8	63.2	400,000	52,600	832
CON-L-4.5-25	Taurus	4.5	8,000	114	98.7	25.0[f]	21.7	77.1	425,000	55,900	725
CON-L-8.8-25	Mars T12000	8.8	8,000	178	278	25.0[f]	39.0	239	700,000	92,100	386
CON-L-10-25	Mars T14000	10.0	8,000	199	341	25.0[f]	42.9	299	725,000	95,300	319
CON-L-39-25	MS6000	39.0	8,000	220	1,480	25.0	168	1,310	1,400,000	184,000	140
CON-L-83-25	ABB GT11N	83.3	8,000	390	5,420	25.0	347	5,070	2,200,000	289,000	57.0
CON-L-85-25	MS7001E	84.7	8,000	154	2,180	25.0	353	1,830	2,140,000	281,000	154
CON-L-39-9	MS6000	39.0	8,000	220	1,480	9.00	60.6	1,420	1,400,000	184,000	130
CON-L-83-9	ABB GT11N	83.3	8,000	390	5,420	9.00	125	5,290	2,200,000	289,000	54.6
CON-L-85-9	MS7001E	84.7	8,000	154	2,180	9.00	127	2,050	2,140,000	281,000	137
PKR-L-3.3-42	Centaur T4500	3.3	2,000	130	22.0	42.0	7.12	14.9	375,000	49,300	3,310
PKR-L-4.0-42	Centaur 'H'	4.0	2,000	105	20.7	42.0	8.30	12.4	400,000	52,600	4,230
PKR-L-4.5-42	Taurus	4.5	2,000	114	24.7	42.0	9.09	15.6	425,000	55,900	3,590
PKR-L-8.8-42	Mars T12000	8.8	2,000	178	69.4	42.0	16.4	53.1	700,000	92,100	1,740
PKR-L-10-42	Mars T14000	10.0	2,000	199	85.4	42.0	18.0	67.3	725,000	95,300	1,420
PKR-L-3.3-25	Centaur T4500	3.3	2,000	130	22.0	25.0[f]	4.24	17.8	375,000	49,300	2,770
PKR-L-4.0-25	Centaur 'H'	4.0	2,000	105	20.7	25.0[f]	4.94	15.8	400,000	52,600	3,330
PKR-L-4.5-25	Taurus	4.5	2,000	114	24.7	25.0[f]	5.41	19.3	425,000	55,900	2,900
PKR-L-8.8-25	Mars T12000	8.8	2,000	178	69.4	25.0[f]	9.75	59.7	700,000	92,100	1,540
PKR-L-10-25	Mars T14000	10.0	2,000	199	85.4	25.0[f]	10.7	74.6	725,000	95,300	1,280
PKR-L-39-25	MS6000	39.0	2,000	220	371	25.0	42.1	328	1,400,000	184,000	560
PKR-L-83-25	ABB GT11N	83.3	2,000	390	1,350	25.0	86.8	1,260	2,200,000	289,000	229
PKR-L-85-25	MS7001E	84.7	2,000	154	540	25.0	88.3	452	2,140,000	281,000	622
*PKR-L-39-9	MS6000	39.0	2,000	220	371	9.00	15.2	355	1,400,000	184,000	518
PKR-L-83-9	ABB GT11N	83.3	2,000	390	1,350	9.00	31.3	1,320	2,200,000	289,000	219
PKR-L-85-9	MS7001E	84.7	2,000	154	540	9.00	31.8	508	2,140,000	281,000	553

[a]Model plant legend: First entry: annual operating hours; Second entry: control technique; Third entry: power output, in MW; Fourth entry: controlled NO_x level, ppmv at 15 percent O

CON - Continuous duty, 8,000 hours; L - dry low-NO_x combustor

PKR - peaking/intermittent duty, 2,000 hours

For example, CON-L-3.3-42 designates that the model plant operates 8,000 hours per year, is fitted with a dry low-NO_x combustor, has a power output of 3.3 MW, and has a controlled NO_x level of 42 ppmv.

[b]Example NO_x emission calculations are shown in Appendix A.

[c]Referenced to 15 percent oxygen.

[d]Incremental capital costs were provided by the manufacturers.

presents the uncontrolled and controlled emission levels, the annual emission reductions, incremental costs for a low-NO_x combustor over a conventional design, and the cost effectiveness of low-NO_x combustors for all gas turbine models for which sufficient data were available. Cost-effectiveness figures were calculated for 8,000 and 2,000 hours of operation annually, using controlled NO_x emission levels of 42, 25, and 9 parts per million, by volume (ppmv), referenced to 15 percent oxygen, which are the achievable levels stated by the turbine manufacturers. The cost effectiveness varies according to the uncontrolled NO_x emission level for the conventional combustor design and the achievable controlled emission level for the low-NO_x design. For continuous-duty applications, cost effectiveness for a controlled NO_x emission level of 42 ppmv ranges from \$353 to \$1,060 per ton of NO_x removed. The cost-effectiveness range decreases to \$57 to \$832 per ton of NO_x removed for a controlled NO_x emission level of 25 ppmv and decreases further to \$55 to \$137 per ton of NO_x removed for a 9 ppmv control level. In all cases, the cost effectiveness increases as the operating hours decrease. In general, the cost effectiveness is higher for smaller gas turbines than for larger turbines due to the relatively higher capital cost per kW for low-NO_x combustors for smaller turbines.

The cost-effectiveness range is lower for low-NO_x combustors than for water or steam injection because the total annual costs are lower and, in some cases, the controlled emission levels are also lower. According to two turbine manufacturers, retrofit costs are 40 to 60 percent greater than the incremental costs shown in Table 6-7 for new installations.[3,14]

c. SELECTIVE CATALYTIC REDUCTION

The costs for SCR for new installations were estimated for all model plants. Retrofit costs for SCR were not available but could be considerably higher than the costs shown for new installations, especially in applications where an existing heat recovery steam generator (HRSG) would have to be moved, modified, or replaced to accommodate the addition of a catalyst reactor.

To date, most gas turbine SCR applications use a base metal catalyst with an operating temperature range that requires cooling of the exhaust gas from the turbine. For this reason, SCR applications to date have been limited to combined cycle or cogeneration applications that include an HRSG, which serves to cool the exhaust gas to temperatures compatible with the catalyst. The introduction of high-temperature zeolite catalysts, however, makes it possible to install the catalyst directly downstream of the turbine, and therefore feasible to use SCR with simple-cycle applications as well as heat recovery applications. As discussed in Section 5.3.2, to date there is at least one gas turbine installation with a high-temperature zeolite catalyst installed downstream of the turbine and upstream of an HRSG. At present, no identified SCR systems are installed in simple-cycle gas turbine applications.

An overview of the procedures used to estimate capital and annual costs are described in Sections 6.3.1 and 6.3.2, respectively; a detailed cost algorithm is presented in Appendix B. The emission reduction and cost-effectiveness calculations are described in Section 6.3.3.

i. <u>Capital Costs</u>

Five documents in the technical literature contained SCR capital costs for 21 gas turbine facilities. Most of these documents presented costs that were obtained from vendors, but some may have also developed at least some costs based on their own experiences.[27-31] Most of the documents presented only the total capital costs, not costs for individual components, and they did not provide complete descriptions of what the costs included. These costs were plotted on a graph of total capital costs versus gas turbine size. To this graph were added estimates of total installed costs for a high-temperature catalyst SCR system for installation upstream of the HRSG for four turbine installations ranging in size from 4.5 to 83 MW (6,030 to 111,000 hp). These high-temperature SCR system estimates include the catalyst reactor, air injection system for exhaust temperature control, ammonia storage and injection system, instrumentation, and continuous emission monitoring equipment. These SCR costs were estimated by the California Air Resources Board (CARB) in 1991 dollars and are based on NO_x emission levels of 42 ppmv into and 9 ppmv out of the SCR.[35] These estimated costs, shown in Appendix B, fit well within the range of costs from the 21 installations discussed above, and the equation of a line determined by linear regression adequately fits the data (R^2 = 0.76) for all 25 points. Based on this graph, the total capital cost for either a base-metal SCR system installed within the HRSG or a high-temperature zeolite catalyst SCR system installed directly downstream of the turbine can be calculated using the equation determined by the linear

TABLE 6-8. PROCEDURES FOR ESTIMATING CAPITAL AND ANNUAL COSTS FOR SCR CONTROL OF NO_x EMISSIONS FROM GAS TURBINES[a]

A. Total capital investment, $[b]	=	(49,700 x TMW) + 459,000
B. Direct annual costs, $/yr		
1. Operating labor[c]	=	(1.0 hr/8 hr-shift) x ($25.60/hr) x (H)
2. Supervisory labor	=	(0.15) x (operating labor)
3. Maintenance labor and materials	=	(1,250 x TMW) + 25,800
4. Catalyst replacement	=	(4,700 x TMW) + 37,200
5. Catalyst disposal[d]	=	(V) x ($15/$ft^3$) x (.2638)
6. Anhydrous ammonia[e]	=	(N) x ($360/ton)
7. Dilution steam[f]	=	(N) x (0.95/0.05) x (MW H_2O/MW NH_3) x ($6/1,000 lb steam) x (2,000 lb/ton)
8. Electricity[g]	=	N/A
9. Performance loss[h]	=	(0.005) x (TMW) x ($0.06/KWH) x (1,000 KW/MW) x (H)
10. Blower (if needed)	=	0.1 x (Performance Loss)
11. Production loss[i]	=	None
C. Indirect annual costs, $/yr		
1. Overhead	=	(0.6) x (all labor and maintenance material costs)
2. Property taxes, insurance, and administration	=	(0.04) x (total capital investment)
3. Capital recovery[j]	=	(0.13147) x [total capital investment - (catalyst replacement/0.2638)]

[a]All costs are in average 1990 dollars.

[b]TMW=turbine output in MW for each model plant.

[c]The annual operating hours are represented by the variable H. The labor rate of $25.60/hr is from Table 6-3.

[d]The catalyst volume in ft^3 is represented by the variable V. The catalyst volume for each model plant is estimated as V = (TMW) x (6,180 ft^3/83 MW).

[e]The ammonia requirement in tons is represented by the variable N and is calculated using a NH_3-to-NO_x molar ratio of 1.0.

The annual tonnage of NO_x is taken from the controlled levels shown in Tables 6-11 and 6-12.

[f]The ammonia is diluted with steam to 5 percent by volume before injection.

[g]The amount of electricity required for ammonia pumps and exhaust fans is not known, but is expected to be small. The electricity cost comprised less than 1 percent of the total annual cost estimated by the South Coast Air Quality Management District (SCAQMD) for SCR applied to a 1.1 MW turbine.

[h]Based on information from three sources, the backpressure from the SCR reduces turbine output by an average of about 0.9 percent.

[i]No production losses are estimated because it is assumed that all SCR maintenance, inspections, cleaning, etc. can be performed during the 760 hours of scheduled downtime per year.

[j]The capital recovery factor for the SCR is 0.13147, based on a 15-year equipment life and 10 percent interest rate. The catalyst is replaced every 5 years. The 0.2638 figure is the capital recovery factor for a 5-year equipment life and a 10 percent interest rate.

regression. This equation is shown in Table 6-8 and was used to calculate the total capital investment for SCR for each model plant shown in Tables 6-9 and 6-10.

TABLE 6-9. CAPITAL AND ANNUAL COSTS FOR SCR USED DOWNSTREAM OF WATER OR STEAM INJECTION (1990 $)

Model plant	GT model	Total capital investment, $[a]	Operating labor, $	Supervisory labor, $	Maintenance labor & materials, $	Catalyst replacement, $	Catalyst disposal, $	Ammonia, $	Dilution steam, $	Performance loss, $	Blower (if needed), $	Overhead, $	Taxes, insurance & admin, $	Capital recovery, $	Total annual cost, $
CON-G-W-3.3	Centaur T4500	622,000	25,600	3,840	29,900	52,600	963	2,980	1,770	7,850	785	35,600	24,900	55,600	242,000
CON-G-W-4.0	501-KB5	658,000	25,600	3,840	30,800	56,000	1,180	3,570	2,130	9,600	960	36,100	26,300	58,600	255,000
CON-G-W-22.7	LM2500	1,590,000	25,600	3,840	54,100	144,000	6,680	14,700	8,740	54,400	5,440	50,100	63,600	137,000	568,000
CON-G-W-26.8	MS5001P	1,790,000	25,600	3,840	59,300	163,000	7,900	22,400	13,300	64,300	6,430	53,200	71,600	154,000	645,000
CON-G-W-83.3	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,500	29,600	17,600	200,000	20,000	95,700	184,000	391,000	1,550,000
CON-G-W-84.7	MS7001E	4,670,000	25,600	3,840	132,000	435,000	25,000	62,000	36,900	203,000	20,300	96,900	187,000	397,000	1,620,000
CON-G-S-4.0	501-KB5	658,000	25,600	3,840	30,800	56,000	1,180	3,570	2,130	9,600	960	36,100	26,300	58,600	255,000
CON-G-S-22.7	LM2500	1,590,000	25,600	3,840	54,100	144,000	6,680	7,110	4,240	54,400	5,440	50,100	63,600	137,000	556,000
CON-G-S-26.8	MS5001P	1,790,000	25,600	3,840	59,300	163,000	7,900	22,400	13,300	64,300	6,430	53,200	71,600	154,000	645,000
CON-G-S-34.4	LM5000	2,170,000	25,600	3,840	68,900	199,000	10,100	10,700	6,380	82,700	8,270	59,000	86,800	186,000	747,000
CON-G-S-83.3	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,500	61,000	36,300	200,000	20,000	95,700	184,000	391,000	1,600,000
CON-G-S-84.7	MS7001E	4,670,000	25,600	3,840	132,000	435,000	25,000	62,000	36,900	203,000	20,300	96,900	187,000	397,000	1,620,000
CON-G-S-161	MS7001F	8,460,000	25,600	3,840	227,000	794,000	47,400	108,000	64,200	386,000	38,600	154,000	338,000	717,000	2,900,000
CON-O-W-3.3	Centaur T4500	622,000	25,600	3,840	29,900	52,600	963	3,890	2,320	7,850	785	35,600	24,900	55,600	244,000
CON-O-W-26.3	MS5001P	1,770,000	25,600	3,840	58,700	161,000	7,750	32,400	19,300	63,100	6,310	52,900	70,800	152,000	654,000
CON-O-W-83.3	MS7001E	4,600,000	25,600	3,840	130,000	429,000	24,500	90,000	53,800	200,000	20,000	95,700	184,000	391,000	1,650,000
PKR-G-W-3.3	Centaur T4500	622,000	6,400	960	7,470	13,100	241	740	440	1,960	196	8,900	24,900	75,300	141,000
PKR-G-W-26.8	MS5001P	1,790,000	6,400	960	14,800	40,800	1,970	5,600	3,330	16,100	1,610	13,300	71,600	215,000	391,000
PKR-G-W-84.7	MS7001E	4,670,000	6,400	960	32,900	109,000	6,240	15,500	9,240	50,800	5,080	24,200	187,000	560,000	1,010,000
PKR-O-W-3.3	Centaur T4500	622,000	6,400	960	7,470	13,100	241	970	580	1,960	196	8,900	24,900	75,300	141,000
PKR-O-W-26.3	MS5001P	1,770,000	6,400	960	14,700	40,200	1,940	8,100	4,830	15,800	1,580	13,200	70,800	213,000	392,000
PKR-O-W-84.7	MS7001E	4,600,000	6,400	960	32,500	107,000	6,140	22,500	13,440	50,000	5,000	23,900	184,000	552,000	1,000,000
STD-O-W-1.1	Saturn T1500	515,000	3,200	480	3,400	5,310	41.6	185	158	339	33.9	4,250	20,600	65,100	103,000
STD-O-E-28.0	TPM FT4	1,850,000	3,200	480	60,800	21,100	1,030	3,180	2,960	8,400	840	38,700	74,000	233,000	448,000

[a]Costs shown are for SCR systems used downstream of gas turbines with wet injection to achieve controlled NO_x emission levels at the inlet to the SCR as shown in Table 6-6.

TABLE 6-10. CAPITAL AND ANNUAL COSTS FOR SCR USED DOWNSTREAM OF LOW-NO_x COMBUSTION

Model plant [a]	GT model	Total capital invest., $ [b]	Operating labor,$	Super-visory labor, $	Main-tenance labor & materials, $	Catalyst replacement, $	Catalyst disposal, $	Ammonia,$	Dilution steam, $	Perfor-mance loss, $	Blower (if needed), $	Over-head, $	Taxes, insurance & admin., $	Capital recovery, $	Total annual cost, $
CON-L-3.3-42	Centaur T4500	622,000	25,600	3,840	29,900	52,700	970	2,980	1,770	7,920	790	35,600	24,900	55,500	242,000
CON-L-4.0-42	Centaur 'H'	658,000	25,600	3,840	30,800	56,000	1,180	3,470	2,070	9,600	960	36,100	26,300	58,600	255,000
CON-L-4.5-42	Taurus	683,000	25,600	3,840	31,400	58,400	1,330	3,800	2,270	10,800	1,080	36,500	27,300	60,700	263,000
CON-L-8.8-42	Mars T12000	896,000	25,600	3,840	36,800	78,600	2,590	6,850	4,080	21,100	2,110	39,700	35,800	78,600	336,000
CON-L-10-42	Mars T14000	956,000	25,600	3,840	38,300	84,200	2,950	7,530	4,490	24,000	2,400	40,600	38,200	83,700	356,000
CON-L-3.3-25	Centaur T4500	622,000	25,600	3,840	29,900	52,700	970	1,440	860	7,920	790	35,600	24,900	55,500	240,000
CON-L-4.0-25	Centaur 'H'	658,000	25,600	3,840	30,800	56,000	1,180	1,680	1,000	9,600	960	36,100	26,300	58,600	252,000
CON-L-4.5-25	Taurus	683,000	25,600	3,840	31,400	58,400	1,330	1,840	1,100	10,800	1,080	36,500	27,300	60,700	260,000
CON-L-8.8-25	Mars T12000	896,000	25,600	3,840	36,800	78,600	2,590	3,320	1,980	21,100	2,110	39,700	35,800	78,600	330,000
CON-L-10-25	Mars T14000	956,000	25,600	3,840	38,300	84,200	2,950	3,650	2,180	24,000	2,400	40,600	38,200	83,700	350,000
CON-L-39-25	MS6000	2,400,000	25,600	3,840	74,600	221,000	11,490	14,300	8,550	93,600	9,360	62,400	96,000	205,000	826,000
CON-L-83-25	ABB GT11N	4,600,000	25,600	3,840	130,000	429,000	24,540	29,600	17,600	200,000	20,000	95,700	184,000	391,000	1,550,000
CON-L-85-25	MS7001E	4,670,000	25,600	3,840	132,000	435,000	24,960	30,100	17,900	203,000	20,300	96,900	186,800	397,000	1,570,000
PKR-L-3.3-42	Centaur T4500	622,000	6,400	960	7,480	55,100	2,870	740	440	1,980	200	8,900	24,900	54,300	164,000
PKR-L-4.0-42	Centaur 'H'	658,000	6,400	960	7,700	107,000	6,140	870	520	2,400	240	9,000	26,300	33,200	201,000
PKR-L-4.5-42	Taurus	683,000	6,400	960	7,860	109,000	6,240	950	570	2,700	270	9,100	27,300	35,500	207,000
PKR-L-8.8-42	Mars T12000	896,000	6,400	960	9,200	9,300	0	1,710	1,020	5,280	530	9,900	35,800	113,000	193,000
PKR-L-10-42	Mars T14000	956,000	6,400	960	9,580	13,200	240	1,880	1,120	6,000	600	10,200	38,200	119,000	207,000
PKR-L-3.3-25	Centaur T4500	623,000	6,400	960	7,480	14,600	330	360	210	1,980	200	8,900	24,900	74,600	141,000
PKR-L-4.0-25	Centaur 'H'	658,000	6,400	960	7,700	19,600	650	420	250	2,400	240	9,000	26,300	76,800	151,000
PKR-L-4.5-25	Taurus	683,000	6,400	960	7,860	21,100	740	460	270	2,700	270	9,100	27,300	79,300	156,000
PKR-L-8.8-25	Mars T12000	896,000	6,400	960	9,200	9,300	0	830	490	5,280	530	9,900	35,800	113,000	192,000
PKR-L-10-25	Mars T14000	956,000	6,400	960	9,580	13,200	240	910	540	6,000	600	10,200	38,200	119,000	206,000
PKR-L-39-25	MS6000	2,400,000	6,400	960	18,600	14,000	290	3,590	2,140	23,400	2,340	15,600	96,000	309,000	492,000
PKR-L-83-25	ABB GT11N	4,600,000	6,400	960	32,500	14,600	330	7,390	4,410	50,000	5,000	23,900	184,000	598,000	927,000
PKR-L-85-25	MS7001E	4,670,000	6,400	960	32,900	19,600	650	7,520	4,480	50,800	5,080	24,200	186,800	604,000	943,000

[a]See Table 6-7 for model plant legend.

[b]Costs shown are for SCR systems used downstream of gas turbines with dry low-NO_x combustion to achieve controlled NO_x emission levels at the inlet to the SCR as shown in Table 6-7.

ii. Annual Costs

Total annual costs for SCR control were developed following standard EPA procedures described in the OAQPS Control Cost Manual for other types of add-on air pollution control devices (APCD's). Information about annual costs was obtained from the same sources that provided capital costs.[27-31] Total annual costs consist of direct and indirect costs; parameters that make up these categories and the equations for estimating the costs are

presented in Table 6-8 and are discussed below. The annual costs are shown in Tables 6-9 and 6-10 for injection and dry low-NO_x combustion, respectively, for each of the model plants.

(1) Operating and Supervisory Labor. Information about operating labor requirements was unavailable. Most facilities have fully automated controls and monitoring/recording equipment, which minimizes operator attention. Therefore, it was assumed that 1 hr of operator attention would be required during an 8-hr shift, regardless of turbine size. This operating labor requirement is at the low end of the range recommended in the OAQPS Control Cost Manual for other types of APCD's.[7] Operator wage rates were estimated to be $25.60/hr in 1990, based on escalating the costs presented in Reference 2 by 5 percent per year to account for inflation. Supervisory labor costs were estimated to be 15 percent of the operating labor costs, consistent with the OAQPS Control Cost Manual.

(2) Maintenance Labor and Materials. Combined maintenance labor and materials costs for 14 facilities were obtained from four articles, but almost half of the data (6 facilities) were provided by one source.[27-30] The costs were escalated to 1990 dollars assuming an inflation rate of 5 percent per year. All of the data are for facilities that burn natural gas. Provided that ammonium salt formation is avoided by limiting ammonia slip and sulfur content, the cost for operation with natural gas should also apply for distillate oil fuel.[32] Therefore, it was assumed that the cost data also apply to SCR control for turbines that fire distillate oil fuel. The costs were plotted versus the turbine size, and least-squares linear regression was used to determine the equation of the line through the data (see Appendix B). This equation, shown in Table 6-8, was used to estimate the maintenance labor and materials costs shown in Table 6-9 for the model plants.

(3) Catalyst Replacement. Replacement costs were obtained for nine gas turbine facilities, and combined replacement and disposal costs were obtained for another six gas turbine facilities.[27-30] The disposal costs were estimated for the six

facilities as described below and in Appendix B. The replacement costs for these six facilities were then estimated by subtracting the estimated disposal costs from the combined costs. A catalyst life of 5 years was used. All replacement costs were escalated to 1990 dollars assuming a 5 percent annual inflation rate.

The estimated 1990 replacement costs were plotted versus the turbine size, and least-squares linear regression was used to determine the equation of the line through the data (see Appendix B). This equation is shown in Table 6-8 and was used to estimate the catalyst replacement costs shown in Table 6-9 for the model plants.

(4) Catalyst Disposal. Catalyst disposal costs were estimated based on a unit disposal cost of $\$15/ft^3$, which was obtained from a zeolite catalyst vendor.[32] This cost was used for each model plant, but the disposal cost may in fact be higher for catalysts that contain heavy metals and are classified as hazardous wastes. The catalyst volume for each model plant was estimated based on information about the catalyst volume for one facility and the assumption that there is a direct relationship between the catalyst volume and the turbine output (i.e., the design space velocity is the same regardless of the SCR size). At one facility, 175 m^3 (6,180 ft^3) of catalyst is used in the SCR with an 83 MW (111,000 hp) turbine.[33] The disposal cost for this catalyst would be \$92,700, using a cost of $\$15/ft^3$.

(5) Ammonia. The annual ammonia (NH_3) requirement is calculated from the annual NO_x reduction achieved by the SCR system. Based on an NH_3/NO_x molar ratio of 1.0, the annual ammonia requirement, in tons, would equal the annual NO_x reduction, in tons, multiplied by the ratio of the molecular weights for NH_3 and NO_x. Anhydrous ammonia with a unit cost of \$360/ton was used.[34,35] The equation to calculate the annual cost for ammonia is shown in Table 6-8.

(6) Dilution Steam. As indicated in Section 5.3.1, steam is used to dilute the ammonia to about 5 percent by volume before injection into the HRSG. According to the OAQPS Control Cost

Manual, the cost to produce steam, or to purchase it, is about $6/1,000 lb.

(7) Electricity. Electricity requirements to operate such equipment as ammonia pumps and ventilation fans is believed to be small. For one facility, the cost of electricity to operate these components was estimated to make up less than 1 percent of the total annual cost, but it is not clear that the number and size of the fans and pumps represent a typical installation.[27] This cost for electricity is expected to be minor, however, for all installations and was not included in this analysis.

For high-temperature catalysts installed upstream of the HRSG, a blower may be required to inject ambient air into the exhaust to regulate the temperature and avoid temperature excursions above the catalyst design temperature range. The cost to operate the blower is calculated to be 10 percent of the fuel penalty.[35]

(8) Performance Loss. The performance loss due to backpressure from the SCR is approximately 0.5 percent of the turbine's design output.[34-36] To make up for this lost output, it was assumed that electricity would have to be purchased at a cost of $0.06/kWH, as indicated in Table 6-3.

(9) Production Loss. No costs for production losses were included in this analysis. It was assumed that scheduled inspections, cleaning, and other maintenance will coincide with the 760 hr/yr of expected or scheduled downtime. It should be recognized that adding the SCR system increases the overall system complexity and the probability of unscheduled outages. This factor should be taken into account when considering the addition of an SCR system.

(10) Overhead. Standard EPA procedures for estimating annual control costs include overhead costs that are equal to 60 percent of all labor and maintenance material costs.

(11) Property Taxes, Insurance, and Administration. According to standard EPA procedures for estimating annual control costs, property taxes, insurance, and administration

costs are equal to 4 percent of the total capital investment for the control system.

(12) Capital Recovery. The CRF for SCR was estimated to be 0.13147 based on the assumption that the equipment life is 15 years and the interest rate is 10 percent.

iii. Cost Effectiveness for SCR

As indicated in Section 5.4, virtually all gas turbine installations using SCR to reduce NO_x emissions also incorporate wet injection or low-NO_x combustors. The NO_x emission levels into the SCR, therefore, were in all cases taken to be equal to the controlled NO_x emission levels shown for these control techniques in Tables 6-6 and 6-7. The most common controlled NO_x emission limit for gas-fired SCR applications is 9 ppmv, referenced to 15 percent oxygen. The capital costs used in this analysis are expected to correspond to SCR systems sized to reduce controlled NO_x emissions ranging from 25 to 42 ppmv from gas-fired turbines to a controlled level of approximately 9 ppmv downstream of the SCR. Based on the controlled NO_x emission limits established by the Northeast States for Coordinated Air Use Management (NESCAUM), shown in Table 5-3, these SCR systems would reduce NO_x emissions to 18 ppmv for oil-fired applications. Cost-effectiveness figures for SCR in this analysis are therefore calculated based on controlled NO_x emission levels of 9 and 18 ppmv, corrected to 15 percent oxygen, for gas- and oil-fired SCR model plants, respectively.

Cost effectiveness for SCR used downstream of wet injection or dry low-NO_x combustion is shown in Tables 6-11

TABLE 6-11. COST-EFFECTIVENESS SUMMARY FOR SCR USED DOWNSTREAM OF GAS TURBINES WIT H WET INJECTION (1990 $)

Model plant	GT model	Turbine output, MW	NO_x emissions[a]				Total NO_x removed, tons/yr	Total annual cost, $[c]	Cost effective-ness, $/ton
			Inlet to SCR		Downstream of SCR				
			ppmv[b]	tons/yr	ppmv	[b] tons/yr			
CON-G-W-3.3	Centaur T4500	3.3	42	28.5	9.0	6.10	22.4	242,000	10,800
CON-G-W-4.0	501-KB5	4.0	42	34.2	9.0	7.32	26.8	255,000	9,500
CON-G-W-22.7	LM2500	22.7	42	140	9.0	30.0	110	568,000	5,160
CON-G-W-26.8	MS5001P	26.8	42	214	9.0	45.8	168	645,000	3,840
CON-G-W-83.3	ABB GT11N	83.3	25	347	9.0	125	222	1,550,000	6,980
CON-G-W-84.7	MS7001E	84.7	42	593	9.0	127	466	1,620,000	3,480
CON-G-S-4.0	501-KB5	4.0	42	34.2	9.0	7.32	26.8	255,000	9,500
CON-G-S-22.7	LM2500	22.7	25	83.5	9.0	30.0	53.4	556,000	10,400
CON-G-S-26.8	MS5001P	26.8	42	214	9.0	45.8	168	645,000	3,840
CON-G-S-34.4	LM5000	34.4	25	126	9.0	45.2	80.4	747,000	9,290
CON-G-S-83.3	ABB GT11N	83.3	42	583	9.0	125	458	1,600,000	3,490
CON-G-S-84.7	MS7001E	84.7	42	593	9.0	127	466	1,620,000	3,480
CON-G-S-161	MS7001F	161	42	1,030	9.0	221	809	2,900,000	3,580
CON-O-W-3.3	Centaur T4500	3.3	60	41.8	18.0	12.5	29.3	244,000	8,340
CON-O-W-26.3	MS5001P	26.3	65	337	18.0	93.3	244	654,000	2,690
CON-O-W-83.3	MS7001E	83.3	65	938	18.0	260	678	1,650,000	2,430
PKR-G-W-3.3	Centaur T4500	3.3	42	7.12	9.0	1.52	5.59	141,000	25,200
PKR-G-W-26.8	MS5001P	26.8	42	53.5	9.0	11.5	42.0	391,000	9,310
PKR-G-W-84.7	MS7001E	84.7	42	148	9.0	31.8	116	1,010,000	8,670
PKR-O-W-3.3	Centaur T4500	3.3	60	10.5	18.0	3.14	7.32	141,000	19,300
PKR-O-W-26.3	MS5001P	26.3	65	84.2	18.0	23.3	60.9	392,000	6,440
PKR-O-W-84.7	MS7001E	84.7	65	234	18.0	64.9	169	1,000,000	5,900
STD-O-W-1.1	Saturn T1500	1.1	60	1.99	18.0	0.60	1.39	103,000	74,000
STD-O-E-28.0	TPM FT4	28.0	50	37.3	18.0	13.4	23.9	448,000	18,800

[a]Example NO_x emission calculations are shown in Appendix A.
[b]Referenced to 15 percent oxygen.
[c]From Table 6-9.

TABLE 6-12. COST-EFFECTIVENESS SUMMARY FOR SCR USED DOWNSTREAM OF DRY LOW-NO_x COMBUSTION (1990 $)

Model plant[a]	GT model	Turbine output, MW	NO_x emissions[b] Uncontrolled ppmv[c]	Uncontrolled tons/yr	Inlet to SCR ppmv	Inlet to SCR tons/yr	Downstream of SCR ppmv	Downstream of SCR tons/yr	Total NO_x removed, tons/yr	Total annual cost, $[d]	Cost effectiveness, $/ton
CON-L-3.3-42	Centaur T4500	3.3	130	88.1	42	28.5	9.0	6.1	22.4	242,000	10,800
CON-L-4.0-42	Centaur 'H'	4.0	105	83.0	42	33.2	9.0	7.1	26.1	255,000	9,780
CON-L-4.5-42	Taurus	4.5	114	98.7	42	36.4	9.0	7.8	28.6	263,000	9,200
CON-L-8.8-42	Mars T12000	8.8	178	278	42	65.5	9.0	14.0	51.5	336,000	6,530
CON-L-10-42	Mars T14000	10.0	199	341	42	72.1	9.0	15.4	56.6	356,000	6,290
CON-L-3.3-25	Centaur T4500	3.3	130	88.1	25	16.9	9.0	6.1	10.8	240,000	22,100
CON-L-4.0-25	Centaur 'H'	4.0	105	83.0	25	19.8	9.0	7.1	12.6	252,000	19,900
CON-L-4.5-25	Taurus	4.5	114	98.7	25	21.7	9.0	7.8	13.9	260,000	18,800
CON-L-8.8-25	Mars T12000	8.8	178	278	25	39.0	9.0	14.0	25.0	330,000	13,200
CON-L-10-25	Mars T14000	10.0	199	341	25	42.9	9.0	15.4	27.5	350,000	12,800
CON-L-39-25	MS6000	39.0	220	1,480	25	168	9.0	61	108	826,000	7,660
CON-L-83-25	ABB GT11N	83.3	390	5,420	25	347	9.0	125	222	1,550,000	6,970
CON-L-85-25	MS7001E	84.7	154	2,180	25	353	9.0	127	226	1,570,000	6,940
PKR-L-3.3-42	Centaur T4500	3.3	130	22.0	42	7.12	9.0	1.52	5.6	164,000	29,300
PKR-L-4.0-42	Centaur 'H'	4.0	105	20.7	42	8.30	9.0	1.78	6.5	201,000	30,800
PKR-L-4.5-42	Taurus	4.5	114	24.7	42	9.09	9.0	1.95	7.1	207,000	29,000
PKR-L-8.8-42	Mars T12000	8.8	178	69.4	42	16.4	9.0	3.5	12.9	193,000	15,000
PKR-L-10-42	Mars T14000	10.0	199	85.4	42	18.0	9.0	3.9	14.2	207,000	14,600
PKR-L-3.3-25	Centaur T4500	3.3	130	22.0	25	4.24	9.0	1.52	2.7	141,000	52,000
PKR-L-4.0-25	Centaur 'H'	4.0	105	20.7	25	4.94	9.0	1.78	3.2	151,000	47,800
PKR-L-4.5-25	Taurus	4.5	114	24.7	25	5.41	9.0	1.95	3.5	156,000	45,000
PKR-L-8.8-25	Mars T12000	8.8	178	69.4	25	9.75	9.0	3.51	6.2	192,000	30,800
PKR-L-10-25	Mars T14000	10.0	199	85.4	25	10.7	9.0	3.9	6.9	206,000	30,000
PKR-L-39-25	MS6000	39.0	220	371	25	42.1	9.0	15.2	26.9	492,000	18,300
PKR-L-83-25	ABB GT11N	83.3	390	1,350	25	86.8	9.0	31.3	55.6	927,000	16,700
PKR-L-85-25	MS7001E	84.7	154	540	25	88.3	9.0	31.8	56.5	943,000	16,700

[a]See Table 6-7 for model plant legend.
[b]Example NO_x emission calculations are shown in Appendix A.
[c]Referenced to 15 percent oxygen.
[d]From Table 6-10.

and 6-12, respectively. For continuous-duty, natural gas-fired model plants using water or steam injection,the cost effectiveness for SCR ranges from approximately $3,500 to $10,800 per ton of NO_x removed.

The cost-effectiveness range for SCR installed downstream of continuous-duty, natural gas-fired turbines from 3 to 10 MW (4,000 to 13,400 hp) using dry low-NO_x combustion is $6,290 to $10,800 per ton of NO_x removed for an inlet NO_x emission level of 42 ppmv. The cost-effectiveness range for SCR increases for an

inlet NO_x emission level of 25 ppmv due to the lower NO_x reduction efficiency. For an inlet NO_x level of 25 ppmv, the cost effectiveness ranges from $12,800 to $22,100 per ton of NO_x removed for 3 to 10 MW (4,000 to 13,400 hp) turbines and decreases to $6,940 to $7,660 per ton of NO_x removed for larger turbines ranging from 39 to 85 MW (52,300 to 114,000 hp). As these ranges indicate, the cost effectiveness for SCR is affected by the inlet NO_x emission level and not the type of combustion control technique used for the turbine. The cost effectiveness for continuous-duty, oil-fired model plants ranges from approximately $2,450 to $8,350 per ton of NO_x removed. The SCR cost-effectiveness range for oil-fired applications is lower than that for gas-fired installations in this cost analysis because the same capital costs were used for both fuels (capital costs were not available for applications using only distillate oil fuel). The percent NO_x reduction for oil-fired applications is higher, so the resulting cost-effectiveness figures for oil-fired applications are lower. It should be noted that this higher NO_x reduction for oil-fired applications may require a larger catalyst reactor, at a higher capital cost. As a result, the cost-effectiveness figures may actually be higher than those shown in Table 6-11 for oil-fired applications.

The cost-effectiveness figures are higher for smaller gas turbines because the fixed capital costs associated with the installation of an SCR system have the greatest impact on smaller gas turbines. Cost-effectiveness figures increase as annual operating hours decrease. For turbines operating 2,000 hours per year, cost-effectiveness figures are more than double those for continuous-duty model plants, and they increase even further for model plants operating 1,000 hr/yr.

Because virtually all SCR systems are installed downstream of controlled gas turbines, combined cost-effectiveness figures for wet injection plus SCR and also dry low-NO_x combustion plus SCR have been calculated and are shown in Tables 6-13

TABLE 6-13. COMBINED COST-EFFECTIVENESS SUMMARY FOR WET INJECTION PLUS SCR (1990 $)

Model plant	GT model	Turbine output MW	NO_x emissions[a] Uncontrolled ppmv[b]	Uncontrolled tons/yr	Inlet to SCR ppmv	Inlet to SCR tons/yr	Downstream of SCR ppmv	Downstream of SCR tons/yr	Total NO_x removed, tons/yr[c]	Total annual cost, $[c]	Cost effective-ness, $/ton[c]
CON-G-W-3.3	Centaur T4500	3.3	130	88.1	42	28.5	9.0	6.10	82.0	366,000	4,460
CON-G-W-4.0	501-KB5	4.0	155	126	42	34.2	9.0	7.32	119	417,000	3,510
CON-G-W-22.7	LM2500	22.7	174	581	42	140	9.0	30	551	1,000,000	1,820
CON-G-W-26.8	MS5001P	26.8	142	723	42	214	9.0	46	677	1,220,000	1,800
CON-G-W-83.3	ABB GT11N	83.3	390	5,410	25	347	9.0	125	5,290	4,460,000	843
CON-G-W-84.7	MS7001E	84.7	154	2,170	42	593	9.0	127	2,040	3,100,000	1,520
CON-G-S-4.0	501-KB5	4.0	155	126	42	34.2	9.0	7.32	119	423,000	3,560
CON-G-S-22.7	LM2500	22.7	174	581	25	83.5	9.0	30.0	551	977,000	1,770
CON-G-S-26.8	MS5001P	26.8	142	723	42	214	9.0	45.8	677	1,130,000	1,670
CON-G-S-83.3	LM5000	34.4	185	930	25	126	9.0	45.2	884	1,440,000	1,630
CON-G-S-84.7	ABB GT11N	83.3	390	5,410	42	583	9.0	125	5,290	3,410,000	645
CON-G-S-84.7	MS7001E	84.7	154	2,170	42	593	9.0	127	2,040	2,780,000	1,360
CON-G-S-161	MS7001F	161	210	5,150	42	1,030	9.0	220	4,930	4,870,000	988
CON-O-W-3.3	Centaur T4500	3.3	179	125	60	42	18.0	12.5	112	387,000	3,450
CON-O-W-26.3	MS5001P	26.3	211	1,090	65	337	18.0	93.3	997	1,410,000	1,410
CON-O-W-83.3	MS7001E	83.3	228	3,290	65	938	18.0	260	3,030	3,230,000	1,070
PKR-G-W-3.3	Centaur T4500	3.3	130	22.0	42	7.1	9.0	1.5	20.5	222,000	10,800
PKR-G-W-26.8	MS5001P	26.8	142	181	42	53.5	9.0	11.5	169	690,000	4,080
PKR-G-W-84.7	MS7001E	84.7	154	543	42	148	9.0	31.8	512	1,710,000	3,340
PKR-O-W-3.3	Centaur T4500	3.3	179	31.2	60	10	18.0	3.14	28.1	228,000	8,130
PKR-O-W-26.3	MS5001P	26.3	211	273	65	84	18.0	23.3	250	751,000	3,000
PKR-O-W-84.7	MS7001E	84.7	228	822	65	234	18.0	64.9	757	1,710,000	2,260
STD-O-W-1.1	Saturn T1500	1.1	150	4.97 122	60	1.99	18.0	0.60	4.4	152,000	34,700
STD-O-E-28.0	TPM FT4	28.0	150		50	37.3	18.0	13.4	109	604,000	5,563

[a]Example NO_x emission calculations are shown in Appendix A.
[b]Referenced to 15 percent oxygen.
[c]Total for both wet injection plus SCR control techniques.

and 6-14, respectively. These combined cost-effectiveness

TABLE 6-14. COMBINED COST-EFFECTIVENESS SUMMARY FOR DRY LOW-NOx COMBUSTION PLUS SCR (1990 $)

Model plant	GT model	Turbine output MW	Annual operating hours	NO_x emissions[a] Uncontrolled ppmv[b]	Uncontrolled tons/yr	Inlet to SCR ppmv	Inlet to SCR tons/yr	Downstream of SCR ppmv	Downstream of SCR tons/yr	Total NO_x removed, tons/yr[c]	Total annual cost, $[c]	Cost effective-ness, $/ton[c]
CON-L-3.3-42	Centaur T4500	3.3	8,000	130	88.1	42	28.5	9.0	6.1	82.0	291,000	3,550
CON-L-4.0-42	Centaur 'H'	4.0	8,000	105	83.0	42	33.2	9.0	7.1	75.8	308,000	4,060
CON-L-4.5-42	Taurus	4.5	8,000	114	98.7	42	36.4	9.0	7.8	90.9	319,000	3,510
CON-L-8.8-42	Mars T12000	8.8	8,000	178	278	42	65.5	9.0	14.0	264	428,000	1,620
CON-L-10-42	Mars T14000	10.0	8,000	199	341	42	72.1	9.0	15.4	326	451,000	1,380
CON-L-3.3-25	Centaur T4500	3.3	8,000	130	88.1	25	16.9	9.0	6.1	82.0	289,000	3,520
CON-L-4.0-25	Centaur 'H'	4.0	8,000	105	83.0	25	19.8	9.0	7.1	75.8	305,000	4,020
CON-L-4.5-25	Taurus	4.5	8,000	114	98.7	25	21.7	9.0	7.8	90.9	316,000	3,470
CON-L-8.8-25	Mars T12000	8.8	8,000	178	278	25	39.0	9.0	14.0	264	422,000	1,600
CON-L-10-25	Mars T14000	10.0	8,000	199	341	25	42.9	9.0	15.4	326	445,000	1,370
CON-L-39-25	MS6000	39.0	8,000	220	1,480	25	168	9.0	60.6	1,420	1,010,000	711
CON-L-83-25	ABB GT11N	83.3	8,000	390	5,420	25	347	9.0	125	5,290	1,840,000	348
CON-L-85-25	MS7001E	84.7	8,000	154	2,180	25	353	9.0	127	2,050	1,850,000	902
PKR-L-3.3-42	Centaur T4500	3.3	2,000	130	22.0	42	7.1	9.0	1.5	20.5	213,000	10,400
PKR-L-4.0-42	Centaur 'H'	4.0	2,000	105	20.7	42	8.3	9.0	1.8	19.0	254,000	13,400
PKR-L-4.5-42	Taurus	4.5	2,000	114	24.7	42	9.1	9.0	1.9	22.7	263,000	11,600
PKR-L-8.8-42	Mars T12000	8.8	2,000	178	69.4	42	16.4	9.0	3.5	65.9	285,000	4,320
PKR-L-10-42	Mars T14000	10.0	2,000	199	85.4	42	18.0	9.0	3.9	81.5	302,000	3,710
PKR-L-3.3-25	Centaur T4500	3.3	2,000	130	22.0	25	4.2	9.0	1.5	20.5	190,000	9,300
PKR-L-4.0-25	Centaur 'H'	4.0	2,000	105	20.7	25	4.9	9.0	1.8	19.0	204,000	10,800
PKR-L-4.5-25	Taurus	4.5	2,000	114	24.7	25	5.4	9.0	1.9	22.7	212,000	9,300
PKR-L-8.8-25	Mars T12000	8.8	2,000	178	69.4	25	9.8	9.0	3.5	65.9	284,000	4,300
PKR-L-10-25	Mars T14000	10.0	2,000	199	85.4	25	10.7	9.0	3.9	81.5	301,000	3,700
PKR-L-39-25	MS6000	39.0	2,000	220	371	25	42.1	9.0	15.2	355	680,000	1,910
PKR-L-83-25	ABB GT11N	83.3	2,000	390	1,350	25	86.8	9.0	31.3	1,320	1,220,000	924
PKR-L-85-25	MS7001E	84.7	2,000	154	540	25	88.3	9.0	31.8	508	1,220,000	2,400

[a]Example NO_x emission calculations are shown in Appendix A.
[b]Referenced to 15 percent oxygen.
[c]Total for both dry low-NO_x combustion plus SCR control techniques.

figures are calculated by dividing the sum of the total annual costs by the

sum of the annual reduction of NO_x emissions for the combined emission control techniques. For continuous-duty, natural gas-fired model plants, the combined cost-effectiveness figures for wet injection plus SCR range from approximately $650 to $4,500 per ton of NO_x removed. For continuous-duty, oil-fired model plants, the combined cost effectiveness ranges from approximately $1,100 to $3,550 per ton of NO_x removed. The combined cost-effectiveness figures for dry low-NO_x combustion plus SCR for continuous-duty, natural gas-fired model plants range from approximately $350 to $3,550 per ton of NO_x removed.

The combined cost-effectiveness figures increase with decreasing turbine size and annual operating hours. Data were not available to quantify the wet injection requirements and controlled emissions levels for oil-fired turbines with low-NO_x combustors, so cost-effectiveness figures were not tabulated for this control scenario.

d. OFFSHORE TURBINES

The only available information about the cost of NO_x controls for offshore gas turbines was presented in a report prepared for the Santa Barbara County Air Pollution Control District (SBCAPCD) in California.[37] The performance and cost of about 20 NO_x control techniques for a 2.8 MW (3,750 hp) turbine were described in the report. Wet injection and SCR were included in the analysis; low-NO_x combustors were not. The costs from the report are presented in Table 6-15

TABLE 6-15. PROJECTED WET INJECTION AND SCR COSTS FOR AN OFFSHORE GAS TURBINE[a]

	Wet injection costs	SCR costs
Capital cost, $	70,000	585,000
Annual costs, $/yr		
Ammonia	N/A[b]	3,050[c]
Catalyst replacement	N/A	28,000
Operating and maintenance[d]	24,600	18,000
Fuel penalty[e]	10,500	5,000
Capital recovery[f]	14,000	117,000
Total annual costs, $/yr	49,100	171,000

[a]Costs are for a 2.8 MW gas turbine and are obtained from Reference 37.

[b]N/A = Not applicable.

[c]Ammonia cost is based on $150/ton and 0.4 lb NH_3/lb NO_X.

[d]Operating and maintenance cost for SCR is estimated as 3 percent of the total capital investment.

[e]Fuel penalty is estimated as 2 percent of the annual fuel consumption for wet injection and 1 percent for SCR.

[f]Capital recovery is estimated based on an equipment life of 8 years and an interest rate of 13 percent.

without adjustment because there is insufficient cost information to know what adjustments need to be made. Additionally, insufficient information is available to scale up these costs for larger turbines. The water and steam injection costs and SCR costs for offshore applications are discussed in Sections 6.4.1 and 6.4.2, respectively.

i. Wet Injection

The report prepared for SBCAPCD assumed water injection costs are the same as steam injection costs. The report did not describe the components in the capital cost analysis for these injection systems, but the results are much lower than those that would be estimated by the procedures described in Section 6.1.1 of this report. The authors may have assumed that the engine-mounted injection equipment cost was included in the turbine capital cost and that a less rigorous water treatment process is installed. Annual costs are also much lower than those that would be estimated by the procedures described in Section 6.1.2 of this report. There are at least three reasons for the difference: (1) the low capital cost leads to a low CRF, even though the turbine life was assumed to be only 8 years; (2) overhead costs and taxes, insurance, and administration costs are not considered; and (3) the capacity factor is only 50 percent (i.e., about 4,400 hr/yr, vs. 8,000 hr/yr, as in Section 6.1.2). The turbine life was only 8 years, which may correspond to a typical service life of an offshore platform.

ii. Selective Catalytic Reduction

The total capital costs presented in the report for SBCAPCD are similar to those that would be estimated by the procedures in Section 6.2.1 of this report. However, it appears that $150,000 of the total in Reference 37 is for structural modifications to the platform and $75,000 is for retrofit installation. When the difference in the load factor is taken into account, some of the annual costs are similar to those that would be estimated by the procedures in Section 6.2.2 for a similarly sized turbine. The catalyst replacement cost, however, is much lower; neither the type of catalyst nor the replacement frequency were identified. Ammonia costs are lower because the uncontrolled NO_x emission level was assumed to be 110 ppmv instead of 150 ppmv and because a unit cost of $150/ton was used instead of $400/ton. The reference does not indicate whether or not catalyst disposal, overhead, taxes, freight, and administration costs were considered. Capital recovery costs are higher because the equipment life is assumed to be only 8 years on the offshore platform.

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7..0 ENVIRONMENTAL AND ENERGY IMPACTS

This chapter presents environmental and energy impacts for the nitrogen oxide (NO_x) emissions control techniques described in Chapter 5.0. These control techniques are water or steam injection, dry low-NO_x combustors, and selective catalytic reduction (SCR). The impacts of the control techniques on air pollution, solid waste disposal, water pollution, and energy consumption are discussed.

The remainder of this chapter is organized in five sections. Section 7.1 presents the air pollution impacts; Section 7.2 presents the solid waste disposal impacts; Section 7.3 presents the water pollution impacts; and Section 7.4 presents the energy consumption impacts. References for the chapter are listed in Section 7.5.

a. AIR POLLUTION

i. Emission Reductions

Applying any of the control techniques discussed in Chapter 5 will reduce NO_x emissions from gas turbines. These emission reductions were estimated for the model plants presented in Table 6-1 and are shown in Table 7-1. For each model plant, the uncontrolled and controlled emissions, emission reductions, and percent reductions are presented. The following paragraphs discuss NO_x emission reductions for each control technique.

Nitrogen oxide emission reductions for water or steam injection are estimated as discussed in Section 6.1.3. The percent reduction in emissions from uncontrolled levels varies for each model plant ranging, from 60 to 96 percent. This reduction depends on each model's uncontrolled emissions, the

TABLE 7-1. MODEL PLANT UNCONTROLLED AND CONTROLLED NO_x EMISSIONS FOR AVAILABLE NO_x CONTROL TECHNIQUES

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions[a]	Uncon-trolled NO_x emissions,[a] tons/yr	Controlled NO_x emissions, tons/year					SCR NH_3 emissions @ SLIP = 10 ppm (tons/yr)[c]
					Wet injection to levels in Table 6-6	Dry low-NO_x combustor to 42 ppmv	Dry low-NO_x combustor to 25 ppm	Dry low-NO_x combustor to 9 ppmv	NO_x emissions, wet injection + SCR[b]	
Centaur T4500	8,000	Water	Emissions, tons/yr	88.1	28.5	28.5	16.9	NA[d]	6.10	2.92
3.3 MW			Reduction, tons/yr		59.6	59.6	71.2	–	22.4	
Gas fuel			Total reduction, %		68%	68%	81%	–	93%	
501-KB5	8,000	Water	Emissions, tons/yr	126	34.2	NA	NA	NA	7.32	2.58
4.0 MW			Reduction, tons/yr		91.8	–	–	–	26.9	
Gas fuel			Total reduction, %		73%	–	–	–	94%	
LM2500	8,000	Water	Emissions, tons/yr	581	140	NA	NA	NA	30.0	11.2
22.7 MW			Reduction, tons/yr		441	–	–	–	110	
Gas fuel			Total reduction, %		76%	–	–	–	95%	
MS5001P	8,000	Water	Emissions, tons/yr	723	214	NA	NA	NA	45.8	20.4
26.8 MW			Reduction, tons/yr		509	–	–	–	168	
Gas fuel			Total reduction, %		70%	–	–	–	94%	
ABB GT11N	8,000	Water	Emissions, tons/yr	5,410	347	NA	347	125	125	51.7
83.3 MW			Reduction, tons/yr		5,060	–	5060	5290	222	
Gas fuel			Total reduction, %		94%	–	94%	98%	98%	
MS7001E	8,000	Water	Emissions, tons/yr	2,170	593	NA	353	127	127	49.6
84.7 MW			Reduction, tons/yr		1580	–	1820	2040	466	
Gas fuel			Total reduction, %		73%	–	84%	94%	94%	
501-KB5	8,000	Steam	Emissions, tons/yr	126	34.2	NA	NA	NA	7.32	2.58
4.0 MW			Reduction, tons/yr		92	–	–	–	26.9	
Gas fuel			Total reduction, %		73%	–	–	–	94%	
LM2500	8,000	Steam	Emissions, tons/yr	581	83.5	NA	NA	NA	30.0	11.2
22.7 MW			Reduction, tons/yr		498	–	–	–	53.5	
Gas fuel			Total reduction, %		86%	–	–	–	95%	
MS5001P	8,000	Steam	Emissions, tons/yr	723	214	NA	NA	NA	45.8	20.4
26.8 MW			Reduction, tons/yr		509	–	–	–	168	
Gas fuel			Total reduction, %		70%	–	–	–	94%	

TABLE 7-1. (continued)

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions[a]	Uncontrolled NO_x emissions,[a] tons/yr	Controlled NO_x emissions, tons/year: Wet injection to levels in Table 6-6	Dry low-NO_x combustor to 42 ppmv	Dry low-NO_x combustor to 25 ppm	Dry low-NO_x combustor to 9 ppmv	NO_x emissions, wet injection + SCR[b]	SCR NH_3 emissions @ SLIP = 10 ppm (tons/yr)[c]
LM5000	8,000	Steam	Emissions, tons/yr	930	126	NA	NA	NA	45.2	20.5
34.4 MW			Reduction, tons/yr		804	_	_	_	80.8	
Gas fuel			Total reduction, %		86%	_	_	_	95%	
ABB GT11N	8,000	Steam	Emissions, tons/yr	5,410	583	NA	347	125	125	51.7
83.3 MW			Reduction, tons/yr		4830	_	5060	5290	458	
Gas fuel			Total reduction, %		89%	_	94%	98%	98%	
MS7001E	8,000	Steam	Emissions, tons/yr	2,170	593	NA	353	127	127	49.6
84.7 MW			Reduction, tons/yr		1580	_	1820	2040	466	
Gas fuel			Total reduction, %		73%	_	84%	94%	94%	
MS7001F	8,000	Steam	Emissions, tons/yr	5,150	1,030	NA	610	NA	221	71.7
161 MW			Reduction, tons/yr		4120	_	4540	_	809	
Gas fuel			Total reduction, %		80%	_	88%	_	96%	
Centaur T4500	8,000	Water	Emissions, tons/yr	125	41.8	NA	NA	NA	12.5	2.9
3.3 MW			Reduction, tons/yr		83.2	_	_	_	29.3	
Oil fuel			Total reduction, %		67%	_	_	_	90%	
MS5001P	8,000	Water	Emissions, tons/yr	1,090	337	NA	NA	NA	46.6	20.4
26.3 MW			Reduction, tons/yr		753	_	_	_	290	
Oil fuel			Total reduction, %		69%	_	_	_	96%	
MS7001E	8,000	Water	Emissions, tons/yr	3,290	938	NA	NA	NA	130	49.6
83.3 MW			Reduction, tons/yr		2350	_	_	_	808	
Oil fuel			Total reduction, %		71%	_	_	_	96%	
Centaur T4500	2,000	Water	Emissions, tons/yr	22.0	7.1	NA	NA	NA	1.5	0.7
3.3 MW			Reduction, tons/yr		14.9	_	_	_	6	
Gas fuel			Total reduction, %		68%	_	_	_	93%	
MS5001P	2,000	Water	Emissions, tons/yr	181	53.5	NA	NA	NA	11.5	5.1
26.8 MW			Reduction, tons/yr		128	_	_	_	42	
Gas fuel			Total reduction, %		70%	_	_	_	94%	

TABLE 7-1. (continued)

Gas turbine model	Annual operating hours	Type of wet injection	Annual emissions[a]	Uncontrolled NO_x emissions,[a] tons/yr	Controlled NO_x emissions, tons/year: Wet injection to levels in Table 6-6	Dry low-NO_x combustor to 42 ppmv	Dry low-NO_x combustor to 25 ppm	Dry low-NO_x combustor to 9 ppmv	NO_x emissions, wet injection + SCR[b]	SCR NH_3 emissions @ SLIP = 10 ppm (tons/yr)[c]
MS7001E	2,000	Water	Emissions, tons/yr	543	148	NA	88	32	31.8	12.4
84.7 MW			Reduction, tons/yr		395	_	455	511	116	
Gas fuel			Total reduction, %		73%	_	84%	94%	94%	
Centaur T4500	2,000	Water	Emissions, tons/yr	31.2	10.0	NA	NA	NA	3.14	0.7
3.3 MW			Reduction, tons/yr		21.2	_	_	_	6.9	
Oil fuel			Total reduction, %		68%	_	_	_	90%	
MS5001P	2,000	Water	Emissions, tons/yr	273	84	NA	NA	NA	23.3	5.1
26.8 MW			Reduction, tons/yr		189	_	_	_	61	
Oil fuel			Total reduction, %		69%	_	_	_	91%	
MS7001E	2,000	Water	Emissions, tons/yr	822	234	NA	NA	NA	64.9	12.4
84.7 MW			Reduction, tons/yr		588	_	_	_	169	
Oil fuel			Total reduction, %		72%	_	_	_	92%	
SATURN T1500	1,000	Water	Emissions, tons/yr	5.00	1.99	NA	NA	NA	0.30	0.13
1.1 MW			Reduction, tons/yr		3	_	_	_	1.7	
Oil fuel			Total reduction, %		60%	_	_	_	94%	
TPM FT4	1,000	Water-in-	Emissions, tons/yr	977	37.3	NA	NA	NA	6.72	NC[e]
28.0 MW		oil	Reduction, tons/yr		940	_	_	_	30.6	_
Oil fuel		emulsion	Total reduction, %		96%	_	_	_	99%	_

[a]Uncontrolled and controlled NO_x emissions are from cost-effectiveness tables in Chapter 6.
[b]Controlled NO_x emission level for wet injection plus SCR is 9 ppmv for natural gas fuel and 18 ppmv for distillate oil fuel.
[c]Ammonia emissions, in tons per year = (SLIP, ppmv) x (MM/1,000,000) x (GT exhaust,lb/sec) x (MW NH3 = 15/MW exhaust = 28.6) x (3,600 sec/hr) x (ton/2,000 lb) x (annual operating hrs).
[d]NA-control technology not available for this model plant.
[e]NC-data not available to calculate emissions for this control scenario.

water-to-fuel ratio (WFR), and type of fuel and whether water or steam is injected.

Achievable emission levels from gas turbines using dry low-NO_x combustors were obtained from manufacturers. Controlled NO_x levels of 42, 25, and 9 parts per million, by volume (ppmv), referenced to 15 percent oxygen, were reported by the various turbine manufacturers, and each of these levels is shown in Table 7-1, where applicable, for each model plant. The percent reduction in NO_x emissions from uncontrolled levels for gas turbines using these combustors ranges from 68 to 98 percent. Virtually all SCR units installed in the United States are used in combination with either wet controls or combustion controls. For this analysis, emission reductions were calculated for SCR in combination with water or steam injection. Using the turbine manufacturers' guaranteed NO_x emissions figures for wet injection and a controlled NO_x emission level of 9 ppmv, referenced to 15 percent oxygen, exiting the SCR, the percent reduction in NO_x emissions for this combination of control techniques ranges from 93 to 99 percent.

