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25 April 2014

US EPA
Region V
Air Programs Branch, Air and Radiation Division
77 West Jackson Boulevard (AR-18J)
Chicago, Illinois 60604-3507

RE: Great Lakes Gas Transmission Limited Partnership
Deer River Compressor Station No. 4 (CS4)
Deer River, Minnesota
Federal Permit to Operate No. V-LL-2706100011-09-02
Part 71 Permit Renewal

Dear Sir or Madam,

This package is a submission for a Title V Part 71 permit renewal for the Deer River Compressor Station No. 4, Permit No. V-LL-2706100011-09-02. Station No. 4 is located near Deer River, Itasca County, Minnesota. Station No. 4 is also located within the external boundaries of the Leech Lake Band of Ojibwe Reservation.

Please contact me with any questions by phone at (832) 320-5835 or via e-mail at tiffany_grady@transcanada.com. Thank you very much for your assistance.

Sincerely,

Tiffany Grady

Tiffany Grady
Air Quality Specialist

cc: Houston Air Files

Great Lakes Gas Transmission Limited Partnership
Deer River Compressor Station No. 4 (CS4)
Itasca County, Minnesota

Part 71 Permit Renewal Application
Federal Permit to Operate No.: V-LL-2706100011-09-02

April 2014

Prepared for:

Great Lakes Gas Transmission, LP
717 Texas Street, Suite 2400
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Prepared by:

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Katy, Texas 77449

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SECTION 1.0 TECHNICAL SUPPORT DOCUMENTATION

1.1 INTRODUCTION

Great Lakes Gas Transmission Company, as operator and agent for Great Lakes Gas Transmission Limited Partnership (GLGT), operated nearly 2,000 miles of large-diameter underground pipeline, which transports natural gas for delivery to customers in the Midwestern and northeastern United States and eastern Canada. Great Lakes also transports gas to and from storage fields located near its pipeline in Michigan. The Great Lakes pipeline system starts at an interconnection with TransCanada Pipelines Limited (TransCanada) near the Manitoba-Minnesota border, and traverses northern Minnesota, northern Wisconsin, and the upper and lower peninsulas of Michigan. The Great Lakes pipeline system then reconnects with the TransCanada system near St. Clair, Michigan. A Great Lakes pipeline in the Upper Peninsula of Michigan interconnects with TransCanada facilities at Sault Ste. Marie. The pipeline's 14 compressor stations, placed approximately 75 miles apart, operate to keep natural gas moving through the system. GLGT has its headquarters in Troy, Michigan. The Great Lakes pipeline system, and other interstate natural gas transmission pipelines, makes up the long-distance link between natural gas production fields, local distribution companies, and end users.

Great Lakes operates a natural gas pipeline compressor station, Deer River Compressor Station No. 4 (CS4), SIC Code 4922, NAICS Code 486210) located approximately 2 miles west of the city of Deer River, Itasca County, Minnesota. The station is located on privately owned fee land within the external boundaries of the Leech Lake Band of Ojibwe Reservation. The primary function of the Deer River Station is to provide motive force for natural gas flowing through the pipeline. The facility operates two stationary natural gas-fired turbines, which in turn drive two natural gas compressors. The pipeline system normally operates continuously but at varying loads, 24 hours per day, 365 days per year.

The Federal Permit to Operate No. V-LL-2706100011-09-02 for the Deer River Compressor Station No. 4 expires November 1, 2014. This application is being submitted in accordance with the requirements set forth in Title 40, Part 71, of the Code of Federal Regulations (40 CFR Part 71) to assure compliance by the source, Deer River Station, with all application requirements of Title V of the Clean Air Act (CAA, 42 USC 7401, et seq.).

As required under Section 4.S of the Operating Permit, GLGT is submitting this permit renewal application within the specified time frame for review by EPA Region V. Therefore, according to 40 CFR §71.5(a)(1) and (2), this is considered a timely renewal application and the facility will be authorized to continue to operate until the permitting authority takes final action on this application.

This document and the completed U.S. EPA Part 71 Federal Operating Permit Application forms attached in Appendix A comprise the application for the Title V Air Permit renewal. This document is provided to support the information contained in the application forms. Section 2.0 describes the facility, its location, the various emission units at the facility, and the operating methods and procedures practiced at the Deer River Station. Sections 3.0 and 4.0 detail the potential and actual emissions from the various emission units at the facility. Finally, Section 5.0 comprises a review of the applicable Federal Regulations. Support materials for calculations and compliance determinations are provided in the attached appendices. Page ii, in the front of the document, lists the appendices and their content.

SECTION 2.0 FACILITY DESCRIPTION

2.1 FACILITY SITE

Located within SE ¼ of the NW ¼ of Section 33, Township 145 North, Range 25 West, the Deer River Station is approximately 2 miles west of the city of Deer River, Itasca County, Minnesota. The Site Location Map is included in Appendix B.

Three buildings house the emission sources on the site: two compressor buildings and one warehouse building. The Plot Plan and the Stack Location Map are included in Appendix B. Each compressor building houses one stationary natural gas-fired turbine/compressor unit. The warehouse building houses a natural gas-fired standby electrical generator. In addition, a service building houses a natural gas-fired boiler and also provides office space, a facility operations computer control and a lunch room. Two full-time staff are employed at the facility and visitors to the station are infrequent.

The facility property is predominately undeveloped and grass-covered. In the middle of the facility property, asphalt-paved driveways and parking areas surround the facility buildings. The entrance to the facility from the access road is located on the east side of the property. The access road extends approximately 0.3 miles south of U.S. Highway 2.

2.2 AREA CLASSIFICATION

Deer River Compressor Station No. 4 is located in Itasca County, Minnesota, which is designated by the U.S. EPA as "Unclassifiable/Attainment" for PM (PM10 and PM2.5), Ozone (1-hour and 8-hour), CO, and Lead, "Better than national standards" for SO2, and "Cannot be classified or better than national standards" for NO2 (40 CFR §81.324, Attainment Status Designations: Minnesota).

The facility property, which occupies an area of approximately 20 acres and is owned by GLGT, is bordered on the west, north, and south by undeveloped grass-covered and wooded land, and on the east by the access road. The Deer River Station is located on privately-owned fee land within the external boundaries of the Leech Lake Band of Ojibwe Reservation. There are no Mandatory Federal Class I areas within 100 kilometers of the Deer River Station.

2.3 PROCESS DESCRIPTION

2.3.1 Current Operations

The Deer River Station operates to transport natural gas through a dual 36-inch pipeline system. Two stationary natural gas-fired turbine-driven compressors are used to increase the pressure of the natural gas in the transmission pipeline. Flow diagrams are included in Appendix C.

Each compressor building at the Deer River Station houses a three-component stationary natural gas-fired turbine system utilized for compressing the natural gas, which include a gas generator, a power turbine, and a gas compressor as illustrated in Figure 2.3.1 below.

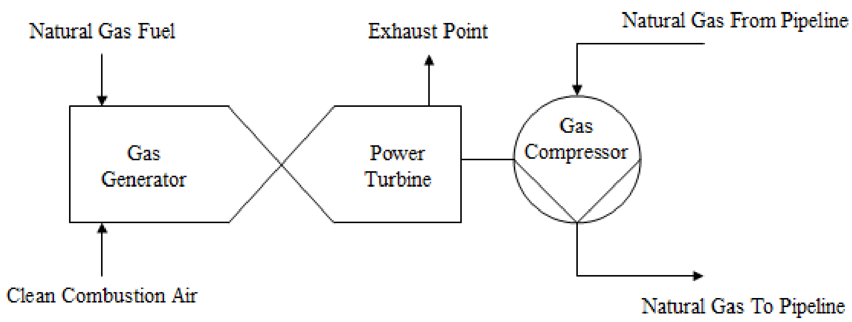

Figure 2.3.1 Turbine/Compressor Process Diagram

The gas generator/power turbine system is considered a simple-cycle system with residual gas energy exhausted into the atmosphere. The gas generator is the component that generates criteria and hazardous air pollutant emissions by means of the combustion of pipeline-quality natural gas. (The FERC Gas Tariff, General Terms and Conditions is included in Appendix D. This document contains pipeline-quality gas standards.) The gas generator, an aircraft-derivative turbine designed to burn natural gas, consists of a clean combustion-air compression section and a natural gas combustor section. The gas generator produces thermodynamic energy or gas horsepower. The gas horsepower, which represents maximum ambient rating for the gas generator unit, is the figure used when calculating the potential to emit (PTE) for the system.

The gas generator is coupled to the power turbine by a transition duct. Gas generator combustion products expand through one or more turbine stages. The power turbine converts the thermodynamic or gas energy from the gas generator to mechanical or rotative energy. The rotative power produced by the power turbine is mechanically coupled to a separate unit, the gas compressor, which pressurizes natural gas to move it through the pipeline system. This rotative power may also be referred to as shaft or brake horsepower.

2.3.2 Natural Gas-Fired Turbine Routine Maintenance and Repair

As a federally regulated public utility, GLGT follows a strict preventive maintenance program for its turbines and auxiliary equipment to provide an uninterrupted flow of natural gas through its transmission pipeline system in compliance with its FERC-issued Certificates of Public Convenience and Necessity, granted pursuant to the federal Natural Gas Act, (15 USC 717, *et seq.*). Because GLGT is a public utility providing essential natural gas transportation services to large portions of the United States and Canada, it cannot accept periods of downtime that would interrupt this flow. GLGT's routine equipment maintenance and repair program is designed to facilitate uninterrupted delivery of natural gas and includes visual inspections, physical examinations, cleaning of combustion areas, and other routine maintenance activities. The program provides for the "change-out" of the gas generator component of a turbine/compressor unit when lengthy repairs or servicing are needed so that the pipeline system remains in full operation.

Routine repair of a gas generator consists of removing it from service and exchanging it for a like-kind gas generator (change-out). The spare gas generator brought in is one of several that are maintained at GLGT's off-site warehouses for this purpose. The defective gas generator is either repaired on site, if the repairs are minor, or shipped to a factory-authorized repair facility. When repairs are completed, the gas generator is returned to one of the off-site warehouses for a future change-out within the GLGT system. The gas generator that was exchanged for the defective unit remains in service until there is a need to remove it for repairs or an overhaul.

2.3.3 Proposed Modifications

There are no process modifications proposed under this permit application. GLGT would like to request an equipment modification in this permit application. Section 2.(B) of the statement of basis associated with the existing permit includes a parts-cleaning bin in the list of insignificant activities. This equipment has been removed from the facility and removed from forms IE and IA-01. Therefore, GLGT would like to request that it also be removed from the permit. It was previously identified as "Parts cleaning bin (30 gallons/year)", insignificant based on 40 CFR 71.5(c)(11)(ii)(A) and Minn. R. 7008.4100.

2.4 DESCRIPTION OF INSIGNIFICANT ACTIVITIES

Regulations contained in 40 CFR Part 71 Subpart A (Federal Operating Permit Programs, Operating Permits) list information required to be included in an application. A list of insignificant activities and emission limits that need not be included in permit applications can be found in 40 CFR §71.5(c)(11). There are certain small emission sources at the Deer River Station that do not fall into those listed in the regulation. GLGT would like to request that the following small emission sources at the Deer River Station be considered for inclusion into the permit as insignificant activities.

