



GE Aerospace

**REASONABLY AVAILABLE CONTROL TECHNOLOGY STUDY
NO_x EMISSIONS
FACILITY-WIDE**

GE AEROSPACE – EVENDALE, OHIO

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Prepared By:

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1. Background

The General Electric Company (GE), through its GE Aerospace business, owns and operates a large industrial complex in Evendale, Hamilton County, Ohio. At the Evendale plant, GE Aerospace assembles and tests aircraft turbines (including military aircraft turbines), aero-derivative turbines, and gas turbines. The Evendale site is also the headquarters for GE and includes its primary research and development (R&D) center. R&D activities at Evendale include test cells dedicated to combustor technology.

Effective March 25, 2022, Ohio EPA amended its NOx emissions limits and other requirements in Ohio Administrative Code (OAC) Chapter 3745-110. OAC § 3745-110-03(J)(1) requires facilities in certain counties (including Hamilton) to conduct a Reasonably Available Control Technology (RACT) study per the following requirements:

“For any affected source of NOx emissions at an affected facility that is not subject to the emissions limitations specified in paragraphs (A) to (G) of this rule and is not exempt under paragraph (K) of this rule, or that is subject to the emissions limitations specified in paragraphs (A) to (G) of this rule but the owner or operator claims that an applicable emissions limitation is technically infeasible or economically unreasonable (not cost-effective) to achieve”

GE Aerospace (GEA) tests many different types of turbines and components under a variety of test plans for commercial and military turbines and has many different types of combustion sources at the facility.

This report presents the RACT study for the LM1500 turbines (B011-B013) at the GE Aerospace Evendale facility. *Italics* are used as a convention in this report to denote terms with specific definitions in the relevant section(s) of the OAC.

The other NOx-emitting units at the facility either meet the NOx limitations listed in the rule or meet one of the exemptions listed in OAC § 3745-110-03(K).

GE Aerospace submitted this study on May 14, 2024 to Ohio EPA Division of Air Pollution (DAPC) and received comments on May 28, 2024. This update addresses these comments as summarized in the following table. This update corrects an error in the efficiency used in the cost analysis for the replacement of the turbines with electric motors.

GE AEROSPACE EVENDALE PLANT RACT STUDY – SUMMARY OF CHANGES – RESPONSES TO COMMENTS FROM DAPC AND SWOAQA		
Comment	Resolution	Report Section
Provide documentation on the type of control equipment employed and the date installed, as well as the efficiency of the control equipment. If no control equipment is being utilized, please state this [110-03(J)(e)(viii) and (J)(g)(iv)].	There is no control equipment installed on these three units.	1
Provide documentation of any emissions testing performed on the affected units [110-03(J)(g)(v)].	There has been no emissions testing conducted on any of the three affected units.	1
Provide the detailed calculations for the annual NOx emissions that are referenced on page 6 of the study [110-03(J)(1)(n)].	See the added annual NOx emission calculations for B011.	3
The study states that engineering testing was performed to determine cost for the options of installing LNBS on the existing turbines, replacing the turbines with new versions, and fuel	The study referred to analyses by GE Aerospace engineers. As the OEM of the source, GE Aerospace is the “vendor” who would design and provide, if feasible, a low-	5

GE AEROSPACE EVENDALE PLANT RACT STUDY – SUMMARY OF CHANGES – RESPONSES TO COMMENTS FROM DAPC AND SWOAQA

emulsification. Please provide vendor quotes to support the costs stated in the study.	NOx combustion system, a replacement turbine, or water injection. The updated study provides additional clarification concerning these technologies.	
The list of technologies in Section 5.A. (close-coupled or separated over-fire ports, flue gas recirculation, low NOx burners with external flue gas recirculation, ignition timing retard, low excess air, and fuels reburn) is stated to be economically infeasible even if they are technically feasible. The expectation is that each option will be evaluated for its economic feasibility after technical feasibility. Provide explanations for the technical feasibility of each of these, then discuss economics for all options considered feasible.	Refined analysis indicates that each of these technologies is technically infeasible for the affected units. This study now presents the technical basis for eliminating these technologies from further consideration.	5
Provide more clarification on the necessity of installing an additional boiler in the section discussing SNCR. The cost of an air preheater is included in the cost spreadsheets with an asterisk for a footnote, but no footnote is included. Please clarify if the boiler is the same as the air preheater, include the footnote, and a vendor quote for the \$1,000,000 cost for the boiler.	In the previous version of the study, the preheater identified in the spreadsheet was the same as a boiler. For simplification, GE Aerospace removed the boiler/preheater from the capital cost of the SNCR. GE Aerospace also added some additional information concerning the cost estimating spreadsheet, a scaling factor to estimate the capital cost of controls, and an RBLC database search of controls on gas turbines.	8A
Provide more detail as to why incineration is not a technically feasible method for NOx reduction.	See updates to this study.	8D
Section 10 mentions that the cost estimating worksheet for NSCR provides estimates with plus or minus 30% accuracy. Please provide additional detail as to the relevance of this, since NSCR is not a technology that was considered technically feasible and was not evaluated for cost effectiveness.	The ± accuracy of the EPA workbook has been removed.	11
In Section 10 where RACT is proposed, please explicitly state what the current fuel usage and emissions limits are that the emissions units will be continuing to adhere to. If the conclusion for RACT continues to be the same after the requested revisions above, include that the provisions can be followed immediately.	See updates to this study with the current limits and conclusion that GE Aerospace can follow the proposed provisions immediately.	11

The report was prepared by:

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2. General Information

The following table provides the general information required in OAC § 3745-21-11(B).

GENERAL INFORMATION FOR RACT STUDY	
Facility Name	GE Aerospace Evendale Plant
Facility Identification Number	1431150060
Facility Address	One Neumann Way, Cincinnati, Ohio 45215
Owner Representative, Contact for Study	Joanne Reinhold, Environmental Manager joanne.reinhold@ge.com (513) 638-2333 (M) (Address Same as Above)
Responsible Official	Jennifer Seeling, Plant Leader jennifer.seeling@ge.com (513) 382-7940 (M) (Address Same as Above)
Standard Industrial Code	3724 – Aircraft Engines and Engine Parts
North American Industry Classification System	336412 – Aircraft Engine and Engine Parts Manufacturing
Source Classification Codes	2-02-002-01 – Natural gas-fired turbines
Application Numbers	Title V renewal application (A0073329)

GENERAL INFORMATION FOR RACT STUDY

OEPA ID	Company ID	Source Description	Month/Year Installed	Typical Fuel	Annual Production Rates (mmscf)			Average Daily Production (mmscf)			Max Daily Prod. (mmscf)	Max Annual NOx Emissions (tpy)	Avg Daily NOx Emissions (lbs/day)	Notes
					2019	2020	2021	2019	2020	2021				
B011	EA-201	LM1500A turbine (EA-201)	June, 1966	Natural Gas	25.126	0.030	6.410	0.0966	1.15E-04	0.0247	3.55	8.240	63.38	Operates only for specific tests in the associated test cell(s).
B012	EA-202	LM1500B turbine (EA-202)	June, 1966	Natural Gas	26.609	0.543	8.783	0.1023	2.09E-03	0.0338	3.55	8.726	67.12	Operates only for specific tests in the associated test cell(s).
B013	EA-203	LM1500C turbine (EA-203)	June, 1966	Natural Gas	24.063	0.000	7.833	0.0926	0.0000	0.0301	3.55	7.891	60.70	Operates only for specific tests in the associated test cell(s).