Estimated ammonia (NH_3) emissions, in tons per year, corresponding to ammonia slip from the SCR system are also shown in Table 7-1. These estimates are based on an ammonia slip level of 10 ppmv, consistent with information and data presented in Section 5.4. For continuous-duty model plants, the annual NH_3 emissions range from approximately 3 tons for a 3.3 megawatt (MW) (4,425 horsepower [hp]) model plant to 72 tons for a 160 MW (215,000 hp) model plant.

ii. <u>Emissions Trade-Offs</u>

The formation of both thermal and fuel NO_x depends upon combustion conditions. Water/steam injection, lean combustion, and reduced residence time modify combustion conditions to reduce the amount of NO_x formed. These combustion modifications may increase carbon monoxide (CO) and unburned hydrocarbon (HC) emissions. Using SCR to control NO_x emissions produces ammonia emissions. The impacts of these NO_x controls on CO, HC, and ammonia emissions are discussed below.

(1) Impacts of Wet Controls on CO and HC Emissions. As discussed in Section 5.1.5, wet injection may increase CO and HC emissions. Injecting water or steam into the flame area of a turbine combustor lowers the flame temperature and thereby reduces NO_x emissions. This reduction in temperature to some extent inhibits complete combustion, resulting in increased CO and HC emissions. Figure 5-12 shows the impact of water and steam injection on CO emissions for production gas turbines.[2] The impact of steam injection on CO emissions is less than that of water injection. As seen in Figure 5-12, CO emissions increase with increasing WFR's. Wet injection increases HC emissions to a lesser extent than it increases CO emissions. Figure 5-13 shows the impact of water injection on HC emissions for one turbine. In cases where water and steam injection result in excessive CO and HC emissions, an oxidation catalyst (add-on control) can be installed to reduce these emissions by converting the CO and HC to water (H_2O) and carbon dioxide (CO_2).

(2) Impacts of Combustion Controls on CO and HC Emissions. As discussed in Section 5.2.1, the performance of lean combustion in limiting NO_x emissions relies in part on reduced equivalence ratios. As the equivalence ratio is reduced below the stoichiometric level of 1.0, combustion flame temperatures drop, and as a result NO_x emissions are reduced. Shortening the residence time in the high-temperature flame zone also will reduce the amount of thermal NO_x formed. These lower equivalence ratios and/or reduced residence time, however, may result in incomplete combustion, which may increase CO and HC emissions. The extent of the increase in CO and HC emissions is specific to each turbine manufacturer's combustor designs and therefore varies for each turbine model. As with wet injection, if necessary, an oxidation catalyst can be installed to reduce excessive CO and HC emissions by converting the CO and HC to CO_2 and H_2O.

(3) Ammonia Emissions from SCR. The SCR process reduces NO_x emissions by injecting NH_3 into the flue gas. The NH_3 reacts with NO_x in the presence of a catalyst to form H_2O and nitrogen

(N_2). The NO_x removal efficiency of this process is partially dependent on the NH_3/NO_x ratio. Increasing this ratio reduces NO_x emissions but increases the probability that unreacted ammonia will pass through the catalyst unit into the atmosphere (known as ammonia "slip"). Some ammonia slip is unavoidable because of ammonia injection control limitations and imperfect distribution of the reacting gases. A properly designed SCR system will limit ammonia slip to less than 10 ppmv (see Section 5.4).

b. SOLID WASTE DISPOSAL

Catalytic materials used in SCR units for gas turbines include precious metals (e.g., platinum), zeolites, and heavy metal oxides (e.g., vanadium, titanium). Vanadium pentoxide, the most commonly used SCR catalyst in the United States, is identified as an acute hazardous waste under RCRA Part 261, Subpart D - Lists of Hazardous Wastes. The Best Demonstrated Available Technology (BDAT) Treatment Standards for Vanadium P119 and P120 states that spent catalysts containing vanadium pentoxide are not classified as hazardous waste.[1] State and local regulatory agencies, however, are authorized to establish their own hazardous waste classification criteria, and spent catalysts containing vanadium pentoxide may be classified as a hazardous waste in some areas. Although the actual amount of vanadium pentoxide contained in the catalyst bed is small, the volume of the catalyst unit containing this material is quite large and disposal can be costly. Where classified by State or local agencies as a hazardous waste, this waste may be subject to the Land Disposal Restrictions in 40 CFR Part 268, which allows land disposal only if the hazardous waste is treated in accordance with Subpart D - Treatment Standards. Such disposal problems are not encountered with other catalyst materials, such as precious metals and zeolites, because these materials are not hazardous wastes.

c. WATER USAGE AND WASTE WATER DISPOSAL

Water availability and waste water disposal are environmental factors to be considered with wet injection. The impact of water usage on the water supply at some remote sites, in small communities, or in areas where water resources may be limited is an environmental factor that should be examined when considering wet injection. The volume of water required for wet injection is shown in Table 7-2

TABLE 7-2. WATER AND ELECTRICITY CONSUMPTION FOR NO_x CONTROL TECHNIQUES

Gas turbine model[a]	Turbine power output, MW	Annual operating hours	Fuel type	Type of emission control	Total water flow, gal/min[a]	Waste water flow, gal/min[b]	Water pump power, kW[c]	Wet injection power consumption, kW-hr/yr[d]	SCR power penalty, kW-hr/yr[e]
Centaur T4500	3.3	8,000	Gas	Water inj.	2.5	0.73	0.40	3,220	132,000
501-KB5	4.0	8,000	Gas	Water inj.	3.94	1.14	0.63	5,070	160,000
LM2500	22.7	8,000	Gas	Water inj.	14.8	4.29	2.38	19,100	908,000
MS5001P	26.8	8,000	Gas	Water inj.	22.2	6.44	3.57	28,600	1,070,000
ABB GT11N	83.3	8,000	Gas	Water inj.	154	44.7	24.8	198,000	3,330,000
MS7001E	84.7	8,000	Gas	Water inj.	69.2	20.1	11.1	89,100	3,390,000
501-KB5	4.0	8,000	Gas	Steam inj.	7.38	2.14	1.19	9,510	160,000
LM2500	22.7	8,000	Gas	Steam inj.	29.5	8.56	4.75	38,000	908,000
MS5001P	26.8	8,000	Gas	Steam inj.	33.3	9.66	5.36	42,900	1,070,000
LM5000	34.4	8,000	Gas	Steam inj.	50.8	14.7	8.18	65,400	1,380,000
ABB GT11N	83.3	8,000	Gas	Steam inj.	178	51.6	28.7	229,000	3,330,000
MS7001E	84.7	8,000	Gas	Steam inj.	104	30.2	16.7	134,000	3,390,000
MS7001F	161	8,000	Gas	Steam inj.	199	57.7	32.0	256,000	6,440,000
Centaur T4500	3.3	8,000	Oil	Water inj.	2.76	0.80	0.44	3,550	132,000
MS5001P	26.3	8,000	Oil	Water inj.	26.7	7.74	4.30	34,400	1,050,000
MS7001E	83.3	8,000	Oil	Water inj.	63.8	18.5	10.3	82,200	833,000
Centaur T4500	3.3	2,000	Gas	Water inj.	2.50	0.73	0.40	3,220	33,000
MS5001P	26.3	2,000	Gas	Water inj.	22.2	6.44	3.57	28,600	263,000
MS7001E	84.7	2,000	Gas	Water inj.	69.2	20.1	11.1	89,100	847,000
Centaur T4500	3.3	2,000	Oil	Water inj.	2.76	0.80	0.44	3,550	33,000
MS5001P	26.3	2,000	Oil	Water inj.	26.7	7.74	4.30	34,400	263,000
MS7001E	84.7	2,000	Oil	Water inj.	63.8	18.5	10.3	82,200	847,000
SATURN T1500	1.1	1,000	Oil	Water inj.	0.81	0.23	0.13	1,040	5,500
TPM FT4	28.0	1,000	Oil	Water-in-oil emulsion	21.7	6.29	3.49	27,900	140,000

[a]From Table 6-2.
[b]Calculated as 29 percent of the total water flow.
[c]Power requirement for water pump is calculated as shown in Section 6.1.2.2.

for each model plant.

Water purity is essential for wet injection systems in order to prevent erosion and/or the formation of deposits in the hot sections of the gas turbine. Water treatment systems are used to achieve water quality specifications set by gas turbine manufacturers. Table 5-4 summarizes these specifications for six manufacturers.

Discharges from these water treatment systems have a potential impact on water quality. As indicated in Section 6.1, approximately 29 percent of the treated water flow rate (22.5 percent of the raw water flow rate) is considered to be discharged as wastewater. The wastewater flow rates for each of the model plants with a water or steam injection control system are estimated using this factor, and the results are presented in Table 7-2. The wastewater contains increased levels of those pollutants in the raw water (e.g., calcium, silica, sulfur, as listed in Table 5-4) that are removed by the water treatment system, along with any chemicals introduced by the treatment process. Based on a wastewater flowrate equal to 29 percent of the influent raw water, the concentration of pollutants discharged from the water treatment system is approximately three times higher than the pollutant concentrations in the raw water.

The impacts of these pollutants on water quality are site-specific and depend on the type of water supply and on the discharge restrictions. Influent water obtained from a municipality will not contain high concentrations of pollutants. However, surface water or well water used at a remote site might contain high pollutant concentrations and may require additional pretreatment to meet the water quality specifications set by manufacturers. This additional pretreatment will increase the pollutant concentrations of the wastewater discharge. Wastewater discharges to publicly-owned treatment works (POTW's) must meet the requirements of applicable Approved POTW Pretreatment Programs.

d. ENERGY CONSUMPTION

Additional fuel and electrical energy is required over baseline for wet injection controls, while additional electrical energy is required for SCR controls. The following paragraphs discuss these energy consumption impacts.

Injecting water or steam into the turbine combustor lowers the net cycle efficiency and increases the power output of the turbine. The thermodynamic efficiency of the combustion process is reduced because energy that could otherwise be available to perform work in the turbine must now be used to heat the water/steam. This lower efficiency is seen as an increase in fuel use. Table 5-10 shows the impacts of wet injection on gas turbine performance for one manufacturer. This table shows a 2 to 4 percent loss in efficiency associated with WFR's required to achieve NO_x emission levels of 25 to 42 ppmv in gas turbines burning natural gas. The actual efficiency loss is specific to each turbine model but generally increases with increasing WFR's and is higher for water injection than for steam injection (additional energy is required to heat and vaporize the water). One exception to this efficiency penalty occurs with steam injection, in which exhaust heat from the gas turbine is used to generate the steam for injection. If the heat recovered in generating the steam would otherwise be exhausted to atmosphere, the result is an increase in net cycle efficiency.

The energy from the increased mass flow and heat capacity of the injected water/steam can be recovered in the turbine, resulting in an increase in power output accompanying the reduced efficiency of the turbine (shown in Table 5-10 for one manufacturer). This increase in power output can be significant and could lessen the impact of the loss in efficiency if the facility has a demand for the available excess power.

Water and steam injection controls also require additional electrical energy to operate the water injection feed water pumps. The annual electricity usage for each model is the product of the pump power demand, discussed in Section 6.1.2.2, and the annual hours of operation. Table 7-2 summarizes this electricity usage for each of the model plants.

For SCR units, additional electrical energy is required to operate ammonia pumps and ventilation fans. This energy requirement, however, is believed to be small and was not included in this analysis.

The increased back-pressure in the turbine exhaust system resulting from adding an SCR system reduces the power output from the turbine. As discussed in Section 6.3.2.9, the power output is typically reduced by approximately 0.5 percent. This power penalty has been calculated for each model plant and is shown in Table 7-2.

e. REFERENCE FOR CHAPTER 7

1.. 55 FR 22276, June 1, 1990.

APPENDIX A

Exhaust NO_x emission levels were provided by gas turbine manufacturers in units of parts per million, by volume (ppmv), on a dry basis and corrected to 15 percent oxygen. A method of converting these exhaust concentration levels to a mass flow rate of pounds of NO_x per hour (lb NO_x/hr) was provided by one gas turbine manufacturer.[1] This method uses an emission index ($EINO_x$), in units of lb NO_x/1,000 lb fuel, which is proportional to the exhaust NO_x emission levels in ppmv by a constant, K. The relationship between $EINO_x$ and ppmv for NO_x emissions is stated in Equation 1 below and applies for complete combustion of a hydrocarbon fuel and combustion air having no CO_2 and an O_2 mole percent of 20.95:

$$\frac{NO_x \text{ Ref. } 15\% \; 0_2}{EINO_x} = K \qquad \text{Equation 1}$$

where: NO_x Ref. 15% 0_2 = NO_x, ppmvd @15% O_2 (provided by gas turbine manufacturers);

$EINO_x$ = NO_x emission index, lb NO_x/1,000 lb fuel; and

K = constant, based on the molar hydrocarbon ratio of the fuel.

The derivation of Equation 1 was provided by the turbine manufacturer and is based on basic thermodynamic laws and supported by test data provided by the manufacturer. According to the manufacturer, this equation can be used to estimate NO_x emissions for operation with or without water/steam injection.

Equation 1 shows that NO_x emissions are dependent only upon the molar hydrocarbon ratio of the fuel and are independent of the air/fuel ratio (A/F). The equation therefore is valid for all gas turbine designs for a given fuel. The validity of this approach to calculate NO_x emissions was supported by a second turbine manufacturer.[2] Values for K were provided for several fuels and are given below:[1,2]

Pipeline quality natural gas:

K = 12.1

Distillate fuel oil No. 1 (DF-1):

K = 13.1

Distillate fuel oil No. 2 (DF-2):

K = 13.2

Jet propellant No. 4 (JP-4):

K = 13.0

Jet propellant No. 5 (JP-5):

K = 13.1

Methane:

K = 11.6

The following examples are provided for calculating NO_x emissions on a mass basis, given the fuel type and NO_x emission level, in ppmv, dry (ppmvd), and corrected to 15 percent O_2.

Example 1. Natural gas fuel

Gas turbine:

Solar Centaur 'H'

Power output:

4,040 kW

Heat rate:

12,200 Btu/kW-hr

NO_x emissions:

105 ppmvd, corrected to 15 percent O_2

Fuel:

Natural gas

- lower heating value = 20,610 Btu/lb

- K = 12.1

Fuel flow:

$$4{,}040 \text{ kW} \times \frac{12{,}200 \text{ Btu}}{\text{kW-hr}} \times \frac{1 \text{ lb fuel}}{20{,}610 \text{ Btu}} = 2{,}391 \text{ lb/hr}$$

From Equation 1:

$$\frac{105}{EINO_x} = 12.1$$

NO_x emissions, lb/hr:

$$2{,}391 \frac{\text{lb fuel}}{\text{hr}} \times \frac{8.68 \text{ lb } NO_x}{1{,}000 \text{ lb fuel}} = 20.8 \frac{\text{lb } NO_x}{\text{hr}}$$

Example 2. Distillate oil fuel

Gas turbine:

General Electric LM2500

Power output:

22670 kW

Heat rate:

9296 Btu/kW-hr

No_x emissions: 345 ppmvd, corrected to 15 percent O_2

Fuel:

Distillate oil No. 2

-

lower heating value = 18,330 Btu/lb

- K = 13.2

Fuel flow:

$$22{,}670 \text{ kW} \times 9296 \frac{\text{Btu}}{\text{kW-hr}} \times \frac{1 \text{ lb fuel}}{18{,}330 \text{Btu}} = 11{,}500 \text{ lb/hr}$$

From Equation 1:

$$\frac{345}{EINO_x} = 13.2$$

NO_x emissions, lb/hr:

$$11{,}500 \frac{\text{lb fuel}}{\text{hr}} \times \frac{26.1 \text{ lb } NO_x}{1{,}000 \text{ lb fuel}} = 300 \frac{\text{lb } NO_x}{\text{hr}}$$

REFERENCES FOR APPENDIX A:

1. Letter and attachments from Lyon, T.F., General Electric Aircraft Engines, to Snyder, R.B., MRI. December 6, 1991. Calculation of NO_x emissions from gas turbines.

2. Letter and attachments from Hung, W.S., Solar Turbines, Inc., to Snyder, R.B., MRI. December 17, 1991. Calculation of NO_x emissions from gas turbines.

APPENDIX B. COST DATA AND METHODOLOGY USED TO PREPARE COST FIGURES PRESENTED IN CHAPTER 6

APPENDIX B. RAW COST DATA AND COST ALGORITHMS

The maintenance costs for water injection and several of the SCR costs presented in Chapter 5 are based on information from turbine manufacturers and other sources that required interpretation and analysis. Information about additional gas turbine maintenance costs associated with water injection is presented in Section B.1. Information on SCR capital costs, catalyst replacement and disposal costs, and maintenance costs is presented in Section B.2. References are listed in Section B.3.

B.1 WATER INJECTION MAINTENANCE COSTS

Information from each manufacturer and the applicable analysis procedures used to develop maintenance cost impacts for water injection are described in the following sections.

B.1.1 Solar

This manufacturer indicated that the annual maintenance cost for the Centaur is $16,000/year.[1] The cost for the Saturn was estimated to be $8,000.[2] This $8,000 cost was then prorated for operation at 1,000/hr/yr, and was multiplied by 1.3 to account for the additional maintenance required for oil fuel.

B.1.2 Allison

Maintenance costs for water injection were provided by a company that packages Allison gas turbines for stationary applications. This packager stated that for the 501 gas turbine model, a maintenance contract is available which covers all maintenance materials and labor costs associated with the turbine, including all scheduled and unscheduled activities. The cost of this contract for the 501 model is $0.0005 to $0.0010 per KW-hour (KWH) more for water injection than for a turbine not using water injection.[3] For an installation operating 8,000 hours per year at a base-rated output of 4,000 KW, and using an average cost of $0.00075 per KWH, the annual additional maintenance cost is $24,000. By the nature of the contract offered, this figure represents a worst case scenario and to some extent may exceed the actual incremental maintenance costs that would be expected for water injection for this turbine.

B.1.3 General Electric

General Electric (GE) offers both aero-derivative type (LM-series models) and heavy-duty type (MS-series models) gas turbines. For the aero-derivative turbines, GE states that the incremental maintenance cost associated with water injection is $3.50 per fired hour. This cost is used to calculate the maintenance cost for water injection for GE aeroderivative turbines. No figures were provided for steam injection and no maintenance cost was used for steam injection with these turbines.[4]

Water injection also impacts the maintenance costs for the heavy-duty MS-series models. Costs associated with more frequent maintenance intervals required for models using water injection have been calculated and summarized below. A GE representative stated that the primary components which must be repaired at each maintenance interval are the combustor liner and transition pieces.[5] Approximate costs to repair these pieces were provided by GE.[5] For this analysis, the maximum cost estimates were used to calculate annual costs to accommodate repairs that may be required periodically for injection nozzles, cross-fire tubes, and other miscellaneous hardware. According to GE, a rule of thumb is that if the repair cost exceeds 60 percent of the cost of a new part, the part is replaced.[5] The cost of a replacement part is therefore considered to be 1.67 times the maximum repair cost. If water purity requirements are met, there are no significant adverse impacts on maintenance requirements on other turbine components, and hot gas path inspections and major inspection schedules are not impacted.[5] Combustion repair schedules, material costs, and labor hours are shown in Table B-1. Scheduled maintenance intervals for models with water injection were provided in Reference 6. Corresponding maintenance intervals for models with steam injection were assumed to be the same as models with no wet injection; these scheduled maintenance intervals were provided in Reference 7. Using the information in Table B-1, the total annual cost is calculated and shown in Table B-2 for three GE heavy-duty turbine models.

B.1.4 Asea Brown Boveri

This manufacturer states there are no maintenance impacts associated with water injection.[8]

B.2 SCR COSTS

The total capital investment, catalyst replacement, and maintenance costs are estimated based on information from the technical literature. The cost algorithms are described in the following sections.

B.2.1 Total Capital Investment

Total capital investment costs, which include purchased costs and installation costs, were available for SCR systems for combined cycle and cogeneration applications from five sources.[9-13] These costs were scaled to 1990 costs using the Chemical Engineering annual plant cost indexes and are applicable to SCR systems in which the catalyst was placed within the heat recovery steam generator (HRSG). In addition, estimated capital investment costs were available from one source for SCR systems in which a high temperature zeolite catalyst is installed upstream of the HRSG.[14] Both the original data and the scaled costs are presented in Table B-3. The scaled costs were plotted against the turbine size and this plot is shown in Figure B-1. A linear regression analysis was performed to determine the equation for the line that best fits the data. This equation was used to estimate the total capital investment for SCR for the model plants and was extrapolated to estimate the costs for model plants larger than 90 MW.

B.2.2 Maintenance Costs

Maintenance costs for SCR controls were obtained from four literature sources, although 6 of the 14 points were obtained from one article.[9,11-13] These costs were scaled to 1990 costs assuming an inflation rate of five percent per year. All of the data are for turbines that use natural gas fuel. Because there are no data to quantify differences in SCR maintenance costs for oil-fired applications, the available data for operation on natural gas were used for both fuels. Both the original data and the scaled costs are presented in Table B-4. The scaled costs were plotted versus the turbine size in Figure B-2. The equation for the line through the data was determined by linear regression, and it was used to estimate the maintenance costs for the model plants.

B.2.3 Catalyst Replacement Costs

Catalyst replacement costs were obtained from three articles for nine gas turbine installations.[9,11,13] Combined catalyst replacement and disposal costs were obtained for another six gas turbine installations from one article.[12] The disposal costs for these six gas turbine installations were estimated based on estimated catalyst volumes and a unit disposal cost of $15/ft^3, given in Reference 15.

The catalyst volumes were estimated assuming there is a direct relationship between the volume and the turbine size; the catalyst volume stated in Reference 16 for one 83 MW turbine is 175 m^3. The resulting disposal costs for these six facilities were subtracted from the combined replacement and disposal costs to estimate the replacement-only costs. All of the replacement costs were scaled to 1990 costs assuming an inflation rate of 5 percent per year. The original data and the scaled costs are presented in Table B-5, and the scaled replacement costs were also plotted versus the turbine size in Figure B-3. Linear regression was used to determine the equation for the line through the data. This equation was used to estimate the catalyst replacement costs for the model plants.

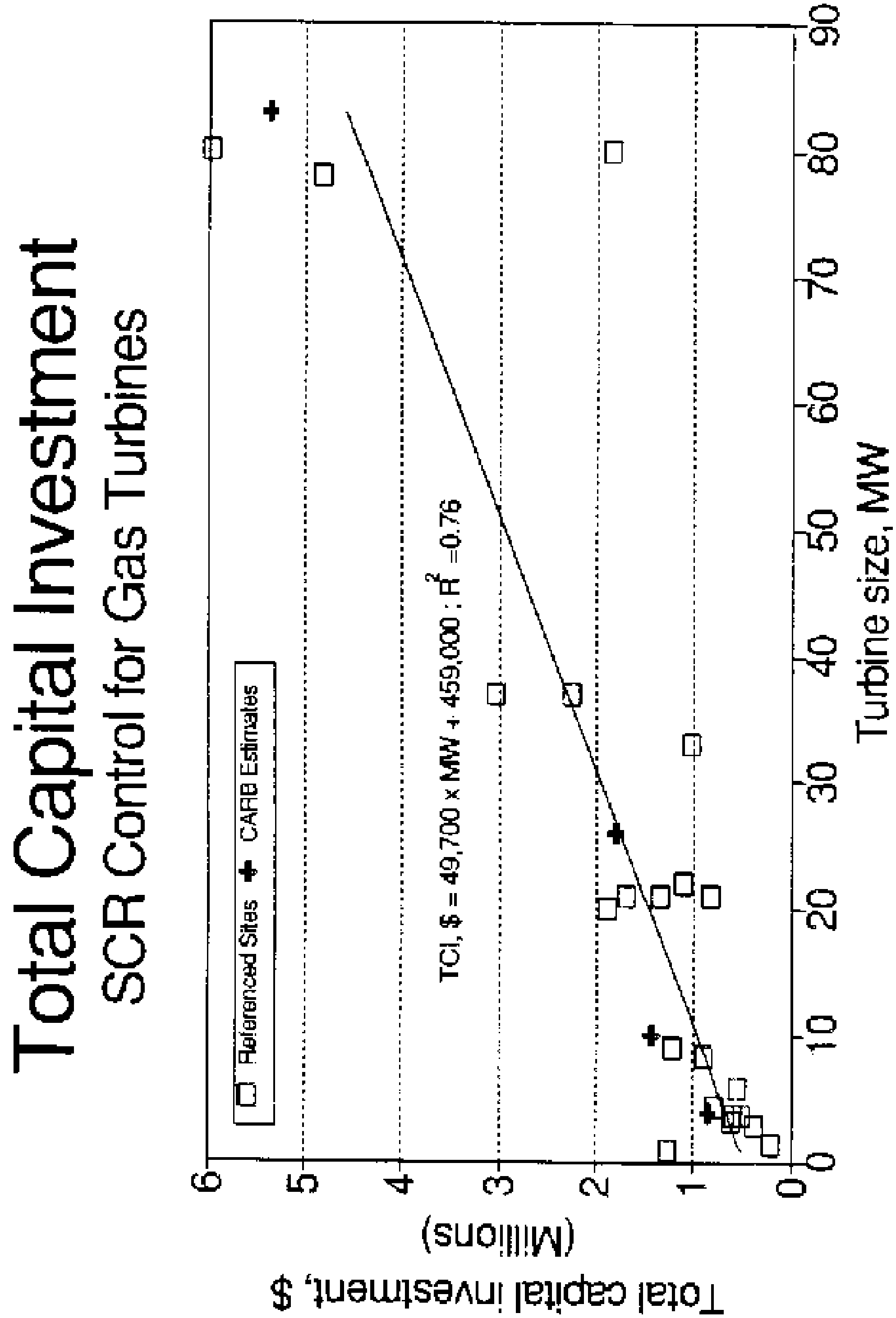

Figure B-1. Total Capital Investment for SCR Control of NO_x Emissions from Gas Turbines

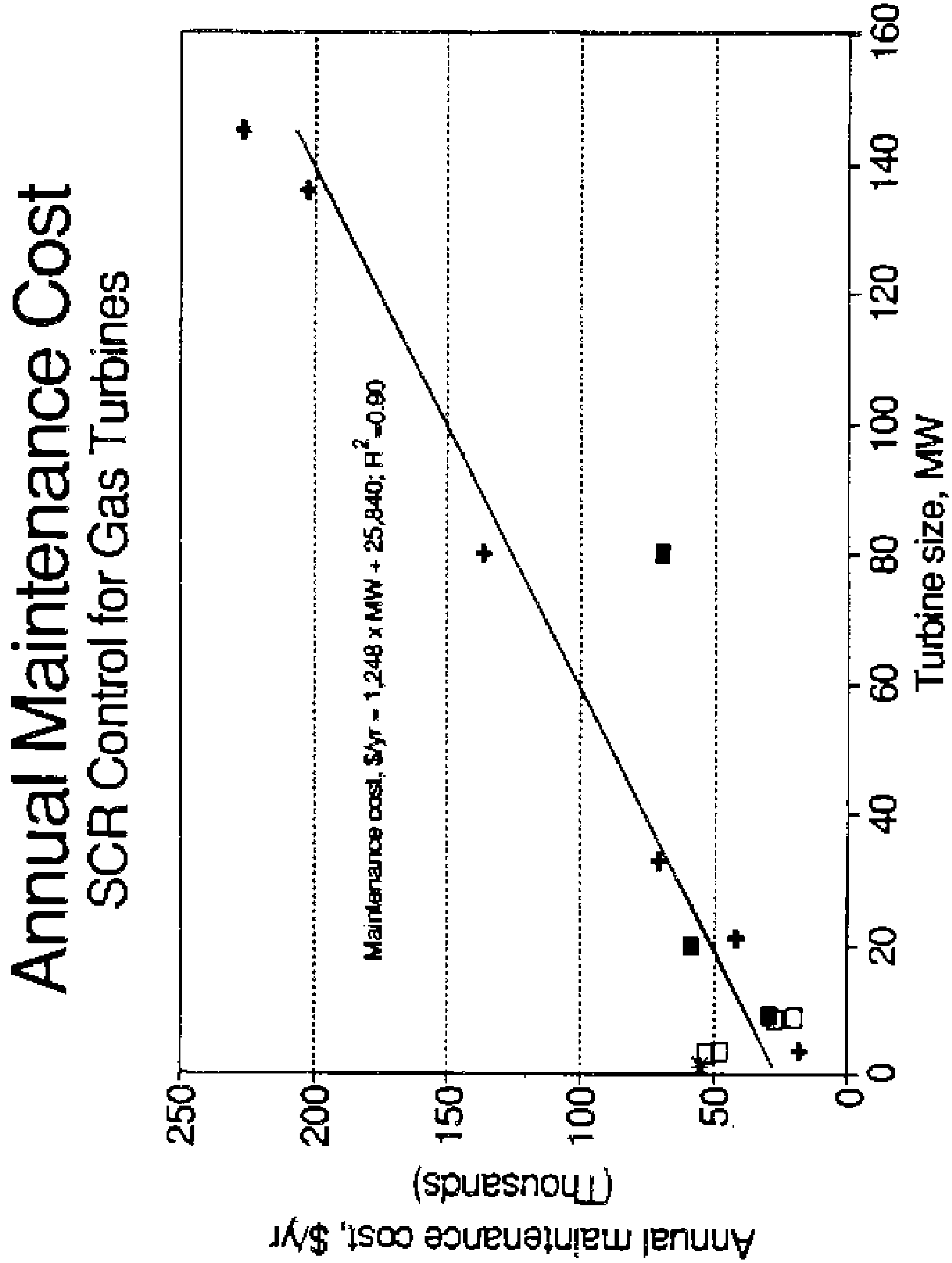

Figure B-2. Annual Maintenance Cost for SCR Control of NO_x Emissions from Gas Turbines

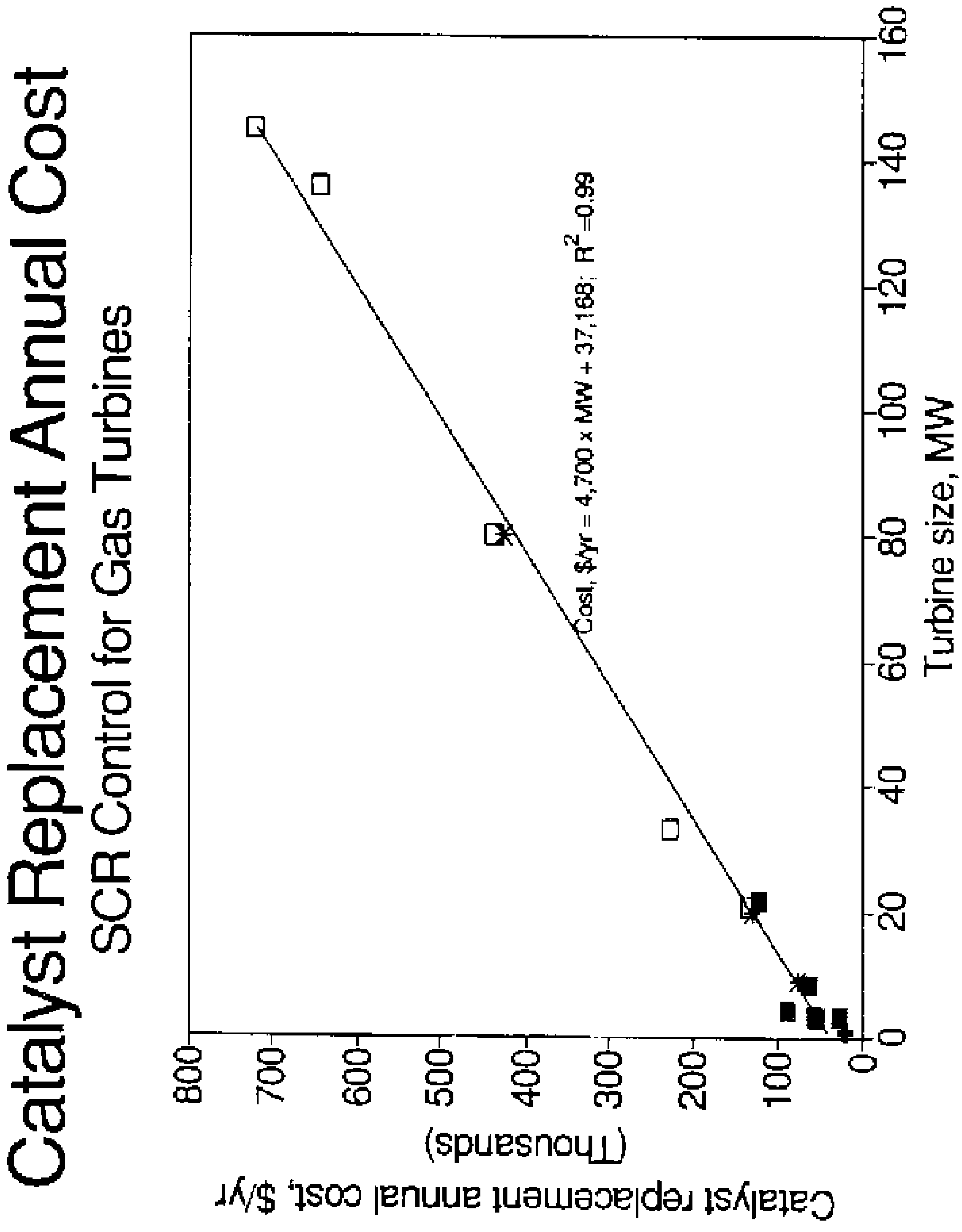

Figure B-3. Catalyst Replacement Annual Cost for SCR Control of Gas Turbines

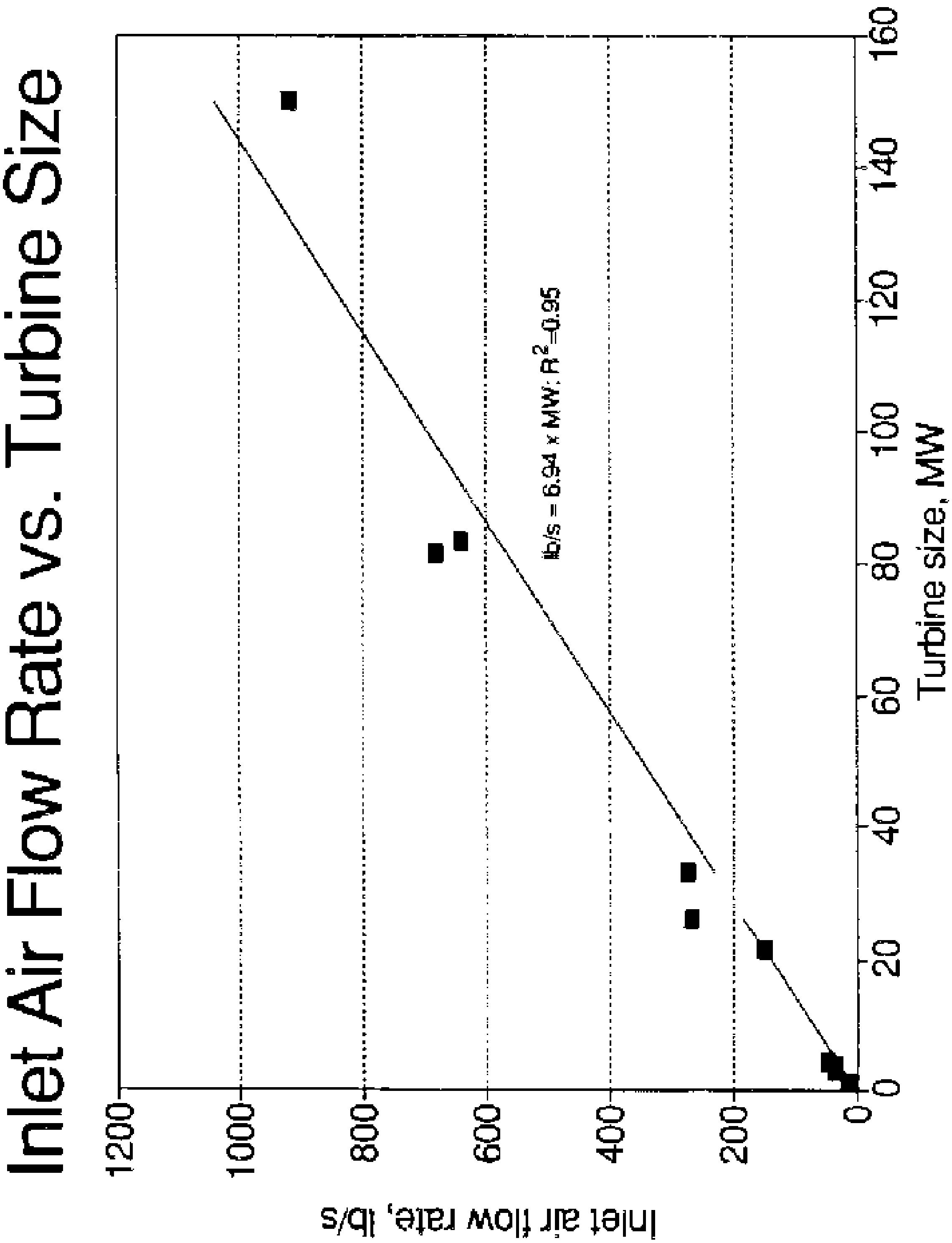

Figure B-4. Inlet Air Flow Rate for Gas Turbines

TABLE B-1. COMBUSTOR REPAIR INTERVALS, HOURS, AND MATERIAL COST

Gas turbine	Repair interval, hr		Replacement interval, hr		Repair cost, $[d]	Replacement cost, $[d]	Item	Labor hours[a]
	Dry[a]	Wet[b]	Dry[a]	Wet[c]				
MS5001P	12,000	6,000	48,000	24,000	10,000-15,000 15,000-20,000	25,000 42,000	Liners Transition pieces	160
MS7001E	8,000	6,500	48,000	39,000	15,000-30,000 30,000-50,000	50,000 83,000	Liners Transition pieces	576
MS9001E	8,000	6,500	48,000	39,000	31,000-62,000 62,000-124,000	103,000 206,000	Liners Transition pieces	624

[a]Reference 7.
[b]Reference 6.
[c]Scaled from Dry Repair/Replace intervals found in Reference 9.
[d]Reference 5.

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TABLE B-2. ANNUAL COST OF ADDITIONAL MAINTENANCE REQUIRED FOR WATER INJECTION

	Number of inspections over 15 years						Material costs		Labor, each inspection			
	Dry		Wet		Added number for wet							
GT Model	Inspection	Replacement	Inspection	Replacement	Inspection	Replacement	Inspection	Replacement	Hours	Cost	Total added cost 15 years	Total added annual cost
MS5001P [a]												
Combustor liners	8	2	15	5	7	3	15,000	25,000			18,000	
Transition pieces	8	2	15	5	7	3	20,000	42,000	160	4,998	315,980	
											495,980	33,065
MS7001E [e]												
Combustor liners	12	3	15	3.5	3	0.5	30,000	50,000			115,000	
Transition pieces	13	2	15.5	3	2.5	1	50,000	83,000	576	17,994	270,979	
											385,979	25,732
MS9001E [e]												
Combustor liners	12	3	15	3.5	3	0.5	62,000	103,000			237,500	
Transition pieces	13	2	15.5	3	2.5	1	124,000	206,000	624	19,494	584,229	
											821,729	54,782

[a]Based on $31.24/hr. Since parts are normally removed and a spare set is installed at each inspection, the labor cost would be the same for either repair or replacement interval.
[b]Schedule assumes liners and transition pieces are replaced every fourth inspection interval.
[c](7 x $15,000) + (3 x $25,000) = $180,000.
[d](7 x $20,000) + (3 x $42,000) + ($4,998 x 10) = $315,980.
[e]Schedule assumes liners are replaced every fifth interval and transition pieces every sixth interval.

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TABLE B-3. TOTAL CAPITAL INVESTMENT FOR SCR TO CONTROL NO_x EMISSIONS FROM GAS TURBINES

Gas turbine size, MW	SCR capital cost[a]			Scaling factor[c]	1990 SCR capital cost, $
	$	Year	Ref[b]		
1.1	1,250,000	1989	9	357.6/355.4	1,260,000
1.5	180,000	1986	10	357.6/318.4	202,000
3	320,000	1986	10	357.6/318.4	359,000
3.2	600,000	1989	11	357.6/3.554	604,000
3.7	477,000	1988	12	357.6/342.5	498,000
3.7	579,000	1989	11	357.6/355.4	583,000
4	839,000	1991	14	1.0	839,000
4.5	750,000	1988	11	357.6/342.5	783,000
6	480,000	1986	10	357.6/318.4	539,000
8.4	800,000	1986	11	357.6/318.4	898,000
9	1,100,000	1987	13	357.6/323.8	1,210,000
10	1,431,000	1991	14	1.0	1,431,000
20	1,700,000	1987	13	357.6/323.8	1,880,000
21	798,000	1988	12	357.6/342.5	833,000
21	1,500,000	1986	10	357.6/318.4	1,680,000
21	1,200,000	1986	10	357.6/318.4	1,350,000
22	1,000,000	1987	11	357.6/323.8	1,100,000
26	1,800,000	1991	14	1.0	1,800,000
33	990,000	1988	12	357.6/342.5	1,030,000
37	2,000,000	1986	11	357.6/318.4	2,250,000
37	2,700,000	1986	10	357.6/318.4	3,030,000
78	4,300,000	1986	10	357.6/318.4	4,830,000
80	5,400,000	1987	13	357.6/323.8	5,960,000
80	1,760,000	1988	12	357.6/342.5	1,840,000
83	5,360,000	1991	14	1.0	5,360,000

continued

TABLE B-3. (Continued)

[a]Total capital costs were provided by several sources, but it is not clear that they are on the same basis. For example, it is likely that the type of catalyst varies and the target NO_x reduction efficiency may also vary. In addition, some estimates may not include costs for emission monitors; auxiliary equipment like the ammonia storage, handling, and transfer system; taxes and freight; or installation.

[b]Reference 12 also provided costs for SCR used with 136 MW and 145 MW turbines. All of the costs for this reference are lower than the costs from other sources, and the differential increases as the turbine size increases. Because there are no costs from other sources for such large turbines, these two data points would exert undue influence on the analysis; therefore, they have been excluded. Costs for large model plants were estimated by extrapolating with the equation determined by linear regression through the data for turbines with capacities less than 90 MW (see Figure B-1).

[c]Costs for years prior to 1990 are adjusted to 1990 dollars based on the annual CE plant cost indexes. Costs estimated in 1991 dollars were not adjusted.

TABLE B-4. MAINTENANCE COSTS FOR SCR

Gas turbine size, MW	SCR maintenance cost[a] $/yr	Year	Ref	Scaling factor[b]	1990 SCR maintenance cost, $
1.1	52,200	1989	9	1.050	54,800
3.2	50,000	1989	11	1.050	52,500
3.7	43,000	1988	11	1.103	47,400
3.7	15,500	1988	12	1.103	17,100
8.4	22,000	1986	11	1.216	26,700
8.9	18,000	1988	11	1.103	19,800
9	25,000	1987	13	1.158	28,900
20	50,000	1987	13	1.158	57,900
21	37,900	1988	12	1.103	41,800
33	63,700	1988	12	1.103	70,200
80	124,000	1988	12	1.103	137,000
80	60,000	1987	13	1.158	69,500
136	184,000	1988	12	1.103	203,000
145	205,000	1988	12	1.103	226,000

[a]All of the maintenance costs are for turbines that are fired with natural gas. Although sulfur in diesel fuel can cause maintenance problems, there are no data to quantify the impact. Therefore, the maintenance costs presented in this table were used for both natural gas and diesel fuel applications.
[b]Scaling factors are based on an estimated inflation rate of 5 percent per year.

TABLE B-5. CATALYST REPLACEMENT AND DISPOSAL COSTS

Gas turbine size, MW	Catalyst replacement cost [a]						Catalyst disposal cost			Catalyst replacement and disposal annual cost, $/yr
	$	Year	Ref.	Scaling factor[b]	1990 catalyst cost, $	Annual cost, $/yr[c]	Catalyst volume, m^3	1990 cost, $[e]	Annual cost, $/yr[c]	
1.1	74,600	1989	9	1.050	78,300	20,700	2.32	1,230	324	21,000
3.2	200,000	1989	11	1.050	210,000	55,400	6.75	3,570	940	56,300
3.7		1988	12	1.103	215,000	56,600	7.80	4,130	1,090	57,700
3.7	100,000	1988	11	1.103	110,000	29,000	7.80	4,130	1,090	30,100
4.5	300,000	1988	11	1.103	331,000	87,300	9.49	5,030	1,330	89,000
8.4	200,000	1986	11	1.216	243,000	64,100	17.7	9,380	2,470	67,000
9	255,000	1987	13	1.158	295,000	77,800	19.0	10,100	2,660	80,000
20	434,000	1987	13	1.158	502,000	132,000	42.2	22,300	5,880	138,000
21		1988	12	1.103	512,000	135,000	44.3	23,500	6,200	141,000
22	400,000	1987	11	1.158	463,000	122,000	46.4	24,600	6,490	128,000
33		1988	12	1.103	864,000	228,000	69.6	36,900	9,700	238,000
80		1988	12	1.103	1,660,000	437,000	169	89,300	23,600	461,000
80	1,400,000	1987	13	1.158	1,620,000	427,000	169	89,300	23,600	451,000
136		1988	12	1.103	2,450,000	645,000	287	152,000	40,100	685,000
145		1988	12	1.103	2,740,000	723,000	306	162,000	42,700	766,000

[a]Reference 12 provided only combined catalyst replacement and disposal costs.
[b]Scaling factors are based on an inflation rate of 5 percent per year.
[c]Annual costs are based on the assumption that the catalyst will be replaced every 5 years. Therefore, the capital recovery factor is 0.2638, assuming an annual interest rate of 10 percent.
[d]In one SCR application, 175 m^3 of catalyst is used with an 83 MW turbine. If the space velocity is the same for any size SCR (assuming the same catalyst), then there is a direct relationship between the amount of catalyst and the exhaust gas flow rate. The exhaust gas flow rate was calculated as equal to the inlet air flow rate, and as Figure B-4 shows, there is nearly a direct relationship between the inlet airflow rate and turbine capacity. Therefore, the catalyst volume for the turbines in this table were estimated assuming there is a direct relationship between the catalyst volume and the turbine output.
[e]Disposal costs are estimated based on a unit cost of $15/ft^3.

B.3 REFERENCES FOR APPENDIX B

I. Letter and attachments from Swingle, R., Solar Turbines Incorporated, to Snyder, R., MRI. May 21, 1991. Maintenance considerations for gas turbines.

II. Letter and attachments from Swingle, R., Solar Turbines Incorporated, to Neuffer, W.J., EPA/ISB. August 20, 1991. Review of draft gas turbine ACT document.

III. Letter and attachments from Lock, D., U.S. Turbine Corporation, to Neuffer, W.J., U.S EPA/ISB. September 17, 1991. Review of draft gas turbine ACT document.

IV. Letter and attachments from Sailer, E.D., General Electric Marine and Industrial Engines, to Neuffer, W.J., EPA/ISB. August 29, 1991. Review of draft gas turbine ACT document.

V. Telecon. Snyder, R., MRI, with Pasquarelli, L., General Electric Company. April 26, 1991. Maintenance costs for gas turbines.

VI. Letter and attachment from Schorr, M., General Electric Company, to Snyder, R., MRI. April 1, 1991. Response to gas turbine questionnaire.

VII. Walsh, E. Gas Turbine Operating and Maintenance Considerations. General Electric Company. Schenectady, NY. Presented at the 33rd GE Turbine State-of-the-Art Technology Seminar for Industrial, Cogeneration and Independent Power Turbine Users. September, 1989. 20 pp.

VIII. Letter and attachments from Gurmani, A., Asea Brown Boveri, to Snyder, R., MRI. May 30, 1991. Response to gas turbine questionnaire.

IX. Permit application processing and calculations by South Coast Air Quality Management District for proposed SCR control of gas turbine at Saint John's Hospital and Health Center, Santa Monica, California. May 23, 1989.

X. Hull, R., C. Urban, R. Thring, S. Ariga, M. Ingalls, and G. O'Neal. NO_x Control Technology Data Base for Gas-Fueled Prime Movers, Phase I. Prepared by Southwest Research Institute for Gas Research Institute. April 1988.

XI. Shareef, G., and D. Stone. Evaluation of SCR NO_x Controls for Small Natural Gas-Fueled Prime Movers. Phase I. Prepared by Radian Corporation for Gas Research Institute. July 1990.

XII. Sidebotham, G., and R. Williams. Technology of NO_x Control for Stationary Gas Turbines. Center for Environmental Studies. Princeton University. January 1989.

XIII. Prosl, T., DuPont,and Scrivner, G., Dow. Technical Arguments and Economic Impact of SCR's Use for NO_x Reduction of Combustion Turbine for Cogeneration. Paper presented at EPA Region 6 meeting concerning NO_x abatement of Combustion Turbines. December 17, 1987.

XIV. State of California Air Resources Board. Draft Proposed Determination of Reasonably Available Control Technology And Best Available Retrofit Technology for Stationary Gas Turbines. August, 1991. Appendix C.

XV. Letter and attachments from Henegan, D., Norton Company, to Snyder, R., MRI. March 28, 1991. Response to SCR questionnaire.

XVI. Schorr, M. NO_x Control for Gas Turbines: Regulations and Technology. General Electric Company. Schenectady, New York. Paper presented at the Council of Industrial Boiler Owners NO_x Control IV Conference. Concord, California. February 11-12, 1991. 11 pp.

THE STATE
of ALASKA
GOVERNOR BILL WALKER

Department of Environmental Conservation

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September 13, 2018

Naomi Knight, Environmental Officer
Golden Valley Electric Association
PO Box 71249
Fairbanks, AK 99707-1249

Subject: Request for additional information for the Best Available Control Technology Technical Memorandum from Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility by November 1, 2018

Dear Ms. Knight:

A portion of the Fairbanks North Star Borough (FNSB) has been in nonattainment with the 24-hour National Ambient Air Quality Standard for fine particulate matter ($PM_{2.5}$) since 2009. In a letter dated April 24, 2015, I requested that GVEA North Pole and Zehnder and other affected stationary sources voluntarily provide the Alaska Department of Environmental Conservation (ADEC) with a Best Available Control Technology (BACT) analysis in advance of the nonattainment area being reclassified to a Serious Area. On May 10, 2017, the US Environmental Protection Agency (EPA) published their determination that the FNSB $PM_{2.5}$ nonattainment area would be reclassified from a Moderate Area to a Serious Area effective June 9, 2017.[1]

Once the nonattainment area was reclassified to Serious, it triggered the need for Best Available Control Measure (BACM)/BACT analyses. A BACM analysis requires that ADEC review potential control measure options for the various sectors that contribute to the $PM_{2.5}$ air pollution in the nonattainment area. A BACT analysis must be conducted for applicable stationary sources such as GVEA North Pole and Zehnder. BACM and BACT are required to be evaluated regardless of the level of contribution by the source to the problem or its impact on the areas ability to attain.[2] The BACT analyses are a required component of a Serious State Implementation Plan (SIP).[3] ADEC sent an email to Ms. Naomi Knight at GVEA on May 11, 2017 notifying her of the reclassification

[1] Federal Register, Vol. 82, No. 89, Wednesday May 10, 2017 (https://dec.alaska.gov/air/anpms/comm/docs/2017-09391-CFR.pdf)

[2] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) and CFR 51.1010(4)(i) require the implementation of BACT for point sources and precursors emissions and BACM for area sources.

[3] https://www.gpo.gov/fdsys/pkg/FR-2016-08-24/pdf/2016-18768.pdf, Clean Air Act 189 (b)(1)(B) and 189 (e) require the implementation of BACT for point sources and precursors emissions and BACM for area sources

to Serious and included a request for the BACT analysis to be completed by August 8, 2017. The BACT analyses from GVEA North Pole and Zehnder, which included emission units found in Operating Permits AQ0110TVP03 and AQ0109TVP03, were submitted by email to the Department on August 30, 2017.

On March 22, 2018, ADEC released a preliminary draft of the BACT determination for GVEA for public discussion on its website at: http://dec.alaska.gov/air/anpms/communities/fbks-pm2-5-serious-sip-development. As indicated in the release, this document is a work in progress. ADEC received additional information from the EPA on the preliminary draft BACT determination and expects to make changes to the determination based upon this input. Therefore, ADEC is requesting additional information from GVEA to assist it in making a legally and practicably enforceable BACT determination for the source.

If ADEC does not receive a response to this information request by November 1, 2018, ADEC will make a preliminary BACT determination based upon the information originally provided. However, ADEC does not have the in depth knowledge of your facility's infrastructure and without additional information, may select a more stringent BACT for your facility in order to be approvable by EPA. It is ADEC's intent to release the preliminary BACT determinations for public review along with any precursor demonstrations and BACM analyses before the required public comment process for the Serious SIP. In order to provide this additional comment opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated.

After ADEC makes final BACT determinations for GVEA North Pole and Zehnder, it must include the determinations in Alaska's Serious SIP that then ultimately requires approval by EPA.[4] In addition, the BACT implementation 'clock' was also triggered by the EPA reclassification of the area to Serious on June 9, 2017. Therefore, the control measures that are included in the final BACT determination will be required to be fully implemented prior to June 9, 2021 - 4 years after reclassification.[5]

As indicated in a meeting on September 21, 2017 between ADEC Air Quality staff and the stationary sources affected by the BACT requirements, ADEC will also be using the information submitted or developed to support the BACT determinations for Most Stringent Measure (MSM) consideration. MSMs will be a required element of the state implementation plan if the State applies for an extension of the attainment date from EPA. Therefore, the information you submit will be used for both analyses.

ADEC appreciates the cooperation that we've received from GVEA. ADEC staff would like to continue periodic meetings to keep track of timelines and progress. If you have any questions related to this request, please feel free to contact us. Deanna Huff (email: Deanna.huff@alaska.gov) and Cindy Heil (email: Cindy.heil@alaska.gov) are the primary contacts for this effort within the Division of Air Quality.

[4] https://www.gpo.gov/fdsys/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partD-subpart4-sec7513a
[5] 40. CFR 51.1010(4)

Sincerely,

Denise Koch, Director
Division of Air Quality

Enclosures:

September 10, 2018	ADEC Request for Additional Information for North Pole and Zehnder Facilities BACT Analyses
May 21, 2018	EPA Comments on ADEC Preliminary Draft Serious SIP Development Materials for the Fairbanks Serious PM-2.5 nonattainment Area
November 16, 2017	ADEC Request for Additional Information for North Pole and Zehnder BACT Analyses;
November 15, 2017	EPA GVEA BACT Analysis Review Comments
May 11, 2017	Serious SIP BACT due date email
April 24, 2015	Voluntary BACT Analysis for GVEA North Pole and Zehnder

cc: Larry Hartig, ADEC/ Commissioner's Office
Alice Edwards, ADEC/ Commissioner's Office
Cindy Heil, ADEC/Air Quality
Deanna Huff, ADEC/ Air Quality
Jim Plosay, ADEC/ Air Quality
Aaron Simpson, ADEC/Air Quality
Naomi Knight/GVEA
Tim Hamlin, EPA Region 10
Dan Brown, EPA Region 10
Zach Hedgpeth, EPA Region 10

ADEC Request for Additional Information
Golden Valley Electric Association – North Pole and Zehnder Facilities
BACT Analysis Review
August 2017

September 10, 2018

Please address the following comments by providing the additional information identified by November 1, 2018. Following the receipt of the information the Alaska Department of Environmental Conservation (ADEC) intends to make its preliminary Best Available Control Technology (BACT) determination and release that determination for public review. In order to provide this additional review opportunity, ADEC must adhere to a strict schedule. Your assistance in providing the necessary information in a timely manner is greatly appreciated. Additional requests for information may result from comments received during the public review period or based upon the new information provided in response to this information request.

This document does not represent a final BACT determination by ADEC. Please contact Aaron Simpson at aaron.simpson@alaska.gov with any questions regarding ADEC's comments.

1. Equipment Life – Page 31 of the North Pole analysis and Page 27 of the Zehnder analysis state "Because of the harsh climate, equipment in this far north location experiences more wear and tear than equipment in moderate climates. On this basis, a ten year return on the [water injection and] SCR system is assumed to be reasonable." This same assumption is made for the other control devices. ADEC identified that the EPA Air Pollution Control Cost Manual[1] uses a hypothetical example that assumes the control equipment has a useful life of ten years. However the cost analyses must use a reasonable estimate of the actual life of the control equipment for each control technology. In order to use an equipment life that is shorter than 30 years, evidence must be provided to support the claim that 10 years is a reasonable timeframe for equipment life. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as turbines.

2. BACT limits – BACT limits by definition, are numerical emission limits. However regulation allows a design, equipment, or work/operational practices if technological or economic limitations make a measurement methodology infeasible. Provide numerical emission limits (and averaging periods) for each proposed BACT selection, or justify why a measurement methodology is technically infeasible and provide the proposed design equipment, or work/operational practices for pollutant for each emission unit included in the analysis. Startup, Shutdown, and Malfunction (SSM) must be addressed in the BACT analysis. Measures to minimize the occurrence of these periods, or to minimize emissions during these periods are control options. Combinations of steady-state control options and SSM control options can be combined to create distinct control strategies. In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by an applicable standard under 40 C.F.R. parts 60 (NSPS) and 61 (NESHAP).

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[1] U.S. EPA OAQPS Air Pollution Control Cost Manual, 6th Edition [EPA/452/B-02-001]

3. Cost Analyses – Page 44 of the North Pole analysis indicates that EUs 1 and 2 have historically low run hours. Page 34 of the Zehnder analysis state that "GVEA believes that an economic analysis based on the actual emissions and operations of these turbines is more relevant for purposes of determining viable ways to reduce PM2.5 ambient concentrations in the Fairbanks area." However, all BACT cost effectiveness calculations must be based upon the potential to emit, and not on historic operation. Please update the cost analyses using the unrestricted potential to emit for each of the emissions units or propose operational limits (including control efficiencies associated with limited operation). Additionally, see Comments 4, 5, and 6 for additional information related to retrofit costs, baseline emissions, and factor of safety.

4. Retrofit Costs – EPA's Control Cost Manual indicates that study-level cost estimates (± 30 percent) should not include a retrofit factor greater than 30 percent, so detailed cost estimates (± 5 percent) are required for higher factors. High retrofit cost factors (50 percent or more) may be justified in unusual circumstances (e.g., long and unique ductwork and piping, site preparation, tight fits, helicopter or crane installation, additional engineering, and asbestos abatement). Provide detailed cost analyses and justification for any difficult retrofit (1.6 – 1.9 times the capital costs) considerations used in the BACT analyses.

5. Baseline Emissions – Include the baseline emissions for all emission units included in the analyses. Typically, the baseline emission rate represents a realistic scenario of upper bound uncontrolled emissions for the emissions unit (unrestricted potential to emit not actual emissions). NSPS and NESHAP requirements are not considered in calculating the baseline emissions. The baseline is usually the legal limit that would exist, but for the BACT determination. Baseline takes into account the effect of equipment that is part of the design of the unit (e.g., water injection and low NOx burners) because they are considered integral components to the unit's design. If the uncontrolled emission rate is 'soft,' run the cost effectiveness calculations using two or three different baselines.

6. Factor of Safety – If warranted, include a factor of safety when setting BACT emission limitations. The safety factor is a legitimate method of deriving a specific emission limitation that may not be exceeded. These limits do not have to reflect the highest possible control efficiencies, but rather, should allow the Permittee to achieve compliance with the numerical emission limit on a consistent basis.

7. Good Combustion Practices –For each emission unit type (oil fuel-fired turbines, combined cycle turbines, emergency generator engines, and boilers) for which good combustion practices was proposed as BACT, describe what constitutes good combustion practices. Include any work or operational practices that will be implemented and describe how continuous compliance with good combustion practices will be achieved.