- 7007.1300, subp. 3(E)(2): Nonhazardous air pollutant VOC storage tanks <10,000 gallons and vapor pressure ≤1.0 psia at 60°F. *One ~400 gallon diesel storage tank with dispensing operation located in the parking lot west of the office/service building.*
- 7007.1300, subp. 3(H)(3): Brazing, soldering, or welding equipment. *Three arc welding torches and one oxy-acetylene welding, approximately 20 hours per year, used to repair equipment and fabricate parts.*
- 7007.1300, subp. 3(I): Individual emission unit with the potential to emit less than limits listed. *Two portable gasoline-powered engines: One 2.8 horsepower Honda GX100 electrical generator and one 3.5 horsepower Honda GX120 water pump.*
- 7007.1300, subp. 4: Emission units with emissions less than all limits listed in supb. 4 but not included in supb. 2. *Three Reznor Space Heaters each with a capacity of 200,000 Btu/hr and a residential hot water heater with a capacity of 33,000 Btu/hr; total capacity 633,000 Btu/hr with potential emissions less than the limits listed in supb. 4.A, 4.B, and 4.C.(1). These heaters are not included in subp. 2, which addresses space heaters with a combined total capacity less than 420,000 Btu/hr. The warehouse houses three Reznor natural gas-fired space heaters each rated at 0.2 MMBtu/hr.*
- 7008.4110: Conditionally insignificant PM and PM10 Emitting Operations: *Small abrasive cleaning operation located in a hood with all emissions filtered and vented inside the building.*

2.5 DESCRIPTION OF EMISSION UNITS

The following emission units are located at the facility: two stationary natural gas-fired turbines, one natural gas-fired standby electrical generator, and one natural gas-fired boiler. Emission unit numbers, stack/vent numbers, and emission unit descriptions are shown in Table 2.5. In addition, a Stack Location Map is located in Appendix B.

None of the emission units at the Deer River Station are equipped with pollution control devices.

Table 2.5: Description of Emission Units

Emission Unit No.	Stack/ Vent No.	Description	Manufacturer/ Model	GLGT Emission Unit No.	Installation Date	Heat Input (MMBtu/hr)
EU 001	SV 001	18,000 hp Natural Gas-Fired Turbine	Rolls Royce Avon 101G	401	1971	187.2
EU 002	SV 002	23,000 hp Natural Gas-Fired Turbine	General Electric LM 1600	402	1993	184.0
EU 003	SV 003	899 hp Natural Gas-Fired Standby Electrical Generator	Waukesha L36GL (4SRB, low emission unit)	N/A	1997	7.2
EU 004	SV 004	Natural Gas-Fired Boiler	Kewanee L3W125-G	N/A	1993	5.23

2.5.1 Stationary Natural Gas-Fired Turbines (EU 001, EU 002)

Two stationary natural gas-fired turbines are located at this facility. The Deer River Station was constructed in 1968-69 and consists of two natural gas-fired turbine units - one Avon (Rolls Royce) 101G and one General Electric LM1600. These are numbered as Units 401 and 402, respectively.

EU001, installed in 1971, is an Avon 101G stationary natural gas-fired turbine. EU001 has a maximum ambient rating of 18,000 horsepower[1] based on ISO standards and a heat input rating of 187.2 MMBtu/hr (calculated using 10,400 Btu per horsepower-hour (Btu/Hp-Hr) as the average heat rate factor; see Section 3.1).

[1] Horsepower is dependent upon ambient temperature and elevation, therefore maximum ambient gas horsepower for the gas generator component is used for emission calculation purposes.

EU002 is a General Electric LM1600 stationary natural gas-fired turbine installed under MPCA Air Emission Facility Permit No. 365E-92-0T-1 in 1993 as a replacement unit for two Orenda units originally installed in 1969 and 1970. EU002 has a maximum ambient rating of 23,000 horsepower[2] based on ISO standards and a heat input rating of 184.0 MMBtu/hr (calculated using 8,000 Btu/Hp-Hr as the heat rate factor; see Section 3.1).

2.5.2 Natural Gas-Fired Standby Electrical Generator (EU 003)

A single natural gas-fired standby electrical generator, located in the warehouse building, provides electrical power for critical operations during temporary electrical power outages and during peak loading. The four stroke rich burn unit, installed in 1997, is a Waukesha model L36GL with a rated heat input of 7.2 MMBtu/hr and a horsepower rating of 899 HP. The natural gas-fired standby electrical generator was installed in 1997.

2.5.3 Natural Gas-Fired Boiler (EU 004)

The Deer River Station uses a 5.23 MMBtu/hr natural gas-fired Kewanee L3W125-G boiler that was installed in 1993.

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[2] FERC has certificated this natural gas-fired turbine compressor assembly at 15,300 horsepower at NEMA conditions (80°F, 1000 ft elevation). Horsepower is dependent upon ambient temperature and elevation, therefore maximum ambient gas horsepower for the gas generator component is used for emission calculation purposes.

SECTION 3.0 POTENTIAL TO EMIT (PTE) – CALCULATIONS

3.1 STATIONARY NATURAL GAS-FIRED TURBINES (EU 001, EU 002)

For the two turbines, calculations of PTE of criteria pollutants and hazardous air pollutants (HAPs), other than NOx and CO, are based upon emission factors published in the latest edition of the U.S. Environmental Protection Agency (EPA) Compilation of Air Pollutant Emission Factors (AP-42), Supplement F, Section 3.1 Stationary Gas Turbines. Appendix F contains the AP-42 information used in determining emission factors. NOx and CO emission factors for the stationary natural gas-fired turbines were calculated from emission test results. Appendix J contains emission factors from the most recent EU001 and EU002 Emission Test Report. Criteria pollutant emission factors are reported in pounds per MMBtu (lb/MMBtu) or pounds per million standard cubic feet (lb/MMSCF).

From maximum rated heat inputs in units of MMBtu/hr and fuel inputs in units of standard cubic feet per hour (SCFH), annual fuel usage in units of MMSCF/yr and annual energy usage in units of MMBtu/yr were calculated. A natural gas heating value of 1,020 Btu/SCF was used. The PTE for criteria pollutants and for HAPs were calculated by multiplying emission factors by the rated heat input and/or by the fuel input figures. Potential emissions calculations for each emission unit are included on individual PTE calculation spreadsheets that are located in Appendix E.

Because no pollution control devices are installed on the emission units at the Deer River Station, all emissions were calculated as uncontrolled emissions.

Using EU001 (Avon 101G) as an example, the following rated heat input was calculated:

18,000 HP x 10,400 Btu/HP-hr x (MMBtu/1,000,000 Btu) = 187.2 MMBtu/hr

3.2 NATURAL GAS-FIRED STANDBY ELECTRICAL GENERATOR (EU 003)

The maximum rated heat input for the natural gas-fired standby electrical generator was calculated by multiplying rated horsepower by an average brake-specific fuel consumption of 8,000 Btu/HP-hr. The standby electrical generator has a rated heat input of 7.2 MMBtu/hr and no backup fuel is used. Criteria and HAP emissions, excluding NOx, for the natural gas-fired standby electrical generator are calculated using the emission factors published in AP-42, Section 3.2 Natural Gas-Fired Reciprocating Engines. The NOx factor was based on the NOx emission rate listed in the manufacturer's specification included in Appendix K. Potential emissions calculations for each emission unit are included on individual PTE calculation spreadsheets that are located in Appendix E.

3.3 NATURAL GAS-FIRED BOILER (EU 004)

The maximum rated heat input for the natural gas-fired boiler is 5.23 MMBtu/hr. Criteria and HAP emissions were calculated using the emission factors published in AP-42, Section 1.4 Natural Gas Combustion. Potential emissions calculations for each emission unit are included on individual PTE calculation spreadsheets that are located in Appendix E.

3.4 SUMMARY OF POTENTIAL EMISSIONS

Table 3.4: Summary of Potential Emissions (tpy)

Emission Unit No.	Emission Unit Description	NOx	VOC	SO_2	PM_{10}	CO	Lead	HAP
EU 001	Avon 101G Turbine	201.70	1.72	2.79	5.41	485.07	n/a	0.84
EU 002	General Electric LM1600 Turbine	483.55	1.69	2.74	5.32	29.01	n/a	0.83
EU 003	Waukesha L36GL Generator	18.08	0.93	0.02	0.61	117.18	n/a	1.02
EU 004	Kewanee L3W125-G Boiler	2.25	0.12	0.01	0.17	1.89	n/a	0.04
Total PTE Emissions (tpy)		705.58	4.47	5.56	11.51	633.16	n/a	2.73

SECTION 4.0 ACTUAL EMISSIONS CALCULATIONS

4.1 EXISTING PERMIT EMISSION LIMITATIONS

According to the current Title V Operating Permit, the stationary natural gas-fired turbine EU002 at the Deer River Station is subject to the following NOx and SO2, emission limits:

EU 002 Permit Limits Under NSPS Subpart GG	
Limit	Regulatory Reference
Emissions shall not exceed 196 ppmv NOx at 15% oxygen, dry basis	40 CFR 60.332(a)(2)
Fuel burned shall not exceed 0.8 % by weight sulfur (8,000 ppmw)	40 CFR 60.333(b)

GLGT performs fuel sulfur testing according to an EPA-approved custom monitoring plan approved on November 20, 1998. In addition, the sulfur content of pipeline quality natural gas throughout the United States is limited by FERC-driven tariff agreements to no more than 20 grains of total sulfur per 100 cubic feet of gas (see Appendix D). This limit is approximately 640 ppm or 0.064 percent by weight.

Based on the demonstration of the current tariff sheet (see Appendix D) for the compressor station, under 40 CFR §60.334(h)(3)(i), EU002 is in compliance with the fuel sulfur limitation of 40 CFR §60.333(b), which assures compliance with 40 CFR §60.333(a). As stated in the current permit, requirement 2.(B).1.ii., GLGT "has elected not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, as allowed by 40 C.F.R. § 60.3 34(h)(1). [GLGT] must demonstrate that the gaseous fuel meets the definition of natural gas in § 60.33 1(u). [GLGT] shall make this demonstration through the use of gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/l00 scf or less.

4.2 ACTUAL EMISSIONS CALCULATIONS

4.2.1 Stationary Natural Gas-Fired Turbines (EU 001, EU 002)

No physical or operational limitations have been imposed upon the stationary natural gas-fired turbines, although a NOx emission limit based on volume has been set for EU002. Compliance testing has shown that the EU002 turbine operates well within the NOx NSPS emission limit of 196 ppmv.

Actual emissions of criteria pollutants and hazardous air pollutants are calculated based on the actual amount of natural gas consumed by each unit in 2012. Actual NOx and CO emissions were calculated for unit EU001 and EU002, by calculating emission factors for each unit based on the results of the most recent stack test. The emissions factors are listed in Appendix J.

4.2.2 Natural Gas-Fired Standby Electrical Generator (EU 003)

Actual emissions for the standby electrical generator were calculated using the recorded hours of operation in 2012.

4.2.3 Natural Gas-Fired Boiler (EU 004)

Actual emissions for the natural gas-fired boiler were calculated using the recorded hours of operation in 2012.

4.3 SUMMARY OF ACTUAL EMISSIONS

Table 4.3: Summary of Actual Emissions (tpy)

Emission Unit No.	Emission Unit Description	NOx	VOC	SO_2	PM_{10}	CO	Lead	HAP
EU 001	Avon 101G Turbine	0.22	0.002	0.003	0.006	0.52	n/a	0.0009
EU 002	General Electric LM1600 Turbine	0.50	0.002	0.003	0.006	0.03	n/a	0.0009
EU 003	Waukesha L36GL Generator	0.48	0.02	0.0005	0.02	3.12	n/a	0.03
EU 004	Kewanee L3W125-G Boiler	0.06	0.003	0.0004	0.005	0.05	n/a	0.001
Total PTE Emissions (tpy)		1.26	0.03	0.007	0.03	3.72	n/a	0.03

SECTION 5.0 REGULATORY APPLICABILITY SUMMARY

5.1 FEDERAL REGULATIONS

5.1.1 Prevention of Significant Deterioration

The Prevention of Significant Deterioration (PSD) applicability is triggered by construction of a "major stationary source" or "major modification" to an existing major stationary source. PSD regulations in 40 CFR 52.21 define a major source as any source type (belonging to a list of 28 categories) that emits or has the potential to emit 100 tpy or more of any regulated pollutant under the CAA, or any other source type that emits or has the potential to emit such pollutants in amounts equal to or greater than 250 tpy [40 CFR 52.21 (b)(1)(i)]. The potential to emit is based on the maximum design capacity of a source, subject to federally enforceable permit limitations (e.g., limits on annual hours of operation) and takes into account pollution control efficiency.