Notes

- The normal operating schedule for the turbines is 24 hours per day, five days per week, 52 weeks per year.
- Fuel use is the best available indicator of annual and daily production.
- The average daily production/fuel use is calculated based on the total annual production and the number of testing days throughout the year (assumed to be five days per week on average, 260 days per year).
- The maximum daily production/fuel use for the turbines is calculated based on the heat input rating of the turbine and assuming that it runs 24 hours per day. This is a worst-case number that rarely occurs during operation.
- A facility plot plan is provided in Appendix 1.
- NOx emissions factors are from the PTI and Title V permit.

3. NOx Emissions Information

This section presents a summary of the NOx-related emissions data calculated in the manner specified in OAC § 3745-110-03(J)(g).

Average Daily NOx Emissions

This value is based on the highest average daily production rate for each of the three full calendar years preceding the effective date of this rule, or any other year that is representative of the highest average daily emissions. The General Information for RACT Study table shows the highest value over the three years for each emissions unit and an example calculation is shown below. The plant typically operates five days per week and 52 weeks per year but will sometimes operate seven days per week. The average daily production rate for a calendar year may be calculated in the following manner:

Sample Calculation: Based on actual annual emissions and fuel use for B011 Combustion Turbine

Average daily production rate = [(total production rate during the calendar year) / (number of days production occurred during the calendar year)].

Average daily production rate = 25.126 mmscf natural gas/260 days = 0.097 mmscf natural gas/day

Average daily emissions = 8.24 tons NOx/year x 2,000 pounds/ton / 260 days/year = **63.38 lbs NOx/day**

Note: Fuel Use is the best available indicator of annual and daily production.

Maximum Daily NOx Emissions

This value should be based upon the highest maximum daily production rate for each of the three full calendar years (2019-2021) preceding the effective date of this rule or any year that may be more representative of the highest maximum daily emissions. Fuel use and thus emissions are not tracked daily, as there is no ongoing requirement to track such data. Therefore, a direct calculation of this parameter is not possible with available data.

As potential add-on NOx control devices are considered on a study-level basis, it is important to evaluate the suitability of air pollution control devices based on the maximum, short-term emission characteristics. Therefore, in compiling this engineering study, it was understood that any control device that appeared to be technically and economically feasible on an annual emissions basis would next need to be evaluated to ensure that the technology would also be suitable for the maximum short-term (hourly or daily) conditions.

Annual NOx Emissions

This value is based upon the highest annual production rate for a year period that is more representative of the annual production rate. Emissions shown are calculated in the annual Fee Emissions Report (FER) and were reported to Ohio EPA. A sample calculation for one of the turbines is shown below.

Sample Calculation: Actual annual emissions for B011 Combustion Turbine

Annual NOx Emissions = 25.126 mmscf natural gas burned by B011 in 2019 x 655.86 lbs NOx/mmscf [site-specific emission factor listed in the Title V permit] / 2,000 lbs/ton →

Annual NOx Emissions = **8.24 tpy NOx [Actual annual emissions for B011 Combustion Turbine]**

Potential to Emit – Daily and Annual NOx Emissions

The daily PTE is based upon the rated heat input capacity of each unit, along with the short-term permit limit. The annual PTE is based on the daily PTE or the annual NOx permit limit, whichever is lower for the specific source.

Sample Calculation: Daily and Annual PTE for B011 Combustion Turbine

Daily NOx Emissions = 155.4 MMBtu/hour x 0.656 lbs NOx/MMBtu x 24 hours/day = 2,446 lbs NOx/day [for B011]

Annual NOx Emissions = 93.05 tons NOx /year [combined for B011-B016, from a Federally enforceable permit limit]

The three LM1500 turbines (B011-B013) and the three Waukesha engines (B014-B016) have a combined annual NOx limit of 93.05 TPY. This limit was used as the PTE value in the analysis assuming that each turbine could theoretically operate up to the limit each year. The PTE values, limits, APCD design flowrates, and associated ppm_v for each emissions unit are shown in the table below.

GENERAL INFORMATION FOR RACT STUDY									
OEPA ID	Company ID	Source Description	Design Capacity (MMBtu/hr)	NOx Short-Term Limit ^a (lbs/MMBtu)	Annual NOx Limit ^a (tons/yr)	Daily NOx PTE (lbs/day)	Annual NOx PTE ^a (tons/yr)	Total APCD Design Flow (scfm)	Design NOx (ppm _v)
B011	EA-201	LM1500A turbine (EA-201)	155.4	0.656	93.05	2,446	93.05	1,785,800	169
B012	EA-202	LM1500B turbine (EA-202)	155.4	0.656	93.05	2,446	93.05	1,785,800	169
B013	EA-203	LM1500C turbine (EA-203)	155.4	0.656	93.05	2,446	93.05	1,785,800	169

Notes

- a. The annual NOx PTE is the permit limit for these sources but is a combined limit for B011-B016.

4. Process Description

The three NOx emissions units addressed in this engineering report are individual combustion units as described in the General Information table. The table describes the type of unit, its function, and the type of fuel combusted.

These three combustion units are identical to and near each other. Therefore, it is assumed to be feasible that they could share a control method or device.

In considering control devices that would serve the group of three combustion turbines, the combined flowrates and emissions for each unit were used in the design of the evaluated control device and calculation of the NOx concentration in the exhaust stream in parts per million by volume (ppm_v).

The grouped turbines support engine testing at the Altitude Test Facility (ATF) at the Evendale plant. Each is a stationary combustion turbine powered by natural gas. The turbines are a version of a marine and industrial engine that has been adapted to fit the purposes of this facility. These engines are no longer in production. The combustion of natural gas in each turbine results in the formation of NOx. The ATF area consists of two test cells (F004 & F005), the three combustion turbines (B011-B013), three Waukesha RICE engines (B014-B016) and some direct-fired preheaters (P283, P284, P285, P293, & P294).

This area is used to conduct tests on commercial and military development engines that are required for FAA engine certification. The ATF can simulate high or low pressure through its two configurations, “push” and “pull.” When in the “pull” configuration the turbines pull air out of the test cell to simulate the lower pressure observed at high altitudes. When in the “push” configurations, the turbines draw in air from outside and push it into compressors that send the compressed air to the test cell. This configuration simulates the high pressure of an engine being in RAM mode. In either configuration, all three turbines may or may not be needed to achieve the desired pressure, depending on the specific test plan and requirements.

5. Engine Design Pollution Controls

This section presents a detailed discussion of the technical feasibility, control efficiency, emissions reduction achievable, and cost effectiveness of employing each of the following types of NOx control measures for the combustion turbines at GE Aerospace.

- Low NOx combustion
 - Replacement units
 - Retrofit combustion systems
- Close-coupled or separated over-fire ports
- Flue Gas Recirculation
- Ignition timing retard
- Fuel Emulsification (includes water/steam injection)
- Fuel switching
- Low excess air
- Gaseous fuels reburn

The evaluation of technical feasibility and cost effectiveness for air pollution control systems begins with developing a fundamental design basis for the emissions unit(s) of interest. Key parameters of the waste gas include NOx concentration (parts per million by volume, ppm_v), flow rate (scfm and/or acfm), and temperature. The following table summarizes the design basis for a NOx control system for a single combustion turbine at the Evendale facility, assuming 100 percent capture with a closed vent system. To simplify the study, a group of the three turbines was not considered for this analysis. A control device controlling all three turbines would have no reduction in emissions compared to a single one but would have an increase in cost because of the need to control a larger flow rate. Thus, if a control were to appear both technically and economically feasible for controlling one turbine, we would need to then evaluate whether such technology remained technically and economically feasible for the group of three.