8. Control Technology Availability – For the North Pole Facility, include Flue Gas Recirculation in the review of NOx control technologies for diesel-fired boilers. Rank the control technologies by efficiency (specify % control). Select the best performing control technology as BACT or provide specific energy, environmental, and economic impacts and other costs justification for why each better performing control technology was not selected instead of good combustion practices. Provide a numerical NOx emission limit for the diesel-fired boilers or identify the work or operational practices that will be utilized to ensure compliance with proposed limits.

9. Alternative Fuel Costs – Please provide a cost analysis for SO_2 emissions reductions for switching from current No. 2 diesel fuel to low sulfur diesel with a sulfur fuel content of 0.05 percent by weight. Also provide a cost analysis for a switch from No. 2 diesel fuel to No. 1 diesel fuel.

10. Interest Rate – All cost analyses must use the current bank prime interest rate. This can be found online at https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table). Please revise the cost analyses as appropriate.

11. Conversion to Natural Gas – For any emission units capable of converting to natural gas combustion (with the requisite changes to the burners, etc.), evaluate the commercial availability of converting to natural gas. For example, GVEA has stated the combustion turbines at its North Pole Expansion Power Plant have the ability to burn natural gas, and the IGU has indicated the intent to expand the supply of natural gas to Fairbanks and North Pole.

Attachment: EPA comments on ADEC Preliminary Draft Serious SIP Development materials for the Fairbanks serious $PM_{2.5}$ nonattainment area

General

The attached comments are intended to provide guidance on the preliminary drafts of SIP documents in development by ADEC. We expect that there will be further opportunities to review the more complete versions of the drafts and intend to provide more detailed comments at that point

1. Statutory Requirements - This preliminary draft does not address all statutory requirements laid out in Title I, Part D of the Clean Air Act or 40 C.F.R. Part 51, Subpart Z. The submitted Serious Area SIP will need to address all statutory and regulatory requirements as identified in Title I, Part D of the Clean Air Act, 40 C.F.R. Part 51, Subpart Z, the August 24, 2016 $PM_{2.5}$ SIP Requirements Rules (81 FR 58010, also referred to at the $PM_{2.5}$ Implementation Rule), and any associated guidance.

   In the preliminary drafts, notable missing elements included: Reasonable Further Progress, Quantitative Milestones, and Conformity. This is not an exhaustive list of required elements.

   The NNSR program is a required element for the serious area SIP. We understand ADEC recently adopted rule changes to address the nonattainment new source review element of the Serious SIP, and that ADEC plans to submit them to the EPA separately in October 2018. Thank you for your work on this important plan element.

2. Extension Request - This preliminary draft does not address the decision to request an attainment date extension and the associated impracticability demonstration. On September 15, 2017, ADEC sent a letter notifying the EPA that it intends to apply for an extension of the attainment date for the Fairbanks $PM_{2.5}$ Serious nonattainment area. The Serious Area SIP submitted to EPA will need to include both an extension request and an impracticability demonstration that meet the requirements of Clean Air Act section 188(e). In order to process an extension request, the EPA requests timely submittal of your Serious Area SIP to allow for sufficient time to review and take action prior to the current December 2019 attainment date, so as to allow, if approvable, the extension of the attainment date as requested/appropriate. For additional guidance, please refer to 81 FR 58096.

3. Split Request - We support the ADEC and the FNSB's decision to suspend their request to the EPA to split the nonattainment area. We support the effort to site a monitor in the Fairbanks area that is more representative of neighborhood conditions and thus more protective of community health. This would provide additional information on progress towards achieving clean air throughout the nonattainment area.

4. BACM (and BACT), and MSM - Best Available Control Measures (including Best Available Control Technologies) and Most Stringent Measures are evaluative processes inclusive of steps to identify, adopt, and implement control measures. Their definitions are found in 51.1000, 51.1010(a).

All source categories, point sources – area sources – on-road sources – non-road sources, need to be evaluated for BACM/BACT and MSM. De minimis or minimal contribution are not an allowable rationale for not evaluating or selecting a control measure or technology.

The process for identifying and adopting MSM is separate from, yet builds upon, the process of selecting BACM. Given that Alaska is intent on applying for an extension to the attainment date, Alaska must identify BACM and MSM for all source categories. These processes are described in 51.1010(a) and 51.1010(b) and in the $PM_{2.5}$ Implementation Rule preamble at 81 FR 58080 and 58096. We further discuss this process in the "BACM (and BACT), MSM" section that starts on page 3 below.

5. Resources and Implementation - The serious area $PM_{2.5}$ attainment plan will be best able to achieves its objectives when all components of the SIP, both the ADEC statewide and FNSB local measures, are sufficiently funded and fully implemented.

6. Use of Consultants- For the purpose of clarity, it will be important to identify that while contractors are providing support to ADEC, all analyses are the responsibility of the State.

Emissions Inventory

1. Extension Request Emission Inventories - Emissions inventories associated with the attainment date extension request will need to be developed and submitted. Table 1 of the Emissions Inventory document is one example where the submittal will need to include the additional emissions inventories, including RFP inventories, extension year inventories for planning and modeling, and attainment year planning and modeling inventories, associated with the attainment date extension request.

2. Modeling Requirements - Related to emissions inventory requirements, the serious area SIP will need to model and inventory 2023 and 2024, at minimum. We recommend starting at 2024 and modeling earlier and earlier until there is a year where attainment is not possible. That would satisfy the requirement that attainment be reached as soon as practicable.

3. Condensable Emissions - All emissions inventories and any associated planning, such as Reasonable Further Progress schedules, need to include condensable emissions as a separate column or line item, where available. Where condensable emissions are not available separately, provide condensable emissions as included (and noted as such) in the total number. The following are examples of where this would need to be incorporated in to the Emissions Inventory document:
    a. Page 20, paragraph 5 (or 2nd from the bottom).
    b. Page 34, Table 8. Include templates.

Precursor Demonstration

1. Ammonia Precursor Demonstration - The draft Concepts and Approaches document, Table 4 on page 9, states that a precursor demonstration was completed for ammonia and that the result was "Not significant for either point sources or comprehensively." The Precursor Demonstration chapter does not include an analysis for ammonia. Please include the precursor demonstration for ammonia in the Serious Plan or amend this table.

2. Sulfur Dioxide Precursor Description - The draft Concepts and Approaches document, Table 4 on page 9, states that sulfur dioxide was found to be significant. All precursors are presumptively considered significant by default and the precursor demonstration can only show that controls on a precursor are not required for attainment. Suggested language is, "No precursor demonstration possible."

BACM (and BACT), MSM

Overall

The EPA appreciates ADECs efforts to identify and evaluate BACM for eventual incorporation into the Serious Area SIP. The documents clearly display significant effort on the part of the state and are a good first step in the SIP development process. In particular, we are supportive of ADECs efforts to evaluate BACT for the major stationary sources in the nonattainment area, as control of these sources is required by the CAA and $PM_{2.5}$ SIP Requirements Rule.

1. BACM/BACT and MSM: Separate Analyses - The "Possible Concepts and Potential Approaches" document appears to conflate the terms BACM/BACT and MSM, as well as, the analyses for determining BACM/BACT and MSM. BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for selecting BACM and MSM are laid out separately in the $PM_{2.5}$ SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM). Accordingly, the serious area SIP submission will need to have both a BACM/BACT analysis and an MSM analysis. We believe that there is flexibility in how these analyses can be presented, so long as the submission clearly satisfies the requirements of both evaluations, methodologies, and findings.

2. Selection of Measures and Technologies - The CAA and the $PM_{2.5}$ SIP Requirements Rule requires that ***all*** available control measures and technologies that meet the BACM (including BACT) and MSM criteria need to be implemented. All source categories need to be evaluated including: point sources (including non-major sources), area sources, on-road sources, and non-road sources.

3. Technological Feasibility - All available control measures and technologies include those that have been implemented in nonattainment areas or attainment areas, or those potential measures and technologies that are available or new but not yet implemented. Similarly, Alaska may not automatically eliminate a particular control measure because other sources or nonattainment areas have not implemented the measure. The regulations do not have a quantitative limit on number of controls that should be implemented.

For technological feasibility, a state may consider factors including local circumstances, the condition and extent of needed infrastructure, or population size or workforce type and habits, which may prohibit certain potential control measures from being implementable. However, in the instance where a given control measure has been applied in another NAAQS nonattainment area, the state will need to provide a detailed justification for rejecting any potential BACM or MSM measure as technologically infeasible (81 FR 58085).

A Borough referendum prohibiting regulation of home heating would not be an acceptable consideration to render potential measures technologically infeasible. The State would be responsible for implementing the regulations in the case that the Borough was not able. We believe that the most efficient path to clean air in the Borough is through a local, community effort.

4. Economic Feasibility - The BACM (including BACT) and MSM analyses need to identify the basis for determining economic feasibility for both the BACM and MSM analyses. In general, the $PM_{2.5}$ SIP Requirements Rule requires the state apply more stringent criteria for determining the feasibility of potential MSM than that used to determine the feasibility of BACM and BACT, including consideration of higher cost/ton values as cost effective.

5. Timing - The evaluations will need to identify the time for selection, adoption, and implementation for all measures. BACT must be selected, adopted, and implemented no later than 4 years after reclassification (June 2021). MSM must be selected, adopted, and implemented no later than 1 year prior to the potentially extended attainment date (December 2023 at latest). The RFP section of the serious area plan will need to identify the BACM and MSM control measures, their time of implementation, and the time(s) of expected emissions reductions. Timing delays in selection, adoption, implementation are not considered for BACM and MSM.

   As mentioned in the comment above in the "General" comment section, there are three criteria distinguishing between BACM and MSM, not one.

BACM - General

1. BACM definition, evaluations - The definition of BACM at 40 CFR 51.1000 describes BACM as any measure "that generally can achieve greater permanent and enforceable emissions reductions in direct $PM_{2.5}$ and/or $PM_{2.5}$ plan precursors from sources in the area than can be achieved through the implementation of RACM on the same sources." We believe that potential measures that are no more stringent than existing measures already implemented in FNSB, those that do not provide additional direct $PM_{2.5}$ and/or $PM_{2.5}$ precursors emissions reductions, do not meet the definition of BACM. These would need to be evaluated in the BACM and MSM analysis.

   For measures that are currently being implemented in Fairbanks that provide equivalent or more stringent control, we recommend identifying the ADEC or Borough implemented measure as part of the BACM control strategy. These implemented measures should be listed in their BACM findings at the end of the document. This comment applies to all of the measures that were screened out from consideration due to not being more stringent than the already implemented measure.

The analyses for a number of measures (e.g., Measure 30, Distribution of Curtailment Program information at time of woodstove sale) conclude that the emission reductions would be insignificant and difficult to quantify and, therefore, the measure is not technologically feasible. These measures may be technologically feasible. However, if existing measures constitute a higher level of control or if implementation of the measures is economically infeasible those would be valid conclusions if properly documented. De minimis or minimal contribution is not a valid rationale for not considering or selecting a control measure or technology.

The conclusion "not eligible for consideration as BACM" is not valid as all assessments for BACM and MSM are part of the evaluation. More appropriate conclusions could include that existing measures qualify as BACM or MSM, or are more stringent. Additional conclusions could include that evaluated measures were not technologically feasible, economically feasible, or could not practically be adopted and implemented prior to the required timeframe for BACM or MSM.

2. BACM and MSM, Ammonia - In the Approaches and Concepts document, Table 5 references that there are no applicable control measures or technologies for the $PM_{2.5}$ precursor ammonia. No information to substantiate this claim are found in the preliminary draft documents. Unless NH_3 is demonstrated to be insignificant for this area, the serious area plan will need to include an evaluation of NH_3 and potential controls for all source categories including points sources.

3. Backsliding Potential - When benchmarking the BACM and MSM analyses for stringency, ensure that the evaluation is based on the measures approved into the current Moderate SIP. This will relate primarily to the current ADEC/FNSB curtailment program but also other related rules. Many wood smoke control measures are interrelated, and changes to those measures may affect determinations on stringency of directly related and indirectly related measures. Examples of this can be found in multiple measures including, but not limited to Measures 5, 7, and 16.

4. Transportation Control Measures - The Approaches and Concepts document, on Page 13, states that the MOVES2014 model does not estimate a PM benefit as a result of an I/M program, and therefore the I/M is not technologically feasible. This is not a valid conclusion given that the Fairbanks area operated an I/M program to reduce carbon monoxide and the Utah Cache Valley nonattainment areas has an I/M program for VOC control. This measure will need to be evaluated. Referring to the 110(l) analysis for the Fairbanks CO I/M program may provide insight into how to quantify the emissions associated with an I/M program.

With regard to control measures related to on-road sources, we have received inquiries from the community regarding idling vehicles and further evaluation emission benefits would be responsive to citizen concern and may provide additional air quality benefit.

BACM - Specific Measures

- Measure 16, page 34-35. Date certain Removal of Uncertified Devices. The "date certain" removal of uncertified woodstoves in Tacoma, Washington appears more stringent than the current Moderate SIP approved Fairbanks ordinance in terms of the regulation and in practice. While the current ordinance appears to provide similar protection during stage 1 alerts, this is dependent on 100% compliance and the curtailment program remaining in its current form. Removal of uncertified stoves guarantees reductions in emissions in the airshed during both the curtailment periods and throughout the heating season. The information provided does not support the conclusion that the Fairbanks controls provides equivalent or more stringent control. Date certain removal of uncertified wood stoves needs to be considered for the area.

  Measures R4, R9, and R12, page 64, 68 and 71. These measures do not reference the Puget Sound Clean Air Agency (Section 13.07) requirement for removal of all uncertified stoves by September 30, 2015. This is equivalent to having all solid fuel burning appliances be certified and would be more stringent than the current SIP approved rules in Fairbanks. We believe that these measures need to be evaluated in the BACM and MSM analyses.

  Measure R4 and R9, page 64 and 68. All Wood Stoves Must be Certified. These measure should be evaluated.

- Measure 19-20 and 25, page 36-38 and 39. Renewal and Inspection Requirements. ADEC has not adequately demonstrated their conclusion that Fairbanks has a more stringent measure than Missoula and San Joaquin. We believe that the renewal requirements and inspection/maintenance requirements associated with the Missoula alert permits and San Joaquin registrations allows the local air agency an opportunity to verify on a regular basis that the device operates properly over times. Wood burning appliances require regular maintenance in order to achieve the certified emissions ratings. The FNSB Stage 1 waivers do not have an expiration and do not have an inspection and maintenance component making it less stringent.

- Measure 31, page 43. While the Borough has SIP approved dry wood requirements that prohibit the burning of wet wood and moisture disclosure requirements by sellers, we believe that a measure limiting the sale of wet wood during the winter months should be further analyzed for BACM (and MSM) consideration.

- Measures 33, 35, 36, 37, 43. Multiple Measures identify that recreational fires have been exempted from existing regulations. Small unregulated recreational fires, bonfires, fire pits, and warming fires have the potential to contribute emissions during a curtailment period. The FNSB and ADEC regulations should be re-evaluated for removing this exclusion.

- Measure 49, page 58. Ban on Coal Burning. We believe the regulations in Telluride are more stringent than in Fairbanks. Telluride prohibits coal burning all year whereas in Fairbanks an existing coal stove can burn when there is no curtailment which could contribute additional emissions to the airshed, especially during poor conditions when a curtailment may not have been called. We do not agree with the conclusion that the PM_{10} controls are ineligible for consideration for control of $PM_{2.5}$.

- Measure R20, page 76. Transportation Control Measures related to Vehicle Idling. We have received multiple inquiries regarding community interest in controlling emissions from idling vehicles. These types of control measures should be further evaluated in the BACM and MSM analyses.

- Measure 1, page 79-81. Surcharge on Solid Fuel Burning Appliances. For purposes of implementing an effective program to reduce $PM_{2.5}$ in the Borough we believe that a surcharge may be a helpful way to supplement limited funds. Implementation efforts within the nonattainment area could benefit from $24,000 of additional funding whether used for a code enforcer or other support of the wood smoke programs.

- Additional controls that should be further evaluated for BACM and MSM include:
    - Measure R1, page 63: Natural gas fired kiln or regional kiln.
    - Measure R12, page 71: Replace uncertified stoves in rental units.
    - Measure R17, page 75: Ban use of wood stoves
    - Measure R6, page 65: Remove Hydronic Heaters at Time of Home Sale & Date certain removal of Hydronic heaters. We suggest evaluating these measures at the state and local level.
    - Weatherization / heat retention programs should be evaluated. These should be evaluated for existing homes through energy audits and increasing insulation and energy efficiency. For new construction, building codes (Fairbanks Energy Code) should be evaluated with reference to the IECC Compliance Guide for Homes in Alaska http://insulationinstitute.org/wp-content/uploads/2015/12/AK_2009.pdf, and the DOE R-value recommendations, http://www.fairbanksalaska.us/wp-content/uploads/2011/07/ENERGY-CODE.pdf. (Note: More recent information may be available.)
    - Fuel oil boiler upgrades / operation & maintenance programs should be evaluated.

BACM - Ultra-Low Sulfur Fuel

1. Incomplete Analysis - The report findings provide analysis of the demand curve over a relatively short (12 month) time frame. This analysis appears to be based on a partial equilibrium model. This is a misleading time frame given the volatility of demand side fuel oil pricing. Also, in order to determine the equilibrium price, the analysis must also analyze

the supply curve. The report does not include information about the future supply side costs but needs to in order to make conclusions about the cost to the community of ultra-low sulfur heating oil.

2. Analysis of Increased Supply, Consumption - The report does not address future change in the market nor potential economies of scale to be achieved by an increase in ultra-low sulfur fuel consumption. Page 3 of the report identifies that, "the additional premium to purchase ULS over HS, decreased significantly since 2008-2010. It is likely that, this can be attributed to increased ULS capacity." We believe that the report should further explore the supply side costs.

3. Supply Cost Analysis - A supply side cost analysis is necessary to better understand the cost to the supplier to produce and provide ULS heating fuel. The BACM analysis must start with a transparent and detailed economic analysis of exclusively supplying ultra-low sulfur heating oil to the nonattainment area.

4. BACM Assessment - The current analysis does not provide information needed to assess BACM economic feasibility. The report should analyze the total cost to industry of delivering ultra-low sulfur heating oil to the entire community in terms of standard BACM metrics, $/ton.

BACT

General Comments

At this time, EPA is providing general comments based on review of the draft BACT analyses prepared by ADEC as well as addressing certain issues discussed in earlier BACT comments provided by EPA. Detailed comments regarding each individual analysis are not being provided at this time. While EPA appreciates the time and effort invested by ADEC staff in preparing the draft BACT analyses, the basic cost and technical feasibility information needed to form the basis for retrofit BACT analyses at the specific facilities has not been prepared. In other words, analyses which are adequate to guide decision making regarding control technology decisions for these rather complex retrofit projects cannot be prepared without site specific evaluation of capital control equipment purchase and installation costs, and site specific evaluation of retrofit considerations. EPA will conduct a thorough review of any future BACT or MSM analyses which are prepared based on adequate site specific information, and will provide detailed comments relative to each emission unit and pollutant at that time.

1. Level of Analysis – The analyses are presented as "preliminary BACT/MSM analyses" on the website, but the documents themselves are titled only as BACT analyses and the conclusions only reflect BACT. Additionally, the determinations may not be stringent enough to be considered BACT given that better performing SO_2 control technologies have not been adequately analyzed. These analyses cannot be considered to provide sufficient basis to support a selection of MSM.
2. Site-Specific Quotes Needed – The cost analyses, particularly for SO_2 control technologies, must be based on emission unit-specific quotes for capital equipment purchase and

installation costs at each facility. These are retrofit projects which must be considered individually in order to obtain reliable study/budget level (+/- 30%) cost estimates which are appropriate to use as the basis for decision making in determining BACT and potentially MSM. EPA believes that control decisions of this magnitude justify the relatively small expense of obtaining site-specific quotes.

3. SO_2 Control Technologies – The analyses must include evaluation of circulating dry scrubber (CDS) SO_2 control technology. This demonstrated technology can achieve SO_2 removal rates comparable to wet flue gas desulfurization (FGD) at lower capital and annual costs, and is more amenable to smaller units and retrofits. Modular units are available.
4. Control Equipment Lifetime – The analyses must use reasonable values for control equipment lifetime, according to the EPA control cost manual (EPA CCM). EPA believes that the following equipment lifetimes reflect reasonable assumptions for purposes of the cost analysis for each technology as stated in the EPA control cost manual and other EPA technical support documents. Use of shorter lifetimes for purposes of the cost analysis must include evidence to support the proposed shortened lifetime. One example where EPA agrees a shortened lifetime is appropriate would be where the subject emission unit has a federally enforceable shutdown date. Certain analyses submitted in the past have claimed shortened equipment lifetimes based on the harshness of the climate in Fairbanks. In order to use an equipment life that is shortened based on the harsh climate, evidence must be provided to support the claim. This evidence could include information regarding the actual age of currently operating control equipment, or design documents for associated process equipment such as boilers. Lacking adequate justification, all cost analyses must use the following values for control equipment lifetime:
    a. SCR, Wet FGD, DSI, CDS, SDA – 30 years
    b. SNCR – 20 years
5. Availability of Control Technologies – Technologically feasible control technologies may only be eliminated based on lack of availability if the analysis includes documented information from multiple control equipment vendors (who provide the technology in question) which confirms the technology cannot be available within the appropriate implementation timeline for the emission unit in question.
6. Assumptions and Supporting Documents – All documents cited in the analyses which form the basis for costs used and assumptions made in the analyses must be provided. Assumptions made in the analyses must be reasonable and appropriate for the control technologies included in the cost analysis.
7. Interest Rate – All cost analyses must use the current bank prime interest rate according to the revised EPA CCM. As of May 10, 2018, this rate is 4.75%. See https://www.federalreserve.gov/releases/h15/ (go to bank prime rate in the table).
8. Space Constraints – In order to establish a control technology as not technologically feasible due to space constraints or other retrofit considerations, detailed site specific information must be submitted in order to establish the basis for such a determination, including detailed drawings, site plans and other information to substantiate the claim.
9. Retrofit Factors – All factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor or whether installation of a specific control technology is technologically infeasible. EPA Region 10

believes that installation factors which would complicate the retrofit installation of the control technology should be evaluated by a qualified control equipment vendor and be reflected in a site-specific capital equipment purchase and installation quote. Lacking site-specific cost information, all factors that the facility believes complicate the retrofit installation of each technology should be described in detail, and detailed substantiating information must be submitted to allow reasonable determination of an appropriate retrofit factor. One example of the many retrofit considerations that must be evaluated is the footprint required for each control technology. A vendor providing a wet scrubber will be able to estimate the physical space required for the technology, and evaluate the existing process equipment configuration and available space at each subject facility. The determination of whether a specific control technology is feasible and what the costs will be may be different at each facility based on this and other factors. Site-specific evaluation of these factors must be conducted in order to provide a reasonable basis for decision making.

10. Control Efficiency – Cost effectiveness calculations for each control technology must be based on a reasonable and demonstrated high end control efficiency achievable by the technology in question at other emission units, or as stated in writing by a control equipment vendor. If a lower pollutant removal efficiency is used as the basis for the analysis, detailed technical justification must be provided. For example, the ability of SCR to achieve over 90% NO_X reduction is well established, yet the ADEC draft analyses assume only 80% control. Use of this lower control efficiency requires robust technical justification.
11. Condensable Particulate Matter – Although the existing control technology on the coal fired boilers may be evaluated as to whether it meets the requirement for BACT for particulate matter, baghouses primarily reduce emissions of filterable particulate matter rather than condensable PM. Given that all condensable PM emitted by the coal fired boilers would be classified as $PM_{2.5}$, the BACT analyses must include consideration of control options for these emissions. Where control technologies evaluated for control of other pollutants may provide a collateral benefit in reducing emissions of $PM_{2.5}$, this should be evaluated as well.
12. Guidance Reference – The steps followed to perform the BACT analysis mentioned in section 2 are from draft NSR/PSD guidance. The correct reference should be 81 FR 58080, 8/24/2016. As a result of this, some of the steps outlined in the BACT analysis need to be updated.
13. Community Burden Estimate – The concepts and approaches document labels capital purchase and installation costs for air pollution control technology at the major source facilities as "community burden" (see Tables 7 and 8, pages 10-11). EPA believes it is important to properly label the cost numbers being used as capital purchase and installation costs, since presenting them as community burden appears to attribute the entire initial capital investment for the various control technologies to the community in a single year, and also ignores annual operation and maintenance costs. As described in the EPA CCM, the cost methodology used by EPA for determining the cost effectiveness of air pollution control technology amortizes the initial capital investment over the expected life of the control device, and includes expected annual operating and maintenance expenses. EPA believes presentation of this annualized cost over the life of the control technology more accurately represents the actual cost incurred and is consistent with how cost effectiveness is estimated in the context of a BACT analysis.
14. Conversion to Natural Gas – For any emission units capable of converting to natural gas combustion (with the requisite changes to the burners, etc), the MSM analysis in particular

should thoroughly evaluate the feasibility of this option. For example, GVEA has stated the combustion turbines at its North Pole Expansion Power Plant have the ability to burn natural gas, and the IGU has indicated the intent to expand the supply of natural gas to Fairbanks and North Pole.

APPENDIX:

Additional Comments and Suggestions

Possible Concepts and Potential Approaches

Throughout all SIP documents references to design values should include a footnote to the source of the information (e.g., "downloaded from AQS on XX/XX/XXX" or "downloaded from [state system] on XX/XX/XXXX") and how exceptional events were treated.

We suggest referencing the August 24, 2016 81 FR 58010 Fine Particulate Matter NAAQS: State Implementation Plan Requirements rule with one consistent term. We suggest the 2016 $PM_{2.5}$ Implementation Rule.

Page 4, Figure 1. The comparative degree days and heating related information is better suited for the sections evaluating BACM and economic feasibility. If intending on using this information to differentiate Fairbanks from other cold climates and/or nonattainment areas, depicting comparative home heating costs would be more supportive.

Page 4, Table 1. The design values in the table and in the discussion need to be updated for 2015-2017.

Page 6-7: The "Totals" row in Table 3 (non-attainment areas emissions by source sector) does not appear to be the sum of the individual source sector emissions.

Page 7: The statement about FNSB experiencing high heating energy demand per square foot needs to be referenced.

Page 7: The discussion of Eielson AFB growth needs a reference to the final EIS.

Page 9: Table 4's title should be changed to "Preliminary Precursor Demonstration Summary"

Page 9: Table 4 includes a column "Modeling Assessment". Not all precursors were assessed with modeling, and modeling is just one tool for the precursor demonstration. A suggestion for the column title is "Result of Precursor Demonstration."

Page 9: Table 5's title should be changed to "Preliminary BACT Summary." Table 5 also needs to update the title to reference "Precursor Demonstration" as the term "Precursor Significance Evaluation" is the incorrect terminology for this analysis.

Page 10: ADEC's proposal to only require one control measure per major stationary source to meet BACT and MSM for SO_2, is not consistent with the Act or rule. As discussed above, BACM and MSM have separate definitions in 40 CFR 51.1000. By extension, the processes for selecting BACM and MSM are laid out separately in the PM2.5 SIP Requirements Rule (compare 40 CFR 51.1010(a) for BACM and 40 CFR 51.1010(b) for MSM).

Page 10: Table 6 should identify the specific dry sorbent injection selected as BACT.

Page 11: Suggest changing "less sources" to "fewer sources."

Page 13: The statement about an I/M program providing PM benefit needs to be clarified. Is this referring just to NOx and VOC precursor contribution to PM2.5, or also direct PM2.5 benefits?

Page 14: The statement "ADEC interprets the main difference between BACT/BACM and MSM as the time it takes to implement a control" is inaccurate. As discussed above, although the rule sets our different schedules for implementation of MSM and BACM, this is not the only major difference between those concepts. Notably, the rule contemplates a higher stringency for MSM as well as a higher cost/ton threshold for determining economic feasibility of the measure.

Technical Analysis Protocol

Page 2: The design values at the top of the page need to be updated to 2015-2017.

Page 2: Recommend removing the sentence "This site will be included in the Serious SIP's attainment plan…" as the North Pole Elementary will be involved in the redesignation to attainment in the sense that all past and current monitoring data will be a part of an unmonitored area analysis to show that the entire area has attained the standard in addition to the regulatory monitor locations.

Page 2: Remove the discussion of the nonattainment area split.

Page 2: Paragraph 2, sentence 3 should refer to the unmonitored area analysis.

Page 2: The timeline described at the bottom of the page needs to be modified to reflect a current schedule. No projected year modeling was included in the preliminary draft documents. Control scenario modeling will likely not be completed in Q2 2018.

Page 3: We suggest a sentence overview of the unmonitored area analysis in Section 3.1.

Page 3: Section 3.2 needs to refer to the SPM data and how that will be used in the Serious Plan unmonitored area analysis. This section should discuss current DEC efforts to site a new monitor in Fairbanks.

Page 3: Section 3.4 needs to describe the CMAQ domain in addition to the WRF domain. A figure (map) would help.

Page 4: Section 3.5 needs a more developed discussion of the WRF assessment, including describing the criteria that were used to assess the state-of-the-art, what the current version is, and what version was used.

Page 4: Section 3.6 needs to reference all emission inventories in development, including potential attainment date extension years and RFP years.

Page 4: In Section 4.1, the statement about the Moderate SIP covering the relevant monitors for the Serious SIP is inaccurate. The statement needs to qualify whether it is referring to regulatory monitors or non-regulatory monitors. In addition, the North Pole Fire Station, NCore, and North Pole Elementary monitors were not included in the Moderate SIP.

Page 5: Table 4.1-1's title suggests that all SPM sites are listed, but only sites with regulatory monitors are listed. Please list all the SPM sites used in the unmonitored area analysis in a separate table and modify this title of Table 4.1-1 to reflect that it lists sites that are regulatory.

Page 5: North Pole Elementary was a regulatory site for a part of the baseline period and was NAAQS comparable. Table 4.1-1 needs to be updated.

Page 8: Table 4.2-1 should be updated to include 2011-2017 98th percentiles. Table 4.2-2 should be updated to include 3-year design values for 2013-2017. For clarity, we recommend the 3-year design values include the full period in order to better distinguish from Table 4.2-1. For instance, "2013" would be "2011-2013".

Page 8: The statement starting, "a clear indication…" needs to be amended or removed. It is inaccurate. The prevalence of organic carbon does not indicate the dominance of wood burning, much less a clear indication. Many sources in Fairbanks emit organic carbon.

Page 8: The statement starting "The concentration share…" need to be amended or removed. Suggest removing "drastically". There is no scientific definition of a drastic change in percentages of $PM_{2.5}$ species, nor does the different 56% to 80% appear "drastic."

Page 9: The detailed description of the Simpson and Nattinger analysis does not reflect that SANDWICH process and it is preliminary data. It should be included within the body of the Serious Plan appendix on monitoring, but is out of place in a summary TAP.

Page 9: there are two different tables with the same table number (Table 4.3-1).

Page 10: Please clarify Table 4.4-1. This appears to be the design value calculation for the 5-year baseline design value, 2011-2015. If correct, then please label the 3-year design values according to the three years (e.g., "2011-2013"), clarify the table heading as being the "Five Year Baseline Design Value, 2011-2015 (µg/m3)", and clarify that the last column is the 5 Year Baseline Design Value associated with the table heading.

Page 11: At the end of section 5, please refer to the emission inventory chapter's meteorological discussion of the episodes.

Page 11: Section 6 needs to justify the extent, resolution, and vertical layer structure of the CMAQ domain (and the WRF domain) or refer to where that is included in the Moderate Plan.

Page 13: We suggest changing "PMNAA" to "NAA" to be consistent with the EI chapter.

Page 15, Section 8.1: There needs to be mention of how the F-35 deployment will be considered, with a reference to the final EIS.

Page 15-19: section 8.2-8.6 use the future tense for tasks that have been completed and are inconsistent with the schedule at the beginning of the TAP. Please adjust based on current status.

Page 20, section 9.2 states that "a BACT analysis is an evaluation of all technically available control technologies for equipment emitting the triggered pollutants and a process for selecting the best option based on feasibility, economics, energy, and other impacts." This sentence should be revised to reflect that the technological feasibility assessment occurs after identification of all potential control measures for each source and source category.

Page 20, section 9.3 the second sentence should read: "BACM measures found to be economically infeasible for BACM *must* be analyzed for MSM."

Page 21: Section 10.1 needs to be updated to reflect the current CMAQ version (5.2.1) and a discussion of why that model has not been used.

Page 21: Suggest sentence starting "There will be a gap…" be changed to "There is a gap in terms of assessing the performance at the North Pole Fire Station monitor for the Serious Plan because the State Office Building in Fairbanks was the only regulatory monitor at the time of the 2008 base case modeling episodes."

Page 23: Please explain the solid and dashed lines in the soccer plot.

Page 23: Please be sure to include a full discussion of North Pole performance in this section. Even though we lack measurements, we can discuss the ratio of the modeling results at NPFS versus SOB versus that ratio from more recent monitoring data (2011-2015 baseline design value period).

Page 23: Please clarify what is meant by "Moderate Area SIP requirements."

Page 24: The discussion of the 2013 base year discusses representative meteorological conditions without describing what the representative meteorological conditions are for high $PM_{2.5}$. Please reference the discussion of representative meteorological conditions that will be found elsewhere in the SIP.

Page 24: The discussion of the modeling years needs to be consistent and reflect the extension request past 2019. The attainment year cannot be earlier than 2019. Each extension year must be individually requested. For modeling efficiency, we recommend starting with 2024. If that year attains, then 2023 and so on until we have one year that attains and the year before that does not. This should give us the information about what is the earliest year for attainment.

Page 25: We suggest changing "modeling design value" to "design value for modeling"

Page 26: Please clarify the "SMAT" label in the tables. They may be the SANDWICH concentrations and the "5-yr DV" rows are the SMAT concentrations. Please clarify the units in the rows.

Emission Inventory

Clarification – In the EI document we would like to understand the functional difference between the base year, and baseline year

Please identify the methodology for generating ammonia and condensable PM emissions numbers.

Page 1: Please be consistent in "emission inventory" versus "emissions inventory".

Page 1: "CAA" to "Clean Air Act" for clarity

Page 3: It would be helpful to refer to 172(c)(3) in Section 1.2, bullet 1 as the planning and reporting requirements.

Page 5: Please include extension years and RFP years in Table 1's calendar years similar to what was done for Table 2. There should be one RFP projected inventory and QM beyond the extended attainment date. It would be helpful to include basic information about extension years and RFP years to better foreshadow Table 2.

Page 7: Please clarify the "winter season" inventory as the "seasonal" inventory that represents the daily average emissions across the baseline episodes.

Page 7, paragraph 1. Please include reference documentation for the following statement, "results in extremely high heating energy demand per square foot experienced in no other location in the lower-48."

Page 9: Please change "Violations" to "Exceedances." Exceedance is the term for concentrations over the standard. Violations is the term for dv over the standard.

Page 9: Add "No exceedances were recorded outside the months tabulated in Table 3 that were not otherwise flagged by Alaska DEC as Exceptional Events.", to the end of the last paragraph on the page.

Page 13: Please clarify the provenance of the BAM data (e.g., "downloaded from [state database or AQS] on XX/XX/XXXX). In particular, it is important to note if the data has been calibrated to the regulatory measurement (aka, corrected BAM).

Page 17-18. Sentence Unclear "For example, a planning inventory based on average daily emissions across the entire six-month nonattainment season will likely reflect a relatively lower fraction of wood use-based space heating emissions than one based on the modeling episode day average since wood use for space heating Fairbanks tends to occur as a secondary heating source on top of a "base" demand typically met by cleaner home heating oil when ambient temperatures get colder."

Page 19: Remove "Where appropriate,". All source sectors should be re-inventoried for 2013, even if the emissions for the sector ends up being the same as in 2008.

Page 19: Change “projected forward” to “re-inventoried”, or similar wording. Reserve “project” for when the emission inventory is estimating emissions in a future year.

Page 20: Please refer to EPA’s memo on the use of MOVES2014a for the plug in adjustment. As a reminder, this information is sufficient only for development of the emissions inventory, not for SIP credit.

Page 20: Please submit the technical appendix referenced on page 20. When that is submitted, we expect to provide additional comment. To allow for review, we request expedited submission.

Page 21: At bottom of page, “project” should be “re-inventoried” or something that refers to an inventory produced after the fact.

Page 22, paragraph 1, Space heating area sources. Please further explain how the combined survey data best represents 2013 emissions.

Page 23: Add information about how NH_3 was inventoried for this category.

Page 23, 2nd paragraph from bottom. Facilities need to provide direct PM and all precursors, whether directly submitted or calculated from emissions factors.

Page 23, last paragraph.

- Potential typo – we believe that 2018 should be 2013.
- Question – Does scaling emissions cause any point source to exceed its PTE?

Page 25, bullet 3, Laboratory – Measured Emissions Factors for Fairbanks Heating Devices. The statement “first and most comprehensive systematic” would be more credible if simplified.

Page 27: Clarify how data from the 2014 NEI was modified to reflect emissions in 2013. Were they assumed to be the same between the two years? Or adjusted based on population change, or some other information?

Page 33: Please include information on how the Speciate database was used to develop the modeling inventory (and perhaps elsewhere for the planning inventory, if appropriate).

Precursor Demonstration

Throughout the Serious Area SIP we recommend using the terminology, Precursor Demonstration, to be consistent with the $PM_{2.5}$ Implementation Rule.

General: The overview of the nitrate chemistry is complicated. We suggest you combine the two discussions into one and organize it with the following logic:

1. Describe the two chemical environments: (1) daytime and (2) nighttime.
2. Describe the information that supports that daytime chemistry is not relevant here.
3. Describe the information that supports that nighttime chemistry is limited by excess NO.

4. Describe what happens if the entire emission inventory was increasing by a factor of 3.6 to get appropriate concentrations in the North Pole area. How does ammonium nitrate change?
5. Describe how increasing the emission inventory and then reducing all source sectors by 75% results in less of a reduction in $P_{M2.5}$ than reducing all source sectors by 75% in the original emission inventory.
6. NOTE: We are willing to provide a rough draft of this organization, if provided the original word document.

Title page: remove "com"

Page 2: Recommend using Section 188-190 instead of 7513-7513b.

Page 2: Recommend moving the last three sentences of the first paragraph to the end of the second paragraph.

Page 2: Please add "threshold" after 1.3 in the third paragraph.

Page 2: Please explain concentration-based and sensitivity-based before using the terms.

Page 2: Please add a footnote whether the numbers in the Executive Summary are SANDWICHed or not.

Page 3: Please change "has decided" to "decided."

Page 3: Make sure the concentrations listed for ammonia include ammonium sulfate and ammonium nitrate.

Page 5-7: The figure captions say that concentrations are presented but the images themselves have percentages. Please use concentrations for this analysis.

Page 9: The first paragraph says that the point sources are not responsible for the majority of sulfate at the monitors. Please substantiate that claim, or modify it.

Page 13: Please explain the relevance of referring to the VOC emissions of home heating in this summary of VOCs.

Page 14: Recommend adding "… and adjusted to reflect speciated concentrations for a total PM2.5 equal to the five year 2011-2015 design value" to the sentence that starts "The speciated PM2.5 data [were] analyzed.

Page 14: Please include the results of the concentration based analysis, perhaps as a table.

Page 14: Clarify that the concentration used for NH_3 is the ammonium sulfate and ammonium nitrate. See the draft EPA Precursor Demonstration Guidance.

Page 17: Recommend removing "slightly" and removing the sentence referring to rounding to the nearest tenth of a microgram.

Page 17-18: To help understand what is going on with the bounding run versus the normal run, it would be helpful to have the RRFs for the Modeled 75% scenario.

BACM

Page 9 and throughout: For clarity, please refer to the implementation rule as "$PM_{2.5}$" not "PM".

Page 14, Table 3. It would be helpful to include filter speciation data.

Page 16, Table 4: Please identify the RACM measures that were technologically and economically feasible but could not be implemented in the RACM timeline or note there were none.

Page 20 and 25, Table 6 and 7: For the final Table identifying the control measures evaluated, it would be helpful to identify the following: measure, cost/ton, BACM determination, MSM determination, and any additional comments.

Page 24: 12 measures were eliminated because they were determined to offer marginal or unquantifiable benefit. However, a measure may offer marginal benefit but may also cost very little. If there is another explanation for why these measures were not considered that follows the BACM steps, please include that in the Serious Area Plan.

Page 28: Stage 1 alerts are referred to multiple times including in Measure 2 on page 28 and Measure 33, pg 47 and pg 48. Please clarify in these analyses whether the measure applies during all stages of alerts and the associated level of control with each stage.

Page 33: Measure 13 identified that no SIPs existed or EPA guidance/requirements for the measure and incorrectly used that rationale as the conclusion for not considering the measure.

Page 34: The discussion of Measure 15 does not clearly state how Alaska and the Borough ensure that devices are taken out at the point of sale. It also does not clearly state the process for ensuring a NOASH application doesn't involve a stove that should have been taken out at the point of sale. It also states that stoves between 2.5 g/hr and 7.5 g/hr can get a NOASH, whereas page 37 implies that a stove must be <2.5 g/hr to be eligible for a NOASH.

Page 47: Measure 33 in Klamath County and Feather River is more stringent than what exists in Fairbanks now. Fairbanks allows open burning without a permit when there is no stage restriction. Alaska DEC prohibits open burning between November 1 and March 31, but the air quality plan makes it clear that the state relies on the Borough to carry out the air quality program in Fairbanks. The fact that the local borough does not require a permit for open burning outside of curtailments makes this measure less stringent in Fairbanks than in other locations. In addition, Fairbanks does not curtail warming fires during a Stage 1.

Page 48: Measure 34 is less stringent in Fairbanks than in Klamath County. Uncertainty in weather forecasting means that Stage 1 alerts are not called correctly all the time, and not everyone is aware of when an alert is in effect. It is much simpler and less prone to error to prohibit burn barrels and outdoor burning devices entirely.

Page 57: Measure 46 review curtailment exemptions. The current Fairbanks curtailment exemption “These restrictions shall not apply during a power failure.” should be reviewed to clarified that it only applies to homes reliant on electricity for heating. As currently written, it appears overly broad.

Page 68: Measure R7, Ban Use of Hydronic Heaters, incorrectly identifies that no other SIPs implemented the measure as rational for not evaluating.

Page 72: Measure R15 is technologically feasible.

Page 78: It may help to make a section break or Section 2 label for “Analysis of Marginal / Unquantifiable Benefit BACM Measures

Page 81-83: The discussion of Measure 6 may need additional documentation. Anecdotal evidence is that damping is common in Fairbanks and is potentially a bigger source of pollution than not having a damper at very cold conditions. If installation by a certified technician addresses this issue, that should be documented.

Page 84: The quote, “did not know if the rule had worked well” needs a reference. It is also not clear of how relevant that is. It could be implemented well in Fairbanks and the fact that it may not have worked well in another location does not make it technologically infeasible for this location.

Page 85-86: While qualitative assessments are helpful to provide context, a quantitative assessment will be necessary to evaluate the measures as BACM and MSM.

Page 88: There are references to Fairbanks in the conclusion for Measure 17, but the analysis refers to AAC code.

Page 89: There appears to be missing text in the Background section related to Method 9.

Page 91: Measure 23 could consider the solution that the decals could be reflective and would be seen by vehicle headlights. Measure 23 could also consider that the decals are used by neighbors to determine who is or is not in compliance. This may be helpful as citizen compliance assistance efforts could supplement the Borough enforcement program.

Page 98-100: Measure 40 needs to include a discussion of all the areas listed on page 22. In addition, if a date certain measure or if Measure 29 were instituted, Measure 40 would essentially be achieved.

Page 114: Measure R5 describes a similar rule in Utah but lists “none” under implementing jurisdictions. Please make consistent.

ULS Heating Oil

Page vii and Page 16: Please check your information on the percentage of households who have a central oil fired furnace. Please consult ADEC's contractor for the emissions inventory and home heating surveys about (1) the percentage of homes that heat only with an oil furnace, and (2) home with a central oil burner and a wood stove. We have seen different numbers than presented here.

Page 13: Please check the labels for Fairbanks HS #2 and Fairbanks HS #1. They may be switched.

Page 14: The statement that there is "a clear explanation" may not be correct, or at minimum is an overstatement. The difference in price between HS#1 and ULSD has varied over time, and the report did not include an explanation for the variations.

Page 14: The third paragraph assumes that the capital costs of shipping ULS would be more than exists today. However, all heating oil is shipped, regardless of sulfur content, and there is no justification for the report for why shipping ULS would be higher than for HS. Additionally, it is possible that the shipping cost per unit could go down marginally if only one product is being supplied to Fairbanks and/or if the quantity supplied increases.

Page 21: The text and Table 7 present inconsistent information. For instance, the text says that the discounted net-present value of scenario 2 is $10,232 while the table says it is $5,768.56.

Golden Valley Electric Association
PO Box 71249, Fairbanks, AK 99707-1249 • (907) 452-1151 • www.gvea.com
Your Touchstone Energy® Cooperative

November 28, 2018

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Denise Koch, Director
Division of Air Quality
Department of Environmental Conservation
410 Willoughby Avenue, Suite 303
PO Box 111800
Juneau, AK 99811-1800

RE: Best Available Control Technology (BACT) Proposal from Golden Valley Electric Association (GVEA) for the North Pole Power Plant and Zehnder Facility.

Dear Ms. Koch,

At the request of the Alaska Department of Environmental Conservation (ADEC), Golden Valley Electric Association (GVEA) has considered alternative Best Available Control Technology (BACT) proposals and in this communication is providing updated and supplemental information. GVEA hopes this additional information is beneficial to ADEC as the Serious $PM_{2.5}$ State Implementation Plan (SIP) is finalized.

Introduction

Due to geography, our northern latitude, climatology, and types of emissions within the Fairbanks North Star Borough (FNSB), concentrations of $PM_{2.5}$ often exceed the maximum levels set by the Clean Air Act; resulting in the area being designated as being in non-attainment of the National Ambient Air Quality Standards (NAAQS) for the 24-hour $PM_{2.5}$ standard in 2009. As original attainment goals were not met, the area was reclassified as a Serious non-attainment area (NAA) and ADEC is working to finalize and submit to EPA an approvable Serious SIP that will outline methodologies for reaching attainment.

GVEA operates two stationary sources within the NAA, the North Pole Power Plant and the Zehnder Facility. With the Serious designation, ADEC requested stationary sources conduct a voluntary BACT analyses for emissions of $PM_{2.5}$ or its precursors (SO_2, NO_x, VOCs and NH_3) that have the potential to be emitted at 70 or more tons per year. GVEA prepared and submitted BACT analyses for both the North Pole and Zehnder plants that analyzed NOx and

SO_2 BACT. All NO_X and SO_2 control options evaluated were deemed infeasible by GVEA. Subsequently, ADEC proposed modifications to GVEA's calculations and presented these in draft BACT documents early in 2018. For NO_x BACT, ADEC's determination included Selective Catalytic Reduction (SCR) and water injection for the two simple cycle gas turbines at both North Pole and Zehnder, and SCR for the combined cycle turbine at North Pole. For SO_2 BACT, ADEC's determination included ULSD for the two simple cycle gas turbines at both North Pole and Zehnder.

In the March 2018 draft documents, ADEC included a draft NO_x precursor demonstration which will show that NOx emissions are not a significant contributor to secondary $PM_{2.5}$ concentrations. ADEC has communicated a high degree of confidence the NO_x precursor demonstration will be accepted and the implementation of NOx controls will not be required. As such GVEA is not addressing any new BACT considerations related to NO_x controls and is focusing on alternative proposals for SO_2 BACT at both plants[1].

Alternative BACT Request

ADEC has been sympathetic to concerns raised by the stationary sources that potential community burden in capital investment for SO_2 controls is unusually high compared to the potential benefit to $PM_{2.5}$ concentrations at ground level; concentrations which are highly influenced by home heating and especially wood burning. ADEC has asked GVEA to consider alternative BACT proposals including the option of paying into an offset fund with the caution that creative and alternative proposals would have to be measurable and enforceable. Though an offset fund could be an options, there are two reasons GVEA does not see contributions to an offset fund as a viable option. First, GVEA does not see a way at this time to equitably incorporate offset fund payments into our member rates. Second, with no assurances that further investments into BACT controls would not be necessary if attainment goals are not met, the potential for investment into both an offset fund and BACT is a deterrent.

GVEA has identified modifications in combustion fuel and operating hours as options available to reduce SO_2 emissions at GVEA's two affected facilities and presents three proposed alternatives in order of descending preference below.

Alternative SO_2 BACT Option 1
Existing Fuels and Good Combustion Practices for North Pole and Zehnder

Current Fuel Supplies

GVEA currently receives all fuel from Petro Star Inc. (PSI) with the majority coming from the local North Pole Refinery adjacent to the North Pole Power Plant. In 2017 the combined cycle turbine at North Pole (EU ID 5) began receiving a Light Straight Run (LSR) naphtha product directly from the Petro Star North Pole Refinery (PSI) via pipeline. The sulfur content of this fuel

[1] At this time, GVEA has no comment on ADEC's modifications to the NOx control calculations.

was specified to be below 30 ppm and extensive testing conducted in 2018 showed a maximum sulfur content of 27 ppm. Less than two percent of the fuel received is composed of other naphtha fuels that have sulfur contents less than 50 ppm. Assuming a maximum fuel sulfur content of 50 ppm would conservatively change the potential SO_2 emissions from this unit and the proposed second LM6000 (EU ID 6) from 6 to 10.1 tons per year (TPY). Tables 1-2 and 1-5 in GVEA's North Pole BACT analysis would be affected by this change and are included in Attachment 1.

High sulfur diesel (HSD) is trucked from the pipe rack at PSI's North Pole facility across the street to a 50,000 gallon holding tank that supplies the two GE Frame 7 gas turbines at the North Pole Plant (EU IDs 1 and 2). Similarly, HSD is trucked from PSI North Pole to the Zehnder Plant GE Frame 5's (EU IDs 1 and 2). The large majority of the fuel is No. 2 HSD that is blended with No. 1 in the winter to lower the pour point. No. 1 HSD is received on rare occasions. ULSD is trucked from PSI's Valdez refinery for use as a starting fuel and is used in smaller quantities. During times when the North Pole refinery is down for planned maintenance outages, additional ULSD is trucked to Fairbanks for production fuel.

BACT Capital Cost Assumptions

GVEA's original BACT and ADEC's proposed BACT evaluated switching to ULSD to reduce SO_2 emissions. These analyses included capital costs for bulk fuel storage to maintain reliability and security of fuel supply; these costs were apportioned between the North Pole and Zehnder plants.

If GVEA were to use ULSD for both starting and production fuel in the Frame 7's and Frame 5's, as considered for SO_2 BACT, the addition of bulk fuel storage would be required to guarantee availability of fuel for the generation units since there is no locally refined source of ULSD[2]. Fuel can be imported from the Valdez area using trucks, or from the Anchorage area using trucks or rail. Both transportation corridors are subject to disruptions from avalanches, flooding, snow storms, forest fires, or earthquakes that could delay fuel delivers. For example, a video clip available online[3] shows a massive avalanche caused ice dam that closed the single road connecting Valdez in January 2014, an avalanche accompanying record snow fall closed the road to Valdez in December 6, 2017, the 2002 Denali Fault earthquake (7.9 on the Richter scale) damaged more than 20 miles of the roadbed between Fairbanks and Valdez[4], and flooding in 2006 closed the Parks Highway near Anchorage for several days[5].

During the short annual PSI maintenance outages (occurring during summer months) GVEA has experienced near outages of fuel when it is delivered solely through long haul trucking,

[2] GVEA uses "neat" fuel for generation that does not contain the additives that are added to most fuel currently stored locally.

[3] https://www.youtube.com/watch?v=X3XzRHLYE0Y video footage of avalanche ice dam isolating Valdez.

[4] https://www.fhwa.dot.gov/publications/publicroads/03nov/05.cfm Denali Fault earthquake.

[5] https://www.matsugov.us/news/4-a-m-flood-and-road-updates Parks highway closure for flooding.

largely because the long haul (700 miles round trip versus .5 miles) complicates the timing of truck offloading. This experience with supply issues, and the potential for transportation disruption, raises concerns with the reliability of year round long hauled fuel supplies on a "just in time" basis from either Valdez or Anchorage, and particularly during the coldest winter months. In 2017, GVEA hired PDC Engineering of Fairbanks to assist in developing a concept design and cost estimate for a bulk fuel tank farm and terminal facility adjacent to the North Pole Power Plant. The technical memo presenting the conceptual study is included as Attachment 2.

As part of the BACT analyses, GVEA sought input from Delma Bratvold, an Energy Analyst with Leidos Engineering, to help extrapolate the PDC concept design. Ms. Bratvold has a long history of assisting GVEA with strategic fuel evaluations and her BACT specific summary is included as Attachment 3, presenting the estimated costs of strategic bulk fuel storage for both the North Pole Plant and Zehnder Facilities based on both potential to emit (PTE) run hours and historic run hours.

Fuel Cost Assumptions

In preparing the original BACT analyses, GVEA used actual fuel costs incurred from August 2015 through April 2016 to obtain a cost differential of $0.2668 per gallon between ULSD and No. 2 HSD. Attachment 4 shows updated pricing data for fuel received between January 2017 and October 2018 and shows an updated weighted average cost differential of $0.424 per gallon between No. 2 HSD and ULSD[6].

Cost Effectiveness

Appling the updated incremental fuel pricing increases the cost effectiveness of SO_2 removal for all primary generating units. Table 1 summarizes the cost effectiveness of switching to ULSD for the primary generating units and compares the iterations in calculations, from GVEA's original, the ADEC's to GVEA's updated. The updated cost effectiveness tables from the BACT analyses are included in Attachment 5[7].

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[6] A digital version of Attachment 4 is included on the enclosed DVD.

[7] Tables referenced in this correspondence refer to similarly numbered tables in GVEA's original BACT analyses. ADEC returned to GVEA proposed modifications to the BACT tables as Excel files following ADEC's preliminary review. GVEA's most current updates are applied to ADEC's version. Updates described here are attached in hard copy and included on the accompanying DVD.

Table 1. Cost Effectiveness, \$/Ton of SO_2 removal[1]			
	GVEA's 2017 BACT Cost Effectiveness (\$/Ton) [2]	ADEC's Cost Effectiveness (\$/Ton) [3]	GVEA's 2018 Alternative BACT Cost Effectiveness (\$/Ton) [4]
North Pole			
EU ID 1	\$10,025	\$9,139	\$13,942
EU ID 2	\$10,204	\$9,233	\$14,037
EU ID 5/6	\$9,282,151	\$9,282,151	\$4,844,020 [5]
Zehnder			
EU ID 1/2	\$9,701	\$9,050 [6]	\$14,250

[1] Capital costs of \$30,425,000 to install fuel storage are apportioned between North Pole and Zehnder and the cost effectiveness calculations for both plants are based on the Potential to Emit. The cost effectiveness based on actual emissions and on the conversion of SO2 to PM2.5 is significantly higher.
[2] Tables 5-4, 5-5, and 5-6 in GVEA's original BACT for North Pole and Table 5-4 in the original BACT for Zehnder.
[3] Tables 5-4, 5-5, and 5-6 in ADEC's modified BACT tables for North Pole and Table 5-4 for ADEC's modified Zehnder BACT calculations
[4] Updated Tables 5-4, 5-5, and 5-6 are included in Attachment 5. The Excel file is included on the enclosed DVD.
[5] As shown on included tables and discussed above, increasing the naphtha fuel from 30 ppm to 50 ppm sulfur content increases the potential annual SO_2 emissions from 6 to 10.1 tons and decreases the cost effectiveness.
[6] ADEC's proposed cost effectiveness for Zehnder was based on avoiding 597 tons SO_2 per year. Condition 9 of Permit No. AQ0109TVP03 already places an Owner Requested Limit (ORL) on SO_2 Emissions of 580 tons per rolling 12-month period for the Zehnder Facility. Considering the ORL, the cost effectiveness is \$9,340 per ton removed.

With a cost effectiveness above \$13,000 per ton of SO_2 removed, GVEA contends that switching to ULSD is not economically feasible and BACT would be the existing fuels and good combustion practices for all units at North Pole and Zehnder.

ADEC has suggested No. 1 HSD with a sulfur content of 900 ppm be considered as an alternative to No. 2 HSD. Currently, No. 1 HSD produced locally by PSI is not available in large enough quantities to be used as a production fuel. PSI is undertaking engineering studies to identify ways to expand their local production of No. 1 HSD, however they have indicated there will be competing demands; the military use is forecast to increase by 50%, and there is the projected conversion of home heating to No. 1 HSD. Production fuel for GVEA would be a non-dedicated supply and last on the priority list behind the military and home heating demands. PSI has indicated they would likely import fuel from Valdez to meet GVEA's full demands. To have a guaranteed fuel supply, this would place GVEA in a situation similar to importing ULSD with similar pricing and reliability constraints. To fully switch to No. 1 HSD would have a cost effectiveness similar to ULSD.

Alternative SO_2 BACT Option 2
North Pole - No. 1 HSD (EU IDs 1&2) on Air Quality Stage 1 and 2 Curtailment Days
Zehnder - Existing Fuels and Good Combustion Practices

North Pole Power Plant Option 2

GVEA wishes to be a constructive contributor to improving regional $PM_{2.5}$ concentrations with practical solutions that do not unfairly burden our cooperative members with negligible benefit.

As such, GVEA proposes as SO_2 BACT for North Pole EU ID's 1 and 2, the continued use of No. 2 HSD during normal operating days, with a switch to receiving No. 1 HSD (when available) when the units operate on air quality curtailment days (during Stage 1 and Stage 2 air quality alerts for the North Pole area). It will take an estimated 5 to10 operating hours to fully transition fuel. With the recent addition of Healy Unit 2 to the generation fleet, which economically produces electricity outside the NAA, GVEA anticipates the actual operation of EU ID's 1 and 2 to be reduced. New Tables 5-4a and 5-5a in Attachment 6 evaluate the cost effectiveness of targeted operation on No. 1 HSD, assuming 10% of the time, at $1,904 per ton of SO_2 avoided.

GVEA proposes as SO_2 BACT for EU ID's 5 and 6, the continued use of the current or equivalent fuels with a sulfur content of 50 ppm or less.

Zehnder Facility Option 2

GVEA proposes as SO_2 BACT the existing fuels and good combustion practices for all units at Zehnder. Condition 9 of Permit No. AQ0109TVP03 already places an Owner Requested Limit (ORL) on SO_2 Emissions of 580 tons per rolling 12-month period for the Zehnder Facility[8]. EU ID's 1 and 2 are the least economical units to run and are run only when absolutely necessary. Attachment 7 shows the 2017 actual operating hours and emissions for the Zehnder Facility as presented in the March 2018 assessable emissions estimates. These emissions are representative of operations from 2012 through 2018 (year to date) where the total SO_2 emissions have been slightly over 30 tons per year. As mentioned above, with the addition of Healy Unit 2 the Zehnder Units are modeled to run even fewer hours.

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[8] If the ORL was reduced to 350 tons per year, the cost effectiveness of ULSD as evaluated in Table 1 goes to $21,989 per ton of SO_2 reduced.

Alternative SO_2 BACT Option 3
North Pole - No. 1 HSD (EU IDs 1&2) on Air Quality Stage 1 and 2 Curtailment Days
Zehnder - ORL to Remove Zehnder as a Major Source of SO_2

North Pole Power Plant Option 3 (same as Option 2)
Similar to Option 2, GVEA proposes to supply No. 1 HSD to EU ID's 1 and 2 when they are operating during air quality Stage 1 and Stage 2 alerts in the North Pole area. SO_2 BACT for EU ID's 5 and 6, would again be the continued use of the current or equivalent fuels with a sulfur content of 50 ppm or less.

Zehnder Facility Option 3
GVEA recognizes the traditional BACT process evaluates the potential to emit pollutants of concern, and the Zehnder Facility has the potential to emit many more tons of SO_2 than it historically has. The Zehnder units are the least economical to run and are run only when necessary, however, they are a critical piece to the overall system reliability and their operation is necessary in cases when other generating units are down, or the transmission Intertie with the Anchorage area is down.