The Deer River area is considered an attainment area for all criteria pollutants (40 CFR 50). As a result, the emissions from a new source or the modification of an existing source must be reviewed for applicability under 40 CFR §52.21. Natural gas pipeline transportation is not among the 28 industrial categories listed in the PSD rules as being major sources if the PTE is equal to or greater than 100 TPY of any single regulated pollutant [40 CFR 52.21(b)(1)(i)(a)]. However, the Deer River Station does have a PTE of more than 250 TPY of CO and NOx. Therefore, the station is considered a major source under the federal PSD rules [40 CFR 52.21(b)(1)(i)(b)].

The Deer River Station was built prior to August 7, 1980, the date of applicability for PSD. One modification to the facility was made after August 7, 1980 (the full replacement in 1993 of two Orenda turbines with a new GE LM 1600 turbine unit, EU002). Consequently, NSR applicability to individual sources would be based upon installation date and the mass of emittants.

EU001 was installed in 1971 which is prior to the August 7, 1980 date of applicability for PSD. Therefore, EU001 is not subject to NSR.

The installation of EU002 in 1993 as a replacement for the two Orenda gas generator units was not considered a significant modification to a PSD major stationary source because the replacement resulted in a non-significant net emissions increase to the major stationary source, as detailed in the Construction Permit Application. This was also confirmed by the Minnesota Pollution Control Agency (MPCA) in the issuance of Air Emission Facility Permit No. 365E-92-OT-1 on July 9, 1992. Because the installation of EU002 resulted in a non-significant net emissions increase to a major stationary source, EU002 is not subject to NSR.

5.1.2 New Source Performance Standards (NSPS)

NSPS contained in 40 CFR 60 require new, modified, or reconstructed sources to control emissions to the level achievable by the best demonstrated technology as specified in the relevant regulations. These NSPS regulations were reviewed to determine their applicability to the Deer River Station equipment or to confirm non-applicability as appropriate. The results of this review are summarized below by regulatory citation.

40 CFR 60 Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

This standard is applicable to each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr). This standard is not applicable to the Deer River Station because there are no natural gas-fired boilers with a design heat input capacity of 2.9 MW (10 MMBtu/hr) or greater.

40 CFR 60 Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973 and prior to May 19, 1978

This regulation applies to petroleum liquids storage vessels with storage capacity greater than 40,000 gallons and constructed, reconstructed, or modified after June 11, 1973 but before May 19, 1978. There are no petroleum storage vessels with capacity greater than 40,000 gallons at this facility. Therefore, this regulation is not applicable.

40 CFR 60 Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978 and prior to July 23, 1984

This regulation applies to petroleum liquids storage vessels with storage capacity greater than 40,000 gallons and constructed, reconstructed, or modified after May 18, 1978 but before July 23, 1984. There are no petroleum storage vessels with capacity greater than 40,000 gallons at this facility. Therefore, this regulation is not applicable.

40 CFR 60 Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

This regulation applies to volatile organic liquid storage vessels with storage capacity greater than 75 cubic meters (19,812.9 gal) and constructed, reconstructed, or modified after July 23, 1984. There are no volatile organic liquid storage vessels with capacity greater than 75 cubic meters at this facility. Therefore, this regulation is not applicable.

40 CFR 60 Subpart GG - Standards of Performance for Stationary Gas Turbines

The standards of performance in Subpart GG apply to stationary gas turbines with a heat input at peak load greater than or equal to 10 MMBtu/hr and have commenced construction, modification, or reconstruction after October 3, 1977. The EU001 turbine at the Deer River Station is greater than 10 MMBtu/hr, but it was installed prior to October 3, 1977. Therefore this regulation is not applicable to EU001. Future modifications or reconstruction of the turbine may make it subject.

The EU002 turbine at the Deer River Station has a capacity of more than 10 MMBtu/hr of heat input, but was installed in 1993. Therefore, EU002 is subject to NSPS.

EU002 is subject to NOx emission standards as calculated by 40 CFR 60.332(a)(2). The rule specifies the following formula be used to calculate the NOx emission concentration limit:

$$STD = 0.0150\frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in §60.335(b)(1)) NOx emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NOx emission allowance for fuel - bound nitrogen as defined in paragraph (a)(4) of this section

Table 4.1 shows the information used to calculate the NSPS NOx emission limitation for EU002.

Table 4.1
Allowable NOx Emissions

Turbine Unit No.	**Y, Actual Measured Heat Rate**[3]	**Y, converted units** (kJ/W-hr)[4]	**F** (NOx % vol)	**Calculated NOx Emission Concentration** (% by volume, 15% O2, dry)[5]
402	7,777.73	11.001	0	0.0196

Fuel Nitrogen Testing Requirements: EPA policy does not require fuel nitrogen testing.

Sulfur Dioxide (SO2) testing and fuel sulfur limitations under NSPS: Per 40 CFR 60.333(b), "...No owner or operator subject to the provisions of this section may burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8% by weight...." GLGT's Federal Energy Regulatory Commission (FERC) Gas Tariff, Second Revised Volume No. 1, limits the amount of sulfur that may be present in the natural gas in GLGT's pipeline system. The FERC tariff, enclosed as Appendix D provides that total sulfur within the natural gas cannot exceed 20 grains per hundred cubic feet of gas (grains/100 ft^3), or 0.064% by weight.

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[3] The Actual Measured Heat Rate is the average of tests at maximum load performed in 1995 of the fleet of same-model turbines owned by ANR at the time.
7,777.73 Btu/HP-hr = 140.89 MMbtu/hr heat input / 18,114.54 HP x 1,000,000 Btu/MMbtu

[4] 11.001 kJ/W-hr = 7,777.73 Btu/HP-hr x 1054.8 J/Btu x 1 kJ/1000 J x 1.341 HP/kW x 1 kW/1000 W

[5] 0.0196 % NOx vol = (0.015 * 14.4/11.001) + 0

Previously, compliance has been demonstrated in accordance with federal NSPS requirements and a custom schedule approved by EPA on November 20, 1998.

With this permit renewal, GLGT intends to demonstrate compliance with the sulfur limits using their current tariff sheet under 40 CFR 60.334(h)(3)(i):

> "(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in §60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:
>
> (i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less"

Table 4.2
Comparison of Unit Concentrations for Applicable Natural Gas Fuel Sulfur Concentrations

Source	Concentration (grains/100 SCF)	Concentration (% by weight)	Concentration (ppm, m/m)
NSPS	248.1	0.8	8,000
Federal Tariff	20.0	0.0645	645
Actual Lab and OM-10 Analyzer Results	0.2	0.000645	6.45

Stack testing has substantiated that EU002 is in compliance with the NOx standards presented above. GLGT is also in compliance with the sulfur standard because the gas quality characteristics of the current tariff sheet specify that the maximum total sulfur content is 20.0 grains/100 scf or less.

40 CFR 60 Subpart KKK-Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants

This regulation is not applicable to the Deer River Station because the facility is not a natural gas processing plant as defined in the regulation. A Natural Gas Processing Plant is defined as: "any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both." The facility does not engage in extraction of natural gas liquids from field gas or fractionate mixed natural gas liquids to natural gas products. Therefore this regulation does not apply.

40 CFR 60 Subpart LLL - Standards of Performance for Onshore Natural Gas Processing: SO_2 Emissions

This regulation is applicable to a sweetening unit and a sulfur recovery unit at a natural gas processing plant. The regulation defines a sweetening unit as a process device used to separate hydrogen sulfide and carbon dioxide contents from sour natural gas and a sulfur recovery unit as a process device that recovers elemental sulfur from acid gas. The Deer River Station processes natural gas but does not operate a sweetening unit or a sulfur recovery unit. Therefore, this regulation is not applicable.

40 CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (CI ICE)

This regulation applies to owners or operators of stationary CI ICE that commence construction, modification or reconstruction after July 11, 2005 and to manufacturers of 2007 and later model year CI ICE. The Deer River Station does not operate any stationary CI ICE; therefore this regulation does not apply.

40 CFR 60 Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (SI ICE)

On March 18th, 2008, US EPA finalized Standards for Performance for Stationary Spark Ignition Internal Combustion Engines (SI ICE). This regulation applies to owners or operators of stationary SI ICE that commence construction, modification or reconstruction after June 12, 2006 and to manufacturers of applicable SI. The Waukesha L36GL generator at the Deer River Station was constructed prior to June 12, 2006 and has not been modified or reconstructed since June 12, 2006. Therefore this regulation does not apply.

40 CFR 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

The standards of performance for Stationary Combustion Turbines, applies to combustion turbines with peak load heat input greater than 10 MMBtu/hour constructed, modified, or reconstructed after February 18, 2005. The turbines at the Deer River station are both greater than 10 MMBtu/hr, but were installed in 1971 and 1993, and have not been modified or reconstructed since February 18, 2005. Therefore this regulation is not applicable. Future modifications or reconstruction of the turbine may make them subject. The periodic replacement of stationary gas turbine components for overhaul or repair, does not subject the permittee to the requirements of Subpart KKKK unless the changes meet the definition of “modification” or “reconstruction”.

5.1.3 National Emission Standards for Hazardous Air Pollutants (NESHAP)

Federal NESHAP regulations promulgated pursuant to Section 112 of the CAA are found in 40 CFR Parts 61 and 63. In general, NESHAP, or Maximum Achievable Control Technology (MACT) standards apply to major stationary sources of HAP emissions, defined as potential-to-emit of 10 tons or more per year of any single HAP or 25 tons or more per year of any combination of HAP and minor stationary sources of HAP emissions (thresholds less than a major source). The Deer River Station is considered a minor source of HAPs due to total potential HAP emissions less than 25 tpy and potential formaldehyde emissions less than 10 tpy. Potentially applicable NESHAPs are discussed below.

40 CFR 61 Subpart M - National Emission Standard for Asbestos

The Deer River Station may at times engage in demolition and/or renovation activities involving asbestos-containing materials (ACM). Therefore, the facility could be potentially subject to Subpart M, Standards for Demolition and Renovation (40 CFR 61.145). Procedures are in place to ensure the facility complies with these standards.

40 CFR 61 Subpart V - National Emission Standard for Equipment Leaks (Fugitive Emission Sources)

This regulation is not applicable to the Deer River Station because the provisions of this subpart apply to sources that are intended to operate in volatile hazardous air pollutant (VHAP) service. "In VHAP service means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 10 percent by weight a volatile hazardous air pollutant (VHAP) as determined according to the provisions of 61.245(d)." The Deer River Station processes do not have any sources that operate in VHAP service.

40 CFR 63 Subpart A – General Provisions

This regulation has general provisions that are referenced by other more specific NESHAP regulations.

40 CFR 63 Subpart HH - NESHAP from Oil and Natural Gas Production Facilities

This regulation is not applicable to the Deer River Station because the facility is a transmission facility and is not an oil and gas production facility as defined in this regulation.

40 CFR 63 Subpart HHH - NESHAP from Natural Gas Transmission and Storage Facilities

Subpart HHH establishes national emission limitations and operating limitations for natural gas transmission and storage facilities that are major sources of HAP emissions. The rule affects facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final user. Not only is the Deer River Station a minor source of HAP emissions, it is a natural gas compression facility, but does not operate a glycol dehydration unit, which is the only "affected" source under the regulation. Therefore, the station is not subject to this regulation.

40 CFR 63 Subpart EEEE – NESHAP for Organic Liquids Distribution (non-Gasoline)

40 CFR 63 Subpart EEEE was promulgated on August 25, 2003 and applies to organic liquids distribution (OLD) operations that are located at, or are part of, a major source of hazardous air pollutant (HAP) emissions as defined in section 112(a) of the Clean Air Act. This regulation does not apply to the tanks or loading operations at the Deer River Station not only because it is a minor source of HAP emissions, but also because per 40 CFR 63.2334(c)(2), OLD operations located at Natural Gas Transmission facilities as defined in 40 CFR 63 Subpart HHH are exempt from the requirements of 40 CFR 63 Subpart EEEE (OLD MACT).