Parameter	Unit of Measure	B011
Air Flow	Actual cubic feet per minute	2,600,000
Temperature	Exhaust temperature, °F	400
Air Flow plus 10% Margin of Safety	Standard cubic feet per minute	1,785,800
Input NOx Emissions	lbs/MM BTU	0.656
Operation	Hours per Year	8,760

A. LOW-NOx REPLACEMENT GAS TURBINES

EPA identifies “low-NOx burners” as a technology applicable to general combustion units such as boilers, furnaces, and heaters. In many cases, the combustion system (burners) of these units can be replaced with equivalent low-NOx technology burners.

In gas turbine design, the analogous technology is a “dry low NOx” (DLN) combustion system, developed in the early 1970s (DLN-1 technology), then refined in the 1980s and beyond with DLN-2. GE Power Systems (now GE Vernova) described the history and technical challenges in developing DLN combustion systems in “Dry Low NOx Combustion Systems for GE Heavy-Duty Gas Turbines.”

GE Vernova currently produces a newer, larger, model of these engines/turbines that have DLN-2 combustion systems. Replacing the gas turbines with new turbines is theoretically feasible. GE Aerospace engineering staff examined this option. The engineers concluded that two new turbines would need to be purchased to replace the three existing turbines. Installation of these new turbines would require major upgrades to the facility including new compressors (powered by the turbines to be used for simulating altitude conditions) to handle the increased output. The project would also require building and structural changes due to the difference in size and capability of the new turbines.

GE Aerospace engineers estimate that the cost of these new turbines is \$7,000,000 (\$3,500,000 each), with an additional \$30,000,000, at minimum, for the building changes needed to accommodate the larger turbines. Additionally, the required design, installations, and upgrades would take **three to five years**. The project would require the ATF facility to be “down” for two to three years. No other GE Aerospace facilities are capable of performing these tests. If the ATF test operations area is not operating, GE Aerospace would lose engine sales and be unable to perform necessary ATF testing for the U.S. military, since the engines would not be able to be tested to confirm that they meet the applicable requirements. In summary, it is infeasible for the facility to be shut down for the length of time required to replace the LM1500 gas turbines with DLN-2 equipped units. This option is considered technically infeasible.

Looking at the replacement turbine cost, and

- Assuming a highly optimistic project life of 30 years,
- Using an industry-specific interest rate of 7.81%,
- The capital recovery factor is 0.0872.
- The annualized cost of the new turbines and building is $\$37M \times 0.0872 = \$3.2M$ (rounded to two significant figures).
- Assuming, optimistically, a 90% NOx reduction and the affected units’ potential to emit, NOx reduction would be $93.05 \times 90\% = 83.75$ tons NOx per year.
- The annualized capital cost of the **building and new turbines alone** would be $\$3.2M / 83.75$ tons NOx removed = \$38,200 dollars per ton of NOx removed.

B. RETROFIT DLN COMBUSTION SYSTEM

Next, GE Aerospace considered replacing the current combustion system of the existing turbines with DLN technology. Presently, no DLN combustion system exists that could be used or adapted to the LM1500 turbines. The LM1500 turbine models have been out of production for more than 20 years. No current supply chain exists to develop and produce the required combustion system. In addition, GE Aerospace or potential suppliers would likely be unwilling to invest the resources to develop new technologies for only this unique application of the LM1500 turbines.

GE Aerospace engineers estimate that development and design for a DLN conversion for these turbines would take four to five years. Based on previous New Product Introduction (NPI) programs with comparable scopes, the cost to develop a DLN combustion system retrofit would be approximately \$80,000,000.

Looking only at the initial development cost, and

- Assuming a highly optimistic project life of 15 years,
- Using an industry-specific interest rate of 7.81%,
- The capital recovery factor is 0.1155.
- The annualized cost of the initial development cost is $\$80M \times 0.1155 = \$9.2M$ (rounded to two significant figures).
- Assuming, optimistically, a 90% NO_x reduction and the affected units' potential to emit, NO_x reduction would be $93.05 \times 90\% = 83.75$ tons NO_x per year.
- The annualized cost of the **development cost alone** would be $\$9.2M / 83.75$ tons NO_x removed = \$109,850 dollars per ton of NO_x removed.

The above cost effectiveness calculation ignores the downtime needed for installation and infrastructure changes. In practice, the cost would be much higher, as the three gas turbines would require conversion one at a time over a multi-year period to maintain the ATF facility's operability.

C. OTHER COMMON SOURCE REDUCTION METHODS FOR NO_x REDUCTION

GE Aerospace referenced EPA documents to develop a list of potential source reduction technologies, i.e. "NO_x limiting" or "combustion control" methods applied to combustion units in general.ⁱⁱ However, combustion controls for a natural gas-fired turbine are water injection and DLN technology.ⁱⁱⁱ While listed for completeness, none of these NO_x-limiting technologies are applicable to a gas turbine. Each is considered to be technically infeasible as described below.

- Close-coupled or separated over-fire ports, a technology used to stage air into the combustion process for more effective NO_x control in boilers. A fuel rich/oxygen lean zone suppresses NO_x formation as the air passes through the fuel rich zone. The overfire air completes the combustion process.
- Flue gas recirculation is a method used to reduce thermal NO_x formation in boilers; it is not applicable to a combustion turbine.
- Low NO_x burners with external flue gas recirculation is a combination of low-NO_x combustors and flue gas recirculation.
- Ignition timing retard is a NO_x limiting method used in diesel engines; it is not applicable to combustion turbines.
- Low excess air is a method used in boilers and similar combustion units; it is not applicable to combustion turbines.
- Gaseous fuels reburn, aka fuel lean gas reburning, injects natural gas above the main combustion zone of a coal-fired furnace to reduce NO_x to N₂; the technology is not applicable to a combustion turbine.

D. FUEL SWITCHING

The specific fuel used can play a significant role in the amount of NO_x produced from combustion. For example, a different fuel may combust at a lower peak flame temperature which decreases the likelihood of NO_x formation. Another fuel may be able to combust and produce the same power/energy output but would require less oxygen/air, and thus could have a reduction in NO_x.

For example, if the affected units were fueled with distillate oil, switching fuel to natural gas would reduce NOx emissions. GE Aerospace presently uses the “cleanest” fuel available for these units, pipeline natural gas. Switching fuels is not a viable option for NOx reduction. This option is technically feasible, but would result in higher NOx emissions than the current operation so this option was not considered further.

E. WATER INJECTION

GE Aerospace Engineering performed an analysis to evaluate the feasibility of water injection NOx control, i.e., introducing water/steam to emulsify the fuel before combustion. Water and steam injection have been used since the 1970’s as a means of controlling NOx emission from combustion turbines. Inside the combustion turbine, fuel rich zones that create high flame temperatures are the result of the simultaneous mixing of fuel and air and their subsequent combustion. Injecting water or steam into the flame area of the combustor provides a heat sink that lowers the combustion zone temperature and reduces thermal NOx formation.

Water injection is a technically feasible option. An emission reduction of approximately 77% would be expected (i.e., 0.15 lbs NOx /MM BTU with water injection compared to the current emission factor of 0.656 lbs NOx/MM BTU).

An order of magnitude estimate for water injection controls can be scaled from a recent study.