As a third option, GVEA proposes to take an additional ORL on SO_2 emissions to limit them to less than 70 tons per year, thus removing the Zehnder Facility as a major source of SO_2. GVEA proposes to submit the request for permit modification by June 1, 2019 and would structure the modification to allow for operation in emergency situations. The health and welfare of GVEA's members are of upmost importance and in consideration of the extreme temperatures and winter conditions that can be experienced in the FNSB, GVEA must be able to supply electrical power to members when other sources are unavailable. Attachment 8 shows a guide used internally to prioritize outage response. For a range of outside temperatures it tabulates the time to a complete house freeze up after the loss of a heat source. With an external temperature of -30 F, a house starting with an internal temperature of 70 F can be expected to freeze after seven hours.

Other Measures

Though not measurable, enforceable, or appropriate for inclusion in the SIP, GVEA is exploring other alternatives that will help minimize emissions from power generation within the non-attainment area.

With the successful restart of Healy Unit 2, the consumption of No. 2 HSD in the North Pole and Zehnder Units has dropped from 12.4 million gallons in 2017, to an estimated 9 million gallons in 2018, to a projected 5.5 million gallons in 2019. In 2019, total SO_2 emissions in the NAA from GVEA's plants is expected to drop 192 tons over 2017. GVEA has modeled the effect of retiring Healy Unit 1 and power would be made up with both purchases from the Anchorage area and generation within the NAA. With the removal of Healy Unit 1, modeling shows an increase in NAA SO_2 emissions from the North Pole and Zehnder Plants of 28%. Options for continuing the operation of Healy Unit 1 are being evaluated.

GVEA is also exploring options that may assist the Interior Gas Utility (IGU) in providing economical natural gas to the Fairbanks area. If feasible, GVEA may be able to convert North Pole EU ID 5 to also burn natural gas, which could help stabilize demand, or help reach some economies of scale for gas supply.

All the sources within FNSB NAA are integrally related and requirements for one source may have unintended consequences for another. As GVEA is the sole purchaser of Aurora Energy's electrical production, any BACT capital investment Aurora makes can potentially affect GVEA's member rates. Knowing that the exact accounting and correlation between the major source SO_2 stack emissions, the at-the-monitor measurements, and the modeling are inconsistent, GVEA encourages ADEC to pursue a Major Source SO_2 precursor demonstration and to work further to explain the sulfate contribution inconsistencies.

Summary

In conclusion, GVEA would like to make meaningful contributions to reducing SO_2 emissions without disproportionally burdening our member owners or sacrificing electrical system reliability. Three BACT options have been presented, in all cases for North Pole's existing EU ID 5 and proposed EU ID 6 (the combined cycle plants at North Pole) GVEA proposes to burn the existing or equivalent fuel with a sulfur content of 50 ppm or less.

As a first option, using updated fuel pricing and the actual differential costs between No. 2 HSD and ULSD, GVEA is submitting updated cost effectiveness calculations for SO_2 reductions at both the North Pole and Zehnder plants that show costs over $13,000 per ton of SO_2 reduced. GVEA proposes as SO_2 BACT the continued use of current fuels and good combustion practices for all units at North Pole and Zehnder.

As a second option, to make reductions in SO_2 emissions during times when they are needed, For EU ID's 1 and 2, the older simple cycle plants at North Pole, GVEA proposes to continue burning No. 2 HSD during normal operations, but to take delivery of No. 1 HSD[9] while operating during air quality curtailment periods.

As a final option, in addition to receiving No. 1 HSD during curtailment periods at North Pole, GVEA proposes to take an additional ORL at the Zehnder Facility to reduce annual SO_2 emissions to less than 70 tons, except in emergency situations.

[9] Subject to availability as GVEA would be third in line of preference behind Military demands and proposed home heating demands.

Sincerely,

Naomi Morton Knight, P.E.
Environmental Health & Safety Officer

Attachments/Enclosures:

Attachment 1 - North Pole BACT Section 1 Tables
Attachment 2 - Technical Memo from PDC Regarding Bulk Fuel Storage
Attachment 3 - Leidos Strategic Fuel Evaluation
Attachment 4 - January 2017 through October 2018 Fuel Prices
Attachment 5 - Updated Cost Effectiveness Tables North Pole and Zehnder
Attachment 6 - Tables 5-4a and 5-5a, North Pole EU ID 1 and 2 Cost Effectiveness with Selective use of No. 1 HSD
Attachment 7 - Zehnder FY2019 Assessable Emissions Summary
Attachment 8 - House Freeze Up Time Estimates.
DVD

GVEA
Alternative BACT
November 2018

Attachment 1
North Pole BACT Section 1 Tables

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Table 1-2. Significant Emission Unit Potential Emission Inventory

Emission Unit			Fuel	Rating	Maximum	Allowable Annual	Construction	Life	Potential Emissions (tpy)			
ID	Description	Make/Model	Type		Capacity	Operation	Date	Span	NO_X [1]	$PM_{2.5}$	SO_2 [2,3]	VOC
1	Simple Cycle Gas Turbine	GE Frame 7, Series 7001, Model BR	Fuel Oil	60.5 MW	672 MMBtu/hr	8,760 hr/yr	1976	10 years	1,600.0	35.3	1,486.4	1.2
2	Simple Cycle Gas Turbine	GE Frame 7, Series 7001, Model BR	Fuel Oil	60.5 MW	672 MMBtu/hr	7,992 hr/yr[4]	1977	10 years	2,363.1	32.2	1,356.1	1.1
3	Fuel Storage Tank	N/A	HAGO/LAGO/ Fuel Oil[5]	50,000 Gallons	50,000 Gallons	8,760 hr/yr	1995	10 years	0	0	0	0.04
4	Fuel Storage Tank	N/A	HAGO/LAGO/ Fuel Oil[5]	50,000 Gallons	50,000 Gallons	8,760 hr/yr	1995	10 years	0	0	0	0.06
5	Combined Cycle Gas Turbine	GE LM6000PC	GVEA LSR Turbine Fuel/GVEA Naphtha[6]	43 MW	455 MMBtu/hr	8,760 hr/yr	2005	10 years	478.3	23.9	10.1	0.8
6	Combined Cycle Gas Turbine	GE LM6000PC	GVEA LSR Turbine Fuel/GVEA Naphtha[6]	43 MW	455 MMBtu/hr	8,760 hr/yr	N/A	10 years	478.3	23.9	10.1	0.8
7	Emergency Generator Engine	Generac 5231150100	Fuel Oil	400 kW	461.6 kW	52 hr/yr[7]	2005	10 years	0.5	0.04	0.01	0.0
11	Boiler	Bryan Steam RV500	Gas Fuel/Propane	5.0 MMBtu/hr	5.0 MMBtu/hr	8,760 hr/yr	2005	10 years	3.1	0.2	0.0003	0.2
12	Boiler	Bryan Steam RV500	Gas Fuel/Propane	5.0 MMBtu/hr	5.0 MMBtu/hr	8,760 hr/yr	2005	10 years	3.1	0.2	0.0003	0.2
Total Potential Emissions									3,969.8	115.7	2,862.6	4.5

[1] Combined emissions from EU IDs 1, 5, and 6 are limited to 1,600 tpy emissions of NO_X on a 12-month rolling basis per Permit AQ0110TVP03, Condition 13. Each emission unit can operate individually up to the potential NO_X emissions shown above.

[2] EU IDs 1 and 2 can combust No. 1 and No. 2 fuel oil, which (by specification) can have a maximum sulfur content of 0.5 wt. pct. The two emission units may emit no more than 24,500 pounds of SO_2 per day, combined, per Permit AQ0110TVP03, Condition 14. The fuel oil sulfur content specification of 0.5 wt. pct. S is more restrictive. Each unit could be operated individually up to the potential SO_2 emissions shown above.

[3] EU IDs 5 and 6 are limited to a combined 12-month rolling total consumption of 1.5 million gallons of startup fuel per Permit AQ0110TVP03, Condition 16.1. Each unit could be operated individually up to that limit.

[4] EU ID 2 is limited to operating no more than 7,992 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 12.

[5] HAGO and Lago are listed for completeness, but those fuels are no longer available due to the closure of the Flint Hills Refinery in North Pole.

[6] GVEA LSR Turbine Fuel (LSR) is currently being combusted in EU ID 5. This fuel is obtained from directly from the Petro Star Inc. (PSI) refinery via pipeline. PSI is supplying this fuel under a long-term contract with GVEA.

[7] EU ID 7 is limited to operating no more than 52 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 10.

Table 1-3. Significant Emission Unit Potential NO_X Emissions

Significant Emission Units		Factor Reference	NO_X Emission Factor	Maximum Capacity	Maximum Operation	Regulatory Limits	Existing Control Technology		Potential NO_X Emissions
ID	Description						Description	Efficiency (pct.)	
1	Simple Cycle Gas Turbine	AP-42 Table 3.1-1	0.88 lb/MMBtu	672 MMBtu/hr	8,760 hr/yr	NA	Regenerative System	Unknown	1,600 tpy [1]
2	Simple Cycle Gas Turbine	AP-42 Table 3.1-1	0.88 lb/MMBtu	672 MMBtu/hr	7,992 hr/yr[2]	NA	Regenerative System	Unknown[6]	2,363.1 tpy
3	Fuel Storage Tank	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
4	Fuel Storage Tank	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
5	Combined Cycle Gas Turbine	AP-42 Table 3.1-1	0.24 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	Subpart GG 146 ppmvd at 15 pct. O_2	Water Injection	73 [3]	478.3 tpy [1]
6	Combined Cycle Gas Turbine	AP-42 Table 3.1-1	0.24 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	Subpart KKKK 74 ppm at 15 pct. O_2 or 3.6 lb/MWh	Water Injection	73 [3]	478.3 tpy [1]
7	Emergency Generator Engine	AP-42 Table 3.3-1	0.031 lb/hp-hr	461.6 kW	52 hr/yr[5]	NA	Turbocharger and Aftercooler + Limited Operation	99	0.5 tpy
11	Boiler	AP-42 Table 1.5-1	13 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		3.1 tpy
12	Boiler	AP-42 Table 1.5-1	13 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		3.1 tpy
							Total Potential Emissions		3,969.8 tpy[4]

Sample Calculations:

Turbine Emissions, tpy= (Emission factor, lb/MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

Engine Emissions, tpy= (Emission factor, lb/hp-hr) * (Capacity, kW) * (Conversion, 1.341 hp/kW) * (Operation, hr/yr) / (2,000 lb/ton)

Heater (Boiler) Emissions, tpy= (Emission factor, lb/10^3gal) * (Conversion, 10^3gal/91.5 MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

- Propane heat content is assumed to equal 91.5 MMBtu/10^3 gallon per AP-42 Table 1.5-1.

Notes:

[1] Combined emissions from EU IDs 1, 5, and 6 are limited to 1,600 tpy NO_X emissions on a 12-month rolling basis per Permit AQ0110TVP03, Condition 13. Each unit can operate individually up to the potential emissions shown above.

[2] EU ID 2 is limited to operating no more than 7,992 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 12.

[3] AP-42, Table 3.1-1 infers a control efficiency of 73 pct. for water injection. While 77 pct. was listed in recent Emission Unit Inventory submittals, 73 pct. is used in this analysis. Permit AQ0110TVP03, Condition 13.2 requires water injection for EU IDs 5 and 6.

[4] Total potential emissions have been adjusted to reflect ORL restrictions.

[5] EU ID 7 is limited to operating no more than 52 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 10.

[6] The EU ID 2 regenerative system was rebuilt during 2012-2013 and is expected to be more effective than the regenerative system on EU ID 1 but has not been quantified.

Table 1-4. Significant Emission Unit Potential $PM_{2.5}$ Emissions

Significant Emission Units		Factor	PM Emission	Maximum	Maximum	Regulatory Limits	Existing Control Technology		Potential $PM_{2.5}$
ID	Description	Reference	Factor	Capacity	Operation		Description	Efficiency (pct.)	Emissions
1	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.012 lb/MMBtu	672 MMBtu/hr	8,760 hr/yr	NA	NA		35.3 tpy
2	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.012 lb/MMBtu	672 MMBtu/hr	7,992 hr/yr[1]	NA	Limited Operation	9	32.2 tpy
3	Fuel Storage Tank	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
4	Fuel Storage Tank	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
5	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a	0.012 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	NA	NA		23.9 tpy
6	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a	0.012 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	NA	NA		23.9 tpy
7	Emergency Generator Engine	AP-42 Table 3.3-1	0.0022 lb/hp-hr	461.6 kW	52 hr/yr[2]	NA	Limited Operation + Positive Crankcase Ventilation	99	0.035 tpy
11	Boiler	AP-42 Table 1.5-1	0.7 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		0.2 tpy
12	Boiler	AP-42 Table 1.5-1	0.7 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		0.2 tpy
							Total Potential Emissions		115.7 tpy

Sample Calculations:

Turbine Emissions, tpy= (Emission factor, lb/MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

Engine Emissions, tpy= (Emission factor, lb/hp-hr) x (Capacity, kW) * (Conversion, 1.341 hp/kW) * (Operation, hr/yr) / (2,000 lb/ton)

Heater (Boiler) Emissions, tpy= (Emission factor, lb/10^3gal) * (Conversion, 10^3gal/91.5 MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

- Propane heat content is assumed to equal 91.5 MMBtu/10^3 gallon per AP-42 Table 1.5-1.

Notes:

[1] EU ID 2 is limited to operating no more than 7,992 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 12.

[2] EU ID 7 is limited to operating no more than 52 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 10.

Table 1-5. Significant Emission Unit Potential SO_2 Emissions

Significant Emission Units		Factor	Maximum Fuel	SO_2 Emission	Maximum	Maximum	Regulatory Limits	Existing Control Technology		Potential SO_2
ID	Description	Reference	Sulfur Content	Factor	Capacity	Operation		Description	Efficiency (pct.)	Emissions
1	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.50 wt. pct. S[1]	0.51 lb/MMBtu	672 MMBtu/hr	8,760 hr/yr	Permit AQ0110TVP03 Combined emission limit of 24,500 lb/day[1]	NA		1,486.4 tpy[1]
2	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.50 wt. pct. S[1]	0.51 lb/MMBtu	672 MMBtu/hr	7,992 hr/yr[2]		Limited Operation	9	1,356.1 tpy[1]
3	Fuel Storage Tank	NA	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
4	Fuel Storage Tank	NA	NA	NA	50,000 Gallons	8,760 hr/yr	NA	NA		0 tpy
5	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a (non-startup)	0.005 wt. pct. S[3]	0.005 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	Subpart GG 150 ppmvd at 15 pct. O_2 or 0.8 wt. pct. S	Low Sulfur Fuel (0.05 pct by weight)	N/A	10.1 tpy
		Mass Balance (startup)	0.3 wt. pct. S[4]	0.037 lb/gal		1,500,000 gal/yr		NA		N/A[4]
		Total								10.1 tpy
6	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a (non-startup)	0.005 wt. pct. S[3]	0.005 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	Subpart KKKK 0.9 lb/MWh emissions	Low Sulfur Fuel (0.05 pct by weight)	N/A	10.1 tpy
		Mass Balance (startup)	0.3 wt. pct. S[4]	0.037 lb/gal		1,500,000 gal/yr	Subpart KKKK 0.06 $lbSO_2$/MMBtu fuel	NA		N/A[4]
		Total								10.1 tpy
7	Emergency Generator Engine	Mass Balance	0.1 wt. pct. S[5]	0.014 lb/gal	32 gal/hr[6]	52 hr/yr[7]	NA	Limited Operation	99	0.01 tpy
11	Boiler	AP-42 Table 1.5-1	0.012 wt. pct. S[8]	0.0012 $lb/10^3gal$	5.0 MMBtu/hr	8,760 hr/yr	NA	Low Sulfur Fuel (propane - 120 ppmv)	Unknown	0.0003 tpy
12	Boiler	AP-42 Table 1.5-1	0.012 wt. pct. S[8]	0.0012 $lb/10^3gal$	5.0 MMBtu/hr	8,760 hr/yr	NA	Low Sulfur Fuel (propane - 120 ppmv)	Unknown	0.0003 tpy
								Total Potential Emissions		2,862.6 tpy[9]

Sample Calculations:

Molar mass ratio is 32 lb S/mol : 64 lb SO_2/mol

Stoichiometry: 1 mol S = 1 mol SO_2

Mass Balance Emission Factor, lb/gal = (Molar mass ratio, 2 lb SO_2:1 lb S) * (wt. pct. S in fuel) * (density of fuel, lb/gal) / 100%

Turbine Emissions (Normal Operation), tpy= (Emission factor, lb/MMBtu) * (Capacity, MMBtu/hr) x (Operation, hr/yr) / (2,000 lb/ton)

Turbine Emissions (Startup), tpy= (Emission factor, lb/gal) * (Throughput, gal/yr) / (2,000 lb/ton)

Engine Emissions, tpy= (Emission factor, lb/gal) * (Capacity, gal/hr) * (Operation, hr/yr) / (2,000 lb/ton)

Heater (Boiler) Emissions, tpy= (Emission factor, $lb/10^3gal$) * (Conversion, 10^3gal / 91.5 MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

wt. pct. S (in diesel) = (Sulfur compound emission limit, ppmv SO_2) * (Conversion, 1.66E-7 lb SO_2/scf / ppm SO_2) x (F-factor, 9,190 scf/MMBtu) * (Conversion, 0.0193 MMBtu/lb) * (Conversion, mole SO_2/64 lb SO_2) x (Conversion, mole S/mole SO_2) * (Conversion, 32 lb S/ mole S)

-Turbine startup fuel is assumed to have an average density of 6.2 lb/gal. Emergency generator fuel is assumed to equal 7.1 lb/gal per note (a) of AP-42 Table 3.4-1.

- Propane heat content is assumed to equal 91.5 MMBtu/10^3 gallon per AP-42 Table 1.5-1.

Notes:

[1] EU IDs 1 and 2 can combust No. 1 and No. 2 fuel oil, which (by specification) can have a maximum sulfur content of 0.5 wt. pct. The two emission units may emit no more than 24,500 pounds of SO_2 per day, combined, per Permit AQ0110TVP03, Condition 14. The fuel oil sulfur content specification of 0.5 wt. pct. S is more restrictive. Each unit could be operated individually up to the potential SO_2 emissions shown above.

[2] EU ID 2 is limited to operating no more than 7,992 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 12.

[3] The normal operating fuel for EU IDs 5 and 6 is LSR Naphtha obtained from PSI under a long-term contract. The sulfur content of the LSR is limited to no more than 30 ppmw by the terms of that contract, a small percentage (<2%) of fuel may be made up with other naphtha blends with sulfur content no more than 50 ppmw. A conservative fuel sulfur content of 50 ppm is used for calculating SO_2 emissions from EU IDs 5 and 6.

[4] EU ID 5 is a "base-load" unit that is operated continuously for extended periods of time. EU ID 6, if constructed, will be operated in the same manner. As a result, startups on No. 1 or No. 2 fuel oil are infrequent, so potential emissions from startups are not included.

[5] EU ID 7 is limited to a fuel sulfur content of 0.1 wt. pct per Permit AQ0110TVP03, Condition 9.

[6] The engine specification datasheet indicates a maximum fuel throughput of 32 gal/hr.

[7] EU ID 7 is limited to operating no more than 52 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 10.

[8] EU IDs 11 and 12 are limited to a fuel sulfur content of 0.012 wt. pct. per Permit AQ0110TVP03, Condition 11.

[9] Total potential emissions have been adjusted to reflect annual operating hour restrictions.

Table 1-6. Significant Emission Unit Potential VOC Emissions

Significant Emission Units		Factor Reference	VOC Emission Factor	Maximum Capacity	Maximum Operation	Regulatory Limits	Existing Control Technology		Potential VOC Emissions
ID	Description						Description	Efficiency (pct.)	
1	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.00041 lb/MMBtu	672 MMBtu/hr	8,760 hr/yr	NA	NA		1.2 tpy
2	Simple Cycle Gas Turbine	AP-42 Table 3.1-2a	0.00041 lb/MMBtu	672 MMBtu/hr	7,992 hr/yr[1]	NA	Limited Operation	9	1.1 tpy
3	Fuel Storage Tank	TANKS 4.0.9d	-	50,000 Gallons	8,760 hr/yr	NA	NA		0.04 tpy
4	Fuel Storage Tank	TANKS 4.0.9d	-	50,000 Gallons	8,760 hr/yr	NA	NA		0.06 tpy
5	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a	0.00041 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	NA	NA		0.8 tpy
6	Combined Cycle Gas Turbine	AP-42 Table 3.1-2a	0.00041 lb/MMBtu	455 MMBtu/hr	8,760 hr/yr	NA	NA		0.8 tpy
7	Emergency Generator Engine	AP-42 Table 3.3-1	0.003 lb/hp-hr	461.6 kW	52 hr/yr[2]	NA	Limited Operation	99	0.0 tpy
11	Boiler	AP-42 Table 1.5-1	0.8 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		0.2 tpy
12	Boiler	AP-42 Table 1.5-1	0.8 lb/10^3gal	5.0 MMBtu/hr	8,760 hr/yr	NA	NA		0.2 tpy
							Total Potential Emissions		4.5 tpy

Sample Calculations:

Turbine Emissions, tpy= (Emission factor, lb/MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

Engine Emissions, tpy= (Emission factor, lb/hp-hr) * (Capacity, kW) * (Conversion, 1.341 hp/kW) * (Operation, hr/yr) / (2,000 lb/ton)

Heater (Boiler) Emissions, tpy= (Emission factor, lb/10^3gal) * (Conversion, 10^3gal/91.5 MMBtu) * (Capacity, MMBtu/hr) * (Operation, hr/yr) / (2,000 lb/ton)

- Propane heat content is assumed to equal 91.5 MMBtu/10^3 gallon per AP-42 Table 1.5-1.

Notes:

[1] EU ID 2 is limited to operating no more than 7,992 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 12.

[2] EU ID 7 is limited to operating no more than 52 hours on a 12-month rolling basis per Permit AQ0110TVP03, Condition 10.

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GVEA
Alternative BACT
November 2018

Attachment 2
Technical Memo from PDC Regarding Bulk Fuel Storage

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PDC ENGINEERS
PLAN • DESIGN • CONSTRUCT

Transforming Challenges into Solutions

TECHNICAL MEMORANDUM

Client #	PO 201751812	**Date**	June 28, 2017
PDC #	17099FB	**Prepared by**	David Sandberg, EIT, Karen Brady, PE
Project Name	North Pole Fuel Storage Facility	**Reviewed by**	Keith Hanneman, PE
Subject	***Concept Design Alternative Site Layout***		

Topic	Discussion

Summary

The proposed Bulk Fuel Tank Farm and Terminal Facility at the GVEA site in North Pole will provide a dependable fuel source for GVEA's critical power generation operations. The purpose of this technical memorandum is to present the requirements for the facility along with alternatives (including costs) for the site arrangement and recommendation.

The various functions of this facility would include storing fuel for the existing power generating systems, with the ability to load and unload fuel from tanker trucks and to unload rail cars on site. It will also provide GVEA with the ability to receive both ultra-low sulfur diesel (ULSD) and QB naphtha from Petro Star to fill the tanks. The facility arrangement will accommodate Interior Gas Utility's (IGU) future needs for liquid natural gas storage, regasification for distribution and GVEA power use. Additionally, it will provide space for a Petro Star rail loading and unloading rack with driveway access to H&H Road and Old Richardson Highway through the GVEA 138 kV right-of-way.

This memo was developed based on information provided from the following:

- PDC Engineers has developed the site arrangements and general coordination between the various stake holders including GVEA, Petro Star, Alaska Railroad, and Interior Gas Utility (IGU).
- Great Northern Engineers (GNE) has developed the design criteria and details for the fuel tanks, containment, controls, pumping, and fuel piping. The costs associated with these items were estimated by GNE.
- Shannon & Wilson has provided a soils analysis and general recommendations based on historical data and recent borings.
- CHI has provided thermal exclusion zones for the future IGU storage facilities.
- HMS, Inc. provided the overall estimate for the three alternatives incorporating the fuel infrastructure pricing that GNE provided, along with additive alternates.

Following the review of these concepts with GVEA and consensus on the preferred alternative, the design team may be given notice to prepare construction documents.

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Anchorage, AK 99503
907.743.3200

FAIRBANKS
1028 Aurora Drive
Fairbanks, AK 99709
907.452.1414

JUNEAU
6205 Glacier Highway
Juneau, AK 99801
907.780.6060

PALMER
125 W. Evergreen Avenue, Suite 102
Palmer, AK 99645
907.707.1215

SOLDOTNA
170 E. Corral Avenue, Suite 2
Soldotna, AK 99669
907.420.0462

General Facility Requirements	The major components of this facility are summarized below. For further details see the attached Basis of Design.
Fuel Storage Tanks	The overall volume for fuel storage is being evaluated by others. Based on the initial evaluation this concept is to provide a total of 3 million gallons (MMG) storage in two tanks. GVEA will have the ability to store either ULSD or QB Naphtha with one tank having a fixed roof and the other a floating roof (as required for QB Naptha). Based on soils information there is approximately 6 to 10 feet of silt overlying alluvial sands and gravels that would need to be removed and replaced with gravel following deep dynamic compaction beneath the proposed tank foundations. The tanks would be constructed within a 6- to 7-foot-high containment dike that would hold 110% of the capacity of a single tank plus precipitation and freeboard. They would be surrounded by a 7-foot-tall security fence that would have gated vehicle access.
Fire Suppression	The fuel tanks would be protected from fire with a fire suppression system, as required by the Fire Marshall since each diesel tank will exceed 1,500 SF of surface area (a much smaller 364,000-gallon tank about 44 feet in diameter would have 1,500 SF surface area). This system would consist of aqueous film forming foam (AFFF) water supply lines originating from a room in the Pump Building that would route to shell mounted foam chambers on each tank. This automated foam system, which will respond when triggered by an alarm, will be housed in the pump building. Additional firefighting infrastructure will be installed around the tank farm, truck rack and rail facility.
Truck Unloading/ Loading	The truck unloading/loading facility would allow for filling or receiving fuel from two A-train double fuel tanker trucks simultaneously at two stations at a maximum rate of 600 gpm per station. It will be a paved surface with a concrete drive-on lane provided with spill containment and drive-off protection. Surface water will be routed to an oil/water separator which would discharge clean water to surface and oily water to the City of North Pole's industrial wastewater line along H&H Road.
Railroad Unloading	A rail spur would be constructed to support the proposed rail rack. This would provide two spurs, with a combined capability of receiving up to 20 23,500-gallon tanker cars. These are the same size cars used for rail distribution at the Flint Hills Terminal Facility. The volume will vary with the site layout, from 423,000 to 470,000 gallons. The rail rack would support unloading ULSD from two rail tanks simultaneously at a maximum rate of 600 gpm. Containment would be provided for potential spills to hold the volume of one car (23,500 gallons). In order for the rail cars to be positioned for unloading, a Trackmobile would be provided along with a 30'x45' CMU structure for housing it at the end of the spur. The trackmobile would be operated by GVEA. A small, heated, wood-framed structure would be provided for operators unloading train cars to warm up in during the winter.

The cost of the rail tracks is included in the estimates for this project and is broken into GVEA, IGU, and Petro Star Rail facilities.

Fuel Metering and Quality Assurance

Liquid metering systems will be provided for all fuels entering and leaving GVEA custody. Meters will be used to deliver a determined flow rate and comply with standard local and federal codes for fuel handling.

Instrumentation will be Ovation or at least compatible with the existing Ovation Terminal Management System. Meters will be periodically tested with a prover system to ensure they accurately record the quantity of fuels transferred.

Fuels quality can be assured through on-site laboratory analysis. The fuels quality control lab will be located in the control building and have the necessary equipment to verify all fuel cargo and inventory meet the standards required, particularly for low sulfur fuel.

Buildings

A 30’x40’ pump house building would be provided to house four centrifugal pumps along with small transfer pumps associated with tank fill/suction, and supply to the fuel transfer facility. It would also contain a pair of filter trains for particulate and water removal for fuels entering and leaving the storage tanks. The building would house two oil water separators. One to treat surface water from the tank containment and unloading facilities. The other to treat water removed from the storage tanks. This building would also house the AFFF support system. The building would be approximately 1,200 sf constructed of CMU block. It would be heated to maintain a comfortable working temperature during the winter utilizing heat from the control building.

The 30’x40’ control building would house controls, a single office space, storage dedicated to the maintenance and operation of this facility, and a bathroom. This will be the central point of operation of the facility but will integrate with the facility operations by means of a packaged terminal management system. This building would be similar size and construction to the pump house building.

Exterior Fuel Piping

The fuel piping would be ASTM A53 Gr. B, Sch. 40 steel pipe rated for an ANSI Class 150 system. It would be fabricated and installed in accordance with ASME B31.3 standards for welding and non-destructive examination requirements.

Piping systems shall be buried where appropriate, adequately supported when above ground, and designed to withstand the maximum stresses in accordance with ASME required load combinations such as pressure, thermal expansion, gravity loads and seismic loading.

All piping will include a three-coat exterior field coating consisting of an appropriate epoxy system with a urethane topcoat to prevent chalking and UV degradation.

Security

Physical security would be provided at the facility with a 7-foot chain link fence topped with razor wire to surround the fuel tanks, rail and truck facilities. Access would be provided to vehicles with electronic proximity readers. Building access would also utilize electronic proximity readers and Best type “TC” keying standard.

Tanks will be located to provide separation distances and vegetated buffers. CCTV surveillance would be provided through video monitoring at vehicle gates, building entrances, perimeter fence, pump control rooms, truck unloading area, and rail area. Intrusion detection would be provided using infrared sensors for motion detection in addition to magnetic switches at doors.

Alarming and monitoring will be provided from a central panel to dispatch local police to potential trespassers should an alarm get triggered.

Access Road

A new paved access road to the power plant would allow GVEA to enter the NPEP and NPG property off of H&H Road without going through Petro Star or Flint Hills. The alignment would be south of the existing traveled way to provide a corridor for the fuel piping between the road and the existing infrastructure. It will be a 30-foot wide, paved, and have gated access off of H&H road. This road would also allow access fuel storage in Alternatives 1A and 1B.

Interior Gas Utility Shared Use of Land East of H&H Road

GVEA has committed to shared use of their land east of H&H with IGU to support IGU development of LNG offloading, storage, and re-gasification to support GVEA power generation and IGU's distribution system. To make sure that the alternatives developed for the GVEA fuels were compatible with code/safety requirements, CHI Engineering performed a planning level analysis on the storage volumes required for the following scenarios as discussed during the project kick-off meeting:

1. Short Term: 3 years to support IGU growth into Phases 1-3
    a. Distribution 100 psi maximum – odorized
    b. 150,000 gallon storage (three 75,000 gallon horizontal tanks to provide (N+1))
    c. 5 day storage needed for residential
2. Long Term: After 3 years to meet long-term growth for IGU into Phase 1-3 and GVEA power generation
    a. May want to increase residential to 7 day supply or 300,000 gallons
    b. 700,000 gallons of LNG storage (7 day supply at 100,000 gallons per day) as previously discussed by GVEA as potential.
    c. 1,000,000 gallons of LNG storage for combined GVEA and residential.
3. Ultimate Plan
    a. IGU is required to provide 5 days of storage for firm customers and will work with GVEA on shared storage. As additional IGU customers are added, the storage will increase. Ultimate storage quantity is undefined at this time so it is important to have room for expansion.

Based on the above storage volumes, the offsets required for the 10,000 kBTU/hr/square foot LNG thermal exclusion zone to property lines or facilities that are not under IGU's control are:

- Short Term 75k Gallon horizontal tanks and LNG unloading station: 184-foot radius
- 1.0 MMG Single Containment: 439' radius
- 1.0 MMG Full Containment: 134' radius

In addition to the tanks, the IGU use will include the "balance of plant," which includes:

- Two low-pressure vaporization trains for distribution
- One high-pressure vaporization train for GVEA powerplant needs
- Truck unloading stations for unloading two trucks simultaneously.
- Plant control building
- boil-off system
- control and hazard detection systems
- send-out metering
- pressure regulation and odorization
- fire protection
- plant utilities
- hazard detection systems.

The planning also included parallel rail spurs to stage railcars for LNG ISO tank offloading. The offset for the railcar unloading to property line and buildings for the 10,000 kBTU/hr/square foot LNG thermal exclusion zone was assumed to be 125 feet but needs detailed coordination with the ARRC before being finalized.

At this planning level, it appears there is sufficient space along the H&H side of the large trapezoidal parcel for the short-term horizontal storage and the balance of plant while allowing room for the future 1MMG single containment storage tank. This is the preferred configuration by IGU as it reduces their development costs.

The final determination of space requirements will require performing a Facility Plan study for the IGU operations at this site. In case the Facility Plan shows that the truck unloading facility or short-term horizontal storage will not fit, the triangle parcel north of the GVEA fuel lines should be reserved for this potential use.

City of North Pole Water Source Protection

The City of North Poles water supply wells are located approximately ¾ of a mile from the proposed fuel facility. Groundwater modeling that was performed for the ADEC Approval to Construct the wells shows that the boundary for the 2-year area of influence crosses through the proposed site. This is shown in the Site Layouts C1-C3.

There are two boundary lines shown on the drawing. The minimum area crosses through the parcel of land east of H&H Road. This assumes that the ground is free of permafrost. The maximum area boundary is located just west of H&H Road. Construction of the fuel storage facility within the area of influence will likely require mitigation to show the City that the wells are protected from potential spills. Additional coordination with ADEC, the City, soil investigation, and groundwater modeling would be needed for placement of tanks within this area. Also, additional soil testing may be required to verify if permafrost is present within the area of influence.

Alternatives

Three alternatives were developed to evaluate the best use of space. The alternatives are described below and shown in attached Site Layouts C1-C3. The cost breakdowns are also attached. Based on the estimates, there is only a 2% difference in cost associated with the alternatives; therefore they should be considered equal at this stage. There is a 50% contingency included in the costs for budgeting.

Alternative 1 ***Fuel Storage Tanks West of H&H Road***

The Tank Farm is sited west of H&H Road and located inside a perimeter that is already fenced. Pump and control buildings are located adjacent to tank farm. The rail facility is located east of H&H. The future peaker plant may be located north of the future rail facility, and future fuels expansion would be possible adjacent to Old Richardson Hwy.

There are two variations with this alternative. In **Alternate 1A** the truck facility would be located adjacent to the fuel facility on the west side of H&H Road and would require the purchase of additional land from Flint Hills. In **Alternative 1B** the tanks would be rotated 90° to keep them within the limits of GVEA property and the truck facility would be located on the east side of H&H Road.

- Cost: $26,800,000
- Pros
  - Tanks (and truck facility in Alt 1A) would be located away from future IGU infrastructure reducing impacts associated with those unknowns
  - Maintains all future items east of H&H Road
  - Fuel storage tanks would be located outside of the 2-year area of influence for the City of North Poles water supply wells.
- Cons
  - Property must be acquired from Flint Hills Resources (FHR) for Alt 1A
  - No room for future fuels storage west of H&H
  - Cold storage tent demolition required for construction of the tanks
  - Potential demolition of existing FHR structures and obstructions requirement (foundations, abandoned piping, conduit, pavement, etc.)

Alternative 2 ***Fuel Storage Tanks East of H&H Road***

Tank Farm is sited east of H&H Road, north of rail facilities. Pump and control buildings are located in-between the tank farm and H&H. The future peaker plant may be located west of H&H, closer to the North Pole Expansion Plant , and future fuels expansion would be possible adjacent to Old Richardson Hwy.

- Cost: $26,500,000
- Pros
  - All existing and future power generation occurs west of H&H Road; would allow for future Peaker Plant to be near other turbine plants
  - No additional property acquisition from FHR required
  - One less pipe crossing H&H Road
  - Room for additional fuels storage. If the tank farm needed additional capacity in future the tanks would be grouped together and could share spill containment/drainage, fire suppression, piping, etc.
  - Cold Storage Building demolition not required for fuel storage construction

- Cons
  - Less efficient tank farm dimensions to fit site
  - Truncated north GVEA rail spur to site Tank Farm (2 less rail cars)
  - More congestion sharing space with Petro Star & IGU
  - Potentially increased soils improvement requirement
  - Mitigation will likely be required to protect City of North Poles water supply wells.

Alternative 3 ***Fuel Storage Tanks Adjacent to Old Richardson Highway***

Similar to Alternative 2, Tank Farm is sited east of H&H Road, north of rail facilities. Pump and control buildings are located in-between the tank farm and H&H. Future peaker plant may be located west of H&H, closer to the North Pole Expansion Plant, and more convenient future fuels expansion would be possible to the west of the Tank Farm.

- Cost: $27,400,000
- Pros
  - Similar to Alternative 2, as all power generation occurs west of H&H Road and Cold Storage does not require demolition for fuel storage construction,but allows easier access for future construction equipment if additional tanks were added and is more flexible if desired tank size increases.
  - Simplifies access to Petro Star Rail Facility
  - Does not bottleneck future development of GVEA land from the west
- Cons
  - Less efficient tank farm dimensions to fit site
  - Greater earthwork requirement for deeper overburden on east side of site
  - Potentially increased soils improvement requirement
  - Greater length of piping than Alternative 2
  - Mitigation will likely be required to protect the City of North Poles water supply wells.

Recommendation

Each alternative is technically viable; however Alternative 1 would keep the fuel storage tanks out of the City of North Poles 2-year Area of Influence which would simplify the permitting process.

Alternative 1A would keep all future facilities east of H&H allowing for the need, sizing, and layout to be further developed with little impact to the storage facility. The other alternatives do not have any significant operational or future expansion benefits. There is also a chance that the peaker plant may not be installed in North Pole. In the event that GVEA wants it to be closer to the other generation facilities in North Pole there is a possibility of that to be installed east to of the Old Turbine Building.

Attachments

1. Basis of Design
2. Alternative Site Layouts
3. Piping Schematics
4. Tank Flow Diagram
5. Fuel Piping List
6. Soils Report
7. CHI LNG Memo
8. Cost Estimate

PDC ENGINEERS PLAN • DESIGN • CONSTRUCT

Transforming Challenges into Solutions

TECHNICAL MEMORANDUM

Client #	PO 201751812	**Date**	June 28, 2017
PDC #	17099FB	**Prepared by**	David Sandberg, EIT, Karen Brady, PE
Project Name	North Pole Fuel Storage Facility	**Reviewed by**	Keith Hanneman, PE
Subject	***Basis Of Design***		

Topic	Discussion

Introduction

The purpose of this technical memorandum is to present the basis of design for the proposed North Pole Fuel Storage Facility.

Design Criteria

- API-650 Standard, *Welded Tanks for Oil Storage*
- ASME B31.3, *Process Piping*
- NFPA 59A
- 2012 IFC
- ADEC
- 2015 IBC
- AASHTO
- ADOT&PF Driveway Standards
- Alaska Railroad – *Technical Standards for Roadway, Trail, and Utility Facilities in the ARRC Right of Way*
- MUTCD 2016 Edition – *Manual on Uniform Traffic Control Devices*
- City of North Pole standards and ordinances
- 49CFR Part 193 Liquefied Natural Gas Facilities: Federal Safety Standards

Fuel Storage Tanks

Size

- Two (2) 36,000 bbl welded steel tanks, for a total storage capacity of 3 million gallons
- Constructed in accordance with the API-650 Standard, *Welded Tanks for Oil Storage*
- 85 feet in diameter and 40 feet tall.
- 36-foot nominal fill height

Configuration

- One (1) internal floating-roof tank for storing more volatile QB Naphtha which Petro Star currently supplies to GVEA. This will prevent vapor emissions from exiting the tank for product conservation and air quality and safety.
- One (1) external fixed-roof tank will store ULSD,
- The construction scope for the tanks would include fabrication, delivery, erection, non-destructive examination, internal appurtenances, hydrostatic testing, and field coating of the tank interior bottom and exterior.
- The tanks would be entirely field fabricated, although shell plates could be rolled, sandblasted and primed prior to delivery to the job site. Field striping of shell welds and final coatings would be performed after erection.
- The Contractor would erect the tanks on the already completed foundations and corrosion protection beds.

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1028 Aurora Drive
Fairbanks, AK 99709
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JUNEAU
6205 Glacier Highway
Juneau, AK 99801
907.780.6060

PALMER
125 W. Evergreen Avenue, Suite 102
Palmer, AK 99645
907.707.1215

SOLDOTNA
170 E. Corral Avenue, Suite 2
Soldotna, AK 99669
907.420.0462

Topic	Discussion
	• Appurtenances for the tanks would consist of cargo and service nozzles, water draw-off system, auto gauge level controls, level switches for overfill prevention and pump protection, pressure/vacuum conservation venting, shell mounted AFFF supports, and double block and bleed plug valves on cargo and service tank nozzles. ***Foundations*** • Soil conditions and geotechnical engineer's recommendation, based on the tank loads, will govern. (See attached "Geotechnical Findings Report.") • As is common in the Fairbanks area, proposed sites have significant liquefaction hazard, primarily loss of shear strength and settlement during seismic events, due to unconsolidated alluvial deposits at depth. • Site preparation for all structures will require removal of surficial silty frost susceptible soils and replacement with compacted structural fills. • Ground improvement will include the entire structure footprint and extend out beyond the outside edge of all foundations a minimum of 25 feet. • Depth of ground improvement is between 30 to 35 feet below grade. • Deep dynamic compaction (DDC) is recommended for ground improvement. • Consider future site expansion/development when defining limits of ground improvement. • Consider ground improvement during periods of low groundwater to maximize depth of improvement (spring, typically). • Excavation for tank foundations assumes 10 feet of native soils will be removed and NFS structural backfill imported, per geotechnical report. • Tank foundations would be nominally 5 feet deep concrete ring wall and be constructed in a typical stem ring wall/footer configuration. • Tank foundation will have significant amounts of steel reinforcement (typical) • Tank stem walls will be nominally 16 to 20 inches thick with footers that are approximately 6 feet wide (typical) • Given the ratio of the height to diameter tank anchoring to the foundation is likely not required. ***Setbacks*** • Minimum distance to nearest property line that is or can be built upon including the opposite side of a public way: 1/2 tank diameter or 42.5 feet • Minimum shell-to-shell tank spacing: 1/6 times sum of adjacent tank diameters or 28.5 feet • Setback from tank and rail car loading/offloading to tanks, buildings, property lines: 25 feet • Minimum distance from nearest side of any public way or from nearest important building on the same property: 14.17' • Construction and maintenance clearances: Minimum 20 feet clear between the tank shell and inside toe of the adjacent dike walls is desirable. • Homeland Security does not have criteria that apply to this facility. However, the site arrangement will be sent for review.

Topic	Discussion
	• General setbacks used for the alternatives match those used by Flint Hills on the adjacent property. ***Containment*** • The tanks would be constructed within an earthen containment dike that is capable of holding a minimum of 110% of the largest tank volume in the event of a release, with an allowance for local precipitation and freeboard. • The containment area would allow for controlled drainage via a subgrade collection system consisting of catch basins, perforated pipe within the porous backfill, and heat traced arctic pipe routed to a central Oily Water Separator (OWS) which also will handle oily water from the rail and truck loading racks before discharging into the city sewer system. • The berm is assumed to be constructed to approximately 6-7 feet above tank farm finished grade. • The berm would have a minimum 3-4 foot flat top (10 feet desirable for ease of construction and maintenance) where the containment liner membrane would be anchored. • This berm would have an outside toe to toe dimension of approximately 28 feet at a 2H:1V slope, which is suitable to maintain vegetation • The containment dike will be underlain with a geo-membrane that is impervious to the petroleum products being stored. The geo-membrane liner will be seam welded and would be installed with a layer of bedding sand and geotextile protective fabric on either side to prevent tearing or puncturing the liner during installation or compaction efforts. The liner would be continuous underneath the tank ring wall foundations. • Tank foundations would be constructed with a separate membrane underneath and within them. This would contain a tank bottom leak inside the foundation system without impacting the rest of the site. • A leak detection system within the foundation containment will allow for notification if a tank leak has occurred. • Excavation for areas not directly underneath tanks is assumed to require the removal of 4 feet of native soils. A geotextile liner will be installed with a minimum 12 inches of bedding material above and below it for protection ***Corrosion Protection*** • Sacrificial anode grid system installed in the bedding beneath each tank to protect the underside from corrosion by means of an impressed current system that requires an external power supply and a rectifier. This is the most common system utilized for tanks of this size and type • Tanks will be externally coated with a three component coating system consisting of prime, intermediate, and top coat. The first two coats are assumed to be a polyamide epoxy and the top coat, polyurethane to prevent chalking of the epoxy when exposed to UV light for extended periods of time. ***Testing*** • The tanks would be hydrostatically tested with water in accordance with API 650 prior to turn over to the Owner.

Topic	Discussion
	• This water will require a permit from ADEC and the City in order to discharge it to the city sewer system.
Rail Offloading	***Rate*** • 600 gallons of ULSD per minute per railcar • Ability to unload two rail cars simultaneously ***Rail Spurs*** • Based on 55'-7-1/8" Tanker Cars (23,500 gallons per car) used at FHR • No. 11 switch from main railroad track • No. 9 switches on rail spurs • Parallel rail spurs to stage railcars for the offloading process. • Gated at eastern end of primary GVEA rail spur • Capacity for 20 railcars in Alternatives 1 & 3 • Reducedcapacity 18 railcars in Alternative 2 ***Rail Unloading Rack*** • Heated building for personnel and fuels equipment and metering/operations • Design spill containment: 30,000 gallons • Trackmobile used to stage railcars during unloading operations • Heated building at west end of rail spur for Track mobile storage and maintenance • Capacity of 470,000 gallons of fuel per delivery in Alternatives 1 & 3 • Capacity of 423,000 gallons of fuel per delivery in Alternative 2 ***Piping*** • One directional flow from unloading rack • Process piping will run between the rail spur with inlet points directed to each of the two rail spur lines. • Avoid running pipes beneath rails if possible • Multiple 10-inch pipelines from rail rack to filtration equipment for redundancy. • All fuel received will pass through filtration equipment consisting of particulate filters prior to entering the storage tanks. ***Oily Water Collection System*** • System of sumps beneath rail unloading rack will collect spills and pass through a central OWS which also will handle oily water from tank farm and truck loading racks before discharging into the industrial wastewater line along H&H Road. ***Trackmobile Building (New)*** • The Trackmobile building will be an approximately 30'x45' structure with a concrete slab on grade capable to support the weight of the Trackmobile unit. • The walls will be CMU block. • Eave height will be approximately 18 feet to allow for an approximate 14'Wx16'H overhead door. • Roof to be wood trusses on 3:12 pitch. • Install 2-ton underhung trolley

Topic	Discussion
	• Building heat to come from shared heat of Control Room Building and Pump House Building ***GVEA Rail Facility Warm-Up Hut (New)*** • Warm-up hut to be 8'x12' wood framed building with concrete slab on grade floor • Walls to be supported by thickened edge slab • Eave height will be approximately 8' • Roof will consist of wood trusses with 4:12 pitch • Building will have single man door and three windows on non-door walls • Building to have electric heat
Truck Loading and Unloading	***General Description*** • Designed to accommodate two (2) "A-Train" double fuel tanker truck configurations for both fuel loading/unloading simultaneously at 600 GPM each • 40 foot minimum turning radius • Two fueling positions for ULSD. Naphtha will not be sent or received by truck. • Currently we have the costs captured to: 1) Offload two tankers simultaneously. 2) Load two tankers simultaneously 3) Offload and load two tankers simultaneously with the same product. • Located adjacent to a concrete drive-on lane, that is depressed in its center to provide the code required containment during transfers. • This concrete slab would be heat traced to allow removal of ice in winter. Waste heat with heating source will be used. • Sump will connect to oily water collection system, pass through a central OWS, which also connects to the tank farm and the rail rack, and then discharge into the industrial wastewater line along H&H Road. • The truck loading rack would not be covered and no structure is included. • The system would contain the necessary primary and secondary shutoff valves, metering, overfill prevention system, drive-off protection, and terminal management system. • Each loading station on the truck loading rack would consist of a meter with a totalizer and reset. • A flow control valve would be used to control the flow into the tanker trucks to a set point and would provide the dead-man shutoff point. ***Loading*** • Loading product will be drawn from the respective tank, through a service header pipeline and into the suction of the diesel supply pumps located in the pump building. The fuel will be pumped to the Truck Loading Rack. • The system would also include an overfill prevention system. We have assumed that vapor recovery is not required, and do not believe that it is due to the relatively small throughput planned for the facility • Two loading arms ***Offloading***

Topic	Discussion
	• Offloading would consist of a 4-inch hose feeding an 8-inch pipeline that leads into the suction of the offloading pump in the pump building.
Waste Heat	• To add efficiencies into this project, waste heat from NPEP will be used to heat structures and the truck loading slab, with secondary source to be used when the turbines are not in operation.
Facility Buildings	***Pump House/Filtration Building*** • 30'x40' CMU block with metal roof, insulated and heated • Waste heat used as primary heat source with backup secondary source • Clearance to other structures: Minimum 25 feet from loading/unloading racks and 14.17 feet from the tanks • Parking for maintenance staff • Foundation designed to contain fuel releases and drain them to a common collection area with the associated alarms to notify the facility operators. • Overhead door • Four (4) large centrifugal pumps, along with smaller transfer pumps with a combined horsepower of nominally 250 HP. • Steel piping, small volume product recovery system, valves, and vessels • A pair of filter trains located within the building to provide particulate and water removal as needed for incoming and outgoing fuel. • Overhead crane rail for equipment maintenance • Structural access walkways • Lighting and Equipment power • Ventilation • AFFF fire suppression system equipment • Controls suitable for use in a hazardous environment • All other associated services necessary to ensure safe and reliable function and access for maintenance and operations. ***Control Building (Controls, AFFF, Maintenance, and Storage Building)*** • 30'x40' CMU block with metal roof, insulated and heated • Waste heat used as primary heat source with backup secondary. • Clearance to other structures: Minimum 25 feet from loading/unloading racks and 14.17 feet from the tanks • Parking for office and maintenance staff • Single office shared fuels control room • Single unisex bathroom • Water, sewer, and electrical service • Heated fueling support equipment storage with overhead door • Mechanical room • Concrete foundation that is designed to suit the soil conditions and is based on the outcome of the geotechnical soils report. Spread Footing and stem wall on improved ground located below frost line is typical. • The offices would be finished in typical office environment fashion and in

Topic	Discussion
	accordance with the occupancy requirements determined by the International Building Code, and will contain document storage • The shop and storage areas of the building would consist of relatively unfinished interiors typical of maintenance and storage shops in arctic environments, and will contain spare parts associated with the facility • The fuel quality control lab would have the necessary ventilation hoods, and the necessary lab equipment would be adequately supported by the building infrastructure, i.e. power, lighting, heat, and ventilation.
Fuel Metering and Quality Assurance	• Liquid metering systems will be provided for all fuels entering and leaving GVEA custody. Meters will be used to deliver a determined flow rate and comply with standard local and federal codes for fuel handling. • Instrumentation will be Ovation or compatible with Ovation as part of the Terminal Management System. Meters will be periodically tested with a prover system to ensure they accurately record the quantity of fuels transferred. • Fuels quality will be assured through on-site laboratory analysis. The fuels quality control lab will be located in the control building and have the necessary equipment to verify all fuel cargo and inventory meet the standards required, particularly for low sulfur fuel.

Fuel Piping	• See attached pipe schedule.
	• All fuel piping will be ASTM A53 Gr. B, Sch. 40 steel pipe rated for an ANSI Class 150 system.
	• Piping will be fabricated and installed in accordance with ASME B31.3 standards for welding and NDE requirements.
	• All piping will include a three (3) coat exterior field coating consisting of an appropriate epoxy system with a urethane topcoat to prevent chalking and UV degradation where exposed.
	• Cathodic protection will be provided. The selection will take into account the proximity of existing piping and its interaction. This will likely be a passive anode system.
	• Piping systems shall be buried where appropriate, adequately supported when aboveground, and designed to withstand the maximum stresses in accordance with ASME required load combinations such as pressure, thermal expansion, gravity loads and seismic loading.
	• Pipe Slopes –
	  o Fuel piping will be graded to slope towards drain points for defueling lines for maintenance where possible.
	  o Offloading piping will be sloped towards pump to allow for system clearing between cargo deliveries.
	  o AFFF piping shall be sloped to meet code with low point drains.

Security	***Access Control – Physical and Electronic*** • Chain link fence with minimum fabric height of 7 feet around tank farm, rail and truck facility. All perimeter fence shall be topped with razor wire.

Topic	Discussion
	• Crash barriers as required by industry best practices • Powered gates will be provided at all access points to tank farm, truck and rail facility, and North Pole Expansion Plant Campus • Personnel gates • Door Hardware – Best type "TC" keying standard • Electronic access at building entrances: Proximity – close read which is currently used at GVEA. • Electronic access at vehicle gates: Proximity – large gap read range which is currently used at GVEA. • Electronic access at locations where additional verification level is desired: Proximity with PIN to open the door without an alarm. ***CCTV Surveillance*** • 4 Megapixel video monitoring at vehicle gates, building entrances, pump control rooms, perimeter fence, truck loading area, and at the tank farm near controls and valves • 3-7 day local video storage if central connection disrupted • Centralized security monitoring office located in the Illinois Street headquarters campus with redundant monitoring available at North Pole Expansion Plant. • Central storage facility that is expandable • Duration of video saved: 30 days ***Intrusion Detection*** • Perimeter motion detection (infrared) • Wide gap balanced magnetic switches used at gates and overhead doors which are less susceptible to spoofing • Magnetic door contracts for interior applications • Motion detection (Infrared) used as backup for magnetic door contracts ***Alarming and Monitoring*** • Central alarm • Central logging • Remote alarm monitoring; since the facility is monitored remotely, this is preferred to dispatch police to detain potential trespassers.
Electrical	• The largest facility loads will be the fuel transfer pumps located in the pump building. • Facility lighting would be installed to provide illumination necessary for operators to have safe access for maintenance and routine functions. • All lighting would likely utilize LED fixtures and will strictly adhere to dark-sky requirements and airport regulations. • Below-grade conduit runs will be routed from the tank farm electrical to a main distribution point at a location to be determined. • Hazardous Area Classification will need to be defined and the device ratings would comply with the NEC regulations relative to their locations.

Topic	Discussion
Controls	• Controls shall be integrated into the facility operations by means of a packaged Terminal Management System (TMS) compliant with the current Ovation system in operation at GVEA. • Any auxiliary controls required to control functions unique to the fuels facility is assumed to be compatible with the existing Ovation system. • Electrical controls required for the tank farm include data transmission from the tank auto gauge system, level and pump flow switches, and alarms. • Additional tank alarms will consist of a high-high level alarm, low level alarm and level indication based on the gauging system. • The conduit, devices and wiring required for the installation will be listed intrinsically safe in accordance with NEC requirements.
Fire Suppression	• Fire Marshal requires that any diesel tank that exceeds 1500 SF (a 364,000 gallon tank about 44 feet diameter) of fuel surface area requires an AFFF system. • Aqueous Film Forming Foam (AFFF) system will be supplied and housed in the Control Building. • The system will be automated. • The AFFF system would consist of foam water supply pipelines that originate in the AFFF room of the Control Building and are routed to shell mounted foam chambers on each tank. • The AFFF supply manifold, located in the AFFF building, would be designed for the future expansion and have provisions for the new supply lines to any new tanks. • The pipe would be painted galvanized steel. All piping would be constructed in accordance with industry standards for welding and NDE requirements. • The piping would be supported from the tank shell as required with welded tabs installed by the tank fabricator. • All piping would also include a three-coat exterior field coating consisting of an appropriate epoxy system with a urethane topcoat to prevent chalking and UV degradation. • The perimeter AFFF system would consist of foam water supply pipelines that originate in the pump house building and are routed around the perimeter of the tank farm on the outside of the dike. • Hose connection points are located nominally every 200’ to allow for fire department connection in fighting tank fires from outside the containment area. • The piping would be supported on vertical supports as required along the dike.
Access Road	• New access road would allow GVEA to enter the NPEP and NPG from H&H Road without having to drive through Flint Hills or Petro Star. • Required to be built for Alternatives 1A and 1B • Not necessary to construct fuel storage for Alternatives 2 and 3 • Alignment chosen will provide room for a piping corridor between the road and existing infrastructure on the north. • 30-foot-wide paved access road west of H&H to GVEA North Pole Expansion Plant

Topic	Discussion
	• Connects H&H to northwest corner of North Pole Expansion Plant yard • Gated at H&H Road
Future Peaker Plant	• Future Peaker Plant has been considered in all conceptual site layouts. ***Potential Location*** • North Pole Generation Campus and Illinois St. Campus have been considered for Peaker plant location. ***Sizing*** • Peaker plant size based on Four (4) Wärtsilä units • Future peaker plant expansion based on another Four (4) Wärtsilä units • Additional space allocated for future Peaker Plant expansion • Substation size is based on other substations located nearby ***Fuel Consumption Rates*** • ULSD: 580 gallons/hr/Wärtsilä unit • Natural Gas: 70,000 scf/hr @ 85 psig + 6 gallons ULSD/hr/Wärtsilä unit
IGU	***LNG Storage Needs*** • Short Term (3 years for phases 1-3): .... 150k Gallon Storage • Long Term (>3 years to meet long term growth): .. 700k Gallon Storage • Ultimate: 1.0 MMG Storage ***Offsets to Property Line and Buildings for 10,000 BTU/hr/square foot LNG Tank Thermal Exclusion Zone*** • Short Term 75k Gallon horizontal tanks with N+1 Availability: 184-foot radius • 1.0 MMG Single Containment: .... 439' radius • 1.0 MMG Full Containment: .... 134' radius ***Future Rail Unloading Facility*** • Parallel rail spurs to stage railcars for the LNG offloading process. • Gated at southern end of primary IGU rail spur • Shared road crossing with GVEA and Petro Star rail facilities • Offset from railcar to property line and buildings for 10,000 BTU/hr/square foot LNG tank thermal exclusion zone: 184 feet
Petro Star	***Pipelines*** • Existing Naphtha to GVEA • 10-inch steel pipeline from Petro Star to GVEA Fuel Forwarding building • Future pipeline to Petro Star Rail Loading Facility ***Future Rail Loading*** • Parallel rail spurs to stage railcars for loading and unloading 20 rail cars • Gated at eastern end of primary Petro Star rail spur • Shared road crossing with GVEA and IGU rail facilities
Soils and	• Relatively flat terrain

Topic	Discussion
Topography	• 2-10 feet of silty soils underlain with sandy gravel and gravels at depth. • High groundwater table, 2-12 feet BGS • High potential for liquefaction settlement during seismic event • No permafrost encountered in preliminary soils exploration

Attachments:

1. Piping Schedule by GNE

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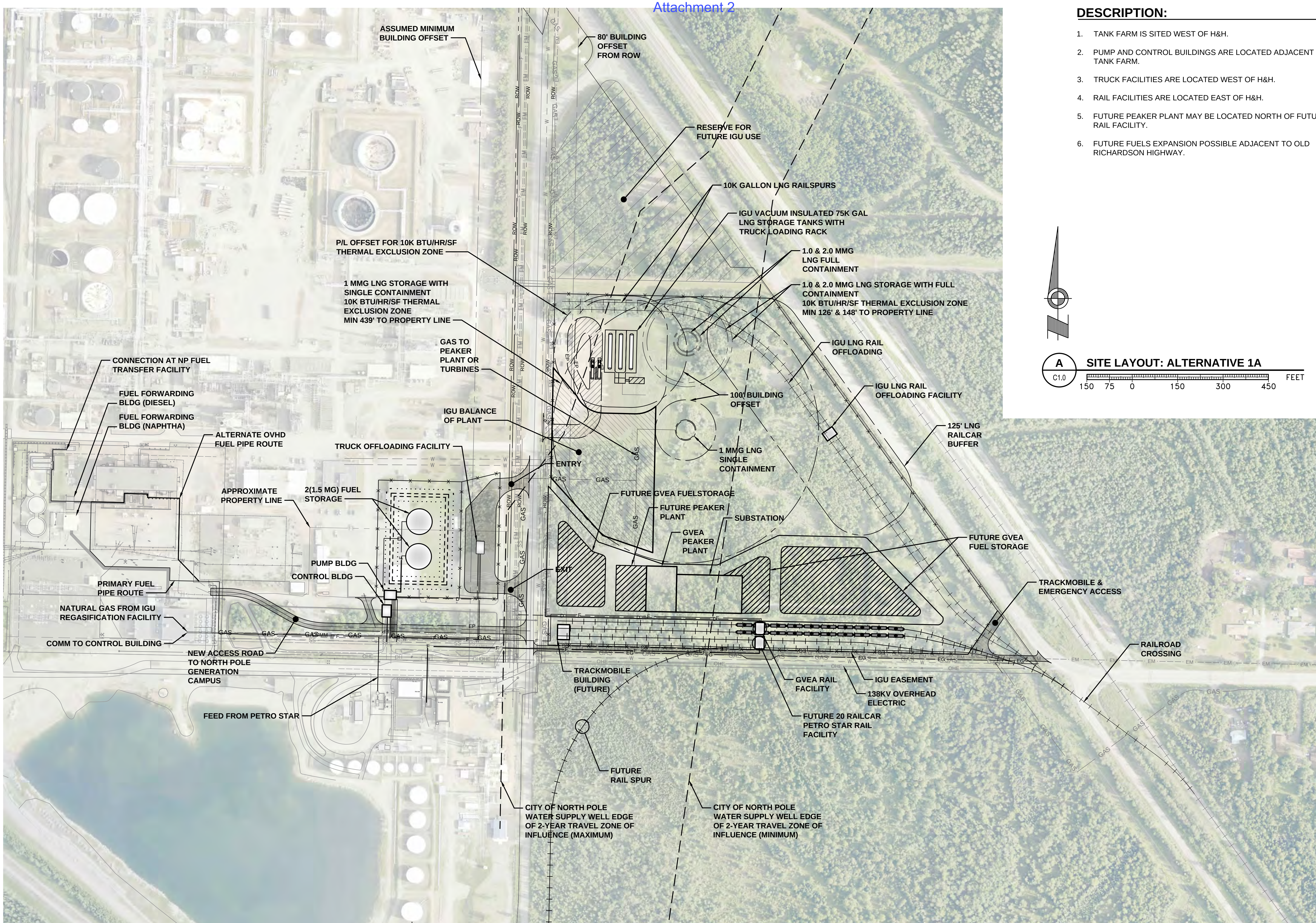

DESCRIPTION:

1. TANK FARM IS SITED WEST OF H&H.
2. PUMP AND CONTROL BUILDINGS ARE LOCATED ADJACENT TO TANK FARM.
3. TRUCK FACILITIES ARE LOCATED WEST OF H&H.
4. RAIL FACILITIES ARE LOCATED EAST OF H&H.
5. FUTURE PEAKER PLANT MAY BE LOCATED NORTH OF FUTURE RAIL FACILITY.
6. FUTURE FUELS EXPANSION POSSIBLE ADJACENT TO OLD RICHARDSON HIGHWAY.