40 CFR 63 Subpart ZZZZ – NESHAP for Stationary Reciprocating Internal Combustion Engines (RICE)

Subpart ZZZZ regulates HAP emissions from existing, new, and reconstructed stationary compression ignition (CI) and spark ignition (SI), emergency and non-emergency, RICE located at major and area sources of HAP emissions. This standard is potentially applicable to the Deer River Station. The facility's 899 hp natural gas-fired emergency generator is an existing (installed in 1997) four-stroke rich burn engine. Per §63.6640(f), the engine will be subject to operating requirements in §63.6640(f)(1)-(4).

40 CFR 63 Subpart DDDDD – NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters

The Industrial/Commercial/Institutional Boilers and Process Heaters MACT for major sources was promulgated on March 21, 2011, and regulates HAP emissions from new and existing industrial, commercial, or institutional boilers and process heaters located at major sources of HAP emissions. The EPA subsequently issued a notice on May 18, 2011 to postpone the effective dates of the final rule until the completion of reconsideration or judicial review, whichever is earlier. On January 9, 2012, the EPA vacated the May 18, 2011 notice that delayed the effective dates of the Boiler MACT rule. The notice on final action on reconsideration was published in the Federal Register on January 31, 2013. This rule is not applicable to the boiler located at the Deer River Station, since the Station is a minor source of HAP.

40 CFR Subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers Area Sources

The Industrial/Commercial/Institutional Boilers and Process Heaters for area sources was promulgated on March 21, 2011, and regulates HAP emissions from industrial, commercial, or institutional boilers located at area sources of HAP emissions. This rule is potentially applicable to the Deer River Station because it is a minor source of HAP. However, per §63.11237, the 5.23 MMBtu/hr natural gas-fired Kewanee L3W125-G (EU004) boiler installed in 1993 is classified as a gas-fired boiler because it burns only natural gas not combined with any solid fuels. As such, the boiler is not subject to Subpart JJJJJJ per §63.11195(e).

5.1.4 Compliance Assurance Monitoring (CAM)

Enhanced monitoring requirements have been adopted into 40 CFR 64. The enhanced monitoring requirements are referred to as Compliance Assurance Monitoring (CAM). CAM is applicable to sources that have a potential to emit in excess of major source thresholds, not considering “tailpipe” emission controls, and use an “active” control device to achieve compliance with the emission limit. Combustion controls may be considered in evaluating the potential to emit.

An emission unit is subject to CAM if all of the following criteria are satisfied:

- the unit is located at a major source that is required to obtain a Part 70 or Part 71 permit;
- the unit is subject to an emission limitation or standard for a regulated air pollutant;
- the unit uses an active control device to achieve compliance with any such emission limit or standard, and
- the unit has potential pre-controlled emissions of the applicable air pollutant above the major source threshold.

The potential emissions of NOx from each of the two natural gas-fired turbines are in excess of the appropriate major source thresholds. EU-002 is subject to a NOx emission limitation of 196 ppmv NOx at 15% oxygen on a dry basis (Section 2.0(A.)1. of the Title V Operating Permit). However, neither of the turbines employ an active control device to control NOx emissions. Therefore, the CAM rule does not apply to these units at this time.

5.1.5 Accidental Releases

Applicability to this regulation is based on the type and quantity of certain regulated substances stored at a facility, and the Deer River Station does not exceed the applicability thresholds (40 CFR 68.10). Therefore, the station is not subject to the Risk Management Programs for Chemical Accidental Release Prevention Requirements.

5.1.6 Acid Rain Requirements

Utilities and other facilities that combust fossil fuel (coal) and generate electricity for wholesale or retail sale may be subject to acid rain program requirements, including the requirements to hold an acid rain permit under 40 CFR 72. The Deer River Station does not fall under this definition and is therefore not subject to the Acid Rain Requirements.

5.2 ADDITIONAL STATE AIR POLLUTION CONTROL REQUIREMENTS

5.2.1 General Construction and Operating Permit Requirements

Per Minn. Rules Part 7007.0200 Sources Required or Allowed to Obtain a Part 70 Permit, Subpart 2, any major stationary source of air pollutants, as defined in section 302 of the act (General Provisions; Definitions), that directly emits or has the potential to emit, 100 tons per year or more of any air pollutant and, effective July 1, 2011, 100,000 tons per year CO_2e of greenhouse gases, must obtain a permit under this part.

The Deer River Station directly and potentially emits concentrations of air pollutants in excess of 100 tons per year. This application satisfies the requirements of Minn. Rules Part 7007.0200 Subpart 2, Sources Required or Allowed to Obtain a Part 70 Permit.

5.2.2 Control of Pollutant Emissions

Minn. Rules Part 7011.0105 Visible Emission Restrictions for Existing Facilities states, "No owner or operator of an existing emission facility to which parts 7011.0100 to 7011.0115 are applicable shall cause to be discharged into the atmosphere from the facility any gases which exhibit greater than 20 percent opacity; except for one six-minute period per hour of not more than 33 percent opacity." Due to the nature of natural gas combustion emissions, little or no opacity is generated. Emission standards for visible air contaminants have not been defined for the stationary natural gas turbines in any other rule. The MPCA has not requested testing for opacity emissions. Therefore, the Deer River Station is in compliance with the visible emissions rule.

Minn. Rules Part 7001.0150 Preventing Particulate Matter from Becoming Airborne states: "No person shall cause or permit the handling, use, transporting, or storage of any material...or permit a building or its appurtenances or a road, or a driveway, or an open area to be constructed, used, repaired, or demolished without applying all such reasonable measures as may be required to prevent particulate matter from becoming airborne." GLGT has written a Fugitive Emission Control Plan, which was approved by the MPCA and has been implemented at the Deer River Station. Therefore, the station is in compliance with the particulate requirements.

Minn. Rules Part 7011.2300 Standards of Performance for Stationary Internal Combustion Engines, Subpart 1, Visible Air Contaminants states: "No owner or operator of any stationary internal combustion engine shall cause or permit the emission of visible air contaminants from the engine in excess of 20 percent opacity once operating temperatures have been attained." The standby electrical generator is the only emission unit at the Deer River Station that meets the definition of stationary internal combustion engine. The MPCA has not required testing for opacity emissions. Therefore, the Deer River Station is in compliance with the visible air contaminants section of the Minnesota standards of performance for stationary internal combustion engines.

Minn. Rules Part 7030.0040 Noise Standards describe the limiting levels of sound established on the basis of present knowledge for the preservation of public health and welfare. The State may request testing of sources. The MPCA has not requested the Deer River Station to do noise testing. Therefore, the station is in compliance with the Noise Standards.

5.2.3 Compliance with Air Emission Inventory Requirements

Minn. Rules Part 7019.3000 Emission Inventory, Subpart 1 states that all owners or operators of emission reporting facilities (those required to obtain an air permit under Chapter 7007) shall submit an annual emission inventory report to the MPCA, in a format specified by the commissioner, relating to ammonia, carbon monoxide, particulate matter, and all “chargeable pollutants” as defined in Minn. Rules Part 7002.0015, Subpart 2a (such as NOx, VOC, PM10, SO2, Lead). The report shall be submitted on or before November 15 of the year following the year being reported per Section 4.0.B of the Title V Operating Permit (40 CFR 71.6(a)(7), 71.9).

The Deer River Station is an emission reporting facility. GLGT provided an emission inventory to the EPA every year that submittal was required. Therefore, the station is in compliance with the Emission Inventory rules.

5.2.4 Reporting, Recordkeeping, Testing, and Inspection Requirements

Minn. Rules Part 7007.0500, Subp. 2(K)(1) Compliance Plan states, "A description of the compliance status of the stationary source at the time of application submittal … and a description of the methods used to determine compliance…" shall be included in the permit application. Section 5 of this Title V application, Regulatory Review and Compliance Plan, constitutes the compliance plan for this Title V application. Additionally, GLGT does submit an annual compliance report to the EPA. Therefore, the Deer River Station is in compliance with the Compliance Plan/Certification Reports requirements.

Minn. Rules Part 7017.2020, Performance Tests General Requirements, Subpart 1 states "The owner or operator of an emission facility shall arrange to conduct a performance test at any emission facility at the times required by an applicable requirement or compliance document and at additional times if the commissioner requests a performance test..." GLGT has submitted all testing notifications, test plans, and test results in a timely manner. GLGT will conduct compliance testing as requested by the commissioner. Therefore, the Deer River Station is in compliance with the monitoring and testing requirements of Minn. Rules Chapter 7017.

APPENDIX A:

PART 71 FEDERAL OPERATING PERMIT

APPLICATION FORMS

- Form 5900-79: General Information and Summary (GIS)
- Form 5900-80: Emissions Unit Description for Fuel Combustion Sources (EUD-1)
  - E0001
  - EU002
  - EU003
  - EU004
- Form 5900-83: Insignificant Emissions (IE)
- Form 5900-84: Emissions Calculations (EMISS)
  - E0001
  - EU002
  - EU003
  - EU004
- Form 5900-85: Potential to Emit Summary (PTE)
- Form 5900-86: Initial Compliance Plan and Compliance Certification (I-COMP)
- Form 5900-02: Certification of Truth, Accuracy, and Completeness (CTAC)

OMB No. 2060-0336, Approval Expires 06/30/2015

Federal Operating Permit Program (40 CFR Part 71)

GENERAL INFORMATION AND SUMMARY (GIS)

A. Mailing Address and Contact Information

Facility name _Great Lakes Gas Transmission – Deer River Compressor Station No. 4 (CS4)_______

Mailing address: Street or P.O. Box _717 Texas Street_______________________________________

City _Houston______________________________ State _TX____ ZIP _77002_____-_________

Contact person: _Tiffany Grady______________ Title _Air Quality Specialist_______________

Telephone (_832_) _320_ - _5835_ Ext. _________

Facsimile (_832_) _320_ - _6835_

B. Facility Location

Temporary source? ___Yes _X_No Plant site location _31641 Great Lakes Road______________

City _Deer River__________________ State_MN__ County_Itasca_________ EPA Region_V__

Is the facility located within:

Indian lands? _X_YES ___ NO OCS waters? ___YES _X_ NO

Non-attainment area? ___ YES _X_NO If yes, for what air pollutants? _N/A_____

Within 50 miles of affected State? ___ YES _X_ NO If yes, What State(s)? _____

C. Owner

Name _Great Lakes Gas Transmission Limited Partnership_ Street/P.O. Box _5250 Corporate Drive___

City _Troy___________________________________ State_MI___ ZIP_48098___ - _________

Telephone (_832_) _320_ - _5835_ Ext_________

D. Operator

Name _Great Lakes Gas Transmission Company__ Street/P.O. Box _5250 Corporate Drive_________

City _Troy___________________________________ State _MI___ ZIP _48098__ - _______

Telephone (_832_) _320_ - _5835_ Ext_________

E. Application Type

Mark only one permit application type and answer the supplementary question appropriate for the type marked.

___Initial Permit _X_ Renewal ___ Significant Mod ___ Minor Permit Mod(MPM)

___ Group Processing, MPM ___ Administrative Amendment

For initial permits, when did operations commence? _____ /_____ /_____

For permit renewal, what is the expiration date of current permit? _11_/_1_/_2014_

F. Applicable Requirement Summary

Mark all types of applicable requirements that apply.