- Project cost: \$5,000,000 for a 50 MW gas turbine^{iv} “all in” cost
- LM1500 capacity 11 MW
- Scaling factor, use “rule of 0.6” exponent = $(11/50)^{0.6} = 0.4031$
- Estimated project cost = \$5,000,000 x 0.4031 = \$2,020,000.

Given the age, design and materials of construction of the LM1500 units, GE Aerospace engineers concluded that water injection would require extensive annual maintenance/component replacements, such that multiple months of overhaul and repair would be required on an annual basis, at an estimated additional cost of \$1,000,000 per turbine per year.

The annualized cost for this technology is estimated as follows:

- Project cost: \$2,020,000 x 3 units = \$6,060,000
- Project life: 15 years
- Interest rate: 7.81%
- Capital Recovery Factor: 0.11548
- Total Annualized Capital: \$700,000
- Total Operating Cost (Maintenance Only, Excludes Water & Treatment): \$3,000,000
- Total Annualized Cost: \$3,700,000
- Annual NOx Removed: 93.05 tons x 77% = 71.65 tons NOx removed
- Cost per Ton NOx Removed: \$51,640

Note that the cost estimate does not factor in the extensive downtime expected and its financial impact on GE Aerospace operations.

6. Process Modification

GE Aerospace considered modifying the ATF simulation and testing process as a whole to reduce NOx emissions. In theory, changes to the process could include:

- lowering the output power of the turbines;
- adjusting the pressure and temperature conditions for the test, and/or,
- decreasing the length of the test.

The tests conducted at the ATF facility are required by the FAA for engine certification. The engines tested need to be operated within a defined design space of temperature and pressure conditions. To remain within the bounds of that design space, the turbines need to deliver consistent and reliable output. Modifying the process would result in different conditions outside of the design space and therefore, not meet the requirements of the FAA specifications. Due to the testing design space and FAA requirements, a process modification to reduce NOx is not technically feasible.

7. Conversion to Electric Motor-Driven ATF Facility

The ATF uses (3) LM1500 turbines to drive (3) line-ups of compressors that create vacuum (altitude) or pressure (ram air) delivery to the two test cells C43 and C44. Each of the LM1500s creates approximately 14,000 shaft horsepower. This power is used to turn Frame Size 5 (FS5) compressor sections to create either vacuum (pull) or pressurized (push) air delivery to the indoor engine test chambers. The LM1500s use high pressure natural gas (NG) for fuel. The natural gas is pressurized by Ingersol Rand (IR) positive-displacement pumps. Those IR pumps are driven by natural gas fueled diesel engines made by Waukesha.

The natural gas burning LM1500 turbines and three Waukesha engines create NOx emissions, up to 93.05 tons per year combined. A possible solution to eliminate the Evendale ATF NOx emissions from the LM1500s and Waukesha engines is to replace the LM1500s with electric motor drives.

The replacement of the LM1500 turbines and Waukesha engines with electric motors is a large project. The cost estimate shown below is what GE Aerospace Test & Systems Engineering call a “random order of magnitude” (ROM) value. It could be off by 50% or more. Pre-engineering to a detailed design level would be required to more accurately estimate the project costs. A cost estimate to convert the ATF to all-electric motor-driven power sources is provided in Appendix 3.

Key factors in the preliminary cost estimate include:

- Electricity cost: GE Aerospace current cost in \$ per kW-hr.
- Natural gas cost: GE Aerospace current cost in \$ per MM BTU. This value varies; the midpoint of two recent monthly bills was used.
- The total time required to retrofit the ATF facility would be approximately 42 months. The preliminary costs do not factor into potential costs of downtime of the current ATF facility.
- The principal costs associated with this conversion are:
- Utility costs would increase from \$1.1M to \$4.8M per year
- Maintenance costs would decrease by an estimated \$1.125M per year. The existing facility’s primary equipment is from the late 1960s. Many replacement components are obsolete and must be custom fabricated, at significant expense.

- Capital expenses and design costs were obtained from a GE Aerospace Senior Electrical Engineer and include an estimated \$10M for a new Electric Supply Master Substation that would be required to support the additional demand for electricity with this project and \$8M for electric motors, variable frequency drives and gearboxes.

The total annualized cost per ton of NOx removed is \$32,000 (see details for this calculation in Appendix 3).

8. Add-On Pollution Controls

This section includes information on control technologies that remove NOx from the exhaust gas of the turbine – post combustion. An analysis of the technical feasibility, reduction efficiency, and cost-effectiveness are included for the following control technologies:

- Selective non-catalytic reduction
- Non-selective catalytic reduction
- Selective catalytic reduction using urea ammonia and methane as reducing agents
- Incineration
- Scrubbing

EPA default cost factors were used for instrumentation, sales taxes, freight, foundations and supports, handling and erection, electrical, piping, insulation, and painting. Default values were also used for engineering, construction and field expenses, start-up, a performance test, overhead, administrative charges, property taxes, and insurance. Due to the location of the combustion turbines with minimal space available for adding equipment, including a control device, the control device would need to be installed outside of the building and ducted through or over the building to the device. GE Aerospace estimated that an additional minimum cost of \$1,200,000 would be required for site preparation/additional building space installation, no matter which add-on control device is needed. This study-level, first-pass engineering estimate was added to EPA default values. The following table summarizes the design basis for a NOx control system for a single combustion turbine at the Evendale facility, assuming 100 percent capture with a closed vent system. A group of the three turbines was not considered for this analysis since in theory, a single turbine could burn natural gas and emit NOx up to the combined limits, so a control device controlling all three turbines would have no reduction in emissions compared to a single one but would have an increase in cost.

Parameter	Unit of Measure	B011
Air Flow	Actual cubic feet per minute	2,600,000
Temperature	Exhaust temperature, °F	400
Air Flow	Standard cubic feet per minute	1,623,500
Air Flow plus 10% Margin of Safety	Standard cubic feet per minute	1,785,800
Input NOx Emissions	lbs/MM BTU	0.656
Removal efficiency for Selective Non-Catalytic Reduction	Percent by Weight	50%
Removal efficiency for Non-Selective Catalytic Reduction	Percent by Weight	50%
Removal efficiency for Selective Catalytic Reduction	Percent by Weight	90%
Operation	Hours per Year	8,760

A. SELECTIVE NON-CATALYTIC REDUCTION

Selective non-catalytic reduction (SNCR) is a NO_x reduction control technology that chemically reduces the amount of NO_x present in the exhaust gas. A reducing agent, normally a substance that is nitrogen based, is injected into the exhaust gas stream where it chemically reacts with NO_x to convert it to mostly CO₂ and N₂. The agent must be in vapor form for the reaction to occur. Therefore, prior to injection, the reducing agent must be heated to a sufficient temperature so that when it comes in contact with the exhaust gas it is either already vaporized or it vaporizes on contact. SNCR is most effective in the temperature range of 1,600°F – 2,400°F. The waste gas temperature of the LM1500 turbines is approximately 400°F. Therefore, the exhaust gas would need to be heated to reach the temperature range at which SNCR is most effective. Heating the exhaust gas could be accomplished by steam addition or an additional heating source, either of which would result in additional combustion source emissions, including NO_x. For simplification, the additional heating source was not included in the cost estimate.

Moreover, SNCR is generally not suited to an emissions unit that is most frequently idle; or has limited, short-term operating hours; or has wide swings in its operating conditions. These swings in operation likely make it impractical to maintain the reducing agent at its desired stoichiometric ratio, and within optimum temperature ranges.