CONSULTANT:

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PROJECT:
GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE:
SITE LAYOUT
ALTERNATIVE 1A
CONCEPT DEVELOPMENT

DESIGN	DES
DRAWN	RJP
CHECKED	KAB
DATE	JUNE 28, 2017

PROJECT No.
17099FB

SHEET NUMBER
C1.0
OF - SHEETS

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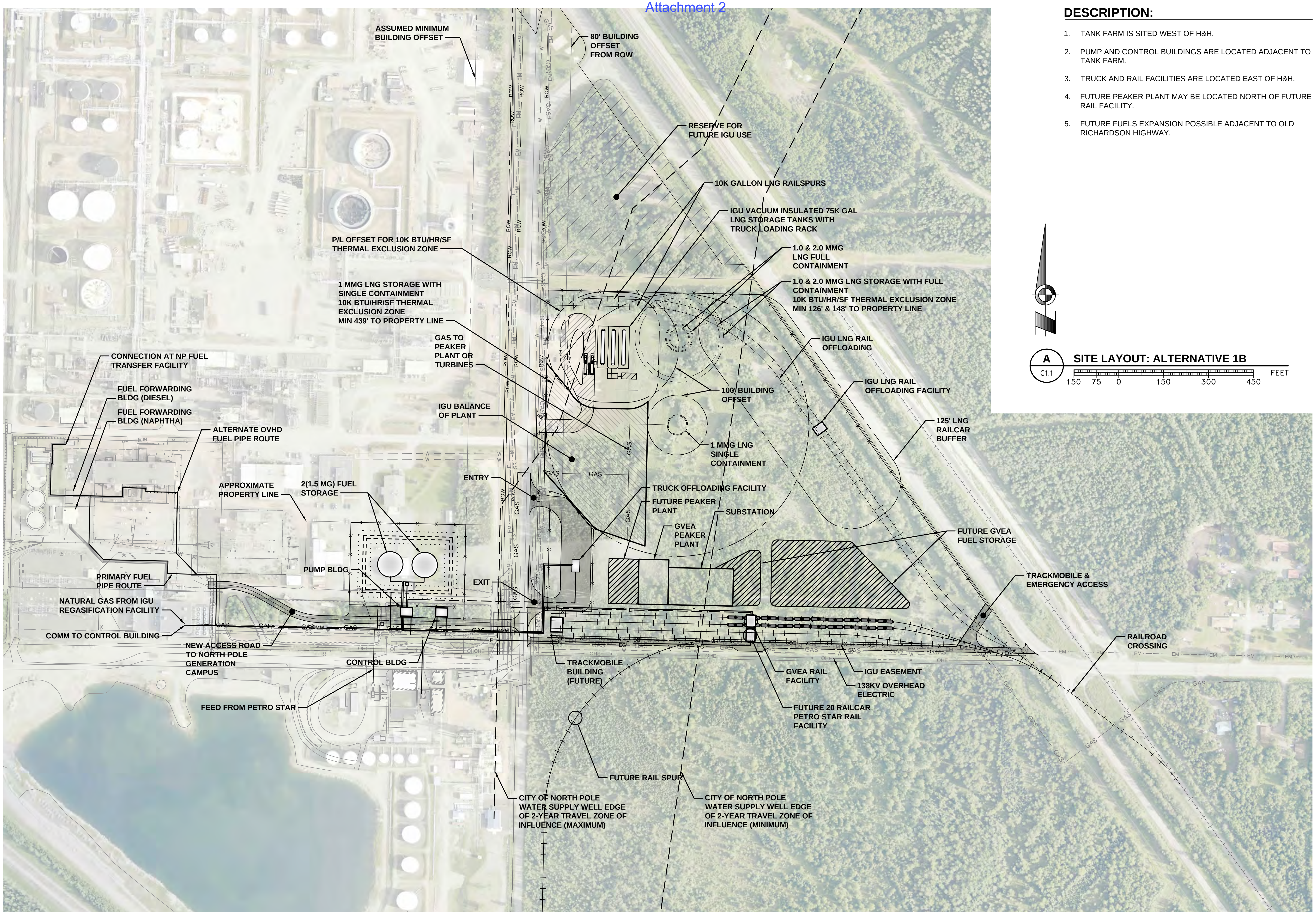
Attachment 2

DESCRIPTION:

1. TANK FARM IS SITED WEST OF H&H.
2. PUMP AND CONTROL BUILDINGS ARE LOCATED ADJACENT TO TANK FARM.
3. TRUCK AND RAIL FACILITIES ARE LOCATED EAST OF H&H.
4. FUTURE PEAKER PLANT MAY BE LOCATED NORTH OF FUTURE RAIL FACILITY.
5. FUTURE FUELS EXPANSION POSSIBLE ADJACENT TO OLD RICHARDSON HIGHWAY.



CONSULTANT :

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PROJECT :
GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SITE LAYOUT ALTERNATIVE 1B
CONCEPT DEVELOPMENT

DESIGN	DES
DRAWN	RJP
CHECKED	KAB
DATE	JUNE 28, 2017

PROJECT No. 17099FB

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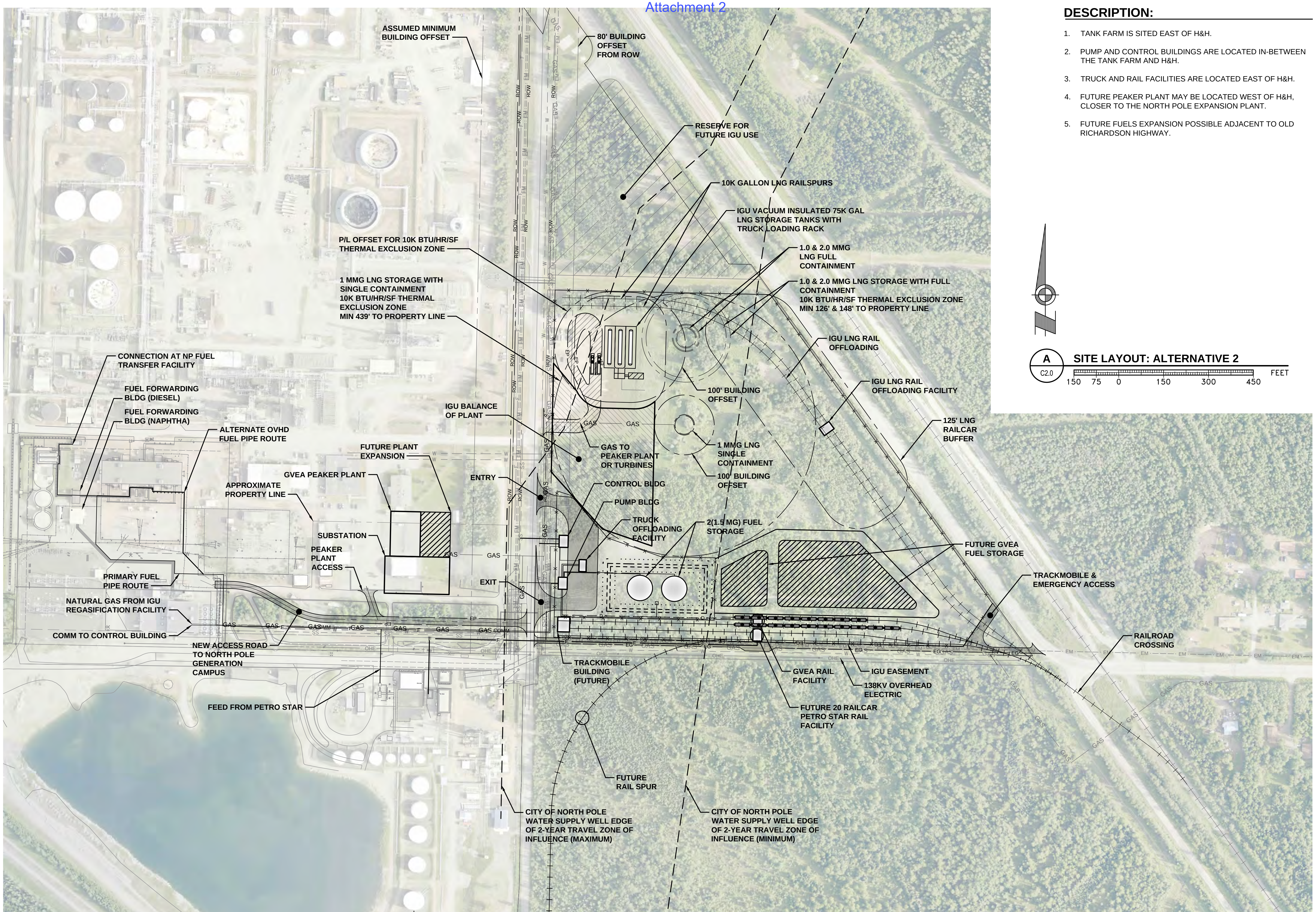
DESCRIPTION:

1. TANK FARM IS SITED EAST OF H&H.
2. PUMP AND CONTROL BUILDINGS ARE LOCATED IN-BETWEEN THE TANK FARM AND H&H.
3. TRUCK AND RAIL FACILITIES ARE LOCATED EAST OF H&H.
4. FUTURE PEAKER PLANT MAY BE LOCATED WEST OF H&H, CLOSER TO THE NORTH POLE EXPANSION PLANT.
5. FUTURE FUELS EXPANSION POSSIBLE ADJACENT TO OLD RICHARDSON HIGHWAY.



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SITE LAYOUT: ALTERNATIVE 2
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CONSULTANT :

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PROJECT :
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SHEET TITLE :
SITE LAYOUT
ALTERNATIVE 2
CONCEPT DEVELOPMENT

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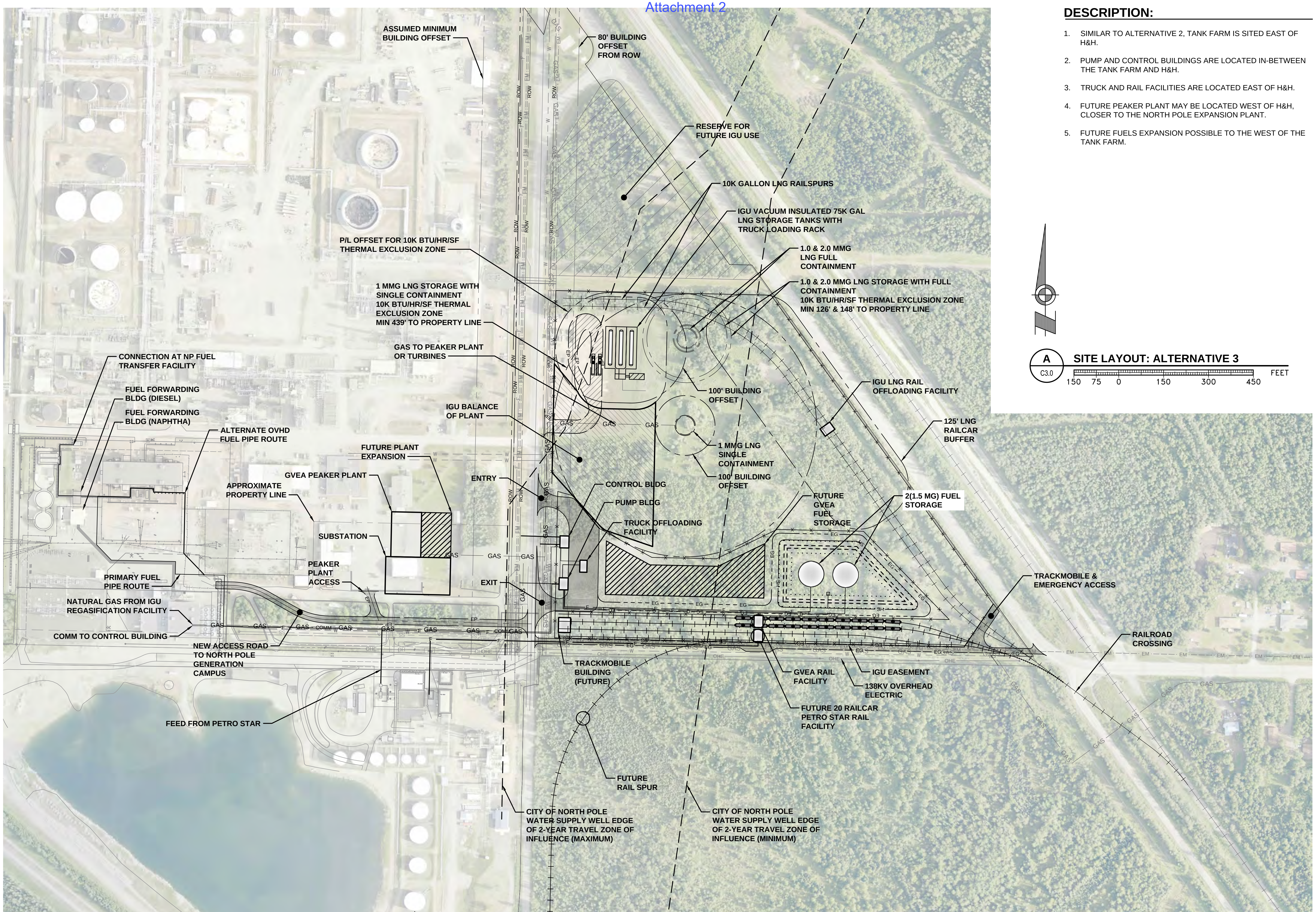
Attachment 2

DESCRIPTION:

1. SIMILAR TO ALTERNATIVE 2, TANK FARM IS SITED EAST OF H&H.
2. PUMP AND CONTROL BUILDINGS ARE LOCATED IN-BETWEEN THE TANK FARM AND H&H.
3. TRUCK AND RAIL FACILITIES ARE LOCATED EAST OF H&H.
4. FUTURE PEAKER PLANT MAY BE LOCATED WEST OF H&H, CLOSER TO THE NORTH POLE EXPANSION PLANT.
5. FUTURE FUELS EXPANSION POSSIBLE TO THE WEST OF THE TANK FARM.



CONSULTANT :

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PROJECT :
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3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SITE LAYOUT ALTERNATIVE 3
CONCEPT DEVELOPMENT

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PROJECT No.
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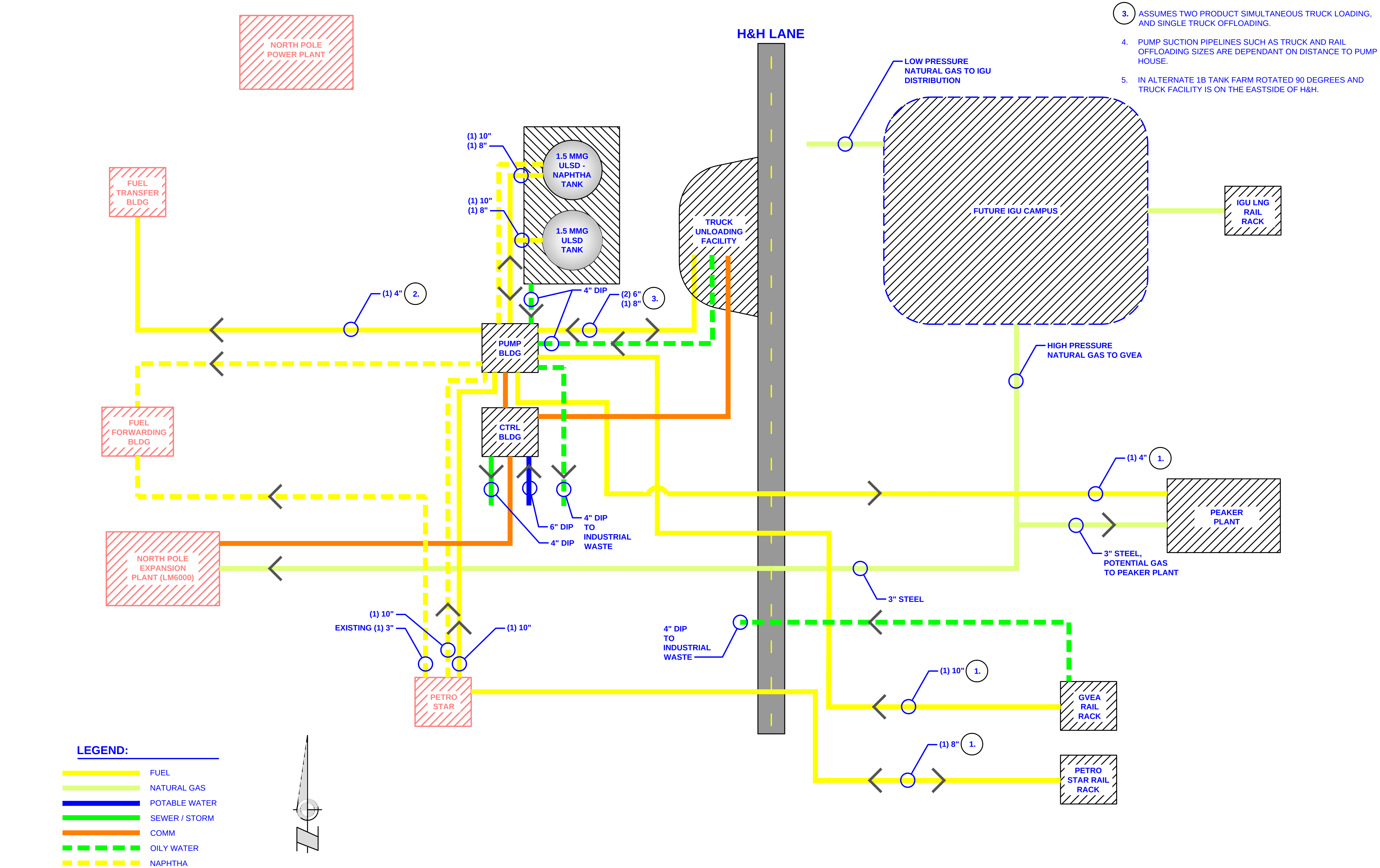
NOTES:

1. ASSUMES SINGLE PIPELINE CAN BE USED FOR ALL PRODUCTS.
2. SIZE ASSUMED BASED ON MAX FLOW RATE OF APPROXIMATELY 400 GPM.
3. ASSUMES TWO PRODUCT SIMULTANEOUS TRUCK LOADING, AND SINGLE TRUCK OFFLOADING.
4. PUMP SUCTION PIPELINES SUCH AS TRUCK AND RAIL OFFLOADING SIZES ARE DEPENDANT ON DISTANCE TO PUMP HOUSE.
5. IN ALTERNATE 1B TANK FARM ROTATED 90 DEGREES AND TRUCK FACILITY IS ON THE EASTSIDE OF H&H.



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PROJECT :
GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SCHEMATIC - FUEL PIPING ALTERNATIVE 1A
CONCEPT DEVELOPMENT

DESIGN	DES
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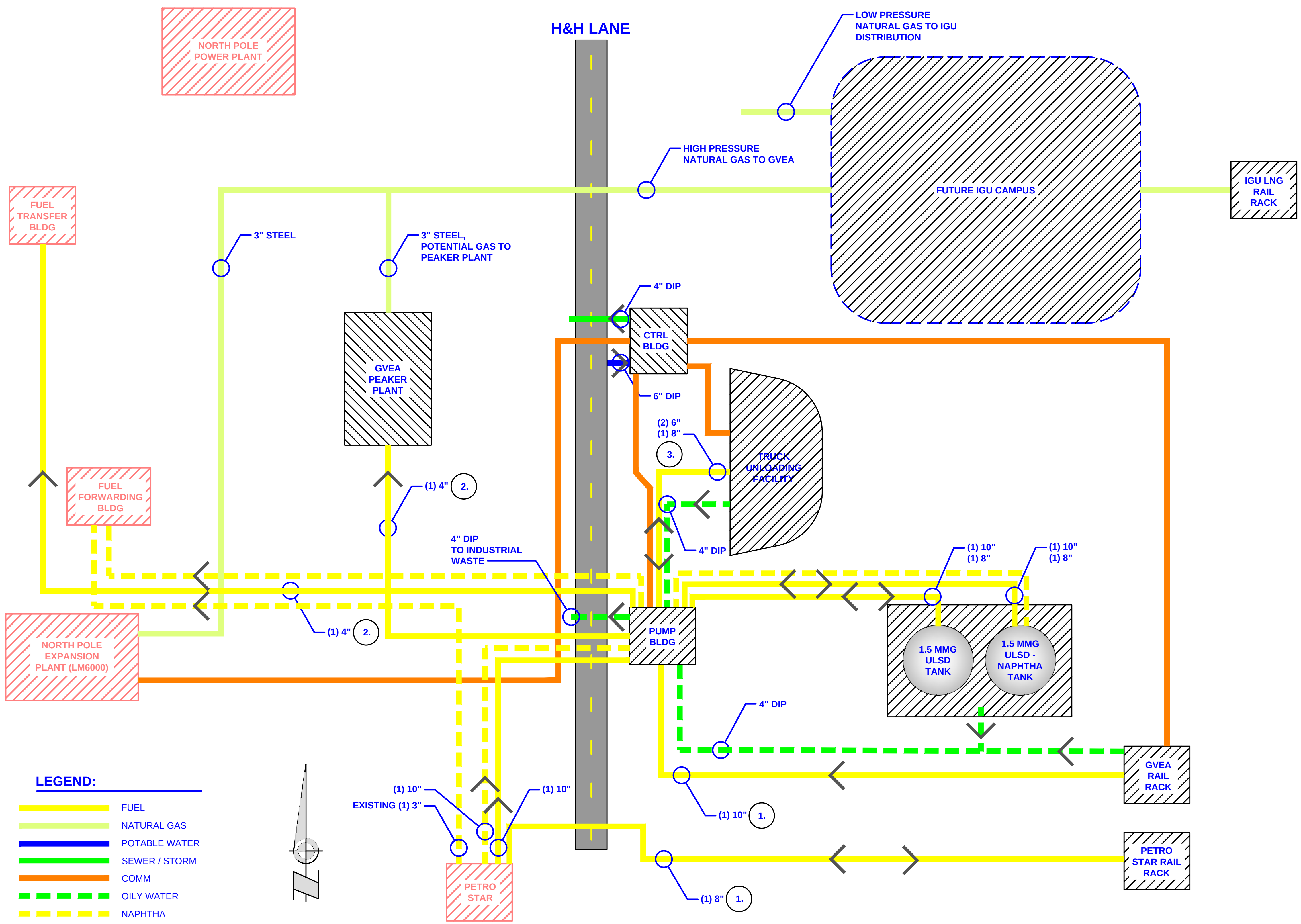
NOTES:

1. ASSUMES SINGLE PIPELINE CAN BE USED FOR ALL PRODUCTS.
2. SIZE ASSUMED BASED ON MAX FLOW RATE OF APPROXIMATELY 400 GPM.
3. ASSUMES TWO PRODUCT SIMULTANEOUS TRUCK LOADING, AND SINGLE TRUCK OFFLOADING.
4. PUMP SUCTION PIPELINES SUCH AS TRUCK AND RAIL OFFLOADING SIZES ARE DEPENDANT ON DISTANCE TO PUMP HOUSE.



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3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SCHEMATIC - FUEL PIPING ALTERNATIVE 2
CONCEPT DEVELOPMENT

DESIGN	DES
DRAWN	RJP
CHECKED	KAD
DATE	JUNE 28, 2017

PROJECT No.
17099FB

SHEET NUMBER
C2.3
OF - SHEETS

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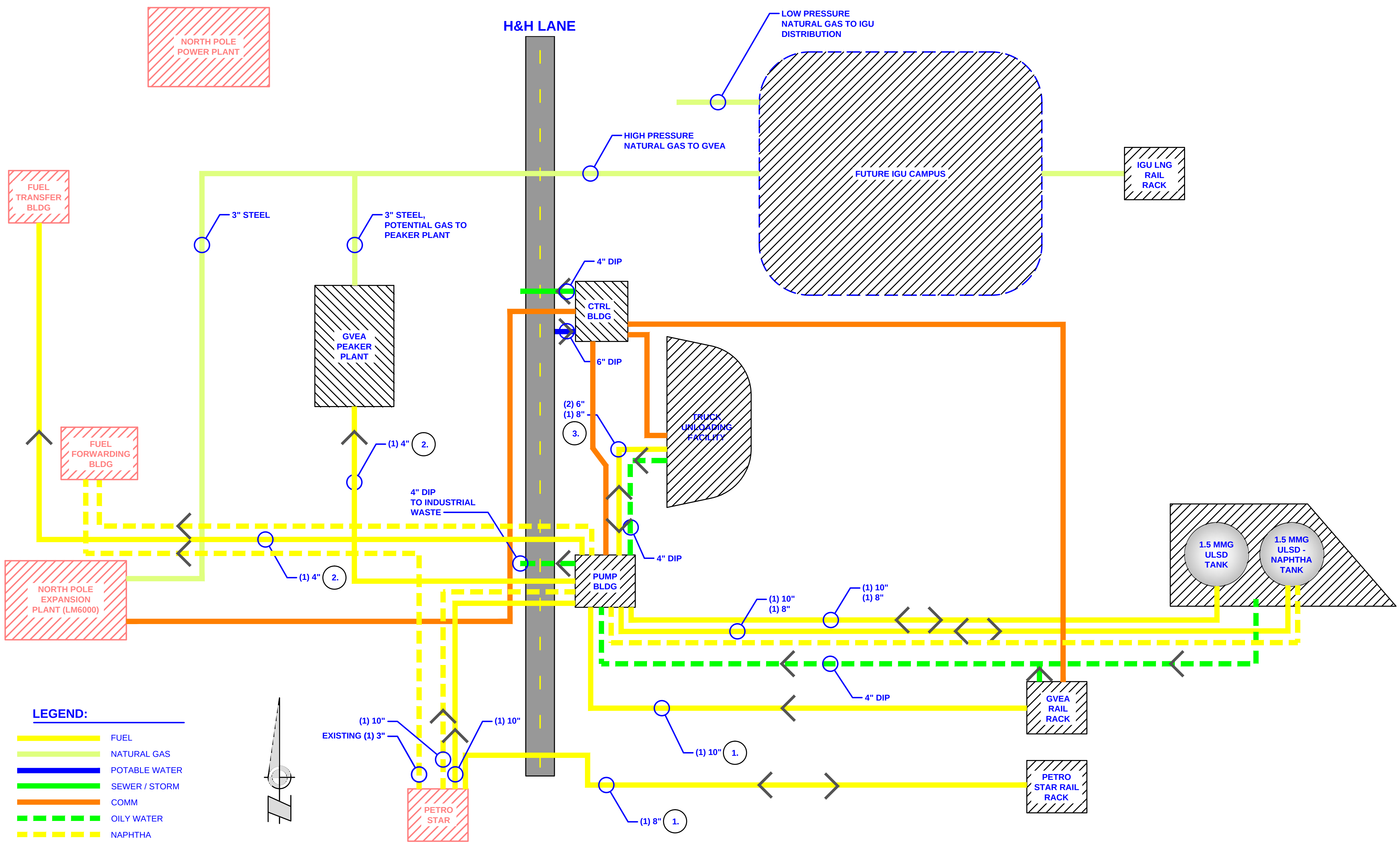
Attachment 2

NOTES:

1. ASSUMES SINGLE PIPELINE CAN BE USED FOR ALL PRODUCTS.
2. SIZE ASSUMED BASED ON MAX FLOW RATE OF APPROXIMATELY 400 GPM.
3. ASSUMES TWO PRODUCT SIMULTANEOUS TRUCK LOADING, AND SINGLE TRUCK OFFLOADING.
4. PUMP SUCTION PIPELINES SUCH AS TRUCK AND RAIL OFFLOADING SIZES ARE DEPENDANT ON DISTANCE TO PUMP HOUSE.



CONSULTANT :

PDC ENGINEERS
PLAN • DESIGN • CONSTRUCT
1028 Aurora Drive, Fairbanks, Alaska 99709
907.452.1414 | AECC605

PROJECT :
GOLDEN VALLEY ELECTRIC ASSOCIATION
3M GALLON STORAGE TANK FOR NORTH POLE GENERATION CAMPUS
NORTH POLE, ALASKA

SHEET TITLE :
SCHEMATIC - FUEL PIPING ALTERNATIVE 3
CONCEPT DEVELOPMENT

DESIGN	DES
DRAWN	RJP
CHECKED	KAD
DATE	JUNE 28, 2017

PROJECT No. 17099FB

SHEET NUMBER C3.3

OF - SHEETS

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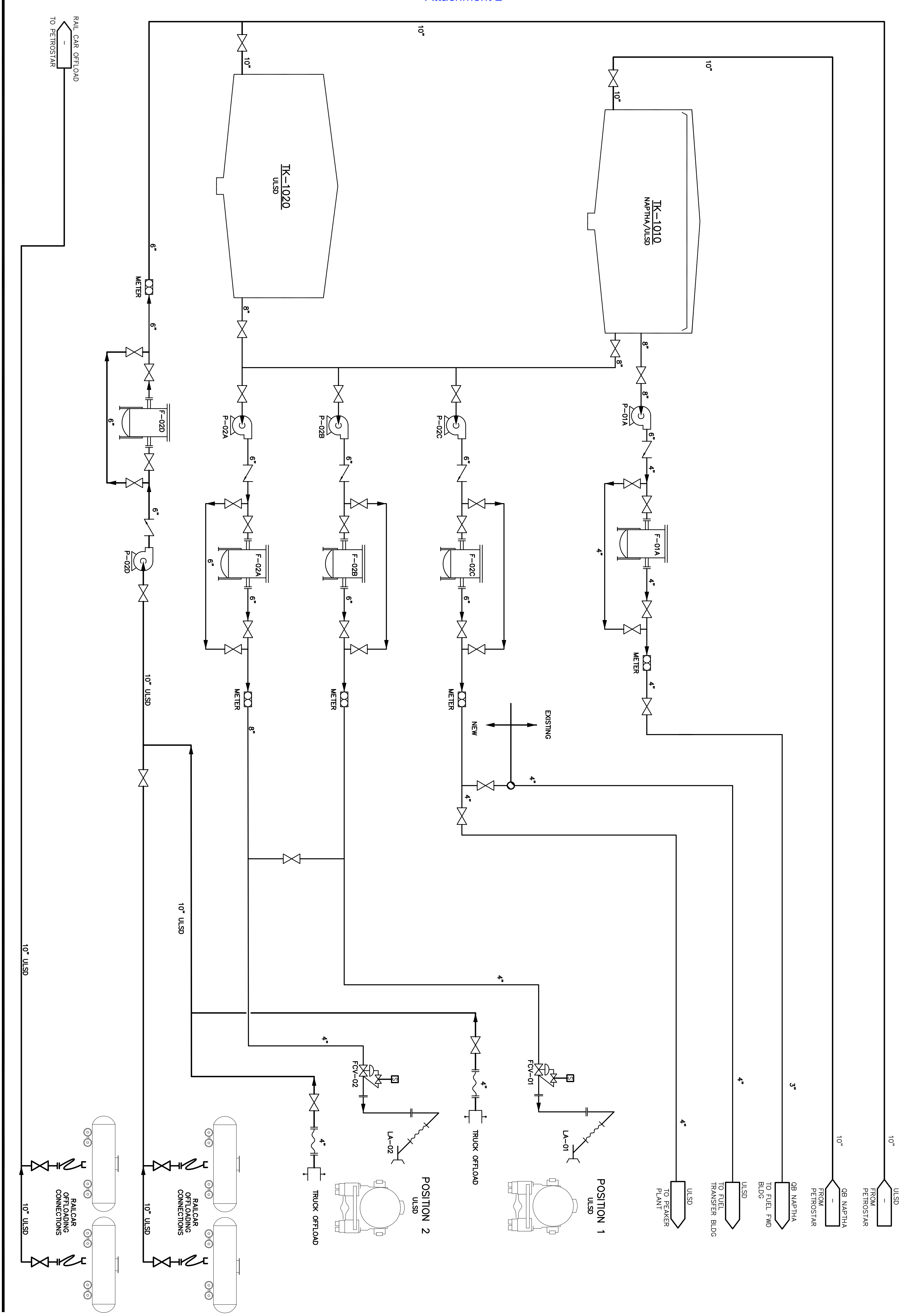
Attachment 2



DATE:	05/26/17
DRAWN:	JM
CHECKED:	DK
DESIGNED:	DK
APPROVED:	

PD-01 B
DWG NO. REV.

17013
PROJECT NO.

FLOW DIAGRAM
SYSTEM OVERVIEW
3MM GALLON TANK FARM
GOLDEN VALLEY ELECTRIC ASSOC.
NORTH POLE, ALASKA

GREAT NORTHERN ENGINEERING
137 E. ARCTIC SUITE 101
PALMER, AK 99645
(907) 745-6988

REV	DATE	REVISION DESCRIPTION	DWN	CHK
B	06/27/17	ISSUED FOR REVIEW	DK	DK

DATE SIGNED

LINE LIST

Line No.	Service	Description	From	To	Size (in)	Schedule	ANSI Class	Design Flow Rate (gpm)	Velocity (ft/s)	Dual Flow Direction (Y/N)
FA-010	ULSD	Truck Offload	Truck Load Rack	Pump Bldg	10	Std	150	1200	4.89	N
FA-020	ULSD	Truck Loading	Pump Bldg	Truck Load Rack	6	Std	150	600	6.79	N
FA-030	ULSD	Truck Loading	Pump Bldg	Truck Load Rack	6	Std	150	600	6.79	N
FA-040	ULSD	GVEA RR Offload	GVEA Rail Rack	Pump Bldg	10	Std	150	1200	4.89	N
FA-050	ULSD	Cargo from Petro Star	Petro Star Facility	Pump Bldg	10	Std	150	2000	8.15	N
FA-060	Naptha	Cargo from Petro Star	Petro Star Facility	Pump Bldg	10	Std	150	2000	8.15	N
FA-070	ULSD	Cargo to Tank 1	Pump Bldg	Tank 1	10	Std	150	1200	4.89	N
FA-080	ULSD	Service from Tank 1	Tank 1	Pump Bldg	8	Std	150	1200	7.64	N
FA-090	ULSD	Cargo to Tank 2	Pump Bldg	Tank 2	10	Std	150	1200	4.89	N
FA-100	ULSD	Service from Tank 2	Tank 2	Pump Bldg	8	Std	150	1200	7.64	N
FA-110	Naptha	Cargo to Tank 2	Pump Bldg	Tank 2	10	Std	150	1200	4.89	N
FA-120	Naptha	Service from Tank 2	Tank 2	Pump Bldg	8	Std	150	1200	7.64	N
FA-130	ULSD	Service to Fuel Transfer Bldg	Pump Bldg	Fuel Transfer Bldg	4	Std	150	400	10.19	N
FA-140	ULSD	Service to Peaker Plant	Pump Bldg	Peaker Plant	4	Std	150	400	10.19	N
FA-150	Naptha	Service to Fuel Fwd Bldg	Pump Bldg	Fuel Fowarding Bldg	3	Std	150	250	11.32	N
FA-160	ULSD	*Petro Star RR Load/Offload	Petro Star Rail Rack	Petro Star Facility	10	Std	150	1200	4.89	Y
FA-170	Naptha	**Service to Fuel Fwd Bldg	Petro Star Facility	Fuel Fowarding Bldg	3	Std	150	250	11.32	N

* This pipeline is NIC
** This pipeline is exsting and may be tied into outside of Fuel Forwarding Bldg

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

June 2017

Submitted To:
PDC Engineers, Inc.
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Fairbanks, Alaska 99709

By:

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GEOTECHNICAL FINDINGS REPORT
GVEA FUEL STORAGE FACILITY
NORTH POLE, ALASKA

1.0 INTRODUCTION

This report presents the results of our concept phase geotechnical services for the proposed fuel storage facility project in North Pole, Alaska. The purpose of our services was to explore subsurface conditions and provide a report of our geotechnical findings to assist in evaluation of conceptual site development plans.

Our services were performed consistent with our proposal dated February 17, 2017. Per your June 26, 2017 request, we have revised our report submitted on June 2, 2017 to include additional ground improvement discussion. This report was prepared for the exclusive use of PDC Engineers, Inc. and their representatives for the fuel storage tank project.

1.1 Project Understanding

We understand GVEA plans to construct a fuel-storage facility to support their power-generation plant in North Pole. GVEA requested a concept phase preliminary assessment of available land and development of three siting options. Future detailed design phases will be conducted to provide detailed exploration of the selected site and concept, and to prepare a final design of the fuel facility. This report presents the results of our concept phase preliminary explorations and a discussion of potential geotechnical site development and design concerns.

We understand two parcels are being considered for the fuel-storage facility site: the 33.8-acre Lot 2 of H&H Industrial Subdivision, and the southeast portion of Lot F1A of the ASLS 2003-50 Subdivision. Based on our previous discussions with GVEA, we also understand the southwest corner of Lot 2 has been considered a primary area of focus for this fuel storage development. We also understand these sites may include a future gasification plant and an additional power plant, as part of an energy campus.

The proposed fuel storage development is planned to include 3 million gallons of fuel storage, a surrounding catch basin, unloading area, and connection to the existing GVEA facility. The intent of this phase of services is to evaluate concepts plans and for site development, as well as to develop a preliminary geotechnical evaluation of likely geotechnical requirements for site development.

Our services are based on:

- The limitations of our approved scope, schedule, and budget.
- Our understanding of the project and information provided by Enterprise Engineering, Inc.
- The results of testing performed on samples we collected from the explorations.

The explorations were performed to evaluate geotechnical conditions at the project area. Our observations are specific to the locations, depths, and dates noted on the boring logs, and may not be applicable to all areas of the site. No amount of explorations or testing can precisely predict the characteristics, quality, or distribution of subsurface and site conditions. Potential variation includes, but is not limited to:

- The conditions between and below explorations may be different.
- The passage of time or intervening causes (natural and manmade) may result in changes to site and subsurface conditions.
- Groundwater levels and flow directions may fluctuate due to seasonal variations.
- Penetration test results in frozen or gravelly soils may be unrealistic. Actual soil density may be lower than estimated if the test was performed on a gravel or cobble.
- Contaminant concentrations may change in response to natural conditions, chemical reactions, and/or other event.
- The presence, distribution, and concentration of contaminants may vary from our sampling locations. Our tests may not represent the highest contaminant concentrations at the site.

If conditions different from those described herein are encountered during construction, we should review our description of the subsurface conditions and reconsider our recommendations and conclusions.

1.2 Scope of Services

Our scope of services included site subsurface explorations, geotechnical laboratory testing of select soil samples, preliminary liquefaction analyses, and preparation of this findings report.

The authorized scope of services was based on your objectives, schedule, and budget. Our scope of services did not include an environmental site assessment or wetland delineation for the project site, or for any of the contaminated sites near the proposed facility. It also did not include research or evaluating the presence of cultural resources at or around the site. If a service is not specifically indicated in this report, do not assume that it was performed.

2.0 FIELD EXPLORATION AND LABORATORY ANALYSES

Our field work consisted of drilling and sampling 5 exploratory borings, designated 17-01 through 17-05, within the proposed project area. Boring 17-01 through 17-04 were located on Lot 2 of H&H Subdivision and boring 17-05 was located on Lot F1A of the ASLS 2003-50 Subdivision. Field explorations were conducted between May 15, 2017 and May 18, 2017. We subcontracted Homestead Drilling of Fairbanks (Homestead) to perform the exploratory drilling.

Peter Grey, a geotechnical staff member with our firm, observed drilling operations, logged subsurface conditions, and collected geotechnical soil samples for soil classification and laboratory testing. The approximate location of the borings are shown in Figure 1; boring logs are presented in Appendix A.

2.1 Field Exploration and Drilling Methods

Homestead advanced the borings using a Mobile B61 track-mounted and Mobile B61 truck-mounted drill rig both of which were equipped with continuous-flight hollow-stem augers. Homestead advanced and sampled the borings to 61.5 feet below the ground surface (bgs). As the borings progressed, we generally collected a grab sample from the surface to 2 feet bgs, and split-spoon samples at 2.5-foot intervals to 20 feet bgs, 5 foot intervals to 50 feet, and 10 foot intervals thereafter, using a 2½-inch inside-diameter split-spoon sampler.

The split-spoon samples were obtained by driving the sampler into the soils at the base of the auger using a 340-pound automatic hammer falling 30 inches onto the drill rods. The number of blows required to advance the sampler 6 inches is recorded over three intervals, resulting in 18 inches of penetration. For each sample, the number of blows required to advance the sampler the final 12 inches is termed the penetration resistance, a measure of the relative consistency of unfrozen fine-grained soils and relative density of unfrozen granular soils. We classified soil samples recovered using these techniques in the field, sealed them in airtight containers, and returned them to our laboratory for testing.

We performed field screening of split-spoon samples above the groundwater table using a hand-held photoionization detector (PID). Soil observations and PID readings are included in the boring logs presented in Appendix A.

The explorations were performed to evaluate subsurface conditions at the site for the proposed fuel facility and associated structures. Our observations are specific to the locations, depths, and dates noted on the logs, and may not be applicable to all areas of the site.

2.2 Geotechnical Laboratory Testing

We visually reviewed field soil classifications in our laboratory and selected samples for testing. We performed moisture-content analyses on frozen samples and samples collected above the water table, and grain-size distribution analyses on select samples. Moisture-content results are plotted on the boring logs in Appendix A. Grain-size distribution curves are shown in Appendix B. Photographs of samples we collected are presented in Appendix C.

3.0 SITE CONDITIONS

3.1 Geological Setting

North Pole is within the Tanana Lowlands physiographic province, which forms a large arcuate band of alluvial sediments between the Alaska Range and the Yukon-Tanana Uplands. The Lowlands consist of vegetated floodplains and low benches cut by the Tanana River, and sloughs and oxbow lakes representing former channel positions of the Tanana or Chena Rivers. Soils in the Lowlands consist of interbedded alluvial sand and gravel covered by silty overbank deposits. The thickness of the alluvial sediments overlying bedrock in the project area is unknown.

Although the depth of alluvial sediments has not been well established in North Pole, it has been established to be as great as 400 feet to 500 feet in the Fairbanks area. We anticipate the thickness of alluvial deposits in North Pole would be similar to Fairbanks. Former slough channels are commonly filled with organic silt and peat deposits. These deposits are laterally discontinuous and vary in thickness. The portion of the Tanana Lowlands in which the site is located has not been glaciated.

The North Pole area is in a subarctic zone underlain by discontinuous permafrost. Permafrost is defined as ground that has remained at a temperature of 32 degrees Fahrenheit or less for two or more years. Although the depth of permafrost has not been well established in North Pole, the maximum depth of permafrost measured in the Fairbanks area is in excess of 250 feet. We anticipate the depth of permafrost in North Pole would be similar to Fairbanks. The thickness of the "active layer," the portion of the ground at or near the surface that undergoes an annual freeze-thaw cycle, is largely dependent on the type of ground cover and snow depth. Seasonal frost-penetration commonly exceeds 10 feet beneath roads or parking areas kept free of snow during winter. In areas covered by thick mats of tundra or organic material, the thickness of the active zone is often 2 feet or less.

3.2 Seismicity

The North Pole area lies between two right-lateral shear systems: the Denali Fault System approximately 60 miles to 80 miles south of Fairbanks, and the Kaltag and Tintina Fault Systems, approximately 80 miles north. The shear along these systems is believed to be the result of crustal adjustments in the North American Plate due to convergence with the Pacific Plate along the Gulf of Alaska.

Within the past century, the area has been subjected to four large earthquakes. On July 22, 1937, a magnitude 7.3 (M_s) event occurred about 23 miles southeast of Fort Wainwright. This event, widely felt throughout central Alaska, produced extensive ground failures in the epicentral area (Page, and others, 1995). Two other earthquakes were an October 15, 1947, M_s 7.2 event about 41 miles south-southwest of Fairbanks, and an August 27, 1904, M_s 7.3 event about 17 miles southwest. A November 3, 2002, M_s 7.9 event on the Denali Fault, approximately 90 miles south of Fairbanks, was felt widely throughout central and southern Alaska, and resulted in minor liquefaction in the Fairbanks area. The peak horizontal ground acceleration of this event recorded on bedrock at the UAF campus was 0.09g.

3.3 Surface Conditions

The Lot 2 parcel is located east of H&H Road and historic photos and studies indicate previous development activity from farmland in the 1970s to initial site development for a refinery in the early 1980s. We evaluated aerial images, and past studies, and portions of the parcel have been cleared and fill materials were placed, but structures were not constructed and vegetation including birch, aspen, and spruce trees and scrub brush has regrown. We also note an abandoned slough that runs approximately from north to south in the middle of the lot.

The Lot F1A parcel is located west of H&H Road and is has been developed by previous owners. The site is generally flat, and includes structures, paving, and landscaped areas.

3.4 Subsurface Conditions

We observed similar conditions in some of our borings. We observed approximately 6 feet to 9.5 feet of silty, frost susceptible soils overlying alluvial sands and gravels to the depths explored. In Boring 17-02, we observed gravel with silt from approximately 2 feet bgs to 4.5 feet bgs that we believe is imported fill material.

We observed groundwater at depths ranging of approximately 3.5 feet bgs to 12 feet bgs at the time of drilling. We did not observe permafrost during exploration; a layer of remnant seasonal frost was observed from approximately 2 feet bgs to 4.5 feet bgs at the time of drilling.

4.0 EARTHQUAKE HAZARDS ANALYSIS

The project is in a seismic area where major earthquakes can and have occurred. Earthquake-induced geologic hazards that may affect a site include ground-surface fault rupture, and liquefaction and associated effects (e.g., loss of shear strength, bearing-capacity failures, loss of lateral support, ground oscillation, and lateral spreading). An associated effect of earthquake shaking is densification of the soils and potential ground settlement. Due to the presence of relatively loose soils and a shallow water table, the primary seismic hazard at the site is liquefaction. In borings drilled for the project, several samples from below the water table had uncorrected penetration resistance values (blow counts) of less than 20; some had blow counts of less than 10.

It has been our experience that soils in the Fairbanks area with blow counts as low as these are susceptible to liquefaction and dynamically induced densification if subjected to earthquake ground motions implied by the 2015 IBC. Densification of granular soils above and below the water table during earthquake shaking could result in significant ground settlement at the site. Associated effects of liquefaction may include a loss of soil shear strength, potential bearing-capacity failures, and lateral spreading. Our preliminary analysis of earthquake ground motions and earthquake-induced geologic hazards that may affect the site are described below.

4.1 Earthquake Ground Motion

Structural design performed in seismic regions for essential facilities generally requires a site-specific seismic analysis. For this concept phase study, we based our analyses on published seismic parameters. A site specific seismic analysis is being conducted for this project based on 150-foot-deep shear wave velocity testing conducted for the GVEA power plant, and will be presented as part of our final studies.

We developed seismic ground motions for the liquefaction analyses in general accordance with the 2015 NEHRP Provisions. The 5 percent damped design spectral response acceleration is defined as two-thirds of the site-adjusted maximum considered earthquake (MCE). The MCE was determined using maps for Site Class B published by the U.S. Geological Survey for ground motions with a two percent chance of occurrence in 50 years. We adjusted these values assuming Site Class D conditions at the site; sample penetration resistance values from our explorations suggest that Site Class D soil conditions prevail at the site without regard for liquefaction. The mapped MCE geometric mean peak ground acceleration (PGA_M) was derived using 2010 ASCE 7 (with 2013 errata).

The following table summarizes earthquake ground motion parameters for this site.

Description	Parameter	Value
Site Class		D
Mapped spectral accelerations for 0.2 seconds (Site Class B, 5% damping)	S_s	0.99g
Mapped spectral accelerations for 1 second (Site Class B, 5% damping)	S_1	0.38g
S_s adjusted for site class	S_{MS}	1.09g
S_1 adjusted for site class	S_{M1}	0.73g
Design spectral response acceleration at short periods	S_{DS}	0.73g
Design spectral response acceleration at 1-second period	S_{D1}	0.49g
Peak ground acceleration	PGA_M	0.48g

4.2 Geologic Hazard Analyses

Earthquake-induced geologic hazards that we reviewed include landsliding, fault rupture, and liquefaction and its associated effects (e.g., loss of shear strength, bearing capacity failures, loss of lateral support, ground oscillation, lateral spreading, and settlement). In our opinion, due to the flat topography at the site, the risk of landsliding is low.

Seismicity in the Fairbanks-North Pole area has historically been concentrated in clusters or bands with a northeast-southwest trend that indicates active faulting, although no faults with Holocene displacement have been recognized in the area. An assessment of geologic maps reveals no conclusive evidence of faulting or fault-related geomorphic structures in the area; however, the absence of obvious fault-related geomorphic structures does not preclude the possibility of active faults in the area. In our opinion, the risk for surface-fault rupture at the project site is low.

4.3 Liquefaction Analyses

Liquefaction of loose, saturated, cohesionless soils occurs when excess pore pressures are generated as a result of earthquake shaking. Additionally, densification of the granular soils above and below the water table could occur when subject to earthquake shaking, resulting in ground settlement at the site. The most widely used methods to evaluate liquefaction potential are empirical and based on correlations between Standard Penetration Test (SPT) resistance (N-value), PGA, and earthquake magnitude. We assumed a magnitude 7.3 for our analyses based on recent earthquakes that have occurred near the area and a peak ground acceleration (PGA_M) of 0.48g in the analyses.

We used three empirical procedures to evaluate liquefaction potential at this site:

- Youd and others (2001)
- Cetin and others (2004)
- Idriss and Boulanger (2014)

In these procedures, the N-value (blow count) is correlated to the liquefaction resistance of the soil (expressed as cyclic resistance ratio). The soil resistance is compared to the earthquake-induced loading (expressed as cyclic stress ratio), and a corresponding factor of safety (FS) against liquefaction is calculated.

In accordance with Section C11.8.3 in ASCE 07, we considered the soil to be potentially liquefiable if the calculated factor of safety is less than or equal to 1. The primary effect of liquefaction at the site is a reduction in the soil shear strength, settlement, and a reduction in bearing capacity.

We used the relationships by Tokimatsu and Seed (1987) and Ishihara and Yoshimine (1992), relating earthquake ground motion and penetration resistance with volumetric strain, to estimate the potential for free-field ground settlement in the borings we considered in the liquefaction analyses.

Using these relationships, in conjunction with the three procedures used to evaluate liquefaction potential in the borings we advanced at the site, we estimate 6 to 8 inches or more of free-field settlement could occur at the ground surface. In our opinion, the ground settlement may not occur uniformly over the project area and could be differential across the site.

4.4 Lateral Spreading

Liquefaction in gently sloping ground or ground adjacent to a free face can result in permanent lateral ground displacement in a phenomenon known as lateral spreading. Lateral spreading ground movement can occur toward a free face during or after seismic shaking in saturated, loose to medium dense, granular soil. Because the proposed structure is more than several hundred feet from the nearest body of water, we believe the risk of lateral spreading for the project site is low.

5.0 DISCUSSION

We observed silty frost susceptible soils overlying alluvial sands and gravels to the depths explored. These silty soils are potentially compressible and frost-susceptible, and may contain organic slough deposits. Site development for structures will require replacing these soils down to relatively clean sands and gravels to improve bearing conditions and reduce the potential for consolidation- related settlement.

Our analyses show potential for widespread liquefaction in the soil mass below the groundwater table during the design earthquake. As a result, 6 inches to 8 inches or more of total and differential ground settlement along with reduction in soil strength could occur. We understand the project is an essential facility and ground improvement will be required to mitigate the liquefaction hazards. Soil improvement has two objectives: 1) to reduce potential dynamic settlement; and 2) improve soil shear strength during a seismic event and reduce the potential for a bearing-capacity failure during liquefaction.

5.1 Ground Improvement

Our approach to ground improvement is to densify the soil sufficiently both above and below the water table to reduce settlement and increase residual soil strength during a design seismic event. The increased residual soil strength will reduce the potential for a punching-type bearing-capacity failure and liquefaction-induced settlement.

In our opinion, deep dynamic compaction (DDC) and vibro-compaction ground improvement are both appropriate techniques that could be used to densify and improve soil conditions at this site.

DDC produces low frequency vibrations that could exceed peak particle velocities of 0.75 inches per second at distances of 75 feet or more from the improvement area. Vibrocompaction produces higher frequency vibrations which may produce peak particle velocities of 0.75 inches per second, or more, up to 30 feet from the point of ground improvement. Vibrocompaction ground improvement can be 3 to 5 times more expensive than DDC. If existing structures and improvements are 100 feet to 150 feet or more from the proposed site(s), DDC may be an appropriate method of ground improvement.

The soil improvement we recommend considering has two components:1) excavating the surficial silty soils and replacing with a relatively thick section of compacted sand and gravel (i.e., structural fill) beneath foundation systems; and 2) densifying the soils below the water table using DDC techniques.

DDC, as referred to in this report, is a ground-improvement technique whereby a large tamper/weight (usually 6 tons to 40 tons) is dropped from a specified height (usually 30 feet to 120 feet) to compact materials in-place. We believe ground improvement may be performed using DDC techniques, based on our successful experience with DDC on multiple projects in similar soil conditions.

DDC soil improvement has been used for several projects in Fairbanks, including the FTW373A Warm Storage Hangar on Fort Wainwright, Hangar 6 on Fort Wainwright, the Carlson Center, the Bureau of Land Management (BLM) building on University Avenue, the FTW357 GSAB Hangar, and the FTW348A AAC Hangar. Soil improvement using vibro-compaction was completed for the University of Fairbanks Combined Heat and Power Plant, the Fairbanks Memorial Hospital Surgery Addition, Bassett Hospital on Fort Wainwright and the Alaska Department of Fish and Game Sport Fish Hatchery in Fairbanks.

5.2 Ground Vibration Monitoring

Visual pre-and post-condition surveys and vibration monitoring during ground improvement is recommended. At a minimum, vibration monitoring and pre-and-post condition surveys are recommended for building structures and utilities within a 150-foot radius of the proposed ground improvement areas, if anticipated ground vibrations exceed 2 inches per second when the frequency is 40 Hz or greater, or 0.75 inches per second when the frequency is less than 40 Hz at structures of concern.

Our experience suggests the frequency of DDC-induced ground motions, generated by a 15-ton weight dropped 50 feet, ranged from 5 to 18 Hz, and were typically less than 10 Hz. Recorded vibrations were about 0.75 inches per second 55 feet from the source, 0.5 inches per second 75 feet from the source, and 0.2 inches per second 150 feet from the source. We anticipate similar vibration levels and frequency for DDC-induced ground motions for this project; however, vibrations are dependent on several factors including depth to groundwater, density of soils, and soil type. We recommend intermittently monitoring ground vibrations within 150 feet of the improvement area to assess frequency and vibration levels and verify thresholds are not exceeded outside the 150-foot radius.

6.0 GEOTECHNICAL CONSIDERATIONS FOR SITE DEVELOPMENT

The following key geotechnical site development and design considerations have been identified during this concept phase study.

- The proposed sites have a significant seismic liquefaction hazard; primarily loss of shear strength and settlement during design seismic events.

- Site preparation for all structures will require removal of surficial silty frost susceptible soils and replacement with compacted structural fills.

- Ground improvement will be required for all essential facilities. Ground improvement will include the entire structure footprint and extend out beyond the outside edge of all foundations a minimum of 25 feet. The depth of required improvement, based on the initial subsurface findings, is about 30 to 35 feet below grade.

- Considerations should be given to performing ground improvement for future planned structure sites as well as initial site development. Future developments near initial planned developments could require more costly ground improvement techniques.

- Site preparation and DDC ground improvement should be performed during periods of low groundwater to maximize the depth of ground improvement. Low groundwater typically occurs in the spring.

7.0 CLOSING

This geotechnical findings report was prepared for the exclusive use of PDC Engineers, Inc. and their representatives for the design of the GVEA Fuel Storage Facility in North Pole, Alaska. This report should not be used without our approval if any of the following occurs:

- Conditions change due to natural forces or human activity under, at, or adjacent to the site.
- Assumptions stated in this report have changed.
- Project details change or new information becomes available such that our conclusions and recommendations may be affected.
- If the site ownership or land use has changed.
- More than one year has passed since the date of this report.

If any of these occur, we should be retained to review the applicability of our recommendations.

Shannon & Wilson, Inc., has prepared the document *"Important Information About Your Geotechnical/Environmental Report"* in Appendix D to assist you and others in understanding the uses and limitations of our reports. Please read this document to learn how you can lower your risks for this project.

Geotechnical Findings:
SHANNON & WILSON, INC.