___ SIP ___ FIP/TIP ___ PSD ___Non-attainment NSR

___ Minor source NSR _X_ Section 111 ___ Phase I acid rain ___Phase II acid rain

_X_ Stratospheric ozone ___ OCS regulations ___ NESHAP ___ Sec. 112(d) MACT

___ Sec. 112(g) MACT ___ Early reduction of HAP ___ Sec 112(j) MACT ___ RMP [Sec.112(r)]

___ Tank Vessel requirements, sec. 183(f)) ___ Section 129 Standards/Requirement

___ Consumer / comm.. products, ' 183(e) ___ NAAQS, increments or visibility (temp. sources)

Has a risk management plan been registered? ___YES _X_NO Regulatory agency ____________

Phase II acid rain application submitted? ___YES _X_NO If yes, Permitting authority ____________

G. Source-Wide PTE Restrictions and Generic Applicable Requirements

Cite and describe any emissions-limiting requirements and/or facility-wide "generic" applicable requirements.

Not applicable.

H. Process Description

List processes, products, and SIC codes for the facility.

Process	Products	SIC
Natural Gas Transmission	Not applicable.	4922

I. Emission Unit Identification

Assign an emissions unit ID and describe each emissions unit at the facility. Control equipment and/or alternative operating scenarios associated with emissions units should by listed on a separate line. Applicants may exclude from this list any insignificant emissions units or activities.

Emissions Unit ID	Description of Unit
EU 001	Natural gas-fired turbine Unit 401
EU 002	Natural gas-fired turbine Unit 402
EU 003	Natural gas-fired Standby Electrical Generator
EU 004	Natural gas-fired Boiler

J. Facility Emissions Summary

Enter potential to emit (PTE) for the facility as a whole for each air pollutant listed below. Enter the name of the single HAP emitted in the greatest amount and its PTE. For all pollutants stipulations to major source status may be indicated by entering "major" in the space for PTE. Indicate the total actual emissions for fee purposes for the facility in the space provided. Applications for permit modifications need not include actual emissions information.

NOx ___705.58___ tons/yr VOC ___7.25___ tons/yr SO2 ___5.56___ tons/yr

PM-10 ___11.22___ tons/yr CO ___525.96___ tons/yr Lead ___N/A___ tons/yr

Total HAP ___3.99___ tons/yr

Single HAP emitted in the greatest amount ___Formaldehyde___ PTE ___2.819___ tons/yr

Total of regulated pollutants (for fee calculation), Sec. F, line 5 of form FEE _1_ tons/yr

K. Existing Federally-Enforceable Permits

Permit number(s) _V-LL-2706100011-09-02_ Permit type _Part 71_ Permitting authority _EPA Region V_

Permit number(s) ________________ Permit type ____________ Permitting authority _________

L. Emission Unit(s) Covered by General Permits

Emission unit(s) subject to general permit _N/A____

Check one: ___ Application made ___ Coverage granted

General permit identifier ______________________________ Expiration Date ____/____/____

M. Cross-referenced Information

Does this application cross-reference information? _X_ YES ___ NO (If yes, see instructions)

INSTRUCTIONS FOLLOW

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 06/30/2015

Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES (EUD-1)

A. General Information

Emissions unit ID _EU 001____ Description_Unit 401, Stationary Natural Gas-Fired Turbine Unit_

SIC Code (4-digit) _4922____ SCC Code_20300202_

B. Emissions Unit Description

Primary use _Natural gas prime mover_________ Temporary Source ___Yes _X_No

Manufacturer _Rolls Royce_________________ Model No. _Avon 101G___________

Serial Number _NA_______________________ Installation Date_1_/_1_/_1971_

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

Other (describe) ____

Boiler horsepower rating_________________ Boiler steam flow (lb/hr)_______________

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___Spreader stoker ___Underfeed stoker ___Overfeed stoker

___ Traveling grate ___Shaking grate ___Pulverized, wet bed ___ Pulverized, dry bed

Actual Heat Input _0.20*_MM BTU/hr Max. Design Heat Input _187.2_MM BTU/hr

* Based on 2012 actual fuel use averaged over 8760 operating hours.

C. Fuel Data

Primary fuel type(s)_Natural gas________ Standby fuel type(s)_None________________

Describe each fuel you expected to use during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (cf, gal., or lb.)
Natural Gas	0.8	0.0	1020

D. Fuel Usage Rates

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas	1.73 MMscf/yr	0.184 MMscf/hr	1,607.72 MMscf/yr

E. Associated Air Pollution Control Equipment

Emissions unit ID_NA________ Device type____

Air pollutant(s) Controlled____________________ Manufacturer__________________________

Model No._______________________ Serial No.________________________

Installation date_____/_____/_________ Control efficiency (%) ____________

Efficiency estimation method____

F. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (this is not common).

Stack height (ft) _48.08_____ Inside stack diameter (ft) _5.8_____

Stack temp(^{o}F) _839_____ Design stack flow rate (ACFM) _NA____

Actual stack flow rate (ACFM) _189,000____ Velocity (ft/sec) _119.22_______

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 06/30/2015

Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES (EUD-1)

A. General Information

Emissions unit ID _EU 002____ Description_Unit 402, Stationary Natural Gas-Fired Turbine Unit_

SIC Code (4-digit) _4922____ SCC Code_20300202_

B. Emissions Unit Description

Primary use _Natural gas prime mover_________ Temporary Source ___Yes _X_No

Manufacturer _General Electric________________ Model No. _LM1600___________

Serial Number _NA_______________________ Installation Date_5_/_1_/_1993_

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

Other (describe) ____

Boiler horsepower rating_________________ Boiler steam flow (lb/hr)_______________

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___Spreader stoker ___Underfeed stoker ___Overfeed stoker

___ Traveling grate ___Shaking grate ___Pulverized, wet bed ___ Pulverized, dry bed

Actual Heat Input _0.19*_MM BTU/hr Max. Design Heat Input _184.0_MM BTU/hr

* Based on 2012 actual fuel use averaged over 8760 operating hours.

C. Fuel Data

Primary fuel type(s)_Natural gas________ Standby fuel type(s)_None________________

Describe each fuel you expected to use during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (cf, gal., or lb.)
Natural Gas	0.8	0.0	1020

D. Fuel Usage Rates

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas	1.64 MMscf/yr	0.180 MMscf/hr	1,580.24 MMscf/yr

E. Associated Air Pollution Control Equipment

Emissions unit ID_NA________ Device type____

Air pollutant(s) Controlled___________________ Manufacturer_________________________

Model No.______________________ Serial No.______________________

Installation date_____/_____/_________ Control efficiency (%) ____________

Efficiency estimation method____

F. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (this is not common).

Stack height (ft) _40.0_____ Inside stack diameter (ft) _6.60_____

Stack temp(^{o}F) _934.0______ Design stack flow rate (ACFM) _NA____

Actual stack flow rate (ACFM) _249,809____ Velocity (ft/sec) _94.67_______

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 06/30/2015

Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES (EUD-1)

A. General Information

Emissions unit ID _EU 003____ Description_Natural gas-fired Emergency Standby Generator_

SIC Code (4-digit) _4922____ SCC Code_20300201_

B. Emissions Unit Description

Primary use _Supplemental Electrical Generator_________ Temporary Source ___Yes _X_No

Manufacturer _Waukesha Motor Co._______________ Model No. _L36GL___________

Serial Number _C-12221/1_____________________ Installation Date_10_/_8_/_1997_

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

Other (describe) ____

Boiler horsepower rating_________________ Boiler steam flow (lb/hr)_______________

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___Spreader stoker ___Underfeed stoker ___Overfeed stoker

___ Traveling grate ___Shaking grate ___Pulverized, wet bed ___ Pulverized, dry bed

Actual Heat Input _7.2_MM BTU/hr Max. Design Heat Input _7.2_MM BTU/hr

C. Fuel Data

Primary fuel type(s) Natural gas Standby fuel type(s) None

Describe each fuel you expected to use during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (cf, gal., or lb.)
Natural Gas	0.8	0.0	1020

D. Fuel Usage Rates

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas	1.643 MMscf/yr	0.007 MMscf/hr	61.77 MMscf/yr

E. Associated Air Pollution Control Equipment

Emissions unit ID NA Device type________

Air pollutant(s) Controlled________ Manufacturer________

Model No.________ Serial No.________

Installation date____/____/____ Control efficiency (%) ________

Efficiency estimation method________

F. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (this is not common).

Stack height (ft) 24.4 Inside stack diameter (ft) 0.67

Stack temp(^{o}F) 800 Design stack flow rate (ACFM) 3,100

Actual stack flow rate (ACFM) 5,743 Velocity (ft/sec) 271.6

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 06/30/2015

Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES (EUD-1)

A. General Information

Emissions unit ID _EU 004____ Description_Natural gas-fired Boiler_

SIC Code (4-digit) _4922____ SCC Code_10200603_

B. Emissions Unit Description

Primary use _Boiler_________ Temporary Source ___Yes _X_No

Manufacturer _Kewanee________________ Model No. _L3W125-G___________

Serial Number ______________________ Installation Date___/___/_1993_

Boiler Type: _X_ Industrial boiler ___ Process burner ___ Electric utility boiler

Other (describe) ____

Boiler horsepower rating_125 hp_______ Boiler steam flow (lb/hr)_maximum 5,000 lb/hr_

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___Spreader stoker ___Underfeed stoker ___Overfeed stoker

___ Traveling grate ___Shaking grate ___Pulverized, wet bed ___ Pulverized, dry bed

Actual Heat Input _5.23_MM BTU/hr Max. Design Heat Input _5.23_MM BTU/hr

C. Fuel Data

Primary fuel type(s)_Natural gas________ Standby fuel type(s)_None________________

Describe each fuel you expected to use during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (cf, gal., or lb.)
Natural Gas	0.8	0.0	1020

D. Fuel Usage Rates

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas	1.194 MMscf/yr	0.005 MMscf/hr	44.92 MMscf/yr

E. Associated Air Pollution Control Equipment

Emissions unit ID_NA________ Device type_______________________________________

Air pollutant(s) Controlled___________________ Manufacturer_________________________

Model No.______________________ Serial No.______________________

Installation date_____/_____/_________ Control efficiency (%) ____________

Efficiency estimation method____

F. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (this is not common).

Stack height (ft) ______ Inside stack diameter (ft) ______

Stack temp(^{o}F) ______ Design stack flow rate (ACFM) _____

Actual stack flow rate (ACFM) _____ Velocity (ft/sec) ________

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 06/30/2015

Federal Operating Permit Program (40 CFR Part 71)

INSIGNIFICANT EMISSIONS (IE)

On this page list each insignificant activity or emission unit. In the "number" column, indicate the number of units in this category. Descriptions should be brief but unique. Indicate which emissions criterion of part 71 is the basis for the exemption.

Number	Description of Activities or Emissions Units	RAP, except HAP	HAP
1	• 7007.1300, subp. 3(E)(2): Nonhazardous air pollutant VOC storage tanks <10,000 gallons and vapor pressure ≤1.0 psia at 60°F. *One ~400 gallon diesel storage tank with dispensing operation located in the parking lot west of the office/service building.*	✓	
4	• 7007.1300, subp. 3(H)(3): Brazing, soldering, or welding equipment. *Three arc welding torches and one oxy-acetylene welding, approximately 20 hours per year, used to repair equipment and fabricate parts.*	✓	
2	• 7007.1300, subp. 3(I): Individual emission unit with the potential to emit less than limits listed. *Two portable gasoline-powered engines: One 2.8 horsepower Honda GX100 electrical generator and one 3.5 horsepower Honda GX120 water pump.*	✓	
4	• 7007.1300, subp. 4: Emission units with emissions less than all limits listed in supb. 4 but not included in supb. 2. *Three Reznor Space Heaters each with a capacity of 200,000 Btu/hr and a residential hot water heater with a capacity of 33,000 Btu/hr; total capacity 633,000 Btu/hr with potential emissions less than the limits listed in supb. 4.A, 4.B, and 4.C.(1). These heaters are not included in subp. 2, which addresses space heaters with a combined total capacity less than 420,000 Btu/hr. The warehouse houses three Reznor natural gas-fired space heaters each rated at 0.2 MMBtu/hr.*	✓	
1	• 7008.4110: Conditionally insignificant PM and PM10 Emitting Operations: *Small abrasive cleaning operation located in a hood with all emissions filtered and vented inside the building.*	✓	

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 06/30/2015

Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID _EU 001_____

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates: Actual Annual Emissions (tons/yr)	Emission Rates: Potential to Emit: Hourly (lb/hr)	Emission Rates: Potential to Emit: Annual (tons/yr)	CAS No.
Emissions for this unit are listed in Appendix E – Table 4 for EU-001.				