Despite these drawbacks to considering SNCR, it was considered to be technically feasible for purposes of this study, and its cost effectiveness was evaluated. US EPA has developed a cost spreadsheet designed for SNCR controlling an industrial or a utility boiler, not a gas turbine. An industrial boiler rated at 155.4 MMBtu/hour (i.e., the input rating of an LM1500) would have an estimated exhaust air flowrate of approximately 32,700 scfm using a default F-Factor of 10,500 scfm/MMBtu and an estimate of 20% excess air.

Sample Calculation: Boiler Exhaust Flowrate

Exhaust Flowrate (scfm) = 155.4 MMBtu/hour x 10,500 ft³/MMBtu / 60 min/hour x 120% [20% excess air] = **32,700 scfm [estimated exhaust flow rate]**

With the LM1500 turbines having a much higher exhaust flowrate than the calculated exhaust flowrate for a boiler of the same heat input capacity, the capital cost from the US EPA spreadsheet would need to be scaled using the ratio of the two flowrates. A cost estimating scaling factor exponent of 0.6 was used, as common for scaling capital costs of air pollution control equipment. The scaled factor used for the capital cost is calculated below.

Sample Calculation: SNCR Capital Cost Scaling Factor

Scaling Factor = (1,623,500 scfm [LM1500 Turbine Flowrate] / 31,300 scfm [calculated boiler exhaust flowrate])^{0.6}
[scaling factor exponent] = **10 [scaling factor for scaling capital cost of SNCR in US EPA Spreadsheet, Appendix 2]**

The updated scaled capital cost of the SNCR equipment is included in the table below.

Despite the infrequent, non-steady state conditions that would be problematic for a SNCR control system on the LM1500's, GE Aerospace performed this study-level cost effectiveness analysis to retrofit the ATF facility to accommodate the equipment which would be required for SNCR. This equipment would include the piping to get

the reducing agent into the stream, the storage tank to hold and supply the reducing agent, heat exchangers required to vaporize reducing agent, and heat exchangers required to heat the exhaust stream to a sufficient temperature.

The following parameters were common to evaluating cost effectiveness for the SNCR control device options.

PARAMETERS INPUT TO US EPA COST EFFECTIVENESS MODEL FOR SNCR			
Parameter	Value	UOM	Reference
Higher Heating Value of Natural Gas	1,070	BTU/scf	Engineering Estimate for Cincinnati
Net Plant Heat Input Rate	8.2	MM BTU/MW	Model Default Value for Natural Gas
Normalized Stoichiometric Ratio	1.05	dimensionless	Model Default Value
Concentration of reagent as stored	29.4	Percent	Model Default Value – Ammonia
	50	percent	Model Default Value – Urea
Density of reagent as stored	56	lbs/ft ³	Model Default Value – 29.4% Ammonia
	71	lbs/ft ³	Model Default Value – 50% Urea Solution
Concentration of reagent injected	10	percent	Model Default Value
Number of days reagent is stored	14	days	EPA Air Pollution Cost Manual ^v
Equipment Life	15	years	Assumed life for the add-on controls for LM1500 turbines
Annual Interest Rate	7.81	percent	Industry Average ^{vi}
Electricity Cost	\$0.0674	\$ per kW-hr	Recent GE Aerospace monthly bill
Natural Gas Cost	\$3.91	\$/MM BTU	Varies – Midpoint of two recent GEA monthly bills
Water Cost	\$0.0047	\$/gallon	Recent GE Aerospace monthly bill
Reagent Cost	\$1.53	\$/gallon	Web search for bulk liquid Ammonia (March 2024 Price)
	\$6.82	\$/gallon	Web search for bulk liquid Urea (March 2024 Price)
Contingency Factor	10	percent	Model Default Value
Scaling Factor	10	dimensionless	Calculated above based on flowrates and 0.6 exponent

A cost-effectiveness analysis was conducted considering a single combustion turbine and the parameters listed above, assuming a single turbine operates up to the combined fuel usage limit of 260.9 mmscf/year. The total capital investment includes a minimum estimated cost (provided by GE Aerospace Test Facilities Engineering) of \$1,200,000 for piping/ductwork, building and roadway modifications, and possible additional energy boosts needed for combining similar sources or housing the control device. The results are summarized in Section 11.

This study-level analysis considers a theoretical, albeit very likely impractical scenario that minimizes the cost of this control technology. A single one of the three identical turbines could, in theory, burn natural gas and emit NO_x up to the combined fuel usage and emissions limits. This summary presents that scenario. Actual costs would be much higher, as certain conditions require the simultaneous use of the three turbines.

GE Aerospace also performed a RACT/BACT/LEAR Clearinghouse (RBLC) search for gas turbines and the results indicated that there are no turbines installed in the last 10 years using SNCR as a control technology. Control technologies listed in the RBLC database included:

- Good combustion and operating practices
- Use of only natural gas

- Low-NOx burners (i.e., DLN)
- Selective catalytic reduction

Moreover, a more refined analysis would be required to consider this technology. Due to the infrequent operating nature and wide swings in operating conditions, GE Aerospace considers it highly unlikely that an air pollution control device manufacturer would recommend or warrant performance of SNCR for the ATF facility's turbines.

B. NON-SELECTIVE CATALYTIC REDUCTION

Non-selective catalytic reduction (NSCR) is similar to SNCR in that it uses a reducing agent to chemically reduce NOx. NSCR is an effective NOx add-on control strategy specifically suited to waste gas streams with low oxygen content, less than 4 percent, but ideally less than 0.5 percent. The oxygen content of the LM1500 waste gas is approximately 15 percent. Therefore, this option is not technically feasible.

C. SELECTIVE CATALYTIC REDUCTION USING AMMONIA, UREA, OR METHANE AS REDUCING AGENTS

"The SCR process chemically reduces the NOx molecule into molecular nitrogen and water vapor. A nitrogen-based reagent such as ammonia or urea is injected into the ductwork, downstream of the combustion unit. The waste gas mixes with the reagent and enters a reactor module containing catalyst. The hot flue gas and reagent diffuse through the catalyst. The reagent reacts selectively with the NOx within a specific temperature range and in the presence of the catalyst and oxygen.

Temperature, the amount of reducing agent, injection grid design and catalyst activity are the main factors that determine the actual removal efficiency. The use of a catalyst results in two primary advantages of the SCR process over the SNCR: higher NOx control efficiency and reactions within a lower and broader temperature range. The benefits are accompanied by a significant increase in capital and operating costs."^{vii}

In general, SNCR, operating within conditions necessary to benefit from a noble metal catalyst, is not suited to an emissions unit that a) is most frequently idle, and then b) has wide and rapid swings in its operating conditions. The technology is suited to conditions closer to steady-state operations.

One issue with non-steady state operation involves ammonia slip. That is, if there is more ammonia/urea than what is stoichiometrically needed to react within the exhaust stream, then ammonia will escape to the atmosphere. In the case of the GE Aerospace turbines, conditions change significantly between tests and during tests. The exhaust flow rate and the stoichiometric ratio of reagent would swing dramatically. Therefore, the use of SCR as a control strategy was determined to be technically infeasible.

This conclusion is consistent with the technology's application on gas turbines. SCR has proven feasible on combined cycle gas turbines, operating under more steady-state, continuous, baseload conditions, especially in conjunction with Heat Recovery Steam Generators (HRSGs).