Stephen Adamczak, Jr. P.E.
Vice President

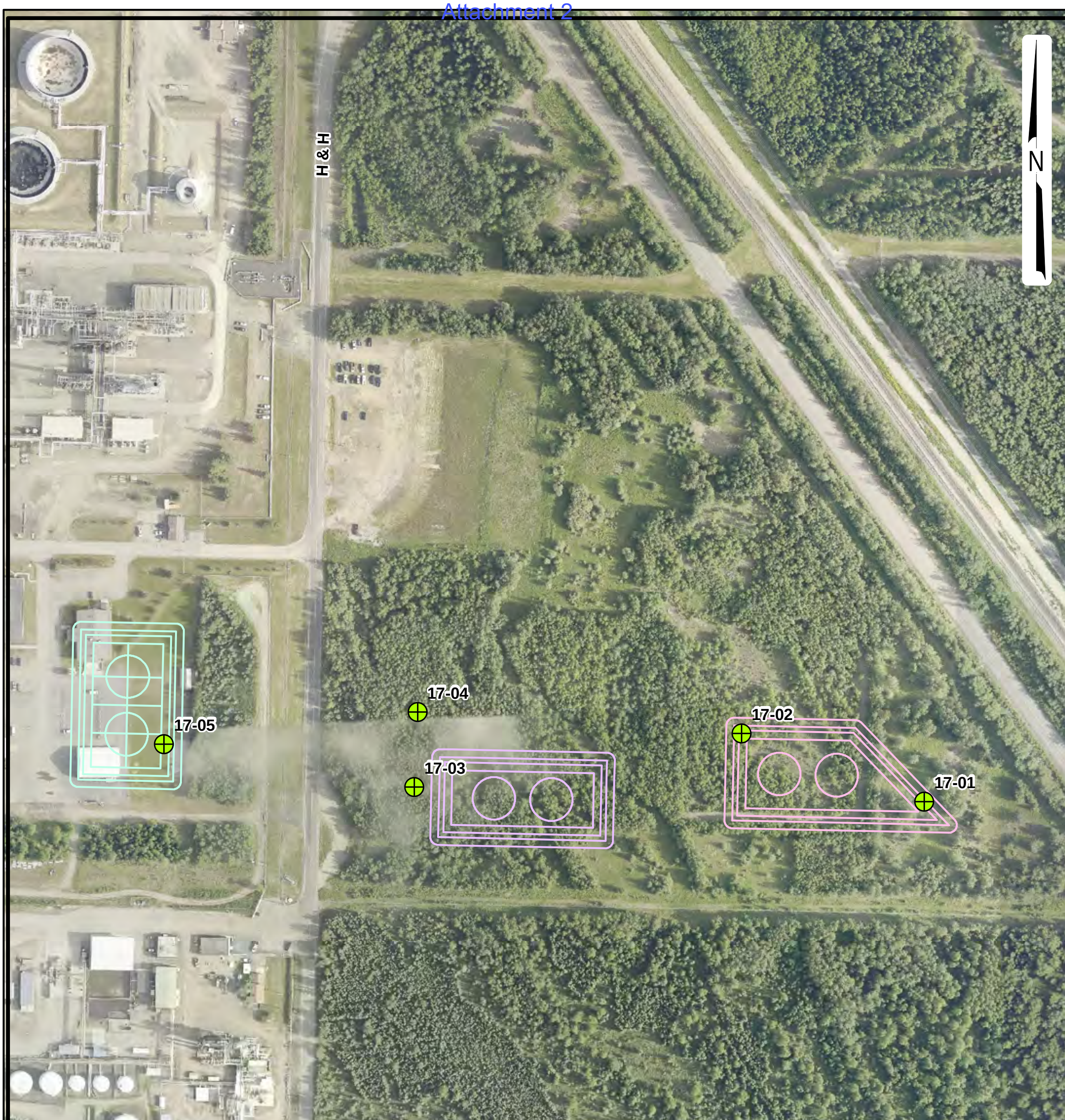

Image provided courtesy of Pictometry International 2012

0 200 400 600

Feet

LEGEND

Approximate Boring Location

Alternative 1 Tank Location

Alternative 3 Tank Location

Alternative 2 Tank Location

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

SITE PLAN AND APPROXIMATE BORING LOCATIONS

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
GEOTECHNICAL AND ENVIRONMENTAL CONSULTANTS

Figure 1

APPENDIX A

SOIL BORING LOGS AND SOIL CLASSIFICATION

APPENDIX A

SOIL BORING LOGS AND SOIL CLASSIFICATION

TABLES

FIGURES

TABLE A-1
SUMMARY OF FROZEN SOIL CLASSIFICATION SYSTEM

Description			Designation
Segregated ice is not visible by eye	Friable, poorly bonded Material is easily broken up		Nf
	Well bonded – Soil particles strongly held together by ice	No excess ice	Nbn
		Excess ice	Nbe
Segregated ice is visible by eye (less than 1 inch thick)	Individual ice crystals or inclusions		Vx
	Ice coatings on soil particles		Vc
	Stratified or distinctly oriented ice formations		Vs
	Randomly or irregularly oriented ice formations		Vr
Ice greater than 1 inch thick	Ice with soil inclusions		ICE + soil type
	Ice without soil inclusions		ICE

Note:
Based on Linell, K.A. and C.W. Kaplar, 1966, Description and Classification of Frozen Soils, U.S. Army Cold Regions Research Engineering Laboratory, Technical Report 150, Hanover, N.H.

Shannon & Wilson, Inc. (S&W), uses a soil identification system modified from the Unified Soil Classification System (USCS). Elements of the USCS and other definitions are provided on this and the following pages. Soil descriptions are based on visual-manual procedures (ASTM D2488) and laboratory testing procedures (ASTM D2487), if performed.

S&W INORGANIC SOIL CONSTITUENT DEFINITIONS

CONSTITUENT[2]	FINE-GRAINED SOILS (50% or more fines)[1]	COARSE-GRAINED SOILS (less than 50% fines)[1]
Major	***Silt, Lean Clay, Elastic Silt,*** or ***Fat Clay***[3]	***Sand*** or ***Gravel***[4]
Modifying (Secondary) Precedes major constituent	30% or more coarse-grained: ***Sandy*** or ***Gravelly***[4]	More than 12% fine-grained: ***Silty*** or ***Clayey***[3]
Minor Follows major constituent	15% to 30% coarse-grained: ***with Sand*** or ***with Gravel***[4]	5% to 12% fine-grained: ***with Silt*** or ***with Clay***[3]
	30% or more total coarse-grained *and* lesser coarse-grained constituent is 15% or more: ***with Sand*** or ***with Gravel***[5]	15% or more of a second coarse-grained constituent: ***with Sand*** or ***with Gravel***[5]

[1]All percentages are by weight of total specimen passing a 3-inch sieve.
[2]The order of terms is: *Modifying Major with Minor*.
[3]Determined based on behavior.
[4]Determined based on which constituent comprises a larger percentage.
[5]Whichever is the lesser constituent.

MOISTURE CONTENT TERMS

Dry	Absence of moisture, dusty, dry to the touch
Moist	Damp but no visible water
Wet	Visible free water, from below water table

STANDARD PENETRATION TEST (SPT) SPECIFICATIONS

Hammer:	140 pounds with a 30-inch free fall. Rope on 6- to 10-inch-diam. cathead 2-1/4 rope turns, > 100 rpm NOTE: If automatic hammers are used, blow counts shown on boring logs should be adjusted to account for efficiency of hammer.
Sampler:	10 to 30 inches long Shoe I.D. = 1.375 inches Barrel I.D. = 1.5 inches Barrel O.D. = 2 inches
N-Value:	Sum blow counts for second and third 6-inch increments. Refusal: 50 blows for 6 inches or less; 10 blows for 0 inches.

NOTE: Penetration resistances (N-values) shown on boring logs are as recorded in the field and have not been corrected for hammer efficiency, overburden, or other factors.

PARTICLE SIZE DEFINITIONS

DESCRIPTION	SIEVE NUMBER AND/OR APPROXIMATE SIZE
FINES	< #200 (0.075 mm = 0.003 in.)
SAND Fine Medium Coarse	 #200 to #40 (0.075 to 0.4 mm; 0.003 to 0.02 in.) #40 to #10 (0.4 to 2 mm; 0.02 to 0.08 in.) #10 to #4 (2 to 4.75 mm; 0.08 to 0.187 in.)
GRAVEL Fine Coarse	 #4 to 3/4 in. (4.75 to 19 mm; 0.187 to 0.75 in.) 3/4 to 3 in. (19 to 76 mm)
COBBLES	3 to 12 in. (76 to 305 mm)
BOULDERS	> 12 in. (305 mm)

RELATIVE DENSITY / CONSISTENCY

COHESIONLESS SOILS		COHESIVE SOILS	
N, SPT, BLOWS/FT.	RELATIVE DENSITY	N, SPT, BLOWS/FT.	RELATIVE CONSISTENCY
< 4	Very loose	< 2	Very soft
4 - 10	Loose	2 - 4	Soft
10 - 30	Medium dense	4 - 8	Medium stiff
30 - 50	Dense	8 - 15	Stiff
> 50	Very dense	15 - 30	Very stiff
		> 30	Hard

WELL AND BACKFILL SYMBOLS

Bentonite Cement Grout	Surface Cement Seal
Bentonite Grout	Asphalt or Cap
Bentonite Chips	Slough
Silica Sand	Inclinometer or Non-perforated Casing
Perforated or Screened Casing	Vibrating Wire Piezometer

PERCENTAGES TERMS[1, 2]

Trace	< 5%
Few	5 to 10%
Little	15 to 25%
Some	30 to 45%
Mostly	50 to 100%

[1]Gravel, sand, and fines estimated by mass. Other constituents, such as organics, cobbles, and boulders, estimated by volume.

[2]Reprinted, with permission, from ASTM D2488 - 09a Standard Practice for Description and Identification of Soils (Visual-Manual Procedure), copyright ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA 19428. A copy of the complete standard may be obtained from ASTM International, www.astm.org.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

SOIL DESCRIPTION AND LOG KEY

June 2017 | 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-1
Sheet 1 of 3

2013_BORING_CLASS1 31-1-20006-001.GPJ SHAN WIL.GDT 6/1/17

UNIFIED SOIL CLASSIFICATION SYSTEM (USCS) (Modified From USACE Tech Memo 3-357, ASTM D2487, and ASTM D2488)				
MAJOR DIVISIONS			**GROUP/GRAPHIC SYMBOL**	**TYPICAL IDENTIFICATIONS**
COARSE-GRAINED SOILS *(more than 50% retained on No. 200 sieve)*	Gravels *(more than 50% of coarse fraction retained on No. 4 sieve)*	Gravel *(less than 5% fines)*	GW	Well-Graded Gravel; Well-Graded Gravel with Sand
			GP	Poorly Graded Gravel; Poorly Graded Gravel with Sand
		Silty or Clayey Gravel *(more than 12% fines)*	GM	Silty Gravel; Silty Gravel with Sand
			GC	Clayey Gravel; Clayey Gravel with Sand
	Sands *(50% or more of coarse fraction passes the No. 4 sieve)*	Sand *(less than 5% fines)*	SW	Well-Graded Sand; Well-Graded Sand with Gravel
			SP	Poorly Graded Sand; Poorly Graded Sand with Gravel
		Silty or Clayey Sand *(more than 12% fines)*	SM	Silty Sand; Silty Sand with Gravel
			SC	Clayey Sand; Clayey Sand with Gravel
FINE-GRAINED SOILS *(50% or more passes the No. 200 sieve)*	Silts and Clays *(liquid limit less than 50)*	Inorganic	ML	Silt; Silt with Sand or Gravel; Sandy or Gravelly Silt
			CL	Lean Clay; Lean Clay with Sand or Gravel; Sandy or Gravelly Lean Clay
		Organic	OL	Organic Silt or Clay; Organic Silt or Clay with Sand or Gravel; Sandy or Gravelly Organic Silt or Clay
	Silts and Clays *(liquid limit 50 or more)*	Inorganic	MH	Elastic Silt; Elastic Silt with Sand or Gravel; Sandy or Gravelly Elastic Silt
			CH	Fat Clay; Fat Clay with Sand or Gravel; Sandy or Gravelly Fat Clay
		Organic	OH	Organic Silt or Clay; Organic Silt or Clay with Sand or Gravel; Sandy or Gravelly Organic Silt or Clay
HIGHLY-ORGANIC SOILS	Primarily organic matter, dark in color, and organic odor		PT	Peat or other highly organic soils (see ASTM D4427)

NOTE: No. 4 size = 4.75 mm = 0.187 in.; No. 200 size = 0.075 mm = 0.003 in.

NOTES

1. Dual symbols *(symbols separated by a hyphen, i.e., SP-SM, Sand with Silt)* are used for soils with between 5% and 12% fines or when the liquid limit and plasticity index values plot in the CL-ML area of the plasticity chart. Graphics shown on the logs for these soil types are a combination of the two graphic symbols (e.g., SP and SM).

2. Borderline symbols *(symbols separated by a slash, i.e., CL/ML, Lean Clay to Silt; SP-SM/SM, Sand with Silt to Silty Sand)* indicate that the soil properties are close to the defining boundary between two groups.

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GVEA Fuel Storage Facility
North Pole, Alaska

SOIL DESCRIPTION AND LOG KEY

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-1
Sheet 2 of 3

2013 BORING CLASS2 31-1-20006-001.GPJ SHAN WIL.GDT 6/1/17

GRADATION TERMS

Poorly Graded	Narrow range of grain sizes present or, within the range of grain sizes present, one or more sizes are missing (Gap Graded). Meets criteria in ASTM D2487, if tested.
Well-Graded	Full range and even distribution of grain sizes present. Meets criteria in ASTM D2487, if tested.

CEMENTATION TERMS[1]

Weak	Crumbles or breaks with handling or slight finger pressure.
Moderate	Crumbles or breaks with considerable finger pressure.
Strong	Will not crumble or break with finger pressure.

PLASTICITY[2]

DESCRIPTION	VISUAL-MANUAL CRITERIA	APPROX. PLASITICITY INDEX RANGE
Nonplastic	A 1/8-in. thread cannot be rolled at any water content.	< 4
Low	A thread can barely be rolled and a lump cannot be formed when drier than the plastic limit.	4 to 10
Medium	A thread is easy to roll and not much time is required to reach the plastic limit. The thread cannot be rerolled after reaching the plastic limit. A lump crumbles when drier than the plastic limit.	10 to 20
High	It takes considerable time rolling and kneading to reach the plastic limit. A thread can be rerolled several times after reaching the plastic limit. A lump can be formed without crumbling when drier than the plastic limit.	> 20

ADDITIONAL TERMS

Mottled	Irregular patches of different colors.
Bioturbated	Soil disturbance or mixing by plants or animals.
Diamict	Nonsorted sediment; sand and gravel in silt and/or clay matrix.
Cuttings	Material brought to surface by drilling.
Slough	Material that caved from sides of borehole.
Sheared	Disturbed texture, mix of strengths.

PARTICLE ANGULARITY AND SHAPE TERMS[1]

Angular	Sharp edges and unpolished planar surfaces.
Subangular	Similar to angular, but with rounded edges.
Subrounded	Nearly planar sides with well-rounded edges.
Rounded	Smoothly curved sides with no edges.
Flat	Width/thickness ratio > 3.
Elongated	Length/width ratio > 3.

ACRONYMS AND ABBREVIATIONS

ATD	At Time of Drilling
Diam.	Diameter
Elev.	Elevation
ft.	Feet
FeO	Iron Oxide
gal.	Gallons
Horiz.	Horizontal
HSA	Hollow Stem Auger
I.D.	Inside Diameter
in.	Inches
lbs.	Pounds
MgO	Magnesium Oxide
mm	Millimeter
MnO	Manganese Oxide
NA	Not Applicable or Not Available
NP	Nonplastic
O.D.	Outside Diameter
OW	Observation Well
pcf	Pounds per Cubic Foot
PID	Photo-Ionization Detector
PMT	Pressuremeter Test
ppm	Parts per Million
psi	Pounds per Square Inch
PVC	Polyvinyl Chloride
rpm	Rotations per Minute
SPT	Standard Penetration Test
USCS	Unified Soil Classification System
q_u	Unconfined Compressive Strength
VWP	Vibrating Wire Piezometer
Vert.	Vertical
WOH	Weight of Hammer
WOR	Weight of Rods
Wt.	Weight

STRUCTURE TERMS[1]

Interbedded	Alternating layers of varying material or color with layers at least 1/4-inch thick; singular: bed.
Laminated	Alternating layers of varying material or color with layers less than 1/4-inch thick; singular: lamination.
Fissured	Breaks along definite planes or fractures with little resistance.
Slickensided	Fracture planes appear polished or glossy; sometimes striated.
Blocky	Cohesive soil that can be broken down into small angular lumps that resist further breakdown.
Lensed	Inclusion of small pockets of different soils, such as small lenses of sand scattered through a mass of clay.
Homogeneous	Same color and appearance throughout.

[1]Reprinted, with permission, from ASTM D2488 - 09a Standard Practice for Description and Identification of Soils (Visual-Manual Procedure), copyright ASTM International, 100 Barr Harbor Drive, West Conshohocken, PA 19428. A copy of the complete standard may be obtained from ASTM International, www.astm.org.

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Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

SOIL DESCRIPTION AND LOG KEY

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-1
Sheet 3 of 3

2013_BORING_CLASS3 31-1-20006-001.GPJ SHAN WIL.GDT 6/1/17

Total Depth:	*61.5 ft.*	Northing:		Drilling Method:	*Hollow Stem Auger*	Hole Diam.:	*8 in.*
Top Elevation:	~	Easting:		Drilling Company:	*Homestead Drilling*	Rod Diam.:	
Vert. Datum:	*NAD 83, Zone 3*	Station:		Drill Rig Equipment:	*B61 Tracked Rig*	Hammer Type:	*Automatic*
Horiz. Datum:	*NAD 83, Zone 3*	Offset:		Other Comments:			

SOIL DESCRIPTION

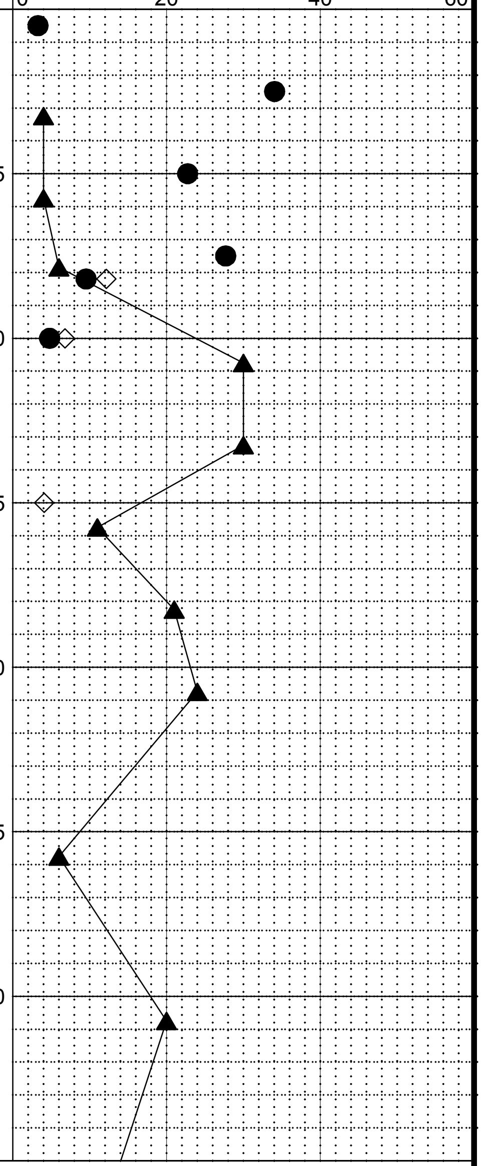
Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

Soil Description	Depth, ft.	PID, ppm	Samples
Gray-brown, *Poorly Graded Gravel with Sand (GP)*; moist.		0.6	1 (G)
Loose, gray-brown, *Sandy Silt (ML)*; moist; trace organics.	2.0	0.3	2
		0.6	3
		0.4	4a
Loose, gray-brown, *Silty Sand (SM)*; moist; trace organics.	8.5	0.6	4b
Loose to medium-dense, gray-brown, *Poorly Graded Gravel with Silt and Sand (GP-GM) to Well-Graded Gravel with Sand (GW) to Poorly Graded Gravel with Sand (GP)*; moist to 12.0 feet, wet below 12.0 feet; fractured gravel up to 3 inches present in some samples.	9.5	0.6	5
			6
			7
			8
			9
			10
			11

Symbol | Ground Water: During Drilling ⊻ | Depth, ft.

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: *300 lbs / 30 inches*



◇ % Fines (<0.075mm)
● % Water Content

CONTINUED NEXT SHEET

LEGEND

* Sample Not Recovered
G Grab Sample
3" O.D. Split Spoon Sample
⊻ Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-01

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-2
Sheet 1 of 2

REV 3 - Approved for Submittal

Total Depth: 61.5 ft.	Northing:	Drilling Method:	Hollow Stem Auger	Hole Diam.:	8 in.
Top Elevation: ~	Easting:	Drilling Company:	Homestead Drilling	Rod Diam.:	
Vert. Datum: NAD 83, Zone 3	Station:	Drill Rig Equipment:	B61 Tracked Rig	Hammer Type:	Automatic
Horiz. Datum: NAD 83, Zone 3	Offset:	Other Comments:			

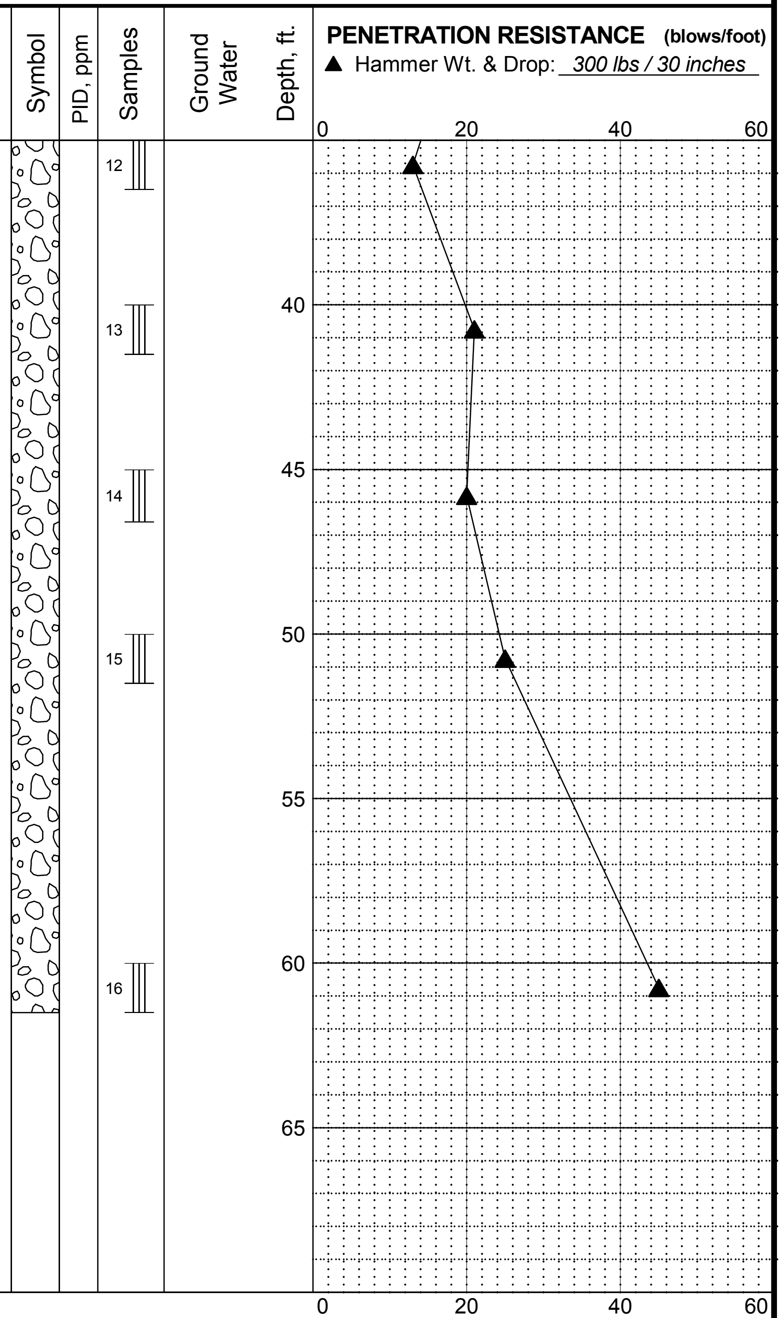
SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

Depth, ft.

61.5

BOTTOM OF BORING
BORING COMPLETED 5/15/2017



LEGEND

* Sample Not Recovered
Grab Sample
3" O.D. Split Spoon Sample
Ground Water Level ATD

◇ % Fines (<0.075mm)
● % Water Content

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-01

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
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FIG. A-2
Sheet 2 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/19/17 Log: Pxg Rev: IAS Typ: Dym

REV 3 - Approved for Submittal

Total Depth: *61.5 ft.*	Northing:	Drilling Method: *Hollow Stem Auger*	Hole Diam.: *8 in.*
Top Elevation: ~	Easting:	Drilling Company: *Homestead Drilling*	Rod Diam.:
Vert. Datum: *NAD 83, Zone 3*	Station:	Drill Rig Equipment: *B61 Tracked Rig*	Hammer Type: *Automatic*
Horiz. Datum: *NAD 83, Zone 3*	Offset:	Other Comments:	

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

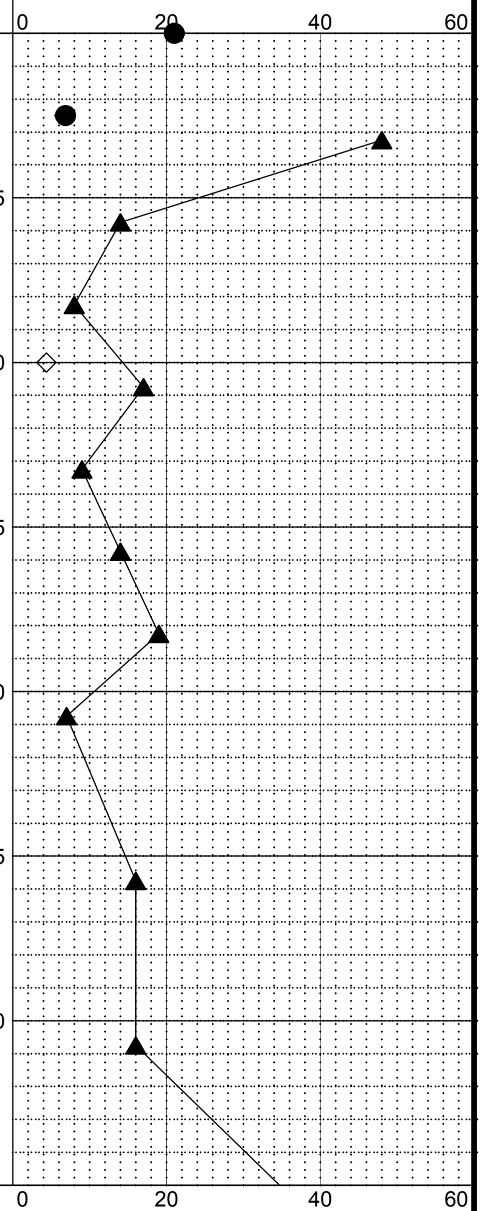
Soil Description	Depth, ft.	PID, ppm	Samples
Brown, *Poorly Graded Sand with Silt (SP-SM)*; moist; trace gravel.		0.2	1 (G)
Gray-brown, *Well-Graded Gravel with Silt and Sand (GW-GM)*; wet to 3.5 feet; frozen, Nbn from 3.5 feet to 4.5 feet.	2.0	0.1	2
Loose to medium-dense, gray-brown, *Poorly Graded Gravel with Sand (GP)*; wet; trace fines.	4.5	0.3	3, 4, 5
Loose to medium-dense, gray-brown, *Poorly Graded Sand (SP)*; wet; trace to few gravel, trace fines.	12.0		6, 7
Loose to dense, gray-brown, *Poorly Graded Gravel with Sand (GP)*; wet; gravel up to 3 inches present in sample 12; trace fines.	17.0		8, 9, 10, 11

Frozen

Ground Water: During Drilling

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: *300 lbs / 30 inches*



CONTINUED NEXT SHEET

LEGEND

- * Sample Not Recovered
- Grab Sample
- 3" O.D. Split Spoon Sample
- Ground Water Level ATD

◇ % Fines (<0.075mm)

● % Water Content

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
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LOG OF BORING 17-02

June 2017 31-1-20006-001R1

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FIG. A-3
Sheet 1 of 2

REV 3 - Approved for Submittal

Total Depth:	61.5 ft.	Northing:		Drilling Method:	Hollow Stem Auger
Top Elevation:	~	Easting:		Drilling Company:	Homestead Drilling
Vert. Datum:	NAD 83, Zone 3	Station:		Drill Rig Equipment:	B61 Tracked Rig
Horiz. Datum:	NAD 83, Zone 3	Offset:		Other Comments:	

Hole Diam.:	8 in.
Rod Diam.:	
Hammer Type:	Automatic

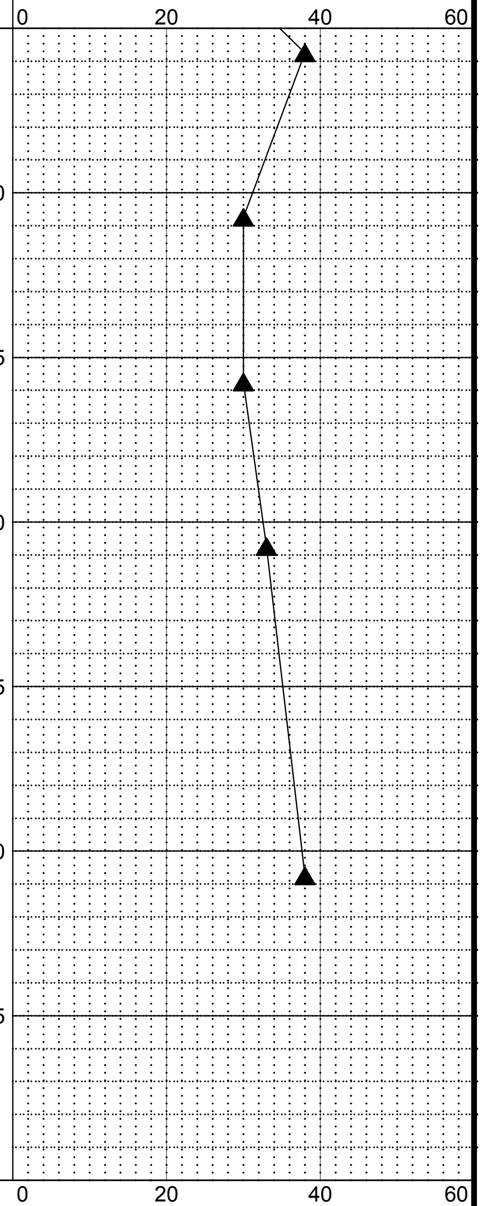
SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

Frozen = ▮ | Depth, ft. | Symbol | PID, ppm | Samples | Ground Water | Depth, ft.

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: 300 lbs / 30 inches



Samples: 12, 13, 14, 15, 16

61.5

BOTTOM OF BORING
BORING COMPLETED 5/16/2017

0 20 40 60

◇ % Fines (<0.075mm)
● % Water Content

LEGEND

- * Sample Not Recovered
- G Grab Sample
- 3" O.D. Split Spoon Sample
- ⊻ Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-02

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
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FIG. A-3
Sheet 2 of 2

REV 3 - Approved for Submittal

Total Depth: 61.5 ft.	Northing:	Drilling Method: Hollow Stem Auger	Hole Diam.: 8 in.
Top Elevation: ~	Easting:	Drilling Company: Homestead Drilling	Rod Diam.:
Vert. Datum: NAD 83, Zone 3	Station:	Drill Rig Equipment: B61 Tracked Rig	Hammer Type: Automatic
Horiz. Datum: NAD 83, Zone 3	Offset:	Other Comments:	

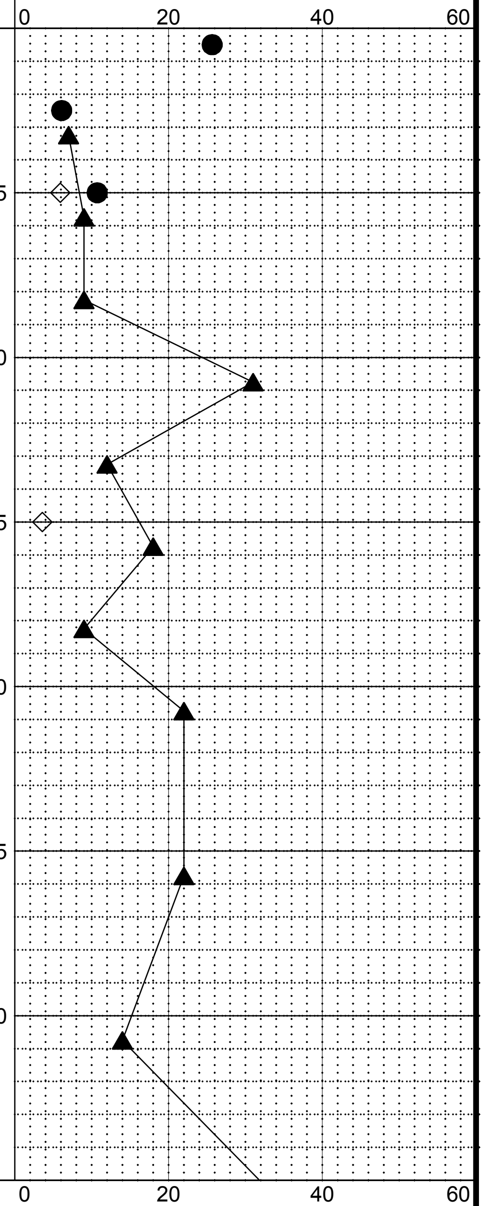
SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

Soil Description	Depth, ft.	PID, ppm	Samples	Ground Water
Gray-brown, *Poorly Graded Sand with Silt (SP-SM)*; moist to 2.0 feet; frozen, Nbn to Nf from 2.0 feet to 4.5 feet.		0.3 0.6	1 (G) 2	
Loose, gray-brown, *Poorly Graded Sand with Silt (SP-SM)*; moist.	4.5	0.2	3	
Loose to dense, gray-brown, *Well-Graded Gravel with Sand (GW) to Poorly Graded Gravel with Sand (GP)*; moist to 7.0 feet, wet below 7.0 feet; fractured gravel up to 3 inches present in some samples; trace fines.	7.0	0.4	4, 5, 6, 7, 8, 9, 10, 11	During Drilling ▽

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: 300 lbs / 30 inches



CONTINUED NEXT SHEET

LEGEND

- * Sample Not Recovered
- G Grab Sample
- 3" O.D. Split Spoon Sample
- ▽ Ground Water Level ATD
- ◇ % Fines (<0.075mm)
- ● % Water Content

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-03

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

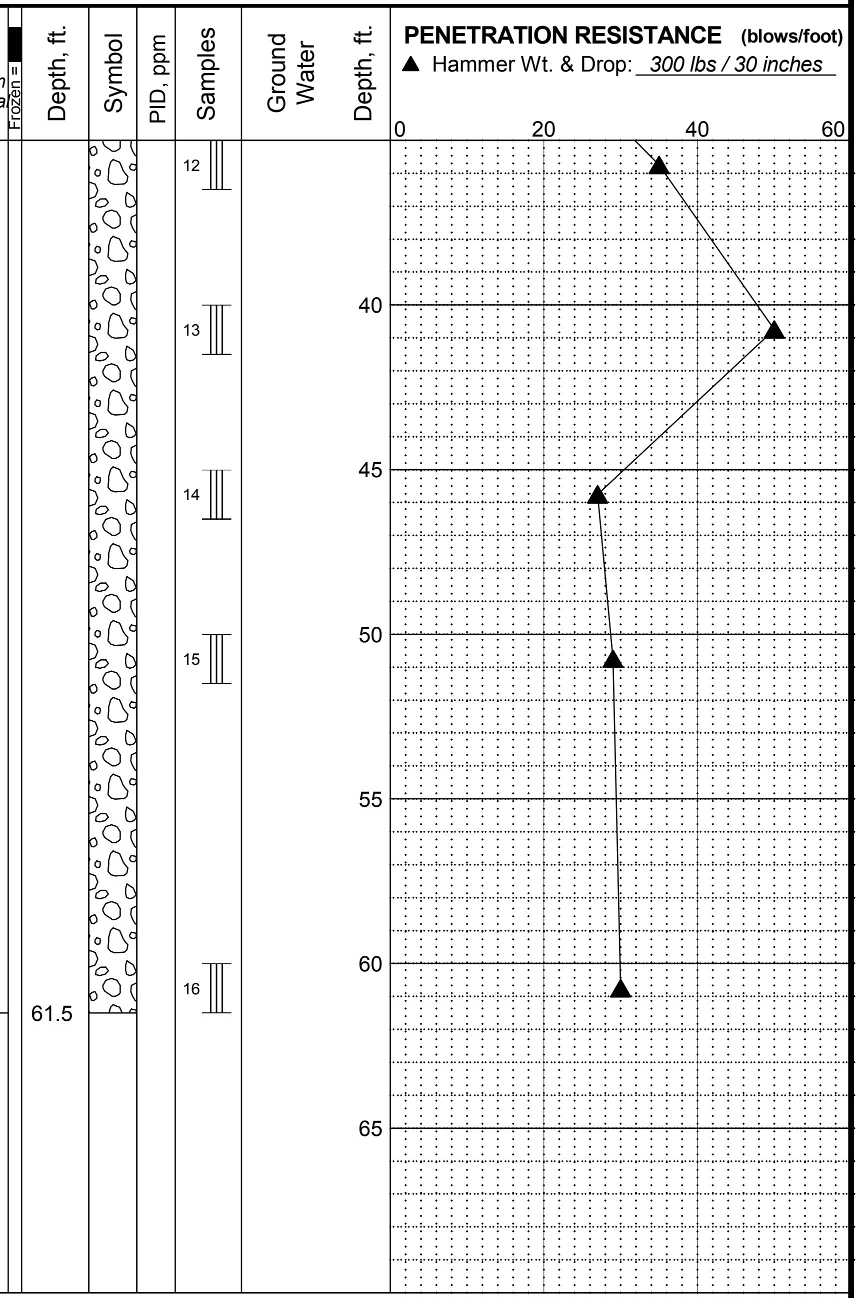
FIG. A-4
Sheet 1 of 2

REV 3 - Approved for Submittal

Total Depth:	61.5 ft.	Northing:		Drilling Method:	Hollow Stem Auger	Hole Diam.:	8 in.
Top Elevation:	~	Easting:		Drilling Company:	Homestead Drilling	Rod Diam.:	
Vert. Datum:	NAD 83, Zone 3	Station:		Drill Rig Equipment:	B61 Tracked Rig	Hammer Type:	Automatic
Horiz. Datum:	NAD 83, Zone 3	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.



BOTTOM OF BORING
BORING COMPLETED 5/17/2017

LEGEND

- * Sample Not Recovered
- G Grab Sample
- 3" O.D. Split Spoon Sample
- ⊻ Ground Water Level ATD
- ◇ % Fines (<0.075mm)
- ● % Water Content

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-03

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
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FIG. A-4
Sheet 2 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN WIL.GDT 6/19/17 Typ: Dym Rev: IAS Typ: Dym

REV 3 - Approved for Submittal

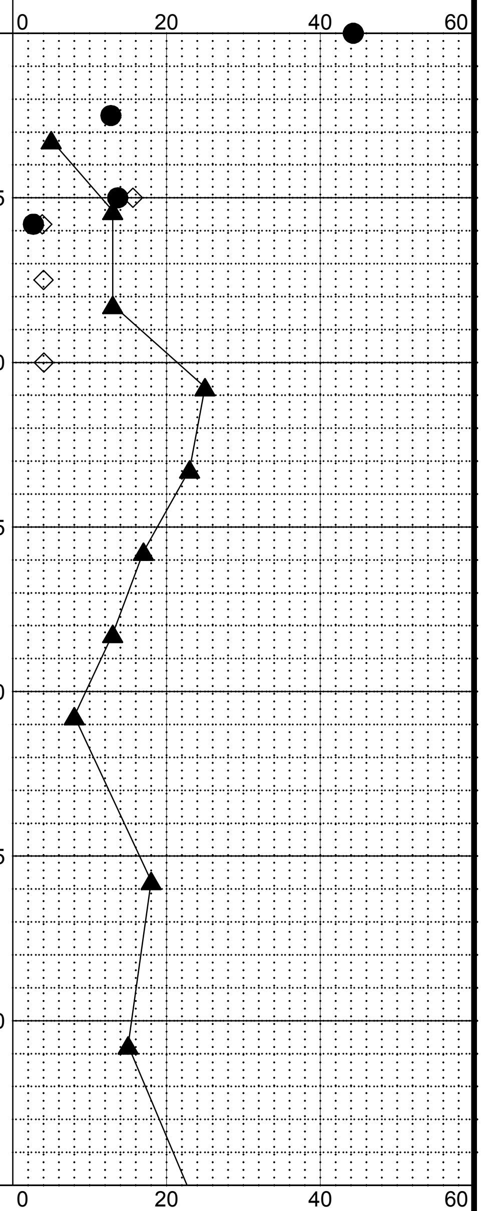
Total Depth:	*61.5 ft.*	Northing:		Drilling Method:	*Hollow Stem Auger*	Hole Diam.:	*8 in.*
Top Elevation:	~	Easting:		Drilling Company:	*Homestead Drilling*	Rod Diam.:	
Vert. Datum:	*NAD 83, Zone 3*	Station:		Drill Rig Equipment:	*B61 Tracked Rig*	Hammer Type:	*Automatic*
Horiz. Datum:	*NAD 83, Zone 3*	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

Soil Description	Depth, ft.	PID, ppm	Samples	Ground Water
Gray-brown, *Sandy Silt (ML)*; moist to 1.0 foot; frozen, Nbn from 1.0 foot to 2.5 feet; trace to few organics.	2.5	0.7	1	
Loose, gray-brown, *Silty Sand (SM)*; moist.	6.0	0.5 0.6 0.7	2 3a 3b	
Loose to dense, gray-brown, *Poorly Graded Gravel with Sand (GP)*; moist to 7.0 feet, wet below 7.0 feet; gravel up to 3 inches present in many samples; trace fines.		0.6	4 5 6 7 8 9 10 11	During Drilling

PENETRATION RESISTANCE (blows/foot)
▲ Hammer Wt. & Drop: *300 lbs / 30 inches*



CONTINUED NEXT SHEET

LEGEND

* Sample Not Recovered
Grab Sample
3" O.D. Split Spoon Sample
Ground Water Level ATD

◇ % Fines (<0.075mm)
● % Water Content

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-04

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-5
Sheet 1 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/19/17 Pxg Rev: IAS Typ: Dym

REV 3 - Approved for Submittal

Total Depth:	*61.5 ft.*	Northing:		Drilling Method:	*Hollow Stem Auger*
Top Elevation:	*~*	Easting:		Drilling Company:	*Homestead Drilling*
Vert. Datum:	*NAD 83, Zone 3*	Station:		Drill Rig Equipment:	*B61 Tracked Rig*
Horiz. Datum:	*NAD 83, Zone 3*	Offset:		Other Comments:	

Hole Diam.:	*8 in.*
Rod Diam.:	
Hammer Type:	*Automatic*

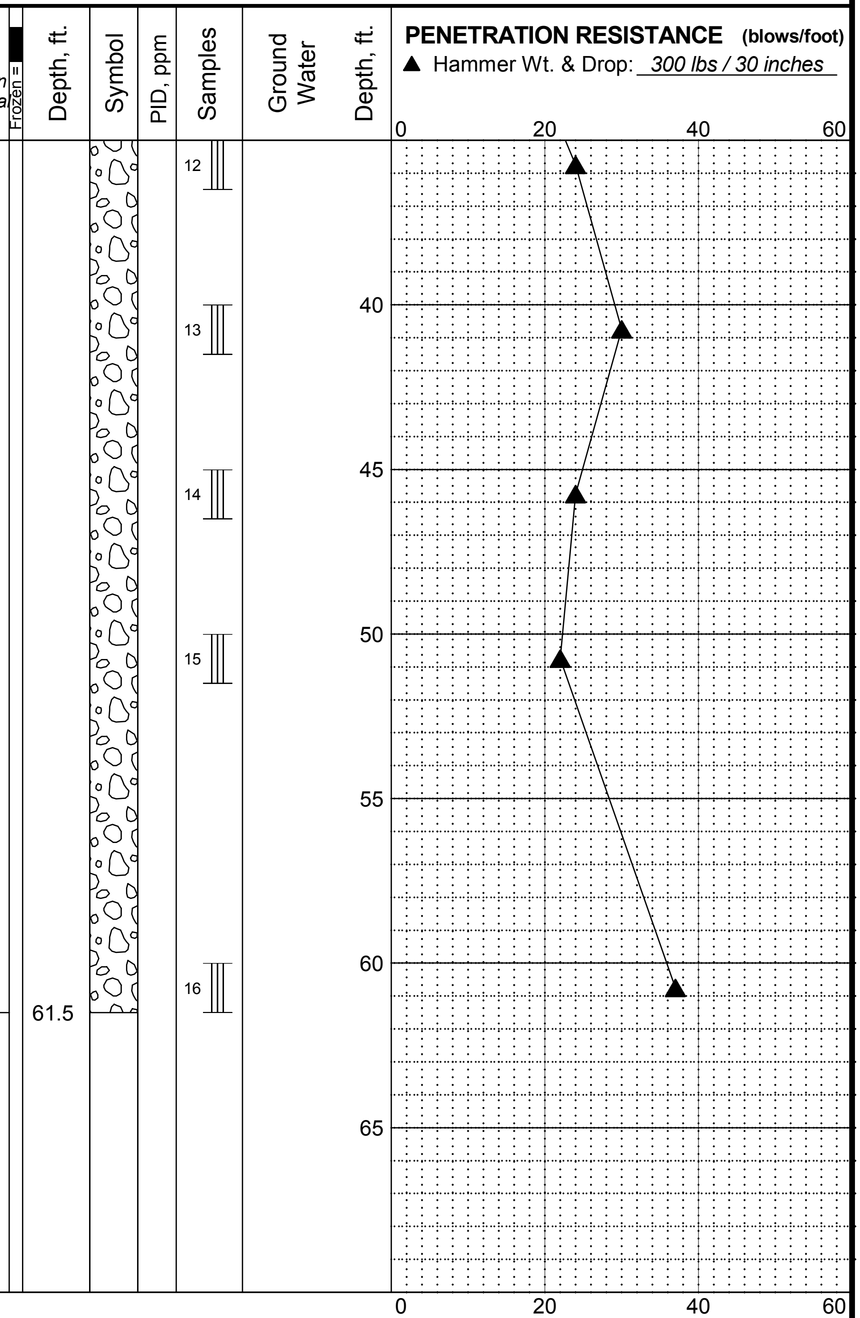
SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

Frozen = ▮ | Depth, ft. | Symbol | PID, ppm | Samples | Ground Water | Depth, ft.

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: *300 lbs / 30 inches*



BOTTOM OF BORING
BORING COMPLETED 5/17/2017

LEGEND

* Sample Not Recovered

G Grab Sample

3" O.D. Split Spoon Sample

Ground Water Level ATD

◇ % Fines (<0.075mm)

● % Water Content

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-04

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
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FIG. A-5
Sheet 2 of 2

MASTER_LOG_E_ALASKA 31-1-20006-001.GPJ SHAN_WIL.GDT 6/19/17 Log: Pxg Rev: IAS Typ: Dym

REV 3 - Approved for Submittal

Total Depth:	61.5 ft.	Northing:		Drilling Method:	Hollow Stem Auger	Hole Diam.:	8 in.
Top Elevation:	~	Easting:		Drilling Company:	Homestead Drilling	Rod Diam.:	
Vert. Datum:	NAD 83, Zone 3	Station:		Drill Rig Equipment:	B61 Tracked Rig	Hammer Type:	Automatic
Horiz. Datum:	NAD 83, Zone 3	Offset:		Other Comments:			

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

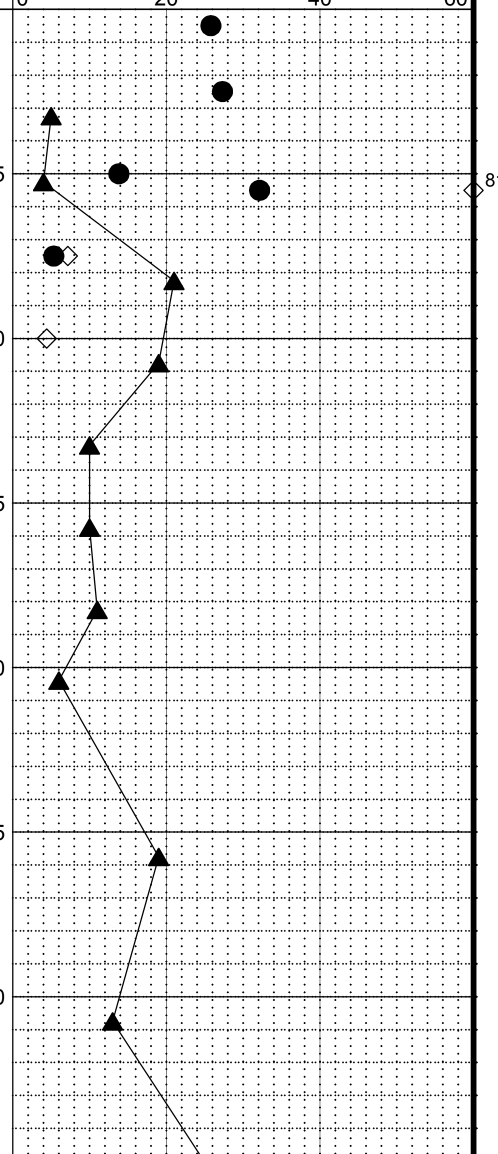
Soil Description	Depth, ft.	PID, ppm	Samples
Gray-brown, *Silt with Sand (ML)*; moist to 1 foot; frozen, Nbn from 1 foot to 2.5 feet; trace organics.	2.5	1.3	1
Loose, gray-brown to gray, *Silt with Sand (ML) to Silty Sand (SM)*; moist; trace organics to 4.5 feet.	7.5	0.7 0.8 0.7	2 3a 3b
Loose to medium-dense, gray-brown, *Poorly Graded Gravel with Silt and Sand (GP-GM) to Poorly Graded Gravel with Sand (GP)*; moist to 9.5 feet, wet below 9.5 feet.	21.0	1 0.2	4 5 6 7 8 9a 9b
Loose, gray-brown, *Poorly Graded Sand (SP)*; wet; trace fines.	23.0		
Medium-dense to dense, gray-brown, *Poorly Graded Gravel with Sand (GP)*; wet; coarse, subangular to subrounded gravel; trace fines.			10 11

Frozen | Depth, ft. | Symbol | PID, ppm | Samples | Ground Water | Depth, ft.

During Drilling

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: 300 lbs / 30 inches



◇ % Fines (<0.075mm)
● % Water Content

CONTINUED NEXT SHEET

LEGEND

- * Sample Not Recovered
- Ground Water Level ATD
- Grab Sample
- 3" O.D. Split Spoon Sample

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-05

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. A-6
Sheet 1 of 2

REV 3 - Approved for Submittal

Total Depth:	61.5 ft.	Northing:		Drilling Method:	Hollow Stem Auger
Top Elevation:	~	Easting:		Drilling Company:	Homestead Drilling
Vert. Datum:	NAD 83, Zone 3	Station:		Drill Rig Equipment:	B61 Tracked Rig
Horiz. Datum:	NAD 83, Zone 3	Offset:		Other Comments:	

Hole Diam.:	8 in.
Rod Diam.:	
Hammer Type:	Automatic

SOIL DESCRIPTION

Refer to the report text for a proper understanding of the subsurface materials and drilling methods. The stratification lines represent the approximate boundaries between material types, and the transition may be gradual.

Frozen = | Depth, ft. | Symbol | PID, ppm | Samples | Ground Water | Depth, ft.

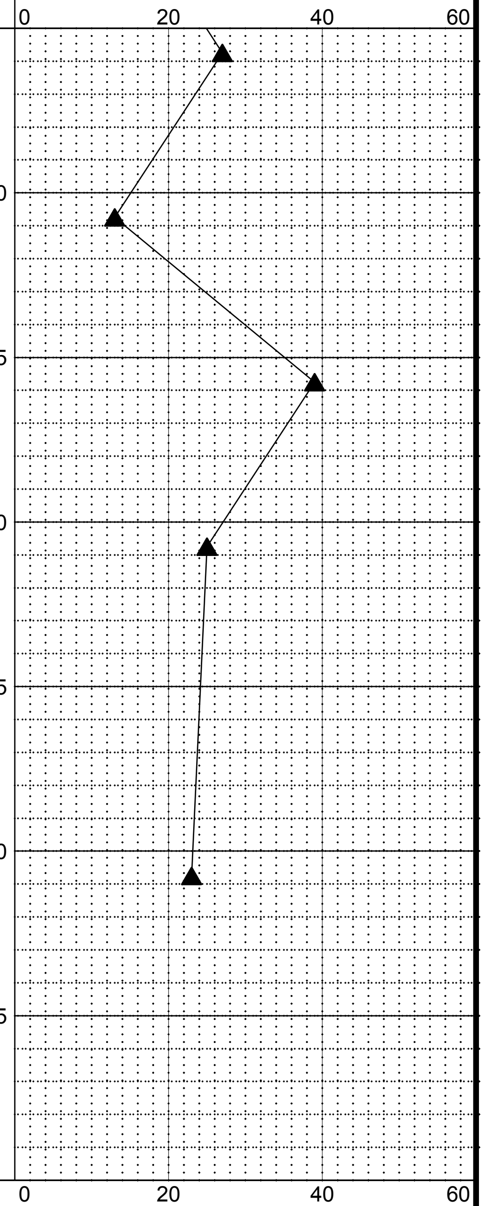
Samples: 12, 13, 14, 15, 16

61.5

BOTTOM OF BORING
BORING COMPLETED 5/18/2017

PENETRATION RESISTANCE (blows/foot)

▲ Hammer Wt. & Drop: 300 lbs / 30 inches



◇ % Fines (<0.075mm)
● % Water Content

LEGEND

* Sample Not Recovered
G Grab Sample
3" O.D. Split Spoon Sample
Ground Water Level ATD

NOTES

1. Refer to KEY for explanation of symbols, codes, abbreviations and definitions.
2. Groundwater level, if indicated above, is for the date specified and may vary.
3. USCS designation is based on visual-manual classification and selected lab testing.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

LOG OF BORING 17-05

June 2017 31-1-20006-001R1

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FIG. A-6
Sheet 2 of 2

REV 3 - Approved for Submittal

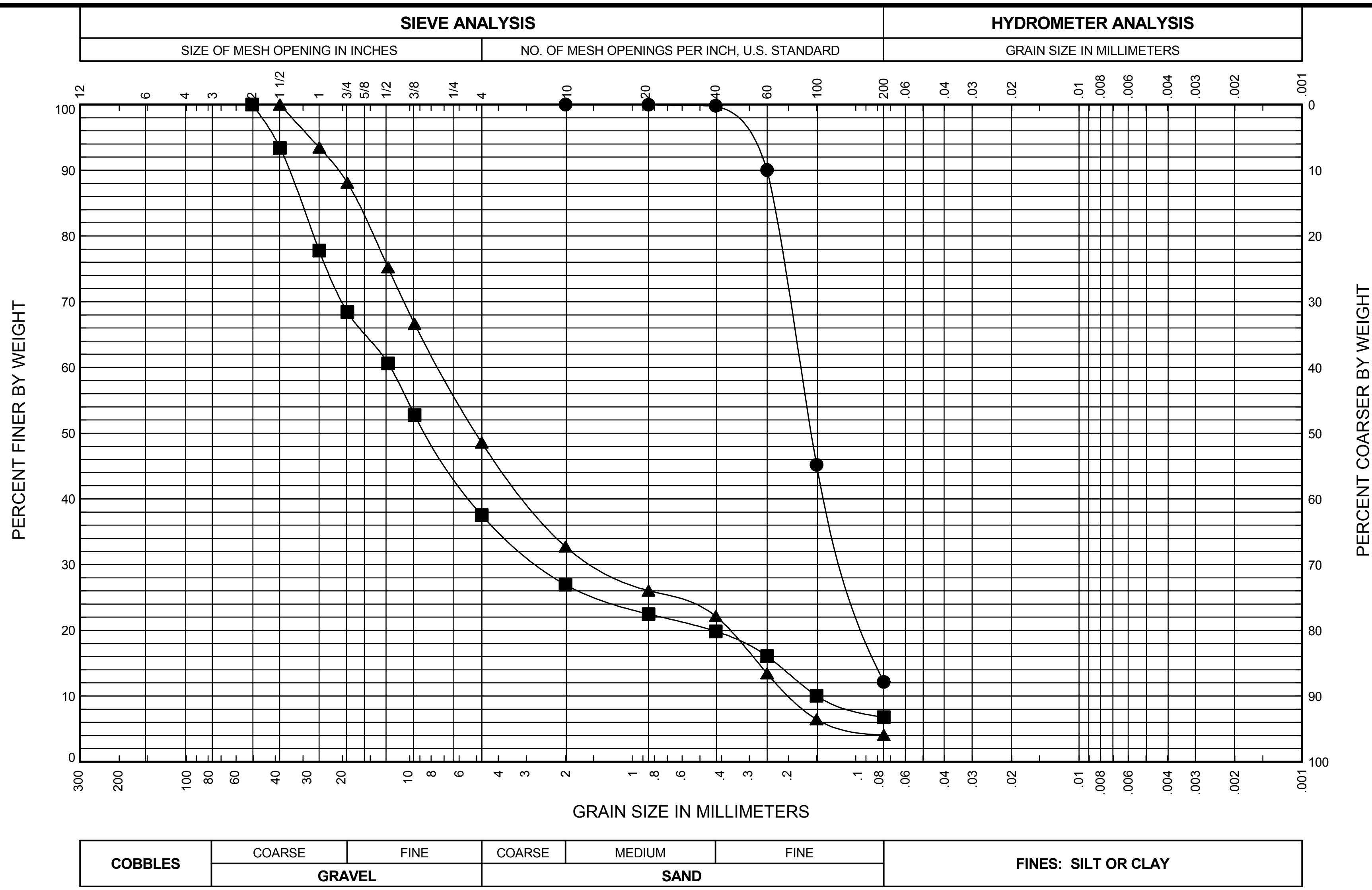
APPENDIX B

GRAIN SIZE DISTRIBUTIONS

APPENDIX B

GRAIN SIZE DISTRIBUTIONS

FIGURES



BORING AND SAMPLE NO.	DEPTH (feet)	U.S.C.S. SYMBOL	SOIL CLASSIFICATION	COBBLE %	GRAVEL %	SAND %	FINES %	NAT. W.C. %	TEST BY	REVIEW BY	ASTM STD
● 17-01, 4b	8.2	SM	Silty Sand			88	12.2	9.5	SLD	AMV	C136
■ 17-01, S-5*	10.0	GP-GM	Poorly Graded Gravel with Silt and Sand		62	31	6.8	4.8	ALW	AMV	C136
▲ 17-01, S-7*	15.0	GW	Well-Graded Gravel with Sand		51	44	4.1		ALW	AMV	C136

* Sample specimen weight did not meet required minimum mass for ASTM test method.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

GRAIN SIZE DISTRIBUTION BORING 17-01

June 2017 31-1-20006-001R1

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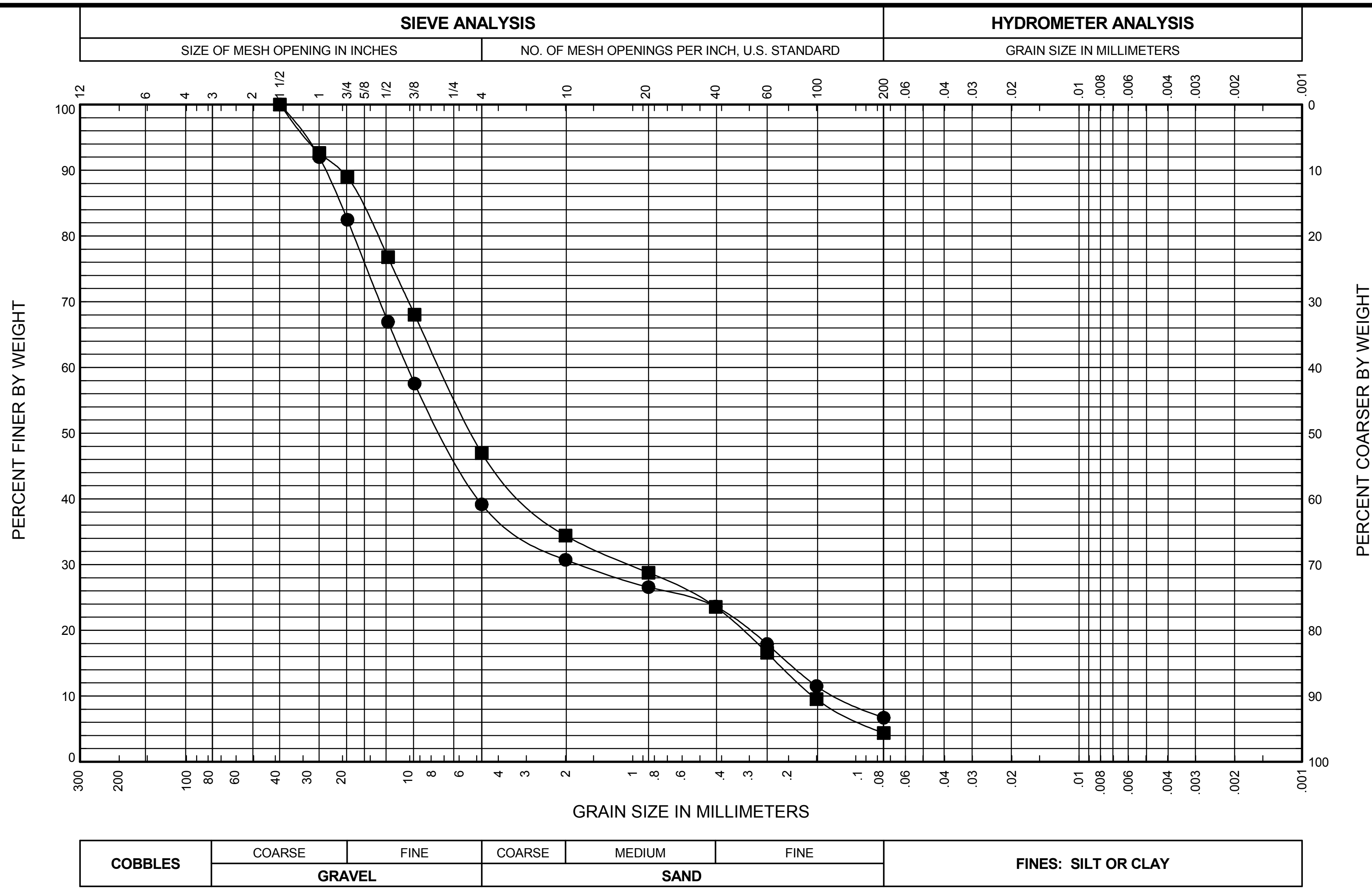
FIG. B-1
Sheet 1 of 1

AASHTO GSA MAIN 31-1-20006-001.GPJ SHAN WIL.GDT 6/1/17

FIG. B-1

PDC Engineers, Inc.