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 06/30/2015

Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID _EU 002_____

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
Emissions for this unit are listed in Appendix E – Table 4 for EU-002.				

Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID _EU 003_____

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates: Actual Annual Emissions (tons/yr)	Emission Rates: Potential to Emit: Hourly (lb/hr)	Emission Rates: Potential to Emit: Annual (tons/yr)	CAS No.
Emissions for this unit are listed in Appendix E – Table 4 for EU-003.				

United States Environmental Protection Agency

Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID _EU 004_____

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

	Emission Rates			
		Potential to Emit		
Air Pollutants	Actual Annual Emissions (tons/yr)	Hourly (lb/hr)	Annual (tons/yr)	CAS No.
Emissions for this unit are listed in Appendix E – Table 4 for EU-004.				

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 06/30/2015

Federal Operating Permit Program (40 CFR Part 71)

POTENTIAL TO EMIT (PTE)

For each unit with emissions that count towards applicability, list the emissions unit ID and the PTE for the air pollutants listed below and sum them up to show totals for the facility. You may find it helpful to complete form **EMISS** before completing this form. Show other pollutants not listed that are present in major amounts at the facility on attachment in a similar fashion. You may round values to the nearest tenth of a ton. Also report facility totals in section **J** of form **GIS**.

Emissions Unit ID	Regulated Air Pollutants and Pollutants for which the Source is Major (tons/yr)						
	NOx	VOC	SO2	PM10	CO	Lead	HAP
EU 001	201.70	1.72	2.79	5.41	485.07	n/a	0.84
EU 002	483.55	1.69	2.74	5.32	29.01	n/a	0.83
EU 003	18.08	3.72	0.02	0.31	9.99	n/a	2.27
EU 004	2.25	0.12	0.01	0.17	1.89	n/a	0.04
FACILTY TOTALS	705.58	7.25	5.56	11.22	525.96	n/a	3.99

Federal Operating Permit Program (40 CFR Part 71)

INITIAL COMPLIANCE PLAN AND COMPLIANCE CERTIFICATION (I-COMP)

SECTION A - COMPLIANCE STATUS AND COMPLIANCE PLAN

Complete this section for each unique combination of applicable requirements and emissions units at the facility. List all compliance methods (monitoring, recordkeeping and reporting) you used to determine compliance with the applicable requirement described above. Indicate your compliance status at this time for this requirement and compliance methods and check "YES" or "NO" to the follow-up question.

Emission Unit ID(s): EU-002 (Unit 402, LM 1600)
Applicable Requirement (Describe and Cite)
Permit Section 2.0(A)(1) NOx limit: 196 ppmv @15% O_2 on a dry basis. 40 CFR 60.332(a)(2).
Compliance Methods for the Above (Description and Citation):
Testing. Performance testing completed on 2/16/2010 –showing compliance (also refer to "Performance Testing" – Permit Condition Section 2.0(B)(2) below.).
Compliance Status:
_X_ In Compliance: Will you continue to comply up to permit issuance? _X_Yes ____No
___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No
___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes ____No

Emission Unit ID(s): EU-002 (Unit 402, LM 1600)
Applicable Requirement (Describe and Cite)
Permit Section 2.0(A)(2) Sulfur NSPS limit: shall not burn any fuel which contains sulfur in excess of 0.8% by weight. 40 CFR 60.333(b)
Compliance Methods for the Above (Description and Citation):
Operation and Tariff Recordkeeping. Unit fueled with pipeline quality natural gas. Company tariff requirements shows compliance: "shall not contain more than 20 grains total sulfur/100 scf of gas" (0.068% by weight).
Compliance Status:
_X_ In Compliance: Will you continue to comply up to permit issuance? _X_Yes ____No
___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No
___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes ____No

Emission Unit ID(s): All Emission Units
Applicable Requirement (Describe and Cite)
Permit Section 2.0(A)(3) Good Air Pollution Control Practice. 40 CFR 60.11(d)
Compliance Methods for the Above (Description and Citation):
Operation Procedures and Recordkeeping. Emission Units are operated in conjunction with manufacturer & industry standards for proper operation & maintenance. Emission units have no pollution control equipment. Standard Operation and Maintenance procedures are located onsite. Permit-specific training was provided to all "facility plant operators" on 10/11/2010. Records of training materials and sign-in sheets are kept onsite.
Compliance Status:
_X_ In Compliance: Will you continue to comply up to permit issuance? _X_Yes ____No
___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No
___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes ____No

Emission Unit ID(s): EU-002 (Unit 402, LM 1600)
Applicable Requirement (Describe and Cite)
Permit Section 2.0(B)(1) and (2) Monitoring and Testing.
Compliance Methods for the Above (Description and Citation):
Tariff Recordkeeping. GLGT does not claim an allowance for fuel bound nitrogen, therefore, the nitrogen content is not monitored. GLGT does not monitor sulfur content and shows compliance with sulfur content through valid tariff sheet.
Compliance Status:
_X_ In Compliance: Will you continue to comply up to permit issuance? _X_Yes ____No
___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No
___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes ____No

Emission Unit ID(s): EU-002 (Unit 402, LM 1600)
Applicable Requirement (Describe and Cite)
Permit Section 2.0(B)(3) Monitoring and Testing
Compliance Methods for the Above (Description and Citation):
Testing and Recordkeeping. Performance testing on EU002 was conducted within 12 months of the effective date of this permit and will be conducted subsequently every 5 years thereafter. Testing for NOx will be conducted in accordance with test methods, procedures & calculations in 40 CFR Part 60 (Method 20). The 2/16/10 stack testing at CS 4 was completed in accordance with an approved stack test plan. A written report was submitted to EPA on 3/11/2010.
Compliance Status:
_X_ In Compliance: Will you continue to comply up to permit issuance? _X_Yes ____No
___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No
___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes ____No

Emission Unit ID(s): Facility
Applicable Requirement (Describe and Cite)
Permit Section 2.0(C) Recordkeeping. 40 CFR 71.6(a)(3)
Compliance Methods for the Above (Description and Citation):
Recordkeeping. Performance test result reports, training records, and operation & maintenance procedures are maintained onsite.
Compliance Status:
_X_ In Compliance: Will you continue to comply up to permit issuance? _X_Yes ____No
___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No
___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes ____No

Emission Unit ID(s): Facility
Applicable Requirement (Describe and Cite)
Permit Section 3.0(A) General Recordkeeping. 40 CFR 71.6(a)(3)(ii)
Compliance Methods for the Above (Description and Citation):
Recordkeeping. All records of required monitoring information and support information are maintained for a period of 5 calendar years from the date of the sampling, measurement, report or application.
Compliance Status:
_X_ In Compliance: Will you continue to comply up to permit issuance? _X_Yes ____No
___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No
___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes ____No

Emission Unit ID(s): Facility
Applicable Requirement (Describe and Cite)
Permit Section 3.0(B) Semiannual monitoring reporting & deviations reporting to EPA by January 30th and July 30th of each year. 40 CFR 71.6(a)(3)(iii).
Compliance Methods for the Above (Description and Citation):
Reporting and Recordkeeping. Submitted as required. Reports on file onsite. Monitoring and deviation reports were submitted by the due dates.
Compliance Status:
_X_ In Compliance: Will you continue to comply up to permit issuance? _X_Yes ____No
___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No
___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes ____No

Emission Unit ID(s): Facility
Applicable Requirement (Describe and Cite)
Permit Section 3.0(C) Permittee shall provide performance testing facilities to comply with 40 CFR 60.8(e), 71.6(a)(3)(l).
Compliance Methods for the Above (Description and Citation):
Testing. All Great Lakes turbine units have adequate sampling ports for air emissions testing; safe access & safe platform; and appropriate utilities to run testing equipment and conduct proper sampling.
Compliance Status:
_X_ In Compliance: Will you continue to comply up to permit issuance? _X_Yes ____No
___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No
___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes ____No

Emission Unit ID(s): Facility – General Requirements
Applicable Requirement (Describe and Cite)
Permit Section 4.0(B) Annual fee payment and annual report of actual emissions due on or before November 15th of each year. 40 CFR 71.6(a)(7); 71.9
Compliance Methods for the Above (Description and Citation):
Reporting and Recordkeeping. An Annual Report of actual emissions for the preceding calendar year; fee calculation work sheet; and full payment of the annual fee is submitted on or before November 15th of each year, as required.
Compliance Status:
_X_ In Compliance: Will you continue to comply up to permit issuance? _X_Yes ____No
___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No
___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes ____No

Emission Unit ID(s): Facility – General Requirements
Applicable Requirement (Describe and Cite)
Permit Section 4.0(C) Compliance Statement - must be in compliance with all conditions of this Part 71 Permit. 40 CFR 71.6(a)(6)
Compliance Methods for the Above (Description and Citation):
Reporting. Refer to accompanying Compliance Certification (CTAC) form and permit conditions as summarized in this Compliance Plan/Certification, as well as associated attachments.
Compliance Status:
_X_ In Compliance: Will you continue to comply up to permit issuance? _X_Yes ____No
___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No
___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes ____No

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 6/30/2015

Federal Operating Permit Program (40 CFR Part 71)

CERTIFICATION OF TRUTH, ACCURACY, AND COMPLETENESS (CTAC)

This form must be completed, signed by the "Responsible Official" designated for the facility or emission unit, and sent with each submission of documents (i.e., application forms, updates to applications, reports, or any information required by a part 71 permit).

A. Responsible Official

Name: (Last) Kornaga (First) Anthony (MI) M.

Title Director Field Operations – Great Lakes Region

Street or P.O. Box 5250 Corporate Drive

City Troy State MI ZIP 48098 - 2644

Telephone (248) 205 - 7465 Ext. ______ Facsimile (___) ___ - ____

B. Certification of Truth, Accuracy and Completeness (to be signed by the responsible official)

I certify under penalty of law, based on information and belief formed after reasonable inquiry, the statements and information contained in these documents are true, accurate and complete.