D. INCINERATION

A thermal incinerator or afterburner destroys air pollutants by oxidation. "Applicable pollutants are primarily volatile organic compounds (VOC), some particulate matter (PM) commonly composed of soot (particles formed as a result of incomplete combustion of hydrocarbons, coke or carbon residue will also be destroyed in various degrees."^{viii} Carbon monoxide can also be oxidized to carbon dioxide by incineration.

NOx present in the stack (i.e., the waste gas) of the affected units in this study is a combination of nitrous oxide (NO) and nitrogen dioxide (NO₂). The NO portion oxidizes to NO₂ in the presence of oxygen upon release to the atmosphere.

Effective NOx flue gas treatment utilizes a redox process, whereby noxious NOx is chemically converted to innocuous compounds (nitrogen (N₂) and water) as described in the simplified equation $4 \text{ NO} + 4 \text{ NH}_3 + \text{O}_2 \rightarrow 4 \text{ N}_2 + 6 \text{ H}_2\text{O}$. NOx is thereby “reduced” (i.e., gains electrons), the opposite of “oxidation.”

In summary, incineration, i.e., thermal oxidation, does not reduce NOx emissions. Incineration is not a technically feasible option.

E. SCRUBBING

A chemical scrubber is a control technology that uses the principle of absorption to remove a substance from a waste gas stream. In this case, a scrubber would be installed where the exhaust stream gas from the turbines would pass through a liquid solvent (normally water) which would flow via gravity down through multiple stages of trays or a column of packing in a counter-current configuration. The portion of NOx that is soluble in the liquid would enter vapor-liquid equilibrium with the liquid, thus reducing NOx. A portion of the scrubbing liquid would be discharged as industrial wastewater. In this manner, liquid scrubbing generally involves a “cross media” transfer of air pollution to water pollution.

However, the waste gas of the turbines is not soluble in water. NO₂ is water soluble, NO is not. Typical NO₂:NOx ratios in the exhaust of combustion sources is 0.1 to 0.5 (based on default factors published by EPA for air dispersion modeling). NOx scrubbing would require a multi-step process, with a minimum of a three-stage scrubber system. The first stage would be to cool the exhaust temperature down to approximately 150°F. Then, the second stage would chemically convert NO to NO₂ with a specific reagent. The third stage would then be used to scrub NO₂, with another reagent. A large chemical system would need to be constructed for the reagents to be used to convert the NO in the exhaust stream into NO₂ and then scrub the NO₂.

In a case study from Tri-Mer Corporation^{ix}, the GE Plastics, now Saudi Arabia Basic Industries Corporation (SABIC), plant located in Mt. Vernon, IN, installed a NOx scrubber for control of nitric acid and NO₂ emissions formed from the use of nitric acid in the production of plastics. The case study indicated that typical NOx scrubbers are designed for continuous-process applications. The ATF operation is anything but a continuous process operation.

Installing a multi-stage NOx scrubbing system is not technically feasible.

9. SCAC

Separate circuit after-cooling (SCAC) is a control technology that cools the air before and/or after combustion to reduce NOx. Within industry, this technology has only been implemented with engines fueled by distillate oil. This technology is not applicable to the GE Aerospace natural gas-fired turbines.

10. Eliminating the NOx Sources

A RACT study must include a review of the NOx-emitting processes and consider pollution prevention opportunities whereby some alternative process or operating mode could reduce or eliminate the NOx emissions.

As described previously, GE Aerospace Engineering investigated eliminating the NOx sources completely with the transition to an electric motor-driven system with the equivalent power output.

No other opportunities for eliminating the ATF or its gas turbines were identified. Test operations are vital functions required by GE Aerospace customers (including the U.S. military) and for R&D purposes. Tests are conducted in a manner designed to obtain the measured performance data required by the FAA.

11. Conclusions and Establishing RACT

For purposes of this RACT study, it was assumed that select combustion controls or add-on NOx controls for the three natural gas-fired combustion turbines are technically feasible. The study considered one individual turbine since in theory, a single turbine could burn natural gas and emit NOx up to the combined limits, when computing estimated capital costs, operating costs, and cost effectiveness.

The following table summarizes the technically feasible technologies, and their overall cost effectiveness in reducing NOx.

COST EFFECTIVENESS OF TECHNICALLY FEASIBLE OPTIONS FOR NOX REDUCTION				
B011-B013 COMBUSTION TURBINES				
Control Method	NOx Removed (tpy)	TCI – Total Capital Investment \$	TAC - Total Annual Cost (\$/year)	Cost Effectiveness (\$/ton VOC Removed)
Conversion to Electric Motors	93.05	\$23,981,800	\$3,012,706	\$32,000
Replacement with New LM2500 Turbines with DLN-2 Combustors	83.75	\$37,000,000	\$3,200,000	\$38,200
Water Injection	73.17	\$6,060,000	\$3,700,000	\$51,640
SNCR – Ammonia	45.8	\$17,735,419	\$2,380,123	\$51,987
SNCR – Urea	45.8	\$17,735,419	\$2,432,985	\$53,142
Retrofit to DLN-2 Combustors	83.75	\$80,000,000	\$9,200,000	\$109,850

The most cost effective option is replacing the current LM1500 turbines with new electric motors. The annualized cost effectiveness for the replacement with electric motors is estimated to be \$32,000. The cost effectiveness was evaluated at the units’ potential to emit (an enforceable permit limit), and assuming that all the NOx in the ATF was created by the LM1500 turbines. These assumptions result in conservatively low estimates of cost effectiveness. The ATF does not operate at or near its PTE, and a significant portion of the NOx emissions (typically 12 percent) result from the Waukesha engines (Emissions Units B014, B015 and B016), which share the ATF’s 93.05 tons-per-year NOx limit.

Ohio EPA does not publish a threshold for cost effectiveness. However, NOx control costs in excess of \$10,000 per ton are generally considered unreasonable.

In conclusion, NOx controls are not economically reasonable for the LM1500 turbines at GE Aerospace.

RACT consists of:

- good combustion practices

- current fuel usage and emissions limits for the combustion turbines, and
- continuing to operate under engineering test plans designed to obtain the desired information within the permit’s emission limits

GE Aerospace proposes that the following language be used to represent RACT for the three combustion turbines (B011-B013).