AASHTO GSA MAIN 31-1-20006-001.GPJ SHAN WIL.GDT 6/1/17



BORING AND SAMPLE NO.	DEPTH (feet)	U.S.C.S. SYMBOL	SOIL CLASSIFICATION	COBBLE %	GRAVEL %	SAND %	FINES %	NAT. W.C. %	TEST BY	REVIEW BY	ASTM STD
● 17-02, S-2*	2.5	GW-GM	Well-Graded Gravel with Silt and Sand		61	32	6.7	6.9	EJB	AMV	C136
■ 17-02, S-5*	10.0	GP	Poorly Graded Gravel with Sand		53	43	4.4		EJB	AMV	C136

Geotechnical Findings Report
GVEA Fuel Storage Facility
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GRAIN SIZE DISTRIBUTION
BORING 17-02

June 2017 31-1-20006-001R1

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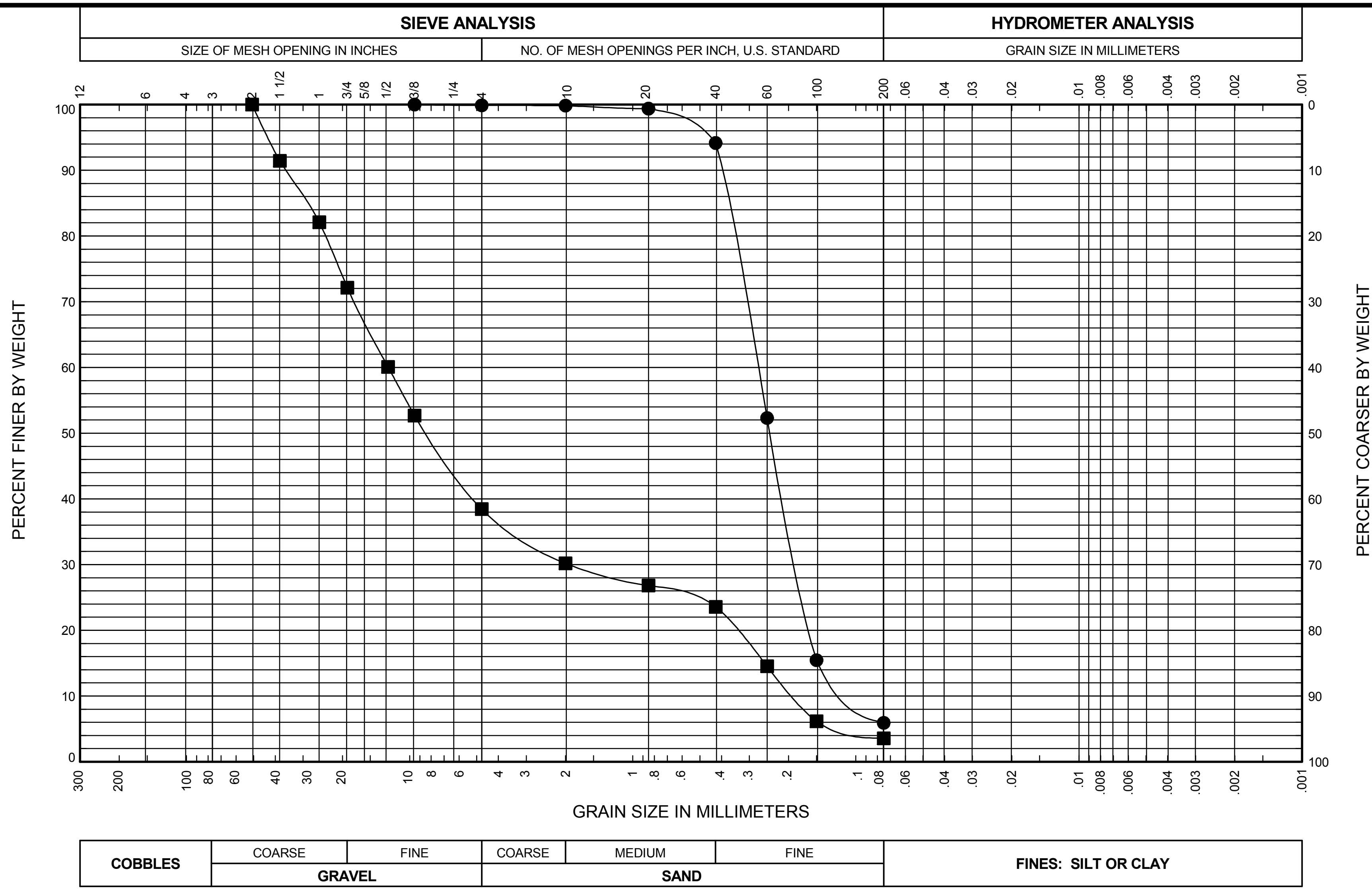
FIG. B-2
Sheet 1 of 1

FIG. B-2

** Sample specimen weight did not meet required minimum mass for ASTM test method.*

PDC Engineers, Inc.



AASHTO GSA MAIN 31-1-20006-001.GPJ SHAN WIL.GDT 6/1/17

BORING AND SAMPLE NO.	DEPTH (feet)	U.S.C.S. SYMBOL	SOIL CLASSIFICATION	COBBLE %	GRAVEL %	SAND %	FINES %	NAT. W.C. %	TEST BY	REVIEW BY	ASTM STD
● 17-03, S-3	5.0	SP-SM	Poorly Graded Sand with Silt		0	94	5.9	10.7	ALW	AMV	C136
■ 17-03, S-7*	15.0	GW	Well-Graded Gravel with Sand		62	35	3.6		ALW	AMV	C136

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

GRAIN SIZE DISTRIBUTION
BORING 17-03

June 2017 31-1-20006-001R1

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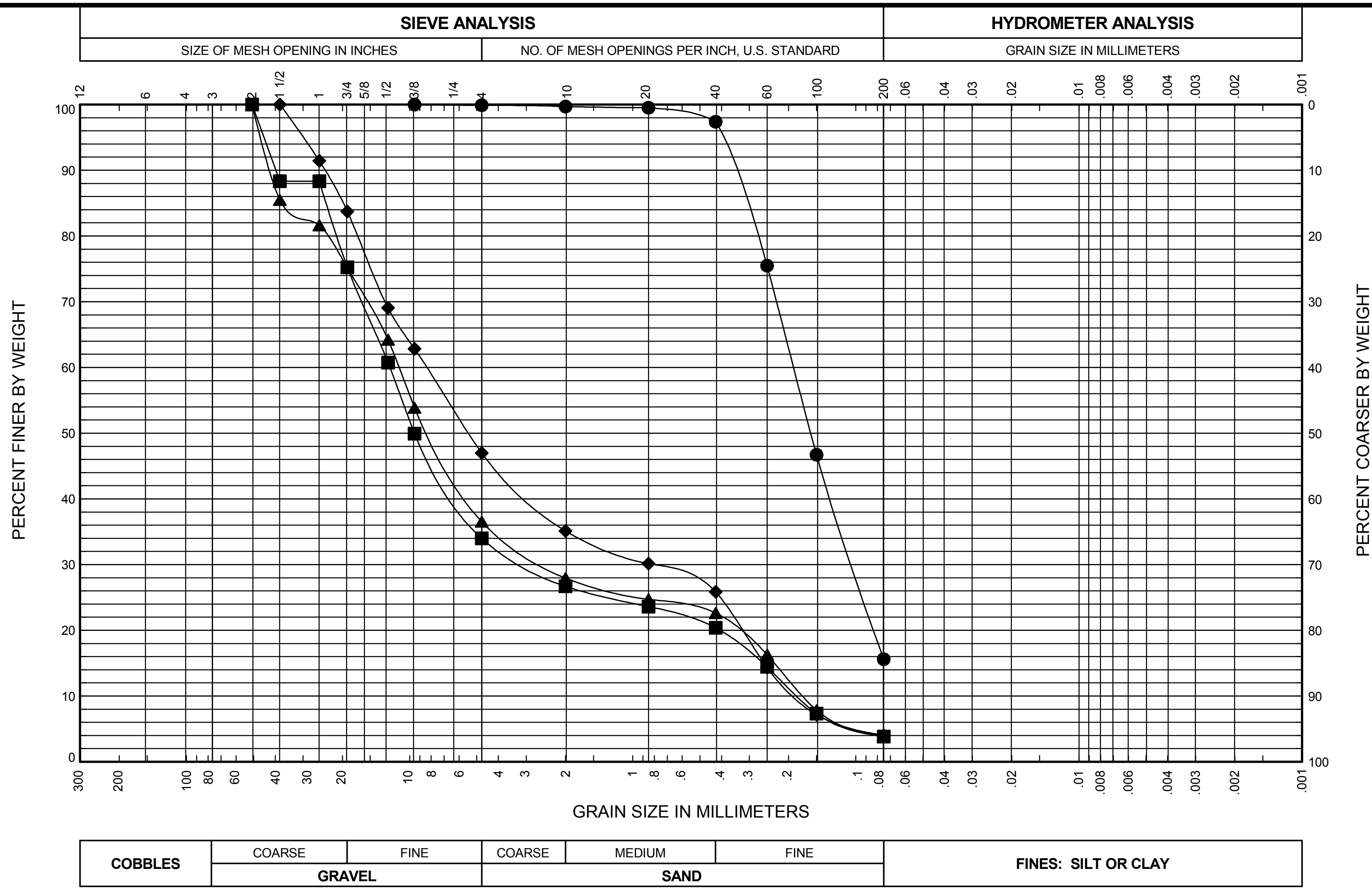
FIG. B-3
Sheet 1 of 1

FIG. B-3

** Sample specimen weight did not meet required minimum mass for ASTM test method.*



BORING AND SAMPLE NO.	DEPTH (feet)	U.S.C.S. SYMBOL	SOIL CLASSIFICATION	COBBLE %	GRAVEL %	SAND %	FINES %	NAT. W.C. %	TEST BY	REVIEW BY	ASTM STD
● 17-04, 3a*	5.0	SM	Silty Sand		0	84	15.6	13.7	EJB	AMV	C136
■ 17-04, 3b*	5.8	GP	Poorly Graded Gravel with Sand		66	30	3.8	2.7	EJB	AMV	C136
▲ 17-04, S-4*	7.5	GP	Poorly Graded Gravel with Sand		63	33	4.0		EJB	AMV	C136
◆ 17-04, S-5*	10.0	GP	Poorly Graded Gravel with Sand		53	43	4.0		EJB	AMV	C136

* Sample specimen weight did not meet required minimum mass for ASTM test method.

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

GRAIN SIZE DISTRIBUTION
BORING 17-04

June 2017 31-1-20006-001R1

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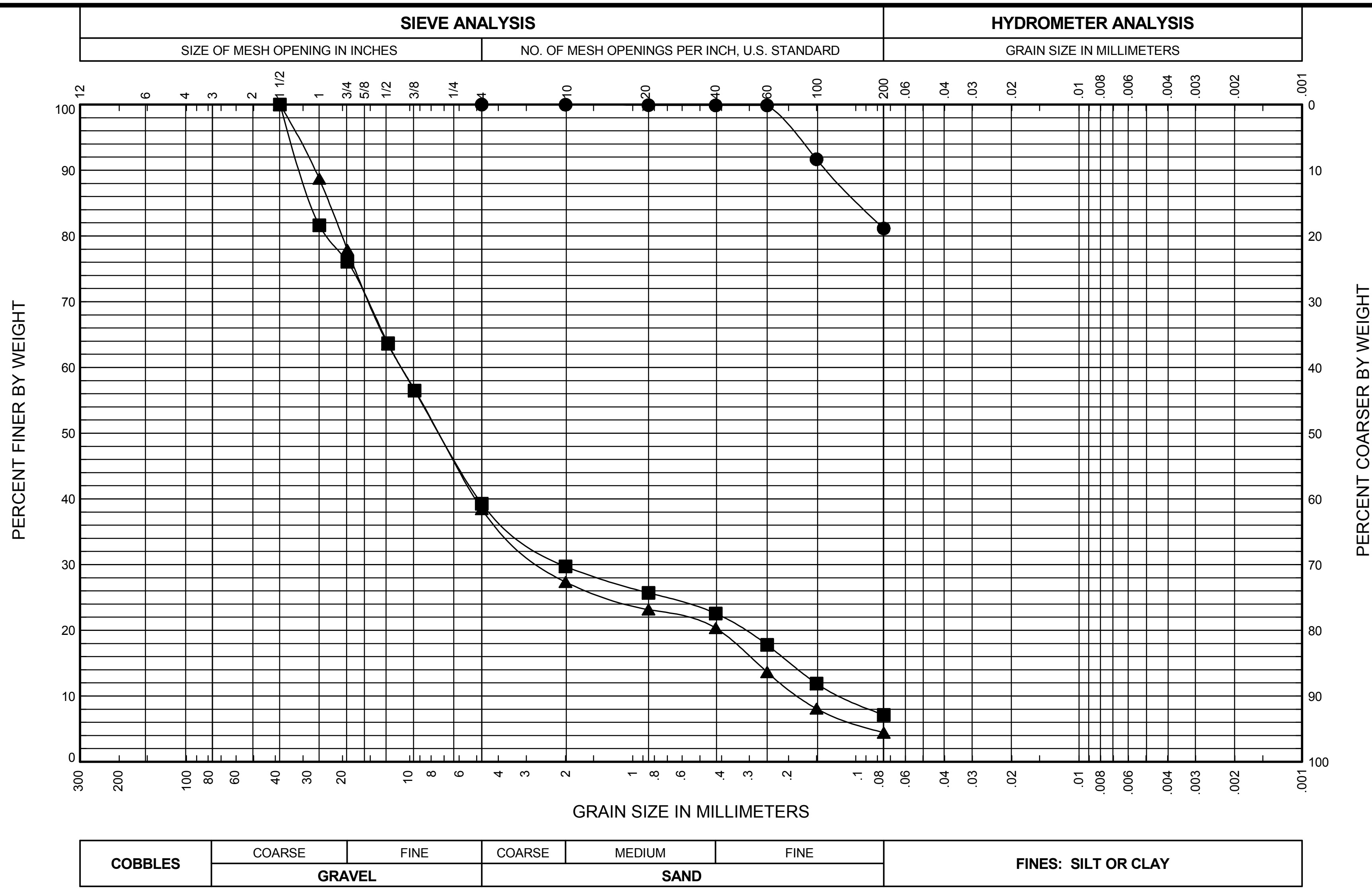
FIG. B-4
Sheet 1 of 1

FIG. B-4

PDC Engineers, Inc.



BORING AND SAMPLE NO.	DEPTH (feet)	U.S.C.S. SYMBOL	SOIL CLASSIFICATION	COBBLE %	GRAVEL %	SAND %	FINES %	NAT. W.C. %	TEST BY	REVIEW BY	ASTM STD
● 17-05, 3b	5.5	ML	Silt with Sand			19	81.1	32.1	EJB	AMV	C136
■ 17-05, S-4*	7.5	GP-GM	Poorly Graded Gravel with Silt and Sand		61	32	7.1	5.3	ALW	AMV	C136
▲ 17-05, S-5*	10.0	GP	Poorly Graded Gravel with Sand		62	34	4.4		ALW	AMV	C136

Geotechnical Findings Report
GVEA Fuel Storage Facility
North Pole, Alaska

GRAIN SIZE DISTRIBUTION
BORING 17-05

June 2017 31-1-20006-001R1

SHANNON & WILSON, INC.
Geotechnical and Environmental Consultants

FIG. B-5
Sheet 1 of 1

* Sample specimen weight did not meet required minimum mass for ASTM test method.

FIG. B-5

APPENDIX C

PROJECT PHOTOGRAPHS

Photograph 1: Drill rig set up at boring location 17-01.

Photograph 2: Sample S-2, boring 17-01, 2.5 feet bgs to 4.0 feet bgs.

Photograph 3: Sample S-4a and S4-b, boring 17-01, 7.5 feet bgs to 9.0 feet bgs.

Photograph 4: Sample S-8, boring 17-01, 17.5 feet bgs to 19.0 feet bgs.

Photograph 5: Sample S-13, boring 17-01, 40.0 feet bgs to 41.5 feet bgs.

Photograph 6: Sample S-16, boring 17-01, 60 feet bgs to 61.5 feet bgs.

Photograph 7: Drill rig set up at boring 17-02.

Photograph 8: Sample S-2, boring 17-02, 2.5 feet bgs to 4.0 feet bgs.

Photograph 9: Sample 3, boring 17-02, 7.5 feet bgs to 9.0 feet bgs.

Photograph 10: Sample S-8, boring 17-02, 17.5 feet bgs to 19.0 feet bgs.

Photograph 11: Sample S-12, boring 17-02, 35.0 feet bgs to 36.5 feet bgs.

Photograph 12: Sample S-16, boring 17-02, 60.0 feet bgs to 61.5 feet bgs.


Photograph 13: Drill rig set up at boring 17-03.

Photograph 14: Sample S-2, boring 17-03, 2.5 feet bgs to 4.0 feet bgs.

Photograph 15: Sample S-10, boring 17-01, 25.0 feet bgs to 26.5 feet bgs.

Photograph 16: Sample S-13, boring 17-03, 40.0 feet bgs to 41.5 feet bgs.

Photograph 17: Sample S-16, boring 17-03, 60.0 feet bgs to 61.5 feet bgs.


Photograph 18: Drill rig set up at boring 17-04.

Photograph 19: Sample S-1 (grab), boring 17-04, 0.5 feet bgs to 2.0 feet bgs.

Photograph 20: Sample S-3a and S-3b, boring 17-04, 5.0 feet bgs to 6.5 feet bgs.

Photograph 21: Sample S-5, boring 17-04, 10.0 feet bgs to 11.5 feet bgs.

Photograph 22: Sample S-10, boring 17-04, 25.0 feet bgs to 26.5 feet bgs.

Photograph 23: Sample S-15, boring 17-04, 50.0 feet bgs to 51.5 feet bgs.

Photograph 24: Drill rig set up at boring 17-05.

Photograph 25: Sample S-2, boring 17-05, 2.5 feet bgs to 4.0 feet bgs.

Photograph 26: Sample S-4, boring 17-05, 7.5 feet bgs to 9.0 feet bgs.

Photograph 27: Sample S-6, boring 17-05, 12.5 feet bgs to 14.0 feet bgs.

Photograph 28: Sample S-9a and S-9b, boring 17-05, 20.0 feet bgs to 21.5 feet bgs.

Photograph 29: Sample S-13, boring 17-05, 40 feet bgs to 41.5 feet bgs.

Photograph 27: Sample S-16, boring 17-05, 60.0 feet bgs to 61.5 feet bgs.

APPENDIX D

IMPORTANT INFORMATION ABOUT YOUR GEOTECHNICAL / ENVIRONMENTAL REPORT

SHANNON & WILSON, INC.
GEOTECHNICAL AND ENVIRONMENTAL CONSULTANTS

Attachment to and part of Report: 31-1-20006-001R1

Date:	June 2017
To:	PDC Engineers, Inc. Attn: Mr. Keith Hanneman, P.E.
Re:	Geotechnical Findings Report, GVEA Fuel Storage Facility

IMPORTANT INFORMATION ABOUT YOUR GEOTECHNICAL/ENVIRONMENTAL REPORT

CONSULTING SERVICES ARE PERFORMED FOR SPECIFIC PURPOSES AND FOR SPECIFIC CLIENTS.

Consultants prepare reports to meet the specific needs of specific individuals. A report prepared for a civil engineer may not be adequate for a construction contractor or even another civil engineer. Unless indicated otherwise, your consultant prepared your report expressly for you and expressly for the purposes you indicated. No one other than you should apply this report for its intended purpose without first conferring with the consultant. No party should apply this report for any purpose other than that originally contemplated without first conferring with the consultant.

THE CONSULTANT'S REPORT IS BASED ON PROJECT-SPECIFIC FACTORS.

A geotechnical/environmental report is based on a subsurface exploration plan designed to consider a unique set of project-specific factors. Depending on the project, these may include: the general nature of the structure and property involved; its size and configuration; its historical use and practice; the location of the structure on the site and its orientation; other improvements such as access roads, parking lots, and underground utilities; and the additional risk created by scope-of-service limitations imposed by the client. To help avoid costly problems, ask the consultant to evaluate how any factors that change subsequent to the date of the report may affect the recommendations. Unless your consultant indicates otherwise, your report should not be used: (1) when the nature of the proposed project is changed (for example, if an office building will be erected instead of a parking garage, or if a refrigerated warehouse will be built instead of an unrefrigerated one, or chemicals are discovered on or near the site); (2) when the size, elevation, or configuration of the proposed project is altered; (3) when the location or orientation of the proposed project is modified; (4) when there is a change of ownership; or (5) for application to an adjacent site. Consultants cannot accept responsibility for problems that may occur if they are not consulted after factors which were considered in the development of the report have changed.

SUBSURFACE CONDITIONS CAN CHANGE.

Subsurface conditions may be affected as a result of natural processes or human activity. Because a geotechnical/environmental report is based on conditions that existed at the time of subsurface exploration, construction decisions should not be based on a report whose adequacy may have been affected by time. Ask the consultant to advise if additional tests are desirable before construction starts; for example, groundwater conditions commonly vary seasonally.

Construction operations at or adjacent to the site and natural events such as floods, earthquakes, or groundwater fluctuations may also affect subsurface conditions and, thus, the continuing adequacy of a geotechnical/environmental report. The consultant should be kept apprised of any such events, and should be consulted to determine if additional tests are necessary.

MOST RECOMMENDATIONS ARE PROFESSIONAL JUDGMENTS.

Site exploration and testing identifies actual surface and subsurface conditions only at those points where samples are taken. The data were extrapolated by your consultant, who then applied judgment to render an opinion about overall subsurface conditions. The actual interface between materials may be far more gradual or abrupt than your report indicates. Actual conditions in areas not sampled may differ from those predicted in your report. While nothing can be done to prevent such situations, you and your consultant can work together to help reduce their impacts. Retaining your consultant to observe subsurface construction operations can be particularly beneficial in this respect.

A REPORT'S CONCLUSIONS ARE PRELIMINARY.

The conclusions contained in your consultant's report are preliminary because they must be based on the assumption that conditions revealed through selective exploratory sampling are indicative of actual conditions throughout a site. Actual subsurface conditions can be discerned only during earthwork; therefore, you should retain your consultant to observe actual conditions and to provide conclusions. Only the consultant who prepared the report is fully familiar with the background information needed to determine whether or not the report's recommendations based on those conclusions are valid and whether or not the contractor is abiding by applicable recommendations. The consultant who developed your report cannot assume responsibility or liability for the adequacy of the report's recommendations if another party is retained to observe construction.

THE CONSULTANT'S REPORT IS SUBJECT TO MISINTERPRETATION.

Costly problems can occur when other design professionals develop their plans based on misinterpretation of a geotechnical/environmental report. To help avoid these problems, the consultant should be retained to work with other project design professionals to explain relevant geotechnical, geological, hydrogeological, and environmental findings, and to review the adequacy of their plans and specifications relative to these issues.

BORING LOGS AND/OR MONITORING WELL DATA SHOULD NOT BE SEPARATED FROM THE REPORT.

Final boring logs developed by the consultant are based upon interpretation of field logs (assembled by site personnel), field test results, and laboratory and/or office evaluation of field samples and data. Only final boring logs and data are customarily included in geotechnical/environmental reports. These final logs should not, under any circumstances, be redrawn for inclusion in architectural or other design drawings, because drafters may commit errors or omissions in the transfer process.

To reduce the likelihood of boring log or monitoring well misinterpretation, contractors should be given ready access to the complete geotechnical engineering/environmental report prepared or authorized for their use. If access is provided only to the report prepared for you, you should advise contractors of the report's limitations, assuming that a contractor was not one of the specific persons for whom the report was prepared, and that developing construction cost estimates was not one of the specific purposes for which it was prepared. While a contractor may gain important knowledge from a report prepared for another party, the contractor should discuss the report with your consultant and perform the additional or alternative work believed necessary to obtain the data specifically appropriate for construction cost estimating purposes. Some clients hold the mistaken impression that simply disclaiming responsibility for the accuracy of subsurface information always insulates them from attendant liability. Providing the best available information to contractors helps prevent costly construction problems and the adversarial attitudes that aggravate them to a disproportionate scale.

READ RESPONSIBILITY CLAUSES CLOSELY.

Because geotechnical/environmental engineering is based extensively on judgment and opinion, it is far less exact than other design disciplines. This situation has resulted in wholly unwarranted claims being lodged against consultants. To help prevent this problem, consultants have developed a number of clauses for use in their contracts, reports, and other documents. These responsibility clauses are not exculpatory clauses designed to transfer the consultant's liabilities to other parties; rather, they are definitive clauses that identify where the consultant's responsibilities begin and end. Their use helps all parties involved recognize their individual responsibilities and take appropriate action. Some of these definitive clauses are likely to appear in your report, and you are encouraged to read them closely. Your consultant will be pleased to give full and frank answers to your questions.

The preceding paragraphs are based on information provided by the
ASFE/Association of Engineering Firms Practicing in the Geosciences, Silver Spring, Maryland

Memo to PDC

Reference: GVEA LNG Siting Study

The following are the pertinent issues associated with siting the LNG facilities to service both GVEA and IGU.

1. I is very difficult to provide much detail for an LNG plant layout without the actual design basis for the facility.
2. I know that there is a preference for single containment storage, because the initial cost is less than full containment. However, Full containment offers many advantages, especially in the planning stages. Therefore, we have performed an initial screening for thermal exclusion for an unconfined LNG storage tank failure, which, in our opinion is what is necessary for preliminary siting.
3. We have offered a site plan for single containment, with a high dike that meets the NFPA X-Y rule.
4. However, the actual layout and configuration of the plant LNG transfer facilities, and their design spill determinations, will be required to determine the thermal exclusion and vapor dispersion requirements.
5. Generally we like to locate design spill containment structure as close to the center of the center of the site as possible to provide the most flexibility for thermal exclusion and vapor dispersion.
6. All LNG transfer activities must be identified and the design LNG spills determined in accordance with the published PHMSA FAQ's
    a. Proposed Trucks per day and method of transfer. Unloading only, or filling and unloading?
    b. Proposed rail cars, of what size, per day and method of transfer. Unloading only, or filling and unloading?
    c. Proposed production rates for each customer of the facility.
    d. Is container filling or unloading foreseen?
7. Any kind of crossing of the existing pipeline ROW should be avoided for a variety of reasons, but mainly cost and schedule.
8. Snow management must be determined in any site plan, as well the allowance for the accumulation of ice and snow in the spill impoundment systems.
9. The configuration of any rail facilities should include a single track, and make it as long as necessary, with one security controlled gate. Most of the facilities I am accustomed to in secure facilities have the tack running in a circle, with a minimum of switches. The prime mover for the cars should never pass the transfer area, or the area must be purged a non-classified electrical area before each transit. (At least I think this is the current DOT thinking)
10. The general technical terms of the potential ownership transaction should be included in the basis of design, flow rates, pressures, and temperature. We are concerned with the complexities of contracting between public utility companies, as they may affect the configuration of the facilities.

ALTERNATIVE 1 COST SUMMARY

BASE BID			
CIVIL WORK (PROVIDED BY GNE)		$	1,309,250
TANK CONSTRUCTION (PROVIDED BY GNE)		$	3,943,000
STRUCTURAL WORK (PROVIDED BY GNE)		$	160,000
MECHANICAL/PIPING WORK (PROVIDED BY GNE)		$	1,120,500
ELECTRICAL WORK (PROVIDED BY GNE)		$	457,000
SITE WORK		$	110,370
SITE MECHANICAL		$	408,153
SITE COMMUNICATIONS		$	50,436
30'0''X40'0" PUMPHOUSE		$	790,141
30'0''X40'0" CONTROL BUILDING		$	603,915
CONSTRUCTION SUBTOTAL		$	8,952,765
DESIGN FEE AND CA	11%	$	984,804.15
PERMITTING/PLAN REVIEWS		$	20,000
SUBTOTAL		$	9,957,569
CONTINGENCY	50%	$	4,978,784.58
SUBTOTAL		$	14,936,354
ALTERNATES			
1	ACCESS ROAD - H&H TO GVEA YARD	$	356,912
2	TRUCK LOADING FACILITY (PROVIDED BY GNE)	$	1,266,406
3	TRACK MOBILE AND SHELTER	$	877,500
4	GVEA RAIL RACK, PIPING, TRACK AND SWITCHING	$	2,201,750
5	PETRO STAR RAIL RACK, PIPING, TRACK AND SWITCHING	$	1,361,750
6	IGU RAIL SPUR TRACK AND SWITCHING	$	1,087,500
DESIGN FEE AND CA	11%	$	786,699.94
CONTINGENCY	50%	$	3,969,258.77
CONSTRUCTION SUBTOTAL		$	11,907,776
CONSTRUCTION TOTAL INCLUDING ALTERNATES		$	26,844,130

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #1

6/26/2017
GNE #17013
Revision C

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
1		**Civil Work**				
	1.01	Excavation for Tank Farm: tank foundations, containment dike	CY	16,500	$6.00	$99,000.00
	1.02	Install geomembrane liner under containment area and within tank ringwalls	SF	106,000	$2.25	$238,500.00
	1.03	Liner Bedding, NFS Backfill, Berm and Compaction	CY	19,750	$28.00	$553,000.00
	1.04	Install Subsurface Drainage System. Catch Basins & OWS	LS	1	$75,000.00	$75,000.00
	1.05	Trenching, Bedding, Compaction for POL Pipeline Installation	LF	2,750	$125.00	$343,750.00
		Task 1 Subtotal				**$1,309,250.00**
2		**Tank 1010 and 1020 Construction (1.5MM Gal ea)**				
	2.01	Tank Foundation Ringwalls - 85' Dia x 5' Deep	EA	2	$122,500.00	$245,000.00
	2.02	Tank CP Anode Grid under tanks	EA	2	$61,500.00	$123,000.00
	2.03	Tank Fabricate, Erection 85' Dia. X 40', Fixed Cone Roof	EA	1	$1,575,000.00	$1,575,000.00
	2.04	Tank Fabricate, Erection 85' Dia. X 40' , Internal Floating Roof	EA	1	$1,650,000.00	$1,650,000.00
	2.05	Field Coatings, Hydro, Appurtenances	EA	2	$175,000.00	$350,000.00
		Task 2 Subtotal				**$3,943,000.00**
3		**Structural Work**				
	3.01	Platform/Handrails/Stairs/Pipe Supports/Catwalks within Diked area	LS	1	$95,000.00	$95,000.00
	3.02	Pipe Supports along external pipe routes	LS	1	$65,000.00	$65,000.00
		Task 3 Subtotal				**$160,000.00**
4		**Mechanical / Piping Work**				
	4.01	10" Cargo piping from Pumphouse to Tanks - A/G	LF	550	$95.00	$52,250.00
	4.02	8" Service piping from Pumphouse to Tanks - A/G	LF	550	$85.00	$46,750.00
	4.03	10" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	1,000	$95.00	$95,000.00
	4.04	6" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	2,000	$76.00	$152,000.00
	4.05	10" Cargo piping from Rail Car Offload to Pump House - B/G	LF	1,650	$95.00	$156,750.00
2	4.06	10" Service piping from Pump House to Rail Car Loading- B/G (Petrostar)	LF	1,650	$95.00	$156,750.00
	4.07	4" Service piping from Pump House to GVEA Transfer Bldg - B/G	LF	1,800	$55.00	$99,000.00
	4.08	4" Service piping from Pump House to Peaker Plant - B/G	LF	1,150	$55.00	$63,250.00
	4.09	3" Service to Fuel Forwarding Bldg - A/G	LF	950	$50.00	$47,500.00
	4.10	10" Cargo pipelines from Petrostar to Pump House - A/G	LF	750	$95.00	$71,250.00
	4.11	600 gpm Pumps for Cargo/Service, Valves and Appurtenances	EA	5	$22,500.00	$112,500.00
	4.12	Filter Vessels, Coalescing Elements, Meters, Flow Control Devices	LS	1	$225,000.00	$225,000.00
	4.13	AFFF Piping from Pump to Foam Chambers and 4" Perimeter Line	LF	1,650	$40.00	$66,000.00
	4.14	AFFF Pump, Control Panel, RBFP, Concentrate Tank, Etc	LS	1	$85,000.00	$85,000.00
	4.15	Foam Chambers	EA	2	$2,500.00	$5,000.00
1	4.16	Water Line Extension and Hydrants	LS	1	$0.00	$0.00
1	4.17	Supplemental Water Storage Tank	EA	1	$0.00	$0.00
		Task 4 Subtotal				**$1,434,000.00**
5		**Rail Car Offloading/Loading Rack**				
1	5.01	Civil Excavation, NFS Fill, Compaction, Rail Extension	LS	1	$0.00	$0.00
	5.02	Six Position Spill Containement, Bottom Unloading Arms, Metering, Valves	LS	1	$225,000.00	$225,000.00
2	5.03	Six Position Rail Car Rack for Loading, Loading Arms, Platforms (Petrostar)	LS	1	$275,000.00	$275,000.00
		Task 5 Subtotal				**$500,000.00**
6		**Truck Loading Rack (TLR)**				
	6.01	Loading Arm, Rest, Connection, 2 Arms	LS	1	$85,000.00	$85,000.00
	6.02	Terminal Management System	LS	1	$105,000.00	$105,000.00
	6.03	Piping, Valves, meter, strainer	LS	1	$84,500.00	$84,500.00
	6.04	Foundation and Heated Lane Containment Slab	LS	1	$65,000.00	$65,000.00
	6.05	Structural Pipe Supports	LS	1	$20,000.00	$20,000.00
1	6.06	Vapor combustion system foundation and equipment	LS	1	$0.00	$0.00
1	6.07	Vapor recovery piping	LS	1	$0.00	$0.00
1	6.08	Fire water and Foam System	LS	1	$0.00	$0.00
1	6.09	Additive System	LS	1	$0.00	$0.00

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #1

6/26/2017

GNE #17013

Revision C

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
	6.1	Scully System	LS	1	$75,000.00	$75,000.00
	6.11	Truck Offload Hose, 6" Piping, Valves, Strainer, Connection, etc.	LS	1	$35,000.00	$35,000.00
		Task 6 Subtotal				**$469,500.00**
7		**Electrical Work**				
	7.01	Power within Tank Farm for CP, MOV's, Lighting, Earth Electrode System	LS	1	$215,000.00	$215,000.00
	7.02	EFSO and Fire Alarm System within Tank Farm	LS	1	$32,000.00	$32,000.00
	7.03	Heat Trace for drainage piping	LS	1	$35,000.00	$35,000.00
	7.04	Tank instruments and conduit routing	LS	1	$75,000.00	$75,000.00
	7.05	New indication panel and computer equipment in control room, TMS	LS	1	$60,000.00	$60,000.00
	7.06	Integration of signals to Ovation System, Programming, Commissioning	LS	1	$40,000.00	$40,000.00
		Task 7 Subtotal				**$457,000.00**
			Construction Cost Subtotal Tasks 1-7			**$8,272,750.00**
			Subtotal Minus Alternate Scope Cost			**$7,841,000.00**
			Permitting/Plan Review Fees			**$15,000.00**
			Contingency (10%)			**$784,100.00**
			GRAND TOTAL			**$8,640,100.00**

Assumptions/ Notes:

1. Not currently in Fuel System Scope, listed for reference only.
2. Alternate scope of work to accommodate Petrostar.

ALTERNATIVE 2 COST SUMMARY

BASE BID			
CIVIL WORK (PROVIDED BY GNE)		$	1,340,500
TANK CONSTRUCTION (PROVIDED BY GNE)		$	3,943,000
STRUCTURAL WORK (PROVIDED BY GNE)		$	160,000
MECHANICAL/PIPING WORK (PROVIDED BY GNE)		$	1,129,675
ELECTRICAL WORK (PROVIDED BY GNE)		$	457,000
SITE WORK		$	110,370
SITE MECHANICAL		$	352,749
SITE COMMUNICATIONS		$	51,662
30'0''X40'0" PUMPHOUSE		$	787,021
30'0''X40'0" CONTROL BUILDING		$	603,915
CONSTRUCTION SUBTOTAL		$	8,935,892
DESIGN FEE AND CA	11%	$	982,948.12
PERMITTING/PLAN REVIEWS		$	20,000
SUBTOTAL		$	9,938,840
CONTINGENCY	50%	$	4,969,420.06
SUBTOTAL		$	14,908,260
ALTERNATES			
1	ACCESS ROAD - H&H TO GVEA YARD	$	348,852
2	TRUCK LOADING FACILITY (PROVIDED BY GNE)	$	1,216,365
3	TRACK MOBILE AND SHELTER	$	877,500
4	GVEA RAIL RACK, PIPING, TRACK AND SWITCHING	$	2,137,625
5	PETRO STAR RAIL RACK, PIPING, TRACK AND SWITCHING	$	1,297,625
6	IGU RAIL SPUR TRACK AND SWITCHING	$	1,087,500
DESIGN FEE AND CA	11%	$	766,201.34
CONTINGENCY	50%	$	3,865,834.02
CONSTRUCTION SUBTOTAL		$	11,597,502
CONSTRUCTION TOTAL INCLUDING ALTERNATES		$	26,505,762

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #2

GREAT NORTHERN ENGINEERING

6/26/2017

GNE #17013

Revision C

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
1		**Civil Work**				
	1.01	Excavation for Tank Farm: tank foundations, containment dike	CY	16,500	$6.00	$99,000.00
	1.02	Install geomembrane liner under containment area and within tank ringwalls	SF	106,000	$2.25	$238,500.00
	1.03	Liner Bedding, NFS Backfill, Berm and Compaction	CY	19,750	$28.00	$553,000.00
	1.04	Install Subsurface Drainage System. Catch Basins & OWS	LS	1	$75,000.00	$75,000.00
	1.05	Trenching, Bedding, Compaction for POL Pipeline Installation	LF	3,000	$125.00	$375,000.00
		Task 1 Subtotal				**$1,340,500.00**
2		**Tank 1010 and 1020 Construction (1.5MM Gal ea)**				
	2.01	Tank Foundation Ringwalls - 85' Dia x 5' Deep	EA	2	$122,500.00	$245,000.00
	2.02	Tank CP Anode Grid under tanks	EA	2	$61,500.00	$123,000.00
	2.03	Tank Fabricate, Erection 85' Dia. X 40', Fixed Cone Roof	EA	1	$1,575,000.00	$1,575,000.00
	2.04	Tank Fabricate, Erection 85' Dia. X 40' , Internal Floating Roof	EA	1	$1,650,000.00	$1,650,000.00
	2.05	Field Coatings, Hydro, Appurtenances	EA	2	$175,000.00	$350,000.00
		Task 2 Subtotal				**$3,943,000.00**
3		**Structural Work**				
	3.01	Platform/Handrails/Stairs/Pipe Supports/Catwalks within Diked area	LS	1	$95,000.00	$95,000.00
	3.02	Pipe Supports along external pipe routes	LS	1	$65,000.00	$65,000.00
		Task 3 Subtotal				**$160,000.00**
4		**Mechanical / Piping Work**				
	4.01	10" Cargo piping from Pumphouse to Tanks - A/G	LF	675	$95.00	$64,125.00
	4.02	8" Service piping from Pumphouse to Tanks - A/G	LF	675	$85.00	$57,375.00
	4.03	10" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	150	$95.00	$14,250.00
	4.04	6" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	300	$76.00	$22,800.00
	4.05	10" Cargo piping from Rail Car Offload to Pump House - B/G	LF	975	$95.00	$92,625.00
2	4.06	10" Service piping from Pump House to Rail Car Loading- B/G (Petrostar)	LF	975	$95.00	$92,625.00
	4.07	4" Service piping from Pump House to GVEA Transfer Bldg - B/G	LF	2,550	$55.00	$140,250.00
	4.08	4" Service piping from Pump House to Peaker Plant - B/G	LF	975	$55.00	$53,625.00
	4.09	3" Service to Fuel Forwarding Bldg - A/G	LF	1,700	$50.00	$85,000.00
	4.10	10" Cargo pipelines from Petrostar to Pump House - A/G	LF	2,050	$95.00	$194,750.00
	4.11	600 gpm Pumps for Cargo/Service, Valves and Appurtenances	EA	5	$22,500.00	$112,500.00
	4.12	Filter Vessels, Coalescing Elements, Meters, Flow Control Devices	LS	1	$225,000.00	$225,000.00
	4.13	AFFF Piping from Pump to Foam Chambers and 4" Perimeter Line	LF	1,750	$40.00	$70,000.00
	4.14	AFFF Pump, Control Panel, RBFP, Concentrate Tank, Etc	LS	1	$85,000.00	$85,000.00
	4.15	Foam Chambers	EA	2	$2,500.00	$5,000.00
1	4.16	Water Line Extension and Hydrants	LS	1	$0.00	$0.00
1	4.17	Supplemental Water Storage Tank	EA	1	$0.00	$0.00
		Task 4 Subtotal				**$1,314,925.00**
5		**Rail Car Offloading/Loading Rack**				
1	5.01	Civil Excavation, NFS Fill, Compaction, Rail Extension	LS	1	$0.00	$0.00
	5.02	Six Position Spill Containement, Bottom Unloading Arms, Metering, Valves	LS	1	$225,000.00	$225,000.00
2	5.03	Six Position Rail Car Rack for Loading, Loading Arms, Platforms (Petrostar)	LS	1	$275,000.00	$275,000.00
		Task 5 Subtotal				**$500,000.00**
6		**Truck Loading Rack (TLR)**				
	6.01	Loading Arm, Rest, Connection, 2 Arms	LS	1	$85,000.00	$85,000.00
	6.02	Terminal Management System	LS	1	$105,000.00	$105,000.00
	6.03	Piping, Valves, meter, strainer	LS	1	$84,500.00	$84,500.00
	6.04	Foundation and Heated Lane Containment Slab	LS	1	$65,000.00	$65,000.00
	6.05	Structural Pipe Supports	LS	1	$20,000.00	$20,000.00
1	6.06	Vapor combustion system foundation and equipment	LS	1	$0.00	$0.00
1	6.07	Vapor recovery piping	LS	1	$0.00	$0.00
1	6.08	Fire water and Foam System	LS	1	$0.00	$0.00
1	6.09	Additive System	LS	1	$0.00	$0.00

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #2

6/26/2017
GNE #17013
Revision C

GREAT NORTHERN ENGINEERING

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
	6.1	Scully System	LS	1	$75,000.00	$75,000.00
	6.11	Truck Offload Hose, 6" Piping, Valves, Strainer, Connection, etc.	LS	1	$35,000.00	$35,000.00
		Task 6 Subtotal				**$469,500.00**
7		**Electrical Work**				
	7.01	Power within Tank Farm for CP, MOV's, Lighting, Earth Electrode System	LS	1	$215,000.00	$215,000.00
	7.02	EFSO and Fire Alarm System within Tank Farm	LS	1	$32,000.00	$32,000.00
	7.03	Heat Trace for drainage piping	LS	1	$35,000.00	$35,000.00
	7.04	Tank instruments and conduit routing	LS	1	$75,000.00	$75,000.00
	7.05	New indication panel and computer equipment in control room, TMS	LS	1	$60,000.00	$60,000.00
	7.06	Integration of signals to Ovation System, Programming, Commissioning	LS	1	$40,000.00	$40,000.00
		Task 7 Subtotal				**$457,000.00**
			Construction Cost Subtotal Tasks 1-7			**$8,184,925.00**
			Subtotal Minus Alternate Scope Cost			**$7,817,300.00**
			Permitting/Plan Review Fees			**$15,000.00**
			Contingency (10%)			**$781,730.00**
			GRAND TOTAL			**$8,614,030.00**

Assumptions/ Notes:

1. Not currently in Fuel System Scope, listed for reference only.
2. Alternate scope of work to accommodate Petrostar.

ALTERNATIVE 3 COST SUMMARY

BASE BID			
CIVIL WORK (PROVIDED BY GNE)		$	1,340,500
TANK CONSTRUCTION (PROVIDED BY GNE)		$	3,943,000
STRUCTURAL WORK (PROVIDED BY GNE)		$	160,000
MECHANICAL/PIPING WORK (PROVIDED BY GNE)		$	1,457,550
ELECTRICAL WORK (PROVIDED BY GNE)		$	457,000
SITE WORK		$	110,370
SITE MECHANICAL		$	439,507
SITE COMMUNICATIONS		$	50,123
30'0''X40'0" PUMPHOUSE		$	787,021
30'0''X40'0" CONTROL BUILDING		$	603,915
CONSTRUCTION SUBTOTAL		$	9,348,986
DESIGN FEE AND CA	11%	$	1,028,388.46
PERMITTING/PLAN REVIEWS		$	20,000
SUBTOTAL		$	10,397,374
CONTINGENCY	50%	$	5,198,687.23
SUBTOTAL		$	15,596,062
ALTERNATES			
1	ACCESS ROAD - H&H TO GVEA YARD	$	348,852
2	TRUCK LOADING FACILITY (PROVIDED BY GNE)	$	1,356,132
3	TRACK MOBILE AND SHELTER	$	877,500
4	GVEA RAIL RACK, PIPING, TRACK AND SWITCHING	$	2,121,000
5	PETRO STAR RAIL RACK, PIPING, TRACK AND SWITCHING	$	1,281,000
6	IGU RAIL SPUR TRACK AND SWITCHING	$	1,087,500
DESIGN FEE AND CA	11%	$	777,918.20
CONTINGENCY	50%	$	3,924,950.90
CONSTRUCTION SUBTOTAL		$	11,774,853
CONSTRUCTION TOTAL INCLUDING ALTERNATES		$	27,370,914

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #3

6/26/2017

GNE #17013

Revision C

GREAT NORTHERN ENGINEERING

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
1		**Civil Work**				
	1.01	Excavation for Tank Farm: tank foundations, containment dike	CY	16,500	$6.00	$99,000.00
	1.02	Install geomembrane liner under containment area and within tank ringwalls	SF	106,000	$2.25	$238,500.00
	1.03	Liner Bedding, NFS Backfill, Berm and Compaction	CY	19,750	$28.00	$553,000.00
	1.04	Install Subsurface Drainage System. Catch Basins & OWS	LS	1	$75,000.00	$75,000.00
	1.05	Trenching, Bedding, Compaction for POL Pipeline Installation	LF	3,000	$125.00	$375,000.00
		Task 1 Subtotal				**$1,340,500.00**
2		**Tank 1010 and 1020 Construction (1.5MM Gal ea)**				
	2.01	Tank Foundation Ringwalls - 85' Dia x 5' Deep	EA	2	$122,500.00	$245,000.00
	2.02	Tank CP Anode Grid under tanks	EA	2	$61,500.00	$123,000.00
	2.03	Tank Fabricate, Erection 85' Dia. X 40', Fixed Cone Roof	EA	1	$1,575,000.00	$1,575,000.00
	2.04	Tank Fabricate, Erection 85' Dia. X 40' , Internal Floating Roof	EA	1	$1,650,000.00	$1,650,000.00
	2.05	Field Coatings, Hydro, Appurtenances	EA	2	$175,000.00	$350,000.00
		Task 2 Subtotal				**$3,943,000.00**
3		**Structural Work**				
	3.01	Platform/Handrails/Stairs/Pipe Supports/Catwalks within Diked area	LS	1	$95,000.00	$95,000.00
	3.02	Pipe Supports along external pipe routes	LS	1	$65,000.00	$65,000.00
		Task 3 Subtotal				**$160,000.00**
4		**Mechanical / Piping Work**				
	4.01	10" Cargo piping from Pumphouse to Tanks - A/G	LF	1,500	$95.00	$142,500.00
	4.02	8" Service piping from Pumphouse to Tanks - A/G	LF	1,500	$85.00	$127,500.00
	4.03	10" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	150	$95.00	$14,250.00
	4.04	6" Service piping from Pumphouse to Truck Load/Offload - B/G	LF	300	$76.00	$22,800.00
	4.05	10" Cargo piping from Rail Car Offload to Pump House - B/G	LF	800	$95.00	$76,000.00
2	4.06	10" Service piping from Pump House to Rail Car Loading- B/G (Petrostar)	LF	800	$95.00	$76,000.00
	4.07	4" Service piping from Pump House to GVEA Transfer Bldg - B/G	LF	2,750	$55.00	$151,250.00
	4.08	4" Service piping from Pump House to Peaker Plant - B/G	LF	1,150	$55.00	$63,250.00
	4.09	3" Service to Fuel Forwarding Bldg - A/G	LF	1,900	$50.00	$95,000.00
	4.10	10" Cargo pipelines from Petrostar to Pump House - A/G	LF	3,300	$95.00	$313,500.00
	4.11	600 gpm Pumps for Cargo/Service, Valves and Appurtenances	EA	5	$22,500.00	$112,500.00
	4.12	Filter Vessels, Coalescing Elements, Meters, Flow Control Devices	LS	1	$225,000.00	$225,000.00
	4.13	AFFF Piping from Pump to Foam Chambers and 4" Perimeter Line	LF	2,500	$40.00	$100,000.00
	4.14	AFFF Pump, Control Panel, RBFP, Concentrate Tank, Etc	LS	1	$85,000.00	$85,000.00
	4.15	Foam Chambers	EA	2	$2,500.00	$5,000.00
1	4.16	Water Line Extension and Hydrants	LS	1	$0.00	$0.00
1	4.17	Supplemental Water Storage Tank	EA	1	$0.00	$0.00
		Task 4 Subtotal				**$1,609,550.00**
5		**Rail Car Offloading/Loading Rack**				
1	5.01	Civil Excavation, NFS Fill, Compaction, Rail Extension	LS	1	$0.00	$0.00
	5.02	Six Position Spill Containement, Bottom Unloading Arms, Metering, Valves	LS	1	$225,000.00	$225,000.00
2	5.03	Six Position Rail Car Rack for Loading, Loading Arms, Platforms (Petrostar)	LS	1	$275,000.00	$275,000.00
		Task 5 Subtotal				**$500,000.00**
6		**Truck Loading Rack (TLR)**				
	6.01	Loading Arm, Rest, Connection, 2 Arms	LS	1	$85,000.00	$85,000.00
	6.02	Terminal Management System	LS	1	$105,000.00	$105,000.00
	6.03	Piping, Valves, meter, strainer	LS	1	$84,500.00	$84,500.00
	6.04	Foundation and Heated Lane Containment Slab	LS	1	$65,000.00	$65,000.00
	6.05	Structural Pipe Supports	LS	1	$20,000.00	$20,000.00
1	6.06	Vapor combustion system foundation and equipment	LS	1	$0.00	$0.00
1	6.07	Vapor recovery piping	LS	1	$0.00	$0.00
1	6.08	Fire water and Foam System	LS	1	$0.00	$0.00
1	6.09	Additive System	LS	1	$0.00	$0.00

GOLDEN VALLEY ELECTRIC ASSOC. (GVEA)
PETROLEUM TERMINAL FACILITY
3MM GAL TOTAL STORAGE
OPTION #3

6/26/2017
GNE #17013
Revision C

Task	Sub	Task Description	Units	Qty	Unit Cost	Total
	6.1	Scully System	LS	1	$75,000.00	$75,000.00
	6.11	Truck Offload Hose, 6" Piping, Valves, Strainer, Connection, etc.	LS	1	$35,000.00	$35,000.00
		Task 6 Subtotal				**$469,500.00**
7		**Electrical Work**				
	7.01	Power within Tank Farm for CP, MOV's, Lighting, Earth Electrode System	LS	1	$215,000.00	$215,000.00
	7.02	EFSO and Fire Alarm System within Tank Farm	LS	1	$32,000.00	$32,000.00
	7.03	Heat Trace for drainage piping	LS	1	$35,000.00	$35,000.00
	7.04	Tank instruments and conduit routing	LS	1	$75,000.00	$75,000.00
	7.05	New indication panel and computer equipment in control room, TMS	LS	1	$60,000.00	$60,000.00
	7.06	Integration of signals to Ovation System, Programming, Commissioning	LS	1	$40,000.00	$40,000.00
		Task 7 Subtotal				**$457,000.00**
			Construction Cost Subtotal Tasks 1-7			**$8,479,550.00**
			Subtotal Minus Alternate Scope Cost			**$8,128,550.00**
			Permitting/Plan Review Fees			**$15,000.00**
			Contingency (10%)			**$812,855.00**
			GRAND TOTAL			**$8,956,405.00**

Assumptions/ Notes:

1. Not currently in Fuel System Scope, listed for reference only.
2. Alternate scope of work to accommodate Petrostar.

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Attachment 3
Leidos Strategic Fuel Evaluation

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BACT Analysis of Zehnder and North Pole Power Plants: Use of Low Sulfur Fuels

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Leidos Engineering
July 2017

The North Pole Power Plant (NPPP) has two GE Frame 7 combustion turbines (GT1 and GT2) and the Zehnder Power Plant has two GE Frame 5 combustion turbines. In 2016, high sulfur diesel comprised 85% of the fuel burned in the North Pole Plant and 98% of the fuel burned in the Zehnder Plant. However, the turbines at both of these plants are capable of burning 100% ultra low sulfur diesel (ULSD). An analysis of the capital investment required for burning 100% ULSD at both the North Pole Power Plant and the Zehnder Power Plant is described below.

1 Needed ULSD Storage Volume

Two scenarios of ULSD storage volume are considered. In the first scenario, the needed storage volume is based on maximum permitted operation of both the NPPP and the Zehnder Plant. In the second scenario, storage volume is based on historic maximum fuel energy use at these plants.

ULSD is produced in Alaska at two refineries: one is 350 miles away in Valdez; the other is 530 miles away in Kenai. Both of these refineries have, or are in the process of establishing bulk storage at marine terminals in Anchorage, which is 370 miles from away. Both refineries are likely to transport bulk ULSD to North Pole through their Anchorage terminals to allow rail transport, which is not directly available from the refineries themselves. The quantities of ULSD required for NPPP and Zehnder operation are preferentially transported by rail rather than truck due to: difficult winter road conditions; periodic regional shortages of truck drivers; and economies of scale in transport by 30,000 gallon railcars versus tank trucks with a maximum load of around 9,000 gallons.

With no delays, rail transport from Anchorage to North Pole is 3 days one way, and 7 days round trip including fuel loading and off-loading. Shipments are assumed to arrive twice a week, and at any one time, half the railcars will be headed towards or in North Pole and the other half will be headed towards or in Anchorage. This requires an operational storage volume equivalent to 3 ½ days of fuel. The longer transport chain for ULSD from Anchorage compared to high sulfur diesel produced in North Pole poses additional delivery risk which is mitigated with North Pole fuel storage capacity that allows for reasonable delivery delays. The Alaska Railroad has stated that in the event of destruction of one of the higher rail bridges between Anchorage and North Pole (e.g., such as due to an avalanche), bridge replacement may take up to 4 days. Thus, fuel storage capacity should be equivalent to a total of 7 ½ days of fuel (i.e., 3 ½ days for operational fuel plus 4 additional days for reasonable delivery delays).

Under the first scenario, with maximum permitted use of NPPP and Zehnder Power Plant, maximum permitted levels are calculated based on the number of days for round-trip fuel deliveries, the potential over-lap in their days of operation, and maximum daily fuel burn rates. The emissions permit for the Zehnder Power Plant allows operation of both GT1 and GT2 365 days per year. The emission permit for NPPP GT2 allows a maximum of 7,992 hours per year by, equivalent to 333 days per year. Maximum use of the NPPP GT1 is limited based on a shared NOx emissions permit, from which maximum operation is estimated to be 3,794 hours,[1] which is equivalent to 158 days per year. Based on the maximum permitted usage of the NPPP and Zehnder Plants, ULSD storage needs to be adequate for simultaneous operation of both NPPP units and both Zehnder units on a continuous basis for months at a time.

NPPP GT1 and GT2 each burn 672 MMBtu per hour, equivalent to a combined 32,256 MMBtu per day. Zehnder GT1 and GT2 each burn 268 MMBtu per hour, equivalent to a combined 12,864 MMBtu per day. Assuming use of ULSD #1 (winter fuel) with a lower heating value of 124,000 Btu/gallon, the combined maximum daily use of ULSD at both of these plants is 363,871 gallons. Multiplied by 7 ½ days (i.e., 3 ½ days regular delivery plus 4 days delay), this daily use volume corresponds to 2.73 million gallons of new storage capacity.

Under the second scenario, storage volume is based on the maximum 3-day fuel energy use at NPPP and Zehnder over the last decade. A 3-day maximum is used because this duration is approximately equal to the one-way delivery period. The maximum is used (rather than the average) to assure adequate fuel supply during winter cold spells. The 3-day maximum since January 2007 occurred in April 2009, when 62,751 MMBtu were consumed at NPP and Zehnder, equivalent to 506,057 gallons of ULSD #1. The average daily use rate during the 3-day maximum is applied to 7 ½ days storage, yielding 1.27million gallons of new storage capacity.

2 Storage and Transport Component Costs

GVEA owns a site in North Pole that is conducive for construction of shared bulk fuel storage for the NPPP and Zehnder Plant. The complete fuel transport chain from Anchorage is assumed to include rail delivery to bulk storage in North Pole with new rail siding and offloading equipment; new rail tankcars; new bulk storage including pipeline transport of ULSD to NPPP GT1 and GT2; and truck loading and transport of ULSD from North Pole storage to the Zehnder Plant in Fairbanks (approximately 10 miles each way).[2] Estimated costs of these components are shown in the table below.

Table 1. Fuel Storage and Transport Capital Costs under Permitted Maximum Use Scenario and Historic Maximum Use Scenario.