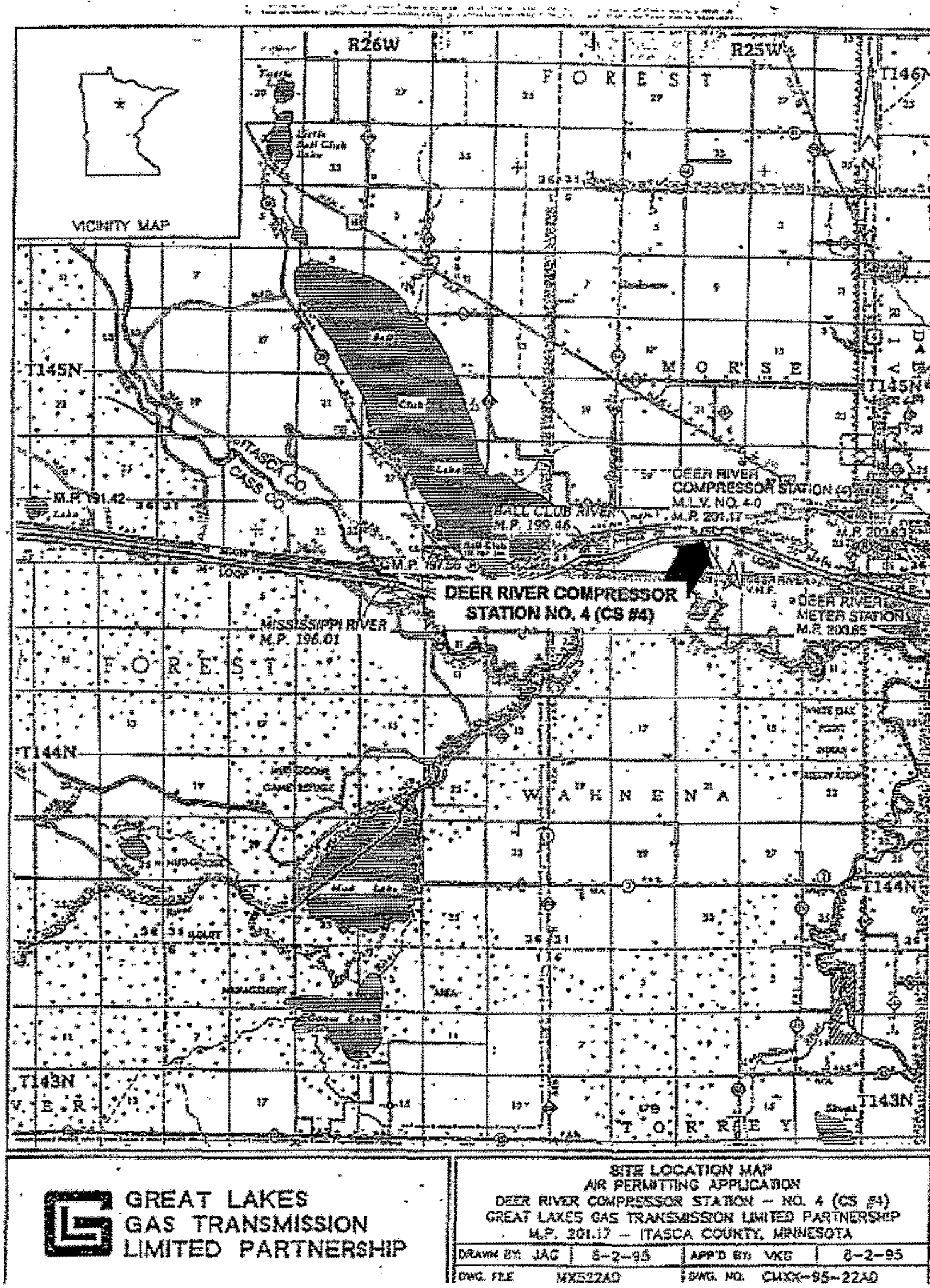
Name (signed) Anthony M. Kornaga

Name (typed) Anthony M. Kornaga Date: 4 / 21 / 2014

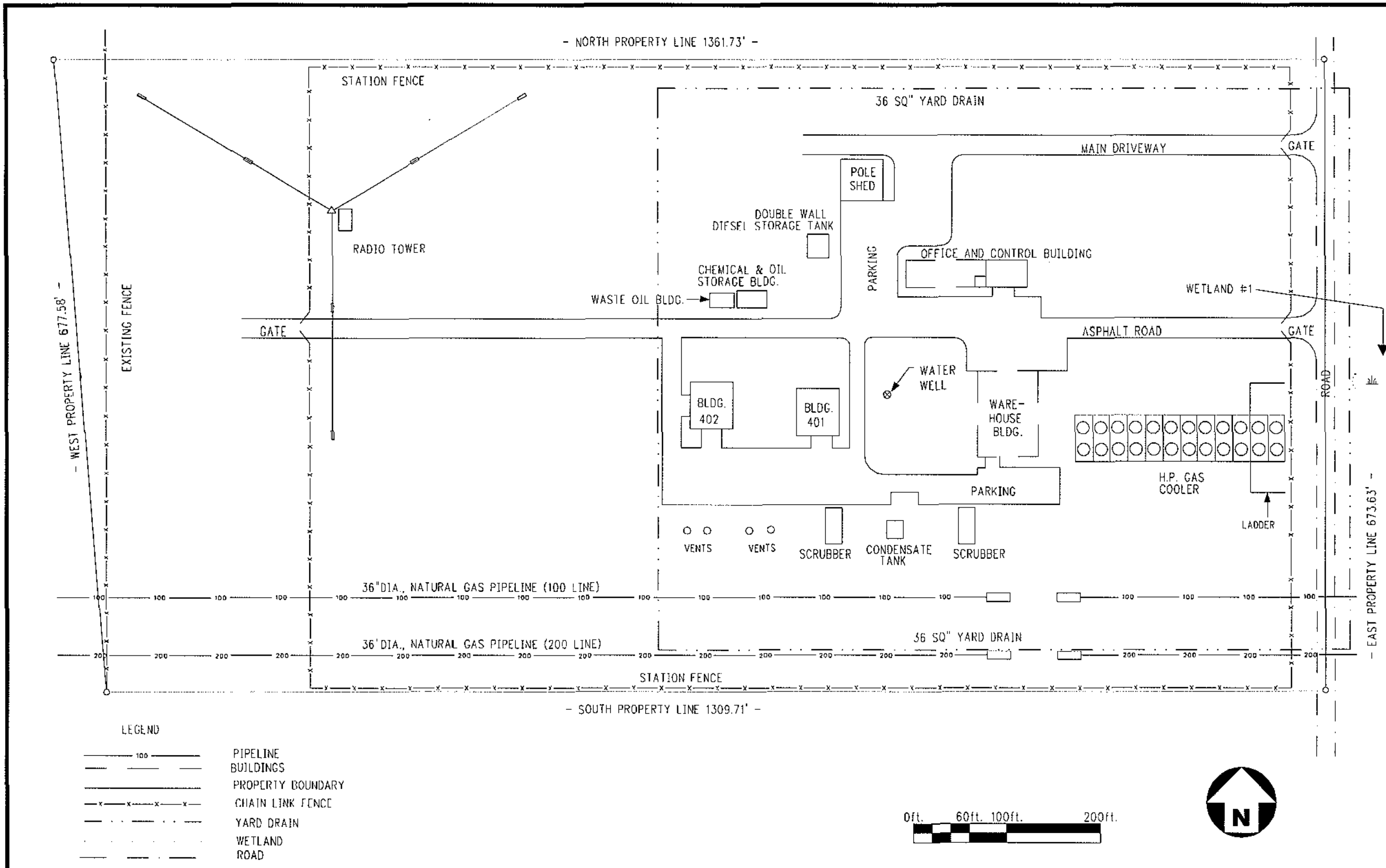
APPENDIX B:

SITE MAP/PLOT PLANS

- Site Location Map
- Plot Plan
- Stack Location Map



VICINITY MAP
R26W
R25W
T146N
T145N
T144N
T143N
FOREST
MORSE
WAHNENA
TORREY
ITASCA CO
CASS CO
M.P. 191.42
BALL CLUB RIVER
M.P. 199.46
M.P. 197.56
DEER RIVER
COMPRESSOR STATION (4)
M.L.V. NO. 4-0
M.P. 201.17
M.P. 203.83
DEER RIVER COMPRESSOR STATION NO. 4 (CS #4)
MISSISSIPPI RIVER
M.P. 196.01
DEER RIVER
METER STATION
M.P. 203.85
GREAT LAKES
GAS TRANSMISSION
LIMITED PARTNERSHIP
SITE LOCATION MAP
AIR PERMITTING APPLICATION
DEER RIVER COMPRESSOR STATION – NO. 4 (CS #4)
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
M.P. 201.17 – ITASCA COUNTY, MINNESOTA
DRAWN BY: JAG
6-2-95
APP'D BY: VKG
6-2-95
DWG. FILE MX522AO
DWG. NO. CMXX-95-22AO

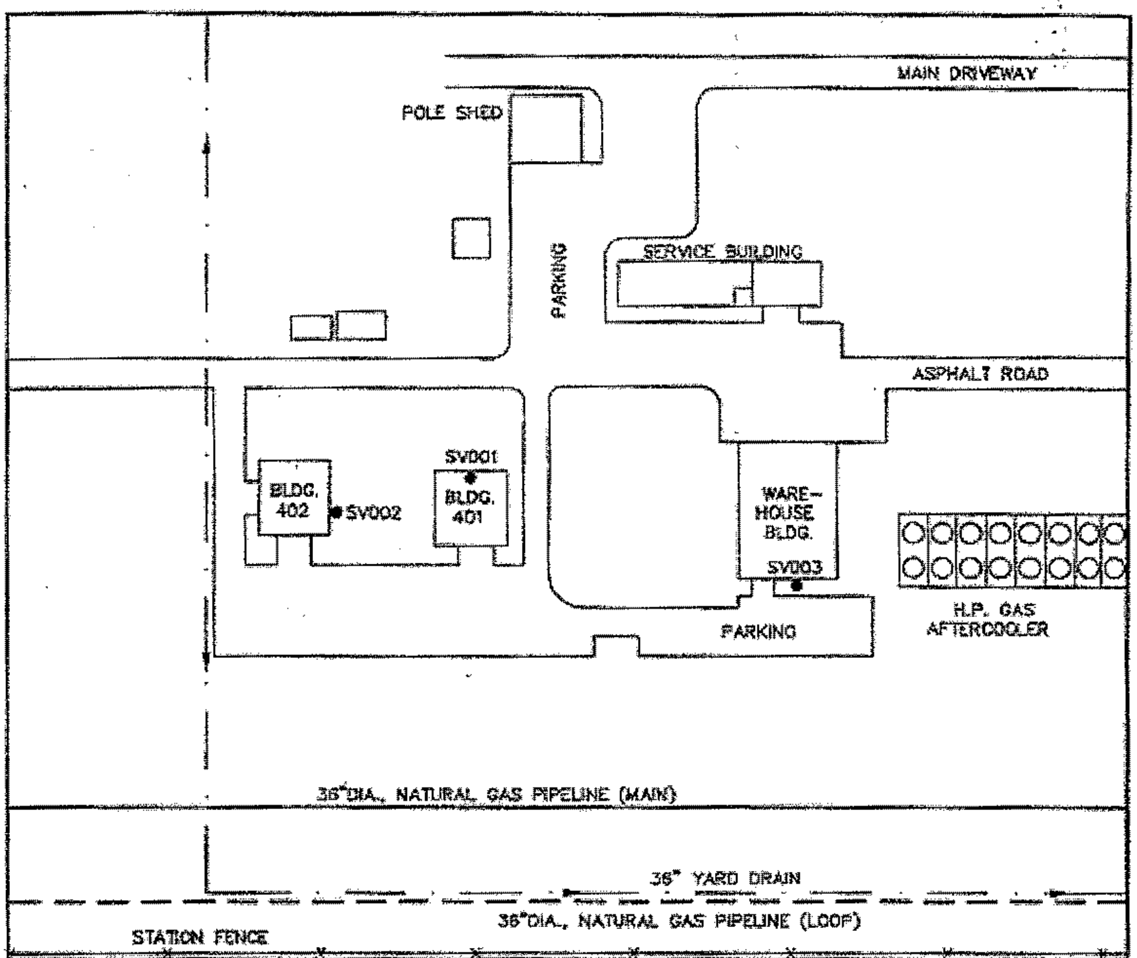


Great Lakes Gas Transmission Company

COMPRESSOR STATION NO. 4

ENVIRONMENTAL CONDITIONS - SITE SKETCH
M.P. 201.17, Itasca County
Deer River, Minnesota

DATE	10/28/93
REVISED	03/05/01
FIGURE NO.	104-WS-1000



— PROPERTY LINE 1309.71' —

LEGEND

- PROPERTY BOUNDARY
- CHAIN LINK FENCE
- YARD DRAIN
- EMISSION POINT

N

50' 0 100'

SCALE 1"=100'

BUILDING DIMENSIONS			
BUILDING DESIGNATION	LENGTH X WIDTH	ROOF HEIGHT AT EDGE	ROOF HEIGHT AT PEAK
401	65.3' X 21'	22.25'	24.88'
402	71.5' X 48'	31.5'	40.00'
SERVICE BLDG	126' X 26.3'	13'	17.33'
WAREHOUSE	88' X 62.8'	23'	33.47'