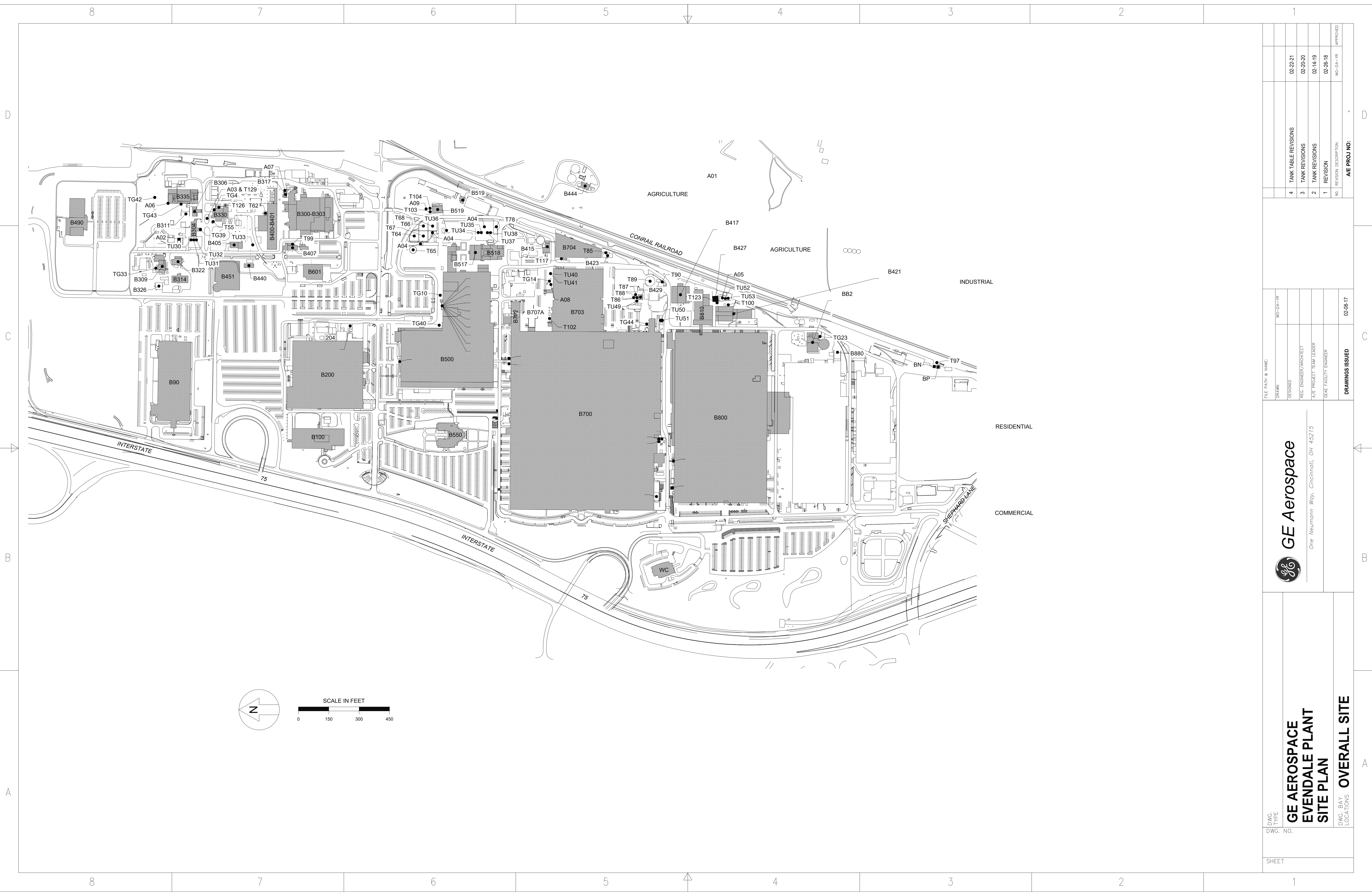
Install, maintain, and operate the source in accordance with the manufacturer’s specifications and with good operating practice for the control of the NOx emissions from the unit. Operate within the fuel use and emissions limits previously established in the Title V permit for these three units combined with B014, B015, and B016.

GE Aerospace is able to immediately follow the provisions of the current permit and demonstrate compliance with the current combined (B011-B016) fuel use and emissions limits shown in the table below.

COMBINED FUEL USE AND EMISSIONS LIMITS: B011-B013 COMBUSTION TURBINES AND B014-B016 WAUKESHA ENGINES	
Material/Pollutant	Annual Combined Limit
Natural Gas	260.9 mmscf/year
NOx	93.05 tons/year
CO	119.71 tons/year
VOC	41.15 tons/year
PE/PM ₁₀	15.67 tons/year
SO ₂	33.39 tons/year


12. References

- i “Dry Low NOx Combustion Systems for GE Heavy-Duty Gas Turbines,” Davis, L.B. and Black, S.H., GE Power Systems, Schenectady, NY, GER-3568G, https://www.gevernova.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/reference/ger-3568g-dry-low-nox-for-hdgt.pdf.
- ii “Nitrogen Oxides, Why and How They Are Controlled,” Table 3, External Combustion NOx Limiting Technologies, EPA-456/F-99-006R, November 1999, Clean Air Technology Center, OAQPS, US EPA. <https://www3.epa.gov/ttnecatc1/dir1/fnoxdoc.pdf>
- iii “Combustion Turbine NOx Control Technology Memo, Final, Rev. 1, January 2022, Eastern Research Group, Inc., Prepared by Sargent & Lundy, Chicago, IL. <https://www.epa.gov/system/files/documents/2022-03/combustion-turbine-nox-technology-memo.pdf>
- iv Ibid.
- v EPA Air Pollution Control Cost Manual, Section 4, Chapter 1, “Selective Noncatalytic Reduction,” Sorrels, J., Air Economics Group, OAQPS, EPA, April 2019.
- vi Average costs of capital by industry group compiled by New York University. “Aerospace/Defense” group selected.
- vii Air Pollution Control Technology Fact Sheet, Selective Catalytic Reduction (SCR); EPA-452/F-03-032.
- viii [Air Pollution Control Technology Fact Sheet, Thermal Incinerator; EPA-452F-03-022.](#)
- ix Case Study for a Resin Pilot Plant: <https://tri-mer.com/wet-scrubbers/nox-treatment.html>, NOx Scrubber install in Mt. Vernon, IN, Saudi Arabia Basic Industries Corporation (SABIC).



NO.	REVISION DESCRIPTION	DATE
4	TANK TABLE REVISIONS	02-22-21
3	TANK REVISIONS	02-20-20
2	TANK REVISIONS	02-14-19
1	REVISION	02-26-18
APPROVED		MD-DA-YR

FILE PATH & NAME	MD-DA-YR
DRAWN	
DESIGNED	
REG. ENGINEER/ARCHITECT	
A/E PROJECT TEAM LEADER	
SCALE FACILITY ENGINEER	
DRAWINGS ISSUED	02-08-17

 GE Aerospace One Neumann Way, Cincinnati, OH 45215	
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DWG. TYPE	GE AEROSPACE EVENDALE PLANT SITE PLAN
DWG. NO.	
DWG. BAY LOCATIONS	OVERALL SITE

SHEET	1
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Cost Estimate

Total Capital Investment (TCI)

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$1,045,746 in 2024 dollars	for Controlling a Boiler
Scaling Factor for Capital Costs =	10	
Capital costs for the SNCR ($SNCR_{cost}$) =	\$10,457,464 in 2024 dollars	for Controlling an LM1500 Turbine
Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2024 dollars	
Infrastructure Costs =	\$1,200,000 in 2024 dollars	
Balance of Plant Costs (BOP_{cost}) =	\$1,985,166 in 2024 dollars	
Total Capital Investment (TCI) =	\$17,735,419 in 2024 dollars	

SNCR Capital Costs ($SNCR_{cost}$)

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEV \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) =	\$1,045,746 in 2024 dollars
--	-----------------------------

Balance of Plant Costs (BOP_{cost})

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_x \text{ Removed/hr})^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) =	\$1,985,166 in 2024 dollars
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Annual Costs

Total Annual Cost (TAC)

$$TAC = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$323,701 in 2024 dollars
Indirect Annual Costs (IDAC) =	\$2,056,422 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	\$2,380,123 in 2024 dollars

Direct Annual Costs (DAC)

$$DAC = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times TCI =$	\$266,031 in 2024 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op} =$	\$49,477 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$742 in 2024 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op} =$	\$263 in 2024 dollars
Additional Fuel Cost =	$\Delta Fuel \times Cost_{fuel} \times t_{op} =$	\$7,188 in 2024 dollars
Additional Ash Cost =	$\Delta Ash \times Cost_{ash} \times t_{op} \times (1/2000) =$	\$0 in 2024 dollars
Direct Annual Cost =		\$323,701 in 2024 dollars