Capital Cost Elements	Permitted Maximum Use	Historic Maximum Use
Rail siding, rail/truck loading/offloading	$4,500,000	$4,500,000
Rail tank cars *(30,000 gallons, $135,000 each)*	$11,475,000	$5,400,000
Storage construction	$14,300,000	$11,000,000
Tanker truck *(1 truck @ 9,000 gallons)*	$150,000	$150,000
TOTAL	**$30,425,000**	**$21,050,000**

[1] The NPPP GT1 annual use estimate is calculated from the NOx emissions permit for 1600 tons per year for combined emissions from NPPP GT1 and the NPEP GT3, the later of which only burns low sulfur fuels. If NPEP GT3 (the more efficient unit) is run 24/7, assuming a burn rate of 455 MMBtu/hr and NOx emission rate of 0.24 lb/MMBtu, 478 tons NOx will be emitted annually from GT3, leaving 1,122 tons that may be emitted from GT1. Assuming a NOx emission rate of 0.88 lb/MMBtu for GE Frame 7 turbines, the GT1 may burn 2,549,327 MMBtu per year, which at a burn rate of 672 MMBtu/hr corresponds to 3,794 hours.

[2] The Zehnder plant already has 100,000 gallons of storage on site, compared to the estimated 103,742 gallons of ULSD that would be burned daily at this site when operating at maximum capacity.

Storage construction cost and rail siding, rail/truck loading/offloading costs shown above are based on a July 2017 estimate developed by PDC Engineers for a 3 million-gallon storage facility in North Pole, AK.[3] The PDC estimate was adjusted with volume-proportionate reductions in tank construction, civil, and structural costs to represent 2.73 and 1.27 million gallons for the "Permitted Maximum Use" and "Historic Maximum Use" scenarios, respectively. Components in the estimate that are not applicable for the scope of NPPP and Zehnder fuel storage, rail offloading, and truck loading were removed. Other components (i.e., electrical, piping, mechanical, etc.) are assumed to not change significantly over this size range. Rail tank car costs are based on a June 2017 quote from Greenbrier, Inc., and does not include the cost of car delivery from the Lower 48 to Alaska. Tanker truck cost is based on online listings for truck sales.

[3] This cost estimate was developed for consideration of storage to supply all GVEA liquid fuel power plants during potential strategic events. No strategic storage investment decision has been made.

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Attachment 4
January 2017 through October 2018 Fuel Prices

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GVEA Fuel Pricing per Gallon

			Average	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-18	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18
North Pole	LSR Naphtha	PSI Base Price		-	$1.329	$1.071	$1.083	$1.022	$1.004	$0.999	$1.055	$1.056	$1.200	$1.418	$1.561	$1.584	$1.540	$1.494	$1.516	$1.682	$1.641	$1.713	$1.716	$1.779	$1.785
		PSI & Federal surcharges *		-	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
		Total $/Gallon	**$1.396**	**-**	**$1.332**	**$1.074**	**$1.086**	**$1.025**	**$1.007**	**$1.002**	**$1.058**	**$1.059**	**$1.203**	**$1.421**	**$1.564**	**$1.587**	**$1.543**	**$1.497**	**$1.519**	**$1.685**	**$1.644**	**$1.716**	**$1.719**	**$1.782**	**$1.788**
	DF2+10	PSI Base Price		-	-	-	-	$1.625	$1.576	$1.621	$1.708	-	-	-	-	-	-	-	-	$2.150	$2.286	$2.395	$2.400	$2.408	-
		PSI & Federal surcharges *		-	-	-	-	$0.003	$0.003	$0.003	$0.003	-	-	-	-	-	-	-	-	$0.003	$0.003	$0.003	$0.003	$0.003	-
		PSI Ops Surcharge		-	-	-	-	$0.05	$0.05	$0.05	$0.05	-	-	-	-	-	-	-	-	$0.05	$0.05	$0.05	$0.05	$0.05	-
		Delivery Charge		-	-	-	-	$0.020	$0.020	$0.020	$0.020	-	-	-	-	-	-	-	-	$0.020	$0.020	$0.020	$0.020	$0.020	-
		Delivery Fuel Surcharge %		-	-	-	-	20.5%	20.5%	20.5%	19.0%	-	-	-	-	-	-	-	-	29.0%	27.0%	27.0%	23.5%	26.0%	-
		Delivery Fuel Surchage (%*Delivery)		-	-	-	-	$0.004	$0.004	$0.004	$0.004	-	-	-	-	-	-	-	-	$0.006	$0.005	$0.005	$0.005	$0.005	-
		Total $/Gallon	**$2.097**	**-**	**-**	**-**	**-**	**$1.702**	**$1.653**	**$1.699**	**$1.785**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**$2.229**	**$2.364**	**$2.474**	**$2.478**	**$2.486**	**-**
	DF2-15	PSI Base Price		$1.750	$1.797	$1.712	$1.732	-	-	-	-	$1.874	$1.911	$2.040	$2.021	$2.174	$2.204	$2.188	$2.175	-	-	-	-	-	$2.499
		PSI & Federal surcharges *		$0.003	$0.003	$0.003	$0.003	-	-	-	-	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	-	-	-	-	-	$0.003
		PSI Ops Surcharge		$0.04	$0.05	$0.05	$0.05	-	-	-	-	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	-	-	-	-	-	$0.05
		Truck Delivery		$0.020	$0.020	$0.020	$0.020	-	-	-	-	$0.020	$0.020	$0.020	$0.020	$0.020	$0.020	$0.020	$0.020	-	-	-	-	-	$0.020
		Delivery Fuel Surcharge %		18.5%	20.5%	20.5%	20.5%	-	-	-	-	23.0%	23.0%	23.0%	23.0%	24.0%	26.0%	26.0%	26.0%	-	-	-	-	-	26.0%
		Delivery Fuel Surchate (%*Delivery)		$0.004	$0.004	$0.004	$0.004	-	-	-	-	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	$0.005	-	-	-	-	-	$0.005
		Total $/Gallon	**$2.083**	**$1.817**	**$1.874**	**$1.789**	**$1.809**	**-**	**-**	**-**	**-**	**$1.951**	**$1.989**	**$2.117**	**$2.099**	**$2.251**	**$2.282**	**$2.266**	**$2.253**	**-**	**-**	**-**	**-**	**-**	**$2.577**
	ULSD	PSI Base Price		$1.963	$1.904	$1.805	$1.852	$1.806	$1.703	$1.622	$1.797	$2.074	$2.107	$2.159	$2.038	$2.129	$2.083	$2.083	$2.309	$2.417	$3.129	$2.301	$2.225	$2.308	$2.406
		PSI & Federal surcharges *		$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
		PSI Delivery Charge		$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155
		PSI Fuel Surcharge %		16.5%	17.5%	17.5%	16.5%	16.5%	16.5%	16.5%	14.5%	16.5%	16.5%	19.5%	20.0%	19.0%	20.0%	20.0%	20.0%	21.5%	22.5%	22.5%	22.0%	21.0%	22.0%
		PSI Fuel Surcharge (%*Delivery)		$0.026	$0.027	$0.027	$0.026	$0.026	$0.026	$0.026	$0.022	$0.026	$0.026	$0.030	$0.031	$0.029	$0.031	$0.031	$0.031	$0.033	$0.035	$0.035	$0.034	$0.033	$0.034
		PSI Truck Freight %		15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
		PSI Truck Freight (%*Delivery+Surchage)		$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028
		Truck Delivery		$0.133	$0.133	$0.133	$0.133	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165	$0.165
		Delivery Fuel Surcharge %		18.5%	20.5%	20.5%	20.5%	20.5%	20.5%	20.5%	19.0%	23.0%	23.0%	23.0%	23.0%	24.0%	26.0%	26.0%	26.0%	29.0%	27.0%	27.0%	23.5%	26.0%	26.0%
		Delivery Fuel Surchage (%*Delivery)		$0.025	$0.027	$0.027	$0.027	$0.034	$0.034	$0.034	$0.031	$0.038	$0.038	$0.038	$0.038	$0.040	$0.043	$0.043	$0.043	$0.048	$0.045	$0.045	$0.039	$0.043	$0.043
		Total $/Gallon	**$2.512**	**$2.331**	**$2.277**	**$2.178**	**$2.223**	**$2.216**	**$2.112**	**$2.032**	**$2.200**	**$2.487**	**$2.521**	**$2.578**	**$2.458**	**$2.549**	**$2.508**	**$2.508**	**$2.734**	**$2.849**	**$3.560**	**$2.732**	**$2.649**	**$2.735**	**$2.834**
Zehnder	DF2+10	PSI Base Price		-	-	-	-	$1.625	$1.576	$1.621	$1.708	-	-	-	-	-	-	-	-	$2.150	$2.286	$2.395	$2.400	$2.408	-
		PSI & Federal surcharges *		-	-	-	-	$0.003	$0.003	$0.003	$0.003	-	-	-	-	-	-	-	-	$0.003	$0.003	$0.003	$0.003	$0.003	-
		PSI Ops Surcharge		-	-	-	-	$0.05	$0.05	$0.05	$0.05	-	-	-	-	-	-	-	-	$0.05	$0.05	$0.05	$0.05	$0.05	-
		Delivery Charge		-	-	-	-	$0.030	$0.030	$0.030	$0.030	-	-	-	-	-	-	-	-	$0.030	$0.030	$0.030	$0.030	$0.030	-
		Delivery Fuel Surcharge %		-	-	-	-	20.5%	20.5%	20.5%	19.0%	-	-	-	-	-	-	-	-	29.0%	27.0%	27.0%	23.5%	26.0%	-
		Delivery Fuel Surchage (%*Delivery)		-	-	-	-	$0.006	$0.006	$0.006	$0.006	-	-	-	-	-	-	-	-	$0.009	$0.008	$0.008	$0.007	$0.008	-
		Total $/Gallon	**$2.109**	**-**	**-**	**-**	**-**	**$1.714**	**$1.665**	**$1.711**	**$1.797**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**$2.242**	**$2.377**	**$2.487**	**$2.490**	**$2.499**	**-**
	DF2-15	PSI Base Price		$1.750	$1.797	$1.712	$1.732	-	-	-	-	$1.874	$1.911	$2.040	$2.021	$2.174	$2.204	$2.188	$2.175	-	-	-	-	-	$2.499
		PSI & Federal surcharges *		$0.003	$0.003	$0.003	$0.003	-	-	-	-	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	-	-	-	-	-	$0.003
		PSI Ops Surcharge		$0.04	$0.05	$0.05	$0.05	-	-	-	-	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	-	-	-	-	-	$0.05
		Truck Delivery		$0.025	$0.025	$0.025	$0.025	-	-	-	-	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	-	-	-	-	-	$0.030
		Delivery Fuel Surcharge %		18.5%	20.5%	20.5%	20.5%	-	-	-	-	23.0%	23.0%	23.0%	23.0%	24.0%	26.0%	26.0%	26.0%	-	-	-	-	-	26.0%
		Delivery Fuel Surchate (%*Delivery)		$0.005	$0.005	$0.005	$0.005	-	-	-	-	$0.007	$0.007	$0.007	$0.007	$0.007	$0.008	$0.008	$0.008	-	-	-	-	-	$0.008
		Total $/Gallon	**$2.093**	**$1.823**	**$1.880**	**$1.795**	**$1.815**	**-**	**-**	**-**	**-**	**$1.964**	**$2.001**	**$2.129**	**$2.111**	**$2.264**	**$2.294**	**$2.279**	**$2.266**	**-**	**-**	**-**	**-**	**-**	**$2.590**
	ULSD	PSI Base Price		$1.963	$1.904	$1.805	$1.852	$1.806	$1.703	$1.622	$1.797	$2.074	$2.107	$2.159	$2.038	$2.129	$2.083	$2.083	$2.309	$2.417	$3.129	$2.301	$2.225	$2.308	$2.406
		PSI & Federal surcharges *		$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.006	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003	$0.003
		PSI Delivery Charge		$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155	$0.155
		PSI Fuel Surcharge %		16.5%	17.5%	17.5%	16.5%	16.5%	16.5%	16.5%	14.5%	16.5%	16.5%	19.5%	20.0%	19.0%	20.0%	20.0%	20.0%	21.5%	22.5%	22.5%	22.0%	21.0%	22.0%
		PSI Fuel Surcharge (%*Delivery)		$0.026	$0.027	$0.027	$0.026	$0.026	$0.026	$0.026	$0.022	$0.026	$0.026	$0.030	$0.031	$0.029	$0.031	$0.031	$0.031	$0.033	$0.035	$0.035	$0.034	$0.033	$0.034
		PSI Truck Freight %		15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
		PSI Truck Freight (%*Delivery+Surchage)		$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.027	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028	$0.028
		Truck Delivery		$0.025	$0.025	$0.025	$0.025	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030	$0.030
		Delivery Fuel Surcharge %		18.5%	20.5%	20.5%	20.5%	20.5%	20.5%	20.5%	19.0%	23.0%	23.0%	23.0%	23.0%	24.0%	26.0%	26.0%	26.0%	29.0%	27.0%	27.0%	23.5%	26.0%	26.0%
		Delivery Fuel Surchage (%*Delivery)		$0.005	$0.005	$0.005	$0.005	$0.006	$0.006	$0.006	$0.006	$0.007	$0.007	$0.007	$0.007	$0.007	$0.008	$0.008	$0.008	$0.009	$0.008	$0.008	$0.007	$0.008	$0.008
		Total $/Gallon	**$2.352**	**$2.203**	**$2.147**	**$2.048**	**$2.093**	**$2.053**	**$1.950**	**$1.869**	**$2.040**	**$2.324**	**$2.355**	**$2.412**	**$2.292**	**$2.382**	**$2.338**	**$2.338**	**$2.564**	**$2.675**	**$3.389**	**$2.560**	**$2.482**	**$2.564**	**$2.664**

Notes: During the time frame shown here, 5,755,774 gallons of DF2+10 and 8,829,573 gallons of DF2-15 were consumed by EU ID's 1 and 2 at the North Pole Plant, giving a weighted average cost differential between No. 2 HSD and ULSD of $0.424 per gallon.

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GVEA
Alternative BACT
November 2018

Attachment 5a
Updated Cost Effectiveness Tables North Pole

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Table 5-1. Summary of Available SO_2 Emission Control Technology

Emission Unit		Available Emission Control Technology
1, 2	Simple Cycle Gas Turbine	ULSD
		Low Sulfur Fuel
		No. 1 HSD
		Good Combustion Practices
5, 6	Combined Cycle Gas Turbine	ULSD
		LSR/Naphtha
		Limited Operation
		Good Combustion Practices
7	Emergency Generator Engine	ULSD
		Low Sulfur Fuel
		Limited Operation
		Good Combustion Practices
11, 12	Propane-Fired Boiler	Low Sulfur Fuel
		Good Combustion Practices

Table 5-2. Summary of Technically Feasible SO_2 Emission Control Technology

Emission Unit		Technically Feasible Control Technology
1, 2	Simple Cycle Gas Turbine	ULSD
		Low Sulfur Fuel
		No. 1 HSD
		Good Combustion Practices
5, 6	Combined Cycle Gas Turbine	ULSD
		Good Combustion Practices and LSR/Naphtha
7	Emergency Generator Engine	ULSD
		Low Sulfur Fuel
		Limited Operation
		Good Combustion Practices
11, 12	Propane-Fired Boiler	Low Sulfur Fuel
		Good Combustion Practices

Table 5-3. Ranking of Technically Feasible SO_2 Emission Control Technology

Emission Unit		Emission Control Technology	Control Efficiency (pct.)	SO_2 Emissions (tpy)	SO_2 Emissions Reduction (tpy)
1	Simple Cycle Turbine	ULSD (0.0015 wt. pct. S)	99.7	4.5	1,481.9
		Low Sulfur Fuel (0.05 wt. pct. S)	90.0	148.6	1,337.8
		No. 1 HSD (0.100 wt. pct. S)	80.0	297.3	1,189.1
		Good Combustion Practices (0.50 wt. pct. S) (existing)	0	1,486.4	0
2	Simple Cycle Turbine	Limited Operation + ULSD (0.0015 wt. pct. S)	99.7	4.1	1,352.0
		Limited Operation + Low Sulfur Fuel (0.05 wt. pct. S)	90.0	135.6	1,220.5
		Limited Operations + No. 1 HSD (0.100 wt. pct. S)	80.0	271.2	1,084.9
		Good Combustion Practices (0.50 wt. pct. S) (existing)	0	1,356.1	0
5, 6	Combined Cycle Gas Turbines (per turbine)	ULSD (0.0015 wt. pct. S)	70.0	3.0	7.1
		LSR/Naphtha (0.0050 wt. pct. S) + Good Combustion Practices (existing)	0	10.1	0.0
7	Emergency Generator Engine	ULSD (0.0015 wt. pct. S) + Limited Operation	98.5	0.00015	0.0099
		Low Sulfur Fuel (0.05 wt. pct. S) + Limited Operation	50	0.005	0.0050
		Limited Operation (0.1 wt. pct. S) (existing)	0	0.01	0
11, 12	Propane-Fired Boiler	Low Sulfur Fuel (existing)	0	0.0002	0

Table 5-4. Annualized Costs for ULSD on the Diesel-fired Simple Cycle Gas Turbine (EU ID 1)

Shaded cells indicate user inputs

Project: GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU ID 1 - GE Frame 7 CT) — Prepared By: / Checked By: / Rev:

Annualized Costs

DIRECT ANNUAL COSTS		QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT		excluded in this estimate		
(4)	Utilities						
	(a) ULSD Costs:	45,282,462	GAL	$ 0.424	$ 19,199,764		$ 19,199,764
Total Direct Annual Costs (TDAC)						TDAC =	$ 19,199,764
INDIRECT ANNUAL COSTS							
(5)	Overhead		%		excluded in this estimate	$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.0944					
(7)	Capital Recovery					CRF * TCI =	$ -
Total Indirect Annual Costs (TIAC) (refer to Table 5-10)						TIAC =	$ 1,461,566
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 20,661,330

Cost Effectiveness Summary

TOTAL TONS SO_2 AVOIDED PER YEAR	=	1,482
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON PTE)	(TAC)/(TPY) =	$ 13,942
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON ACTUAL HISTORIC RUN TIMES, AVOIDING 111 TONS PER YEAR)[1]	(TAC)/(TPY) =	$ 25,530
COST EFFECTIVENESS ($ PER TON PM AVOIDED BASED ON 6 TONS SO_2 AVOIDED = 1 TON PM AVOIDED)[2]	(TAC)/(TPY) =	$ 153,183

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

[1] Annual average run hours for EU 1 from 2009-2016 is 833 hours, and the peak in the last four years has been 587 hours. 833 hours equates to 4,305,969 gallons of fuel, a TDAC of $1,791,283, and a TAC of $3,208,769. The capital cost of bulk fuel storage would be less and the TIAC for actuals is shown in Table 5-10. 4,305,969 gallons of .381 wt pct. S replaced with .0015 wt pct. = 111 tons avoided. Monthly testing of No. 2 HSD for 2017 showed 0.381 wt. pct. S. average

[2] Alaska Department of Environmental Conservation, Amendments to State Air Quality Control Plan Vol. III: Appendix III.D.5.7, page 52. In reference to fuel oil emissions, "Ambient sampling and modeling in FNSB indicates that reduction of six tons of SO_X emissions result in the same reduction in ambient $PM_{2.5}$ concentration as the reduction of one ton of directly emitted $PM_{2.5}$".

Table 5-5. Annualized Costs for ULSD on the Diesel-fired Simple Cycle Gas Turbine (EU ID 2)

Shaded cells indicate user inputs

Project:	GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU ID 2 - GE Frame 7 CT)				Prepared By:	
					Checked By:	
					Rev:	
Annualized Costs						
DIRECT ANNUAL COSTS		**QTY**	**UNIT**	**TOTAL MATERIALS COST**	**TOTAL LABOR COST**	**TOTAL**
(1)	Operating & Maintenance Costs		%		$ -	$ -
(2)	Repair & Replacement Costs		%		$ -	$ -
(3)	Maintenance Materials		LOT	excluded in this estimate		
(4)	Utilities					
	(a) ULSD Costs:	41,312,492	GAL	$ 0.424	$ 17,516,497		$ 17,516,497
Total Direct Annual Costs (TDAC)					TDAC =	$ 17,516,497
INDIRECT ANNUAL COSTS						
(5)	Overhead		%	excluded in this estimate	$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital		$ -	$ -
	Capital Recovery Factor [see inputs below]	0.0944				
(7)	Capital Recovery				**CRF * TCI =**	$ -
Total Indirect Annual Costs (TIAC) **(refer to Table 5-10)**					TIAC =	$ 1,461,566
TOTAL ANNUALIZED COSTS (TAC)					TAC = (TDAC) + (TIAC) =	$ 18,978,063
Cost Effectiveness Summary						
TOTAL TONS SO_2 AVOIDED PER YEAR					=	1,352
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON PTE)					(TAC)/(TPY) =	$ 14,037
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON ACTUALS, AVOIDING 330 TONS PER YEAR)[1]					(TAC)/(TPY) =	$ 19,497
COST EFFECTIVENESS ($ PER TON PM AVOIDED BASED ON 6 TONS SO_2 AVOIDED = EQUIVALENT TO 1 TON PM AVOIDED)[2]					(TAC)/(TPY) =	$ 116,981

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

[1] Annual average run hours for EU 2 from 2009-2016 is 2472 hours, and the peak in the last four years has been 2873 hours. 2472 hours equates to 12,778,338 gallons of fuel, a TDAC of $5,315,789 and a TAC of $6,730,274. The capital cost of bulk fuel storage would be less and the TIAC for actuals is shown in Table 5-10. 12,778,338 gallons of .381 wt pct. S replaced with .0015 wt pct. = 330tons avoided. Monthly testing of No. 2 HSD for 2017 showed 0.381 wt. pct. S. average

[2] Alaska Department of Environmental Conservation, Amendments to State Air Quality Control Plan Vol. III: Appendix III.D.5.7, page 52. In reference to fuel oil emissions, "Ambient sampling and modeling in FNSB indicates that reduction of six tons of SO_X emissions result in the same reduction in ambient $PM_{2.5}$ concentration as the reduction of one ton of directly

Table 5-6. Annualized Costs for ULSD on the Diesel-fired Combined Cycle Gas Turbines (EU IDs 5 and 6)

Shaded cells indicate user inputs

Project:	GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU IDs 5 and 6 - GE LM6000PC CT)					Prepared By:	
						Checked By:	
						Rev:	
			Annualized Costs				
DIRECT ANNUAL COSTS		**QTY**	**UNIT**		**TOTAL MATERIALS COST**	**TOTAL LABOR COST**	**TOTAL**
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT		excluded in this estimate		
(4)	Utilities						
	(a) ULSD Costs:	30,660,000	GAL	1.117	$ 34,247,220		$ 34,247,220
Total Direct Annual Costs (TDAC)						TDAC =	$ 34,247,220
INDIRECT ANNUAL COSTS							
(5)	Overhead		%		excluded in this estimate	$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.0944					
(7)	Capital Recovery					**CRF * TCI =**	$ -
Total Indirect Annual Costs (TIAC)						TIAC =	$ -
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 34,247,220
			Cost Effectiveness Summary				
TOTAL TONS SO_2 AVOIDED PER YEAR						=	7.1
COST EFFECTIVENESS ($ PER TON AVOIDED)						(TAC)/(TPY) =	$ 4,844,020

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

Table 5-7. Annualized Costs for ULSD on the Diesel-fired Emergency Generator Engine (EU ID 7)

Shaded cells indicate user inputs

Project: GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU ID 7 - Generac Gen Set Engine)

Prepared By:
Checked By:
Rev:

Annualized Costs							
DIRECT ANNUAL COSTS		**QTY**	**UNIT**		**TOTAL MATERIALS COST**	**TOTAL LABOR COST**	**TOTAL**
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT		excluded in this estimate		
(4)	Utilities						
	(a) ULSD Costs:	1,664	GAL	0.2668	$ 444		$ 444
Total Direct Annual Costs (TDAC)						TDAC =	$ 444
INDIRECT ANNUAL COSTS							
(5)	Overhead		%		excluded in this estimate	$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.0944					
(7)	Capital Recovery					**CRF * TCI =**	$ -
Total Indirect Annual Costs (TIAC)						TIAC =	$ -
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 444
Cost Effectiveness Summary							
TOTAL TONS SO_2 AVOIDED PER YEAR						=	0.00985
COST EFFECTIVENESS ($ PER TON AVOIDED)						(TAC)/(TPY) =	$ 45,072

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

Table 5-8. GVEA North Pole Facility - SO_2 BACT Cost Effectiveness Summary[1] for Each Emission Unit Based on PTE

Control Technology Option	SO2 Emissions (tpy)	Total Installed Capital ($)	Total Annualized Cost ($/year)	Annual O&M Cost ($/year)	Cost Effectiveness ($/ton SO2 removed)
Simple Cycle Gas Turbine (EU ID 1)					
ULSD (0.0015 wt. pct. S)	4	$10,875,319	$20,661,330	$19,199,764	$13,942
No. 1 HSD (0.100 wt. pct. S)	297	~	$226,412	$226,412	$1,904
Good Combustion Practices (0.50 wt. pct. S) (existing)	1,486	~	~	~	~
Simple Cycle Gas Turbine (EU ID 2)					
Limited Operation + ULSD (0.0015 wt. pct. S)	4	$10,875,319	$18,978,063	$17,516,497	$14,037
Limited Operations + No. 1 HSD (0.100 wt. pct. S)	271	~	$206,562	$206,562	$1,904
Good Combustion Practices (0.50 wt. pct. S) (existing)	1,356	~	~	~	~
Combined Cycle Gas Turbines (EU IDs 5 and 6)					
ULSD (0.0015 wt. pct. S)	3	~	$34,247,220	~	$4,844,020
LSR/Naphtha (0.0050 wt. pct. S) + Good Combustion Practices (existing)	10	~	~	~	~
Emergency Generator Engine (EU ID 7)					
ULSD (0.0015 wt. pct. S) + Limited Operation	0.0002	~	$444	~	$45,072
Limited Operation (0.1 wt. pct. S) (existing)	0.01	~	~	~	~
Propane Fired Boilers (EU IDs 11 and 12)					
Low Sulfur Fuel (propane) (existing)	0	~	~	~	~

[1] All emission costs are on a per emission unit basis.

Table 5-9. GVEA North Pole Facility - Proposed SO_2 BACT and Associated Emission Rate for Each Emission Unit

ID	Description		Description	Emission Rate[1]
1, 2	Simple Cycle Gas Turbine	Fuel Oil	Good Combustion Practices (existing) + No. 1 HSD on air quality curtailment days	500 ppm S in fuel
5, 6	Combined Cycle Gas Turbine	LSR	LSR/Naphtha (existing)	50 ppm S in fuel
7	Emergency Generator Engine	Fuel Oil	Good Combustion Practices (existing)	500 ppm S in fuel
11, 12	Boiler	Propane	Low Sulfur Fuel - Propane (existing)	0.0012 lb/kgal

[1] Emissions are on a per emission unit basis.

Table 5-10. Capital Cost for New ULSD Storage Based on Maximum Fuel Use and Actual Fuel Use

	North Pole EUs 1 and 2 Maximum Fuel Use	Zehnder EUs 1 and 2 Maximum Fuel Use	North Pole EUs 1 and 2 Actual Fuel Use	Zehnder EUs 1 and 2 Actual Fuel Use
Capital Cost Estimate	$30,425,000		$21,050,000	
Heat Input, MMBtu/day (combined for each set of combustion turbines)	32,256	12,864	32,256	12,864
Percentage of Heat Input	71.5%	28.5%	71.5%	28.5%
Capital Cost (apportioned based on heat input ratio)	$ 21,750,638	$ 8,674,362	$ 15,048,511	$ 6,001,489
Capital Cost (apportioned per combustion turbine)	$ 10,875,319	$ 4,337,181	$ 7,524,255	$ 3,000,745
Capital Recovery (per combustion turbine)	$ 1,026,553	$ 409,399	$ 710,236	$ 283,249
Administrative Charges, Property Taxes, Insurance (per combustion turbine)	$ 435,013	$ 173,487	$ 300,970	$ 120,030
Total Annual Indirect Cost (per combustion turbine)	**$ 1,461,566**	**$ 582,886**	**$ 1,011,207**	**$ 403,279**

Capital recovery factor: 0.0944

Data Inputs for Capital Recovery Factor:

Annual Interest Rate (EPA OAQPS Control Cost Manual): 7.00 pct.

Project Life (EPA OAQPS Control Cost Manual): 20 years

Administrative Charges, Property Taxes Insurance (percentage of total capital cost): 4.00%

Capital cost estimate for 1.27 million gallons of storage capacity.

GVEA
Alternative BACT
November 2018

Attachment 5b
Updated Cost Effectiveness Tables Zehnder

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Table 5-1. GVEA - Zehnder Facility - Summary of Available SO_2 Emission Control Technologies

Emission Unit ID	Emission Unit Description	Available Emission Control Technology
1, 2	Simple Cycle Gas Turbine	ULSD
		Low Sulfur Fuel
		Good Combustion Practices
3, 4	Diesel-fired Emergency Generator Engine	ULSD
		Low Sulfur Fuel
		Limited Operations
		Good Combustion Practices
10, 11	Diesel-fired Boiler	ULSD
		Low Sulfur Fuel
		Good Combustion Practices

Table 5-2. GVEA - Zehnder Facility - Summary of Technically Feasible SO_2 Emission Control Technologies

Emission Unit		Emission Control Technology
ID	Description	
1,2	Simple Cycle Combustion Gas Turbine	ULSD
		Low Sulfur Fuel
		Good Combustion Practices
3, 4	Diesel-fired Emergency Generator Engine	ULSD
		Low Sulfur Fuel
		Limited Operation
		Good Combustion Practices
10, 11	Diesel-fired Boiler	ULSD
		Low Sulfur Fuel
		Good Combustion Practices

Table 5-3. GVEA - Zehnder Facility - Ranking of Technically Feasible SO_2 Emission Control Technology

Emission Unit ID	Emission Unit Description	Control Technology Used	Control Efficiency (pct)[2]	SO_2 Emissions Per Unit (tpy)	SO_2 Emissions Reduction (tpy)
1, 2[1]	Simple Cycle Combustion Gas Turbines	ULSD Fuel (0.0015 wt. pct. S)	99.7	1.8	578.2
		Low-Sulfur Fuel (0.05 wt. pct. S)	89.8	59.3	520.7
		Good Combustion Practices (0.5 wt. pct. S) (existing)	0	580	0
3, 4[1]	Diesel-fired Emergency Generator Engines	ULSD Fuel (0.0015 wt. pct. S)	99.7	0.01	3.7
		Low-Sulfur Fuel (0.05 wt. pct. S)	90.0	0.37	3.3
		Limited Operation and Good Combustion Practices (0.5 wt. pct. S) (existing)	0	3.7	0
10, 11[1]	Diesel-fired Boilers	ULSD Fuel (0.0015 wt. pct. S)	99.7	0.012	3.8
		Low-Sulfur Fuel (0.05 wt. pct. S)	90.0	0.39	3.5
		Good Combustion Practices (0.5 wt. pct. S) (existing)	0	3.9	0

Note:

[1] Combined SO_2 emissions from EU IDs 1 through 4, 10, and 11 are limited to 580 tpy on a 12-month rolling basis per Permit AQ0109TVP03 Condition 9. Each emission unit can operate individually up to the potential emissions listed in this table. The fuel sulfur content is limited to 1.0 wt. pct. for EU IDs 1 through 4, per Permit AQ0109TVP03, Condition 10. However, No. 1 and No. 2 fuel oil (by specification) can have a maximum sulfur content of 0.5 wt. pct., so 0.5 percent fuel sulfur content is used as the baseline for each emission unit.

[2] The use of low-sulfur fuel and ULSD both result in the 580 tpy SO_2 limit being unncessary. For each emission unit, the control efficiencies are based on the emission reduction between the existing PTE and the PTE that would result due to the use of lower sulfur fuel.

Table 5-4. Annualized Costs for ULSD Combustion in the Diesel-fired Simple Cycle Gas Turbines (EU ID 1 and 2)

Shaded cells indicate user inputs

Cost Effectiveness Determination - ULSD Fuel Switch - No Additional Tank Storage

Project: GVEA Zhender - SO_2 BACT Analysis (EU ID 1 and 2 - Frame 5 CTs, cost per turbine)

Date:
Prepared By:
Checked By:
Rev:

Annualized Costs

DIRECT ANNUAL COSTS			QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating & Maintenance Costs			%			$ -	$ -
(2)	Repair & Replacement Costs			%			$ -	$ -
(3)	Maintenance Materials			LOT				
(4)	Utilities							
	(a)	ULSD Costs:	18,059,076.92	GAL	0.424	$ 7,657,049		$ 7,657,049
Total Direct Annual Costs (TDAC)							TDAC =	$ 7,657,049
INDIRECT ANNUAL COSTS								
(5)	Overhead			%			$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance			% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]		0.0944					
(7)	Capital Recovery						CRF * TCI =	$ -
Total Indirect Annual Costs (TIAC) (refer to Table 5-10)							TIAC =	$ 582,886
TOTAL ANNUALIZED COSTS (TAC)							TAC = (TDAC) + (TIAC) =	$ 8,239,935

Cost Effectiveness Summary

TOTAL TONS SO2 AVOIDED PER YEAR	=	578
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON PTE)	(TAC)/(TPY) =	$ 14,250
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON ACTUAL HISTORIC RUN TIMES, AVOIDING 51.9 TONS PER YEAR)[1]	(TAC)/(TPY) =	$ 20,734
COST EFFECTIVENESS ($ PER TON PM AVOIDED BASED ON 6 TONS SO_2 AVOIDED = 1 TON PM AVOIDED)[2]	(TAC)/(TPY) =	$ 124,401

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

[1] Annual average run hours of 770 for EU IDs 1 and 2, see Table 5-9. 700 hours equates to 1,587,385 gallons of fuel, a TDAC of $423,514 and a TAC of $970,728. The capital cost of bulk fuel

[2] Alaska Department of Environmental Conservation, Amendments to State Air Quality Control Plan Vol. III: Appendix III.D.5.7, page 52. In reference to fuel oil emissions, "Ambient sampling and

Table 5-5. Annualized Costs for ULSD Combustion in the Diesel-fired Engines (EU ID 3 and 4)

Shaded cells indicate user inputs

Cost Effectiveness Determination - ULSD Fuel Switch - No Additional Tank Storage

Project: GVEA Zhender - SO_2 BACT Analysis (EU ID 3 and 4 - General Motors Gen Set Engines, cost per engine)

Date:
Prepared By:
Checked By:
Rev:

Annualized Costs						
DIRECT ANNUAL COSTS	**QTY**	**UNIT**		**TOTAL MATERIALS COST**	**TOTAL LABOR COST**	**TOTAL**
(1) Operating & Maintenance Costs		%			$ -	$ -
(2) Repair & Replacement Costs		%			$ -	$ -
(3) Maintenance Materials		LOT				
(4) Utilities						
(a) ULSD Costs:	107,692.31	GAL	0.2668	$ 28,732		$ 28,732
Total Direct Annual Costs (TDAC)					TDAC =	$ 28,732
INDIRECT ANNUAL COSTS						
(5) Overhead		%			$ -	$ -
(6) Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
Capital Recovery Factor [see inputs below]	0.1424					
(7) Capital Recovery					**CRF * TCI =**	$ -
Total Indirect Annual Costs (TIAC)		**Not applicable**			TIAC =	$ -
TOTAL ANNUALIZED COSTS (TAC)					TAC = (TDAC) + (TIAC) =	$ 28,732

Cost Effectiveness Summary		
TOTAL TONS SO2 AVOIDED PER YEAR	=	3.7
COST EFFECTIVENESS ($ PER TON AVOIDED)	(TAC)/(TPY) =	$ 7,768

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years

Table 5-6 Annualized Costs for ULSD Combustion in the Diesel-fired Boilers (EU ID 10 and 11)

Shaded cells indicate user inputs

Cost Effectiveness Determination - ULSD Fuel Switch - No Additional Tank Storage

Project: GVEA Zhender - SO_2 BACT Analysis (EU ID 10 and 11 - Weil McLain Boilers, cost per boiler)

Date:
Prepared By:
Checked By:
Rev:

Annualized Costs							
DIRECT ANNUAL COSTS		**QTY**	**UNIT**		**TOTAL MATERIALS COST**	**TOTAL LABOR COST**	**TOTAL**
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT				
(4)	Utilities						
	(a) ULSD Costs:	114,553.85	GAL	0.2668	$ 30,563		$ 30,563
Total Direct Annual Costs (TDAC)						TDAC =	$ 30,563
INDIRECT ANNUAL COSTS							
(5)	Overhead		%			$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.1424					
(7)	Capital Recovery					**CRF * TCI =**	$ -
Total Indirect Annual Costs (TIAC)			**Not applicable**			TIAC =	$ -
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 30,563
Cost Effectiveness Summary							
TOTAL TONS SO2 AVOIDED PER YEAR						=	3.8
COST EFFECTIVENESS ($ PER TON AVOIDED)						(TAC)/(TPY) =	$ 7,946

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	10	years

Table 5-7. GVEA - Zehnder Facility - SO_2 BACT Cost Effectiveness Summary for Each Emission Unit

Emission Control Technology	SO_2 Emissions (tpy)	Total Installed Capital ($)	Total Annualized Cost ($/year)	Annual O&M Cost ($/year)	Cost Effectiveness ($/ton SO_2 removed)
Diesel-fired Simple Cycle Gas Turbines (EU IDs 1 and 2, per turbine)					
ULSD Fuel (0.0015 wt. pct. S)	1.8	$4,337,181	$8,239,935	$7,657,049	$14,250
Good Combustion Practices (0.5 wt. pct. S) (existing)	580	~	~	~	~
Emergency Generator Engines (EU IDs 3 and 4, per engine)					
ULSD Fuel (0.0015 wt. pct. S)	0.01	~	$28,732	$28,732	$7,768
Limited Operation and Good Combustion Practices (0.5 wt. pct. S) (existing)	3.71	~	~	~	~
Diesel-fired Boilers (EU IDs 10 and 11, per boiler)					
ULSD Fuel (0.0015 wt. pct. S)	0.01	~	$30,563	$30,563	$7,946
Good Combustion Practices (0.5 wt. pct. S) (existing)	3.9	~	~	~	~

Note:
All costs are on a per unit basis.

Table 5-8. GVEA - Zehnder Facility - Proposed SO_2 BACT and Associated Emission Rate for Each Emission Unit

Emission Unit		Fuel	SO_2 BACT	
ID	Description		Description	Sulfur Content of Fuel
1, 2	Simple Cycle Gas Turbines	Fuel Oil	Fuel Oil and Good Combustion Practices (existing) - Refer to Table 5-9	0.5 wt. pct. S
3, 4	Emergency Generator Engines	Diesel	Fuel Oil and Good Combustion Practices (existing)	0.5 wt. pct. S
10, 11	Boilers	Diesel	ULSD	0.0015 wt. pct. S

Note:
[1] Emissions are on a per unit basis.

Table 5-9. GVEA - Zehnder Facility - SO_2 BACT Analysis for EU IDs 1 and 2 Based on Actual Operations

	SO_2 BACT Analysis Based on Potential Emissions	SO_2 BACT Analysis Based on Actual (Historical) Operations
Operating Basis	8,760 hr/yr	770 hr/yr
Emissions (EU 1 or EU 2)	580.0 tpy	52.1 tpy
Good combustion practices, 0.5 wt. pct. S (existing)		
PTE	580.0 tpy	52.1 tpy
PTE reduction	0.0 tpy	0.0 tpy
Cost effectiveness	N/A	N/A
ULSD Fuel (0.0015 wt. pct. S)		
PTE	1.8 tpy	0.2 tpy
PTE reduction	578.2 tpy	51.9 tpy
Total Direct annual Costs (TDAC)	$ 7,657,049 (Table 5-4)	$ 673,051 [1]
Total Indirect Annual Costs (TIAC)	$ 582,886 (Table 5-10)	$ 403,279 (Table 5-10)
Total annualized Costs (TAC = TDAC + TIAC)	$ 8,239,935	$ 1,076,330
Cost effectiveness	14,250 $/ton	20,734 $/ton

[1] Assuming 770 hours, 268 MMBtu/Hr, and .13 MMBtu/gal, for 1,587,385 gallons, and the fuel costs shown in Table 5-4)

Notes:

1. Historical Operating Hours

Year	EU 1	EU 2	Total
2007	267	529	797
2008	745	57	802
2009	**833**	408	1,241
2010	527	1,012	**1,539**
2011	756	509	1,265
2012	440	635	1,075
2013	226	936	1,162
2014	139	1,068	1,207
2015	339	991	1,330
2016	93	**1,137**	1,230

*2016 is not representative of typical use because EU 1 has been down waiting for a rebuild.
*Maximum annual operating hours for each turbine and total are shown in bold.
*The basis for this analysis is half of the total hours from 2010 for each turbine (770 hr/yr).

2. Basis for Emissions Calculations

SO_2 Emission Factor for EUs 1 and 2

Fuel with 0.5 wt. pct. S content	0.51 lb/MMBtu	(AP-42 Table 3.1-2a)
Fuel with 0.05 wt. pct. S content	0.051 lb/MMBtu	(AP-42 Table 3.1-2a)
Fuel with 0.015 wt. pct. S content	0.015 lb/MMBtu	(AP-42 Table 3.1-2a)
Heat input capacity for EUs 1 and 2	268 MMBtu/hr	

Total Annual Costs

Emission Control Technology	Control Efficiency (pct) from Table 5-3
ULSD Fuel (0.0015 wt. pct. S)	99.7
Good Combustion Practices (existing)	0

Table 5-10. Capital Cost for New ULSD Storage Based on PTE Maximum Fuel Use and Historic Actual Use

	North Pole EUs 1 and 2 Maximum Fuel Use	Zehnder EUs 1 and 2 Maximum Fuel Use	North Pole EUs 1 and 2 Actual Fuel Use	Zehnder EUs 1 and 2 Actual Fuel Use
Capital Cost Estimate	$30,425,000		$21,050,000	
Heat Input, MMBtu/day (combined for each set of combustion turbines)	32,256	12,864	32,256	12,864
Percentage of Heat Input	71.5%	28.5%	71.5%	28.5%
Capital Cost (apportioned based on heat input ratio)	$ 21,750,638	$ 8,674,362	$ 15,048,511	$ 6,001,489
Capital Cost (apportioned per combustion turbine)	$ 10,875,319	$ 4,337,181	$ 7,524,255	$ 3,000,745
Capital Recovery (per combustion turbine)	$ 1,026,553	$ 409,399	$ 710,236	$ 283,249
Administrative Charges, Property Taxes, Insurance (per combustion turbine)	$ 435,013	$ 173,487	$ 300,970	$ 120,030
Total Annual Indirect Cost (per combustion turbine)	**$ 1,461,566**	**$ 582,886**	**$ 1,011,207**	**$ 403,279**

Capital recovery factor: 0.0944

Data Inputs for Capital Recovery Factor:

Annual Interest Rate (EPA OAQPS Control Cost Manual): 7.00 pct.

Project Life (EPA OAQPS Control Cost Manual): 20 years

Administrative Charges, Property Taxes Insurance (percentage of total capital cost): 4.00%

Table E-1a. Summary of Identified SO_2 Control Technology - Liquid Fuel-Fired Simple Cycle Turbines > 25 MW (RBLC 15.190)

Pollutant	Control Technology Used	Number of RBLC Entries (11 Total)
SO_2	Low Sulfur Fuel	7
	None	4

Note: Data is based on a RBLC review from January 1, 2005 through September 15, 2015.

Table E-1b. Summary of Identified SO_2 Control Technology - Large Diesel Engines > 500 hp (RBLC 17.110)

Pollutant	Control Technology Used	Number of RBLC Entries (30 Total)
SO_2	Low-Sulfur Fuel	13
	ULSD Fuel	7
	None	3
	Good Combustion Practices	5
	NSPS Standards	2

Note: Data is based on a RBLC review from January 1, 2005 through September 15, 2015.

Table E-1c. Summary of Identified SO_2 Control Technology - Diesel-Fired Commercial/Institutional Boilers <100 MMBtu/hr (RBLC 13.220)

Pollutant	Control Technology Used	Number of RBLC Entries (6 Total)
SO_2	Low Sulfur Fuel	2
	Low Sulfur Fuel + Good Combustion Practices	2
	Wet or Dry Scrubber + Good Combustion Practices	1
	None	1

Note: Data is based on a RBLC review from January 1, 2005 through September 15, 2015.

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Attachment 6
Tables 5-4a and 5-5a, North Pole EU ID 1 and 2 Cost Effectiveness with selective use of No. 1 HSD

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Attachment 6 - Cost Effectiveness North Pole Selective Use No. 1 HSD

Table 5-5b. Annualized Costs for No. 1 HSD on the Diesel-fired Simple Cycle Gas Turbine (EU ID 2)

Shaded cells indicate user inputs

Project: GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU ID 2 - GE Frame 7 CT)

Prepared By:
Checked By:
Rev:

Annualized Costs

DIRECT ANNUAL COSTS		QTY	UNIT		TOTAL MATERIALS COST	TOTAL LABOR COST	TOTAL
(1)	Operating & Maintenance Costs		%			$ -	$ -
(2)	Repair & Replacement Costs		%			$ -	$ -
(3)	Maintenance Materials		LOT		excluded in this estimate		
(4)	Utilities			10%	Estimated time running No. 1		
	(a) No 1 Costs:	41,312,492	GAL	0.05	$ 206,562		$ 206,562
Total Direct Annual Costs (TDAC)						TDAC =	$ 206,562
INDIRECT ANNUAL COSTS							
(5)	Overhead		%		excluded in this estimate	$ -	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$ -	$ -
	Capital Recovery Factor [see inputs below]	0.0944					
(7)	Capital Recovery					CRF * TCI =	$ -
Total Indirect Annual Costs (TIAC)						TIAC =	$ -
TOTAL ANNUALIZED COSTS (TAC)						TAC = (TDAC) + (TIAC) =	$ 206,562

Cost Effectiveness Summary

TOTAL TONS SO_2 AVOIDED PER YEAR [1]	=	108
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON PTE)	(TAC)/(TPY) =	$ 1,904

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

[1] Assuming PTE and running No. 1 HSD 10% of the days. Running No. 1 on curtailment days.

Table 5-4a. Annualized Costs for No. 1 HSD on the Diesel-fired Simple Cycle Gas Turbine (EU ID 1)

Shaded cells indicate user inputs

Project: GVEA North Pole - $PM_{2.5}$ BACT Analysis (EU ID 1 - GE Frame 7 CT)

Prepared By:
Checked By:
Rev:

Annualized Costs								
DIRECT ANNUAL COSTS		**QTY**	**UNIT**		**TOTAL MATERIALS COST**	**TOTAL LABOR COST**		**TOTAL**
(1)	Operating & Maintenance Costs		%			$	-	$ -
(2)	Repair & Replacement Costs		%			$	-	$ -
(3)	Maintenance Materials		LOT		excluded in this estimate			
(4)	Utilities			10%	Estimated time running No. 1			
	(a) ULSD Costs:	45,282,462	GAL	0.05	$ 226,412			$ 226,412
Total Direct Annual Costs (TDAC)							TDAC =	$ 226,412
INDIRECT ANNUAL COSTS								
(5)	Overhead		%		excluded in this estimate	$	-	$ -
(6)	Administrative Charges, Property Taxes, Insurance		% of capital			$	-	$ -
	Capital Recovery Factor [see inputs below]	0.0944						
(7)	Capital Recovery						**CRF * TCI =**	$ -
Total Indirect Annual Costs (TIAC)							TIAC =	$ -
TOTAL ANNUALIZED COSTS (TAC)							TAC = (TDAC) + (TIAC) =	$ 226,412
Cost Effectiveness Summary								
TOTAL TONS SO_2 AVOIDED PER YEAR							=	119
COST EFFECTIVENESS ($ PER TON AVOIDED BASED ON PTE)							(TAC)/(TPY) =	$ 1,904

Data Inputs for Capital Recovery Factor:		
Annual Interest Rate (EPA OAQPS Control Cost Manual)	7.00	%
Project Life (EPA OAQPS Control Cost Manual)	20	years

[1] Assuming PTE and running No. 1 HSD 10% of the days. Running No. 1 on curtailment days.

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Attachment 7
Zehnder FY2019 Assessable Emissions Summary

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Table 1. FY2019 Assessable Emissions Summary
Golden Valley Electric Association - Zehnder Facility

Assessable Emissions - Tons Per Year							
Description	**NO_X**	**CO**	**PM_{10}**	**SO_2**	**VOC**	**HAPs**	**Total**
Assessable PTE	2,854	217	746	580	23	-	4,420

From Condition 30 and Table C of the SOB for AQ0109TVP03

Potential to Emit	**Regulated Air Pollutant Emissions (tons per year) [1]**					
	NO_X	**CO**	**PM_{10}**	**VOC**	**SO_2**	**HAP**
Significant	70.8	0.3	1.0	0.0	30.1	
Insignificant	0.2	0.1	0.0	0.0	0.5	
Total Emissions	**71**	**0**	**1**	**0**	**31**	
Use Assessable PTE						**0**
Assessable Emission Subtotals	**71**	**0**	**1**	**0**	**31**	**0**
Fees Apply to Pollutant? [2]	**Yes**	**No**	**No**	**No**	**Yes**	**No**
2017 Actual Emissions	**102**					
Fee Estimate [3]	**$4,366**					

Notes:

[1] Regulated air pollutant calculations based on emission factors shown in accompanying spreadsheets.

[2] Fees paid on each pollutant emitted in quantities greater than 10 tpy per 18 AAC 50.410.

[3] A fee rate of $42.95 per ton applies in accordance with 18 AAC 50.410(b)(1).

[4] Actual emissions are not provided for HAPs because potential emissions for HAPs are less than 10 tpy. Actual emissions must be less than or equal to potential emissions, so actual emissions are also less than 10 tpy.

Table 2a. FY2019 Significant Emission Unit Summary
Golden Valley Electric Association - Zehnder Facility

Emission Unit			Fuel	2017 Actual	Maximum	2017 Actual
ID	Description	Make/Model	Type	Operation	Capacity	Fuel Consumption
1	Simple Cycle Gas Turbine	General Electric Frame 5 MS 5001-M	No. 1 Diesel	0.3 hr/yr	268 MMBtu/hr	90 gal/yr
			No. 2 Diesel			0 gal/yr
2	Simple Cycle Gas Turbine	General Electric Frame 5 MS 5001-M	No. 1 Diesel	1,133.4 hr/yr	268 MMBtu/hr	88,231 gal/yr
			No. 2 Diesel			1,072,989 gal/yr
3	Diesel Generator Engine	General Motors Electro-Motive Diesel 20-645E4	No. 2 Diesel	2.7 hr/yr	28 MMBtu/hr	588 gal/yr
4	Diesel Generator Engine	General Motors Electro-Motive Diesel 20-645E4	No. 2 Diesel		28 MMBtu/hr	
10	Boiler	Weil McLain H-688	No. 2 Diesel	755 hr/yr	1.7 MMBtu/hr	17,810 gal/yr
11	Boiler	Weil McLain H-688	No. 2 Diesel	755 hr/yr	1.7 MMBtu/hr	

Table 7. FY2019 Assessable Emission Calculations - Sulfur Dioxide (SO_2) Emissions
Golden Valley Electric Association - Zehnder Facility

Emission Unit ID	Emission Unit Description	Fuel Type	Factor Reference	Fuel Sulfur Content [1,2]	SO_2 Emission Factor	2017 Actual Operation	2017 Actual SO_2 Emissions
1	Simple Cycle Gas Turbine	No. 1 Diesel	Mass Balance	0.095 wt. pct. S	0.013 lb/gal	90 gal/yr	5.8E-04 tpy
		No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	0 gal/yr	0 tpy
2	Simple Cycle Gas Turbine	No. 1 Diesel	Mass Balance	0.095 wt. pct. S	0.013 lb/gal	88,231 gal/yr	0.57 tpy
		No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	1,072,989 gal/yr	29.03 tpy
3	Diesel Generator Engine	No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	588 gal/yr	1.6E-02 tpy
4	Diesel Generator Engine	No. 2 Diesel					
10	Boiler	No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	17,810 gal/yr	0.48 tpy
11	Boiler	No. 2 Diesel					
						Significant Emission Units - 2017 Actual Emissions - SO_2	**30.1 tpy**
			Insignificant Emission Units				
6	Fuel Oil Storage Tank	No. 2 Diesel	N/A	N/A	N/A	8,760 hr/yr	0 tpy
7	Fuel Oil Storage Tank	No. 2 Diesel	N/A	N/A	N/A	8,760 hr/yr	0 tpy
N/A	Fuel Oil Storage Tank	No. 1 Diesel	N/A	N/A	N/A	8,760 hr/yr	0 tpy
8	Burnham Boiler	No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	6,215 gal/yr	1.7E-01 tpy
9	Burnham Boiler	No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	6,215 gal/yr	1.7E-01 tpy
N/A	Burnham Boiler - FE Building	Natural Gas	AP-42 Table 1.4-2	2,000 gr/10^6scf	0.6 lb/10^6scf	1,069,200 scf	3.2E-04 tpy
N/A	Burnham Boiler - FE Building	Natural Gas					
N/A	Lean Burn Inc. CB 2800 Overhead Shop Heater	Waste Oil	Mass Balance	0.124 wt. pct. S	0.018 lb/gal	0 gal/yr	0 tpy
N/A	Energy Logic EL-340H Heater	Waste Oil	Mass Balance	0.124 wt. pct. S	0.018 lb/gal	1,238 gal/yr	1.1E-02 tpy
N/A	Metzger Machine Corp. Boiler	No. 2 Diesel	Mass Balance	0.381 wt. pct. S	0.054 lb/gal	5,808 gal/yr	1.6E-01 tpy
N/A	Energy Logic EL-200H Heater	Waste Oil - Transformer	Mass Balance	0.121 wt. pct. S	0.017 lb/gal	1,764 gal/yr	1.5E-02 tpy
N/A	Energy Logic EL-200H Heater	Waste Oil - Transformer	Mass Balance	0.121 wt. pct. S	0.017 lb/gal	1,383 gal/yr	1.2E-02 tpy
N/A	Energy Logic EL-350H Heater	Waste Oil - Transformer	Mass Balance	0.121 wt. pct. S	0.017 lb/gal	0 gal/yr	0 tpy
						Insignificant Emission Units - 2017 Actual Emissions - SO_2	**0.53 tpy**
						2017 Actual Emissions - SO_2	**30.6 tpy**

Sample Calculations: [3]

Molar mass ratio is 32 lb S/mol : 64 lb SO_2/mol

Stoichiometry: 1 mol S = 1 mol SO_2

Mass Balance Emission Factor, lb/gal = (Molar mass ratio, 2 lb SO_2:1 lb S) x (weight % S in fuel) x (density of fuel, lb/gal) / 100%

Emissions, tpy= (Emission factor, lb/gal) x (Fuel Use gal/yr) / (2,000 lb/ton)

Boiler Emissions, tpy= (Emission factor, lb/10^6scf) / (Conversion 1,000,000 scf/10^6scf) x (Fuel Consumption, scf) / (2,000 lb/ton)

Notes:

1 For diesel fuels, fuel sulfur content is the average of the monthly maximum fuel sulfur content values for calendar year 2017.

2 For waste oil and waste transformer oil, fuel sulfur content was determined by testing conducted in December 2016.

[3] Diesel fuel density is equal 6.8 lb/gal for No. 1 Diesel and 7.1 lb/gal for No. 2 Diesel per plant report.

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Attachment 8
House Freeze Up Time Estimates

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? HOUSE COOL DOWN MODEL

If more than twenty five (25) house/services involved in outage,
Notify FNSB Emergency Services
to trigger Red Cross Assistance

Inside Temperature @ T(0) = 70 °F
mCp = 2.5 kWh/°F = 8532.5 BTU/°F
k = 0.16 kW/°F = 546.1 BTU/Hr-°F

	Time Hours	Inside Temperature of House following loss of heat source												
		-80 F	-70 F	-60 F	-50 F	-40 F	-30 F	-20 F	-10 F	0 F	10 F	20 F	30 F	40 F
	0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
	1	60.7	61.3	61.9	62.6	63.2	63.8	64.4	65.0	65.7	66.3	66.9	67.5	68.1
Notification	2	52.0	53.2	54.4	55.6	56.8	58.0	59.2	60.4	61.6	62.8	64.0	65.2	66.4
Time	3	43.8	45.5	47.3	49.0	50.8	52.5	54.3	56.0	57.8	59.5	61.3	63.0	64.8
0% Freeze	4	36.1	38.4	40.6	42.9	45.2	47.4	49.7	51.9	54.2	56.4	58.7	61.0	63.2
	5	28.9	31.7	34.4	37.1	39.9	42.6	45.4	48.1	50.8	53.6	56.3	59.0	61.8
	6	22.2	25.4	28.5	31.7	34.9	38.1	41.3	44.5	47.7	50.9	54.1	57.2	60.4
	7	15.8	19.4	23.1	26.7	30.3	33.9	37.5	41.1	44.7	48.3	51.9	55.6	59.2
	8	9.9	13.9	17.9	21.9	25.9	29.9	33.9	37.9	42.0	46.0	50.0	54.0	58.0
Estimated	9	4.3	8.7	13.1	17.5	21.8	26.2	30.6	35.0	39.3	43.7	48.1	52.5	56.9
100% Freeze	10	-0.9	3.8	8.5	13.3	18.0	22.7	27.5	32.2	36.9	41.6	46.4	51.1	55.8
	11	-5.8	-0.8	4.3	9.4	14.4	19.5	24.5	29.6	34.6	39.7	44.7	49.8	54.8
	12	-10.4	-5.0	0.3	5.7	11.0	16.4	21.8	27.1	32.5	37.8	43.2	48.6	53.9
	13	-14.7	-9.1	-3.4	2.2	7.9	13.5	19.2	24.8	30.5	36.1	41.8	47.4	53.1
	14	-18.8	-12.9	-6.9	-1.0	4.9	10.8	16.7	22.7	28.6	34.5	40.4	46.3	52.2
	15	-22.6	-16.4	-10.2	-4.1	2.1	8.3	14.5	20.6	26.8	33.0	39.1	45.3	51.5
	16	-26.1	-19.7	-13.3	-6.9	-0.5	5.9	12.3	18.7	25.1	31.5	38.0	44.4	50.8
	17	-29.5	-22.8	-16.2	-9.6	-2.9	3.7	10.3	17.0	23.6	30.2	36.8	43.5	50.1
	18	-32.6	-25.8	-18.9	-12.1	-5.2	1.6	8.4	15.3	22.1	29.0	35.8	42.6	49.5
	19	-35.5	-28.5	-21.5	-14.4	-7.4	-0.4	6.7	13.7	20.7	27.8	34.8	41.9	48.9
	20	-38.3	-31.1	-23.9	-16.6	-9.4	-2.2	5.0	12.2	19.5	26.7	33.9	41.1	48.3
	21	-40.9	-33.5	-26.1	-18.7	-11.3	-3.9	3.5	10.9	18.3	25.6	33.0	40.4	47.8
	22	-43.3	-35.8	-28.2	-20.6	-13.1	-5.5	2.0	9.6	17.1	24.7	32.2	39.8	47.3
	23	-45.6	-37.9	-30.2	-22.5	-14.8	-7.1	0.7	8.4	16.1	23.8	31.5	39.2	46.9
	24	-47.7	-39.9	-32.0	-24.2	-16.3	-8.5	-0.6	7.2	15.1	22.9	30.8	38.6	46.5
	25	-49.7	-41.7	-33.8	-25.8	-17.8	-9.8	-1.8	6.2	14.1	22.1	30.1	38.1	46.1
	26	-51.6	-43.5	-35.4	-27.3	-19.2	-11.1	-3.0	5.2	13.3	21.4	29.5	37.6	45.7
	27	-53.4	-45.1	-36.9	-28.7	-20.5	-12.2	-4.0	4.2	12.4	20.7	28.9	37.1	45.3

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