Cost Estimate

Indirect Annual Cost (IDAC) IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	\$7,981 in 2024 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$2,048,441 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$2,056,422 in 2024 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$2,380,123 per year in 2024 dollars
NOx Removed =	45.8 tons/year
Cost Effectiveness =	\$51,987 per ton of NOx removed in 2024 dollars

Cost Estimate

Total Capital Investment (TCI)

For Fuel Oil and Natural Gas-Fired Boilers: $TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$

Capital costs for the SNCR ($SNCR_{cost}$) =	\$1,045,746 in 2024 dollars	for Controlling a Boiler
Scaling Factor for Capital Costs =	10	
Capital costs for the SNCR ($SNCR_{cost}$) =	\$10,457,464 in 2024 dollars	for Controlling an LM1500 Turbine
Air Pre-Heater Costs (APH_{cost}) =	\$0 in 2024 dollars	
Infrastructure Costs =	\$1,200,000 in 2024 dollars	
Balance of Plant Costs (BOP_{cost}) =	\$1,985,166 in 2024 dollars	
Total Capital Investment (TCI) =	\$17,735,419 in 2024 dollars	

SNCR Capital Costs ($SNCR_{cost}$)

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEV \times RF$$

SNCR Capital Costs ($SNCR_{cost}$) = \$1,045,746 in 2024 dollars

Balance of Plant Costs (BOP_{cost})

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_x \text{ Removed/hr})^{0.12} \times RF$$

Balance of Plant Costs (BOP_{cost}) = \$1,985,166 in 2024 dollars

Annual Costs

Total Annual Cost (TAC)

$$TAC = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$376,563 in 2024 dollars
Indirect Annual Costs (IDAC) =	\$2,056,422 in 2024 dollars
Total annual costs (TAC) = DAC + IDAC	\$2,432,985 in 2024 dollars

Direct Annual Costs (DAC)

$$DAC = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times TCI =$	\$266,031 in 2024 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op} =$	\$102,282 in 2024 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	\$742 in 2024 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op} =$	\$319 in 2024 dollars
Additional Fuel Cost =	$\Delta Fuel \times Cost_{fuel} \times t_{op} =$	\$7,188 in 2024 dollars
Additional Ash Cost =	$\Delta Ash \times Cost_{ash} \times t_{op} \times (1/2000) =$	\$0 in 2024 dollars
Direct Annual Cost =		\$376,563 in 2024 dollars

Indirect Annual Cost (IDAC)

$$IDAC = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$7,981 in 2024 dollars
Capital Recovery Costs (CR) =	$CRF \times TCI =$	\$2,048,441 in 2024 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$2,056,422 in 2024 dollars

Cost Estimate

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$2,432,985 per year in 2024 dollars
NOx Removed =	45.8 tons/year
Cost Effectiveness =	\$53,142 per ton of NOx removed in 2024 dollars

Cost Estimate

NOx Control Cost Estimate		Electrification
DIRECT COST (Pollution Control Equipment)	Unit Cost (EPA Default Factors)	TOTAL (\$)
Direct Purchased Equipment		
Equipment Total (See Note 3)	A =	\$8,000,000
Instrumentation		\$100,000
Sales Taxes	0.07 A	\$560,000
Freight	0.05 A	\$400,000
Total Equipment Costs	B =	\$9,060,000
Direct Installation Cost		
Foundation and Support		\$2,000,000
New Building		\$0
Handling and Erection		\$500,000
Piping		\$0
Insulation		\$0
Painting		\$0
Electrical (new substation, service, lines)		\$10,000,000
Demolition		\$100,000
Ductwork		\$0
Total Direct Installation Costs		\$12,600,000
TOTAL Direct Investment (TDI) = (Total Equipment Cost + Total Direct Installation Cost)	TDI =	\$21,660,000
Indirect Installation Costs		
Engineering and Supervision		\$1,000,000
Construction and Field Expenses		\$1,000,000
Contractor Fees		\$0
Start-up		\$50,000
Model Study		\$0
Performance Tests	Estimate *	\$0
Overall Contingencies	0.03 B	\$271,800
Working Capital		
Total Indirect Installation Costs (TIC)	TIC =	\$2,321,800
TOTAL CAPITAL INVESTMENT (TCI) = (TDI +TIC)	TCI =	\$23,981,800

Cost Estimate

ANNUAL OPERATION & MAINTENANCE			
Direct Operating Costs (DA)			
	Operating Labor - Operator (0.5 hr/shift)	\$50.00 per hour	\$27,375
	Operating Labor - Supervisor	0.15 of operator	\$4,106
	Maintenance Labor (0.5 hr/shift)	\$50.00 per hour	\$27,375
	Maintenance Material	same as maintenance labor	\$27,375
	Replacement Parts		
			0 gals/hr
	Water	\$0.00468 per gallon	\$0
			0.000 MMBtu/hr
	Natural Gas Savings - Note 1	\$3.91 per MMBtu	-\$1,109,224
			0 kW
	Electricity Note 2	\$0.0674 per kWhr	\$2,182,488
	Savings - Maintenance Cost Reduction		-\$1,250,000
Total Direct Operating Costs (DA)		DA =	(\$90,505)
Indirect Operating Costs (IC)			
	Overhead	60% of total labor and materials	\$51,739
	Administrative Charges	0.02 TCI	\$479,636
	Property Tax	0.01 TCI	\$239,818
	Insurance	0.01 TCI	\$239,818
	Capital Recovery Cost (Assumes 7.81% interest over 30 years)	7.81% 30 TCI	\$2,092,200
Total Indirect Operating Costs (IA)		IA =	\$1,011,011
	Heat Recovery Credits		
Total Operating Costs (DA + IA - Heat Recovery Credits)		TOC =	\$920,506
Total Annualized Cost (Capital Recovery Cost + TOC)		TAC =	\$3,012,706
Permitted NOx Emissions (Tons) =			93.05
Tons VOC Removed @ 100% =			93.05
Cost per Ton NOx Removed (TAC / Tons VOC Removed) =		(nearest \$1,000)	\$32,000

Cost Estimate

NOTES:

Note 1 - Natural Gas Costs and Power Output		Note 2 - Electricity Needed	
Max NOx Emissions	93.05 tons NOx/year 186,100 lbs NOx/year	Power Output	30,762,075 kW-hr
Emission Factor	0.656 lbs NOx/MM BTU	Motor Efficiency	95%
Energy Input	283,689 MM BTU/year	Energy Input	32,381,131 kW-hr
Conversion Factor	293.07 kW-hr/MM BTU		
Energy Input	83,140,742 kW-hr		
Estimated Efficiency	37%		
Power Output	30,762,075 kW-hr		
Note 3 - Capital Cost Primary Items		Basis	
3 Electric Motors, 20K HP	\$2,000,000	Various motor & VFD quotes for other projects	
3 VFDs 15 MW	\$3,000,000	Various motor & VFD quotes for other projects	
3 Gearboxes 20K HP 1800 to 1500 RPM	\$3,000,000	Engineering estimate	
TOTAL	\$8,000,000		
Note 4 - Other Cost Items			
Engineering	\$1,000,000	5,000 hours engineering - estimate	
Installation Labor	\$1,000,000	6,000 hours labor -estimate	
Master Substation	\$10,000,000	Evendale estimate 2023 for 120 MW	