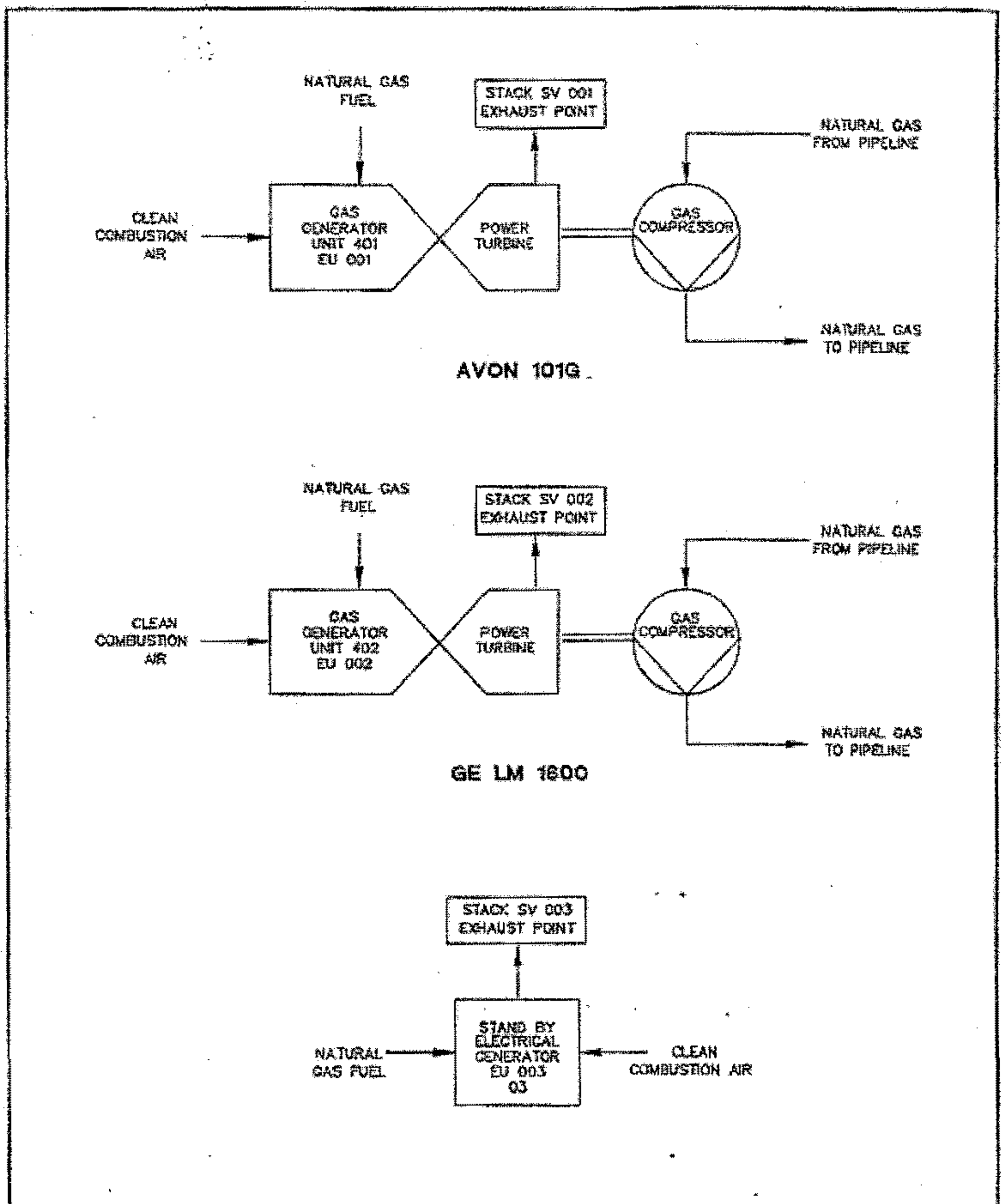
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

STACK LOCATION MAP
AIR PERMITTING APPLICATION
DEER RIVER COMPRESSOR STATION — NO. 4 (CS #4)
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
M.P. 201.17 — ITASCA COUNTY, MINNESOTA

DRAWN BY: JAG	8-2-95	APP'D BY: VKG	8-2-95
DWG. FILE	MX522AD2	DWG. NO.	CMXX-95-22AD

APPENDIX C:

PROCESS FLOW DIAGRAMS



GREAT LAKES
GAS TRANSMISSION
LIMITED PARTNERSHIP

PROCESS FLOW DIAGRAM
AIR PERMITTING APPLICATION
DEER RIVER COMPRESSOR STATION – NO. 4 (CS #4)
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
M.P. 201.17 – ITASCA COUNTY, MINNESOTA

DRAWN BY: LDL	DATE: 09-07-95
APP'D BY: RC	DATE: 09-07-95
PROJECT: CMXX-95-22AD	
DWG. NO. MX522A03	
SHEET 1 OF 1	
FIGURE NO. 1	

APPENDIX D:

FERC GAS TARIFF

GENERAL TERMS AND CONDITIONS

FERC Gas Tariff

Third Revised Volume No. 1

of

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

Filed with

Federal Energy Regulatory Commission

Communications Covering This Tariff Should be Addressed to:

Joan Collins
Manager, Tariffs and Compliance
Great Lakes Gas Transmission Limited Partnership
Mailing Address: P.O. Box 2446
Houston, TX 77252-2446
Courier Address: 717 Texas Street
Houston, TX 77002-2761
Phone: (832) 320-5651
Fax: (832) 320-6651

6.8 QUALITY

1. Heating Value. Gas delivered by Shipper to Transporter at each point of receipt shall have a heating value not greater than 1069 BTUs per cubic foot nor less than 967 BTUs. Transporter shall have the right to waive such Btu content limits if, in Transporter's sole opinion, Transporter is able to accept gas with a Btu content outside such limits without affecting Transporter's operations. The heating value shall be determined at intervals of not more than thirty (30) Days by means of an instrument(s) of standard manufacture accepted in the industry for this purpose or using a sample of gas representative of the gas stream that is being delivered to Transporter or received from Transporter at the point(s) of receipt or delivery.

   In the event, however, that the heating value of Gas received by Transporter at any point drops below 1013 Btu, which is the Btu level at which the MDQs of Service Agreements are currently based and Transporter is unable to Transport a Shipper's Scheduled Daily Delivery due to the drop in the Btu level, Transporter shall utilize the Curtailment provision of Section 6.11.4 of the General Terms and Conditions, but only for those Shippers from whom Transporter receives Gas at that point.

   For the purpose of calculating receipts and deliveries, the heating value of the gas so determined at each such point shall be deemed to remain constant at such point until the next determination.

2. Freedom from Objectionable Odor and Matter

   The gas received and delivered hereunder:

   (a) shall be commercially free (at prevailing pressure and temperature) from objectionable odors, dust, or other solid or liquid matter that might interfere with its merchantability or cause injury to or interference with proper operation of the lines, regulators, meters and other equipment of Transporter;

   (b) shall not contain more than one quarter (1/4) grain of hydrogen sulfide per one hundred (100) cubic feet of gas;

   (c) shall not contain more than twenty (20) grains of total sulfur (including the sulfur in any hydrogen sulfide and mercaptans) per one hundred (100) cubic feet of gas;

   (d) shall not at any time have an oxygen content in excess of one percent (1%) by volume and the parties shall make every reasonable effort to keep the gas free of oxygen;

   (e) shall not contain as nearly as practicable any free water nor contain more than four (4) pounds of water vapor per million cubic feet of gas;

(f) shall not contain more than two percent (2%) by volume of carbon dioxide;

(g) shall be at a temperature not in excess of one hundred twenty degrees (120°) Fahrenheit or less than twenty degrees (20°) Fahrenheit; and

(h) shall not contain more than three percent (3%) by volume of nitrogen.

3. Failure to Meet Specifications. Should any gas tendered for delivery by Shipper fail at any time to conform to any of the specifications of this section, Transporter shall notify Shipper of the failure and Transporter may suspend all or a portion of the receipt of any such gas if it will jeopardize operation of Transporter's system or will cause Transporter to suffer an economic loss; and Transporter shall be relieved of all obligations for the duration of such time as the gas does not meet the specifications; provided however that Transporter shall have the right to waive the specifications set forth in this section if, in Transporter's sole opinion, Transporter is able to accept such non-conforming gas without adversely affecting Transporter's operations.

4. Commingling. It is recognized that gas delivered by Shipper will be commingled with other gas transported by Transporter. Accordingly, the gas of Shipper shall be subject to such changes in heat content as may result from such commingling and Transporter shall, notwithstanding any other provision in this FERC Gas Tariff, Third Revised Volume No. 1, herein, be under no obligation to redeliver for Shipper's account, gas of a heat content identical to that caused to be delivered by Shipper to Transporter.

APPENDIX E:

EMISSION CALCULATION SPREADSHEETS

- Table 1 – Potential Emissions Summary
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Appendix E - Table 1 - Potential Emissions Summary

For EPA Part 71 Form PTE

Criteria Pollutant	**NOx**	**VOC**	**SO2**	**PM10**	**CO**	**Lead**	**HAP**
Turbine Unit 401 (EU 001)	201.70	1.72	2.79	5.41	485.07	n/a	0.84
Turbine Unit 402 (EU 002)	483.55	1.69	2.74	5.32	29.01	n/a	0.83
Standby Generator (EU 003)	18.08	0.93	0.02	0.61	117.18	n/a	1.02
Boiler (EU 004)	2.25	0.12	0.01	0.17	1.89	n/a	0.04
Total PTE Emissions (tpy)	705.58	4.47	5.56	11.51	633.16	n/a	2.73

Appendix E - Table 2 - Potential Emissions of Hazardous Air Pollutants

For EPA Part 71 Form PTE
Potential Emissions - HAPs - TPY

Hazardous Air Pollutant (HAP)	CAS Number	Turbine Unit 401 (EU 001)	Turbine Unit 402 (EU 002)	Standby Generator (EU 003)	Boiler (EU 004)	Total PTE Emissions (tpy)
1,1,2,2-Tetrachloroethane	79-34-5			0.0008		0.0008
1,1,2-Trichloroethane	79-00-5			0.0005		0.0005
1,3-Butadiene	106-99-0	0.0004	0.0003	0.021		0.022
1,3-Dichloropropene	542-75-6			0.0004		0.0004
2-Methylnaphthalene	91-57-6*				0.0000005	0.0000005
3-Methylchloranthrene	56-49-5*				0.00000004	0.00000004
7,12-Dimethylbenz(a)anthracene	57-97-6*				0.0000004	0.0000004
Acenaphthene	83-32-9*				0.00000004	0.00000004
Acenaphthylene	203-96-8*				0.00000004	0.00000004
Acetaldehyde	75-07-0	0.033	0.032	0.088		0.153
Acrolein	107-02-8	0.005	0.005	0.083		0.093
Anthracene	120-12-7*				0.00000005	0.00000005
Benz(a)anthracene	56-55-3*				0.00000004	0.00000004
Benzene	71-43-2	0.010	0.010	0.050	0.00005	0.069
Benzo(a)pyrene	50-32-8*				0.00000003	0.00000003
Benzo(b)fluoranthene	205-99-2*				0.00000004	0.00000004
Benzo(g,h,i)perylene	191-24-2*				0.00000003	0.00000003
Benzo(k)fluoranthene	205-82-3*				0.00000004	0.00000004
Carbon Tetrachloride	56-23-5			0.0006		0.0006
Chlorobenzene	108-90-7			0.0004		0.0004
Chloroform	67-66-3			0.0004		0.0004
Chrysene	218-01-9*				0.00000004	0.00000004
Dibenzo(a,h)anthracene	53-70-3*				0.00000003	0.00000003
Dichlorobenzene	25321-22-6				0.00003	0.00003
Ethylbenzene	100-41-4	0.026	0.026	0.0008		0.053
Ethylene Dibromide	106-93-4			0.0007		0.0007
Fluoranthene	206-44-0*				0.00000007	0.00000007
Fluorene	86-73-7*				0.00000006	0.00000006
Formaldehyde	50-00-0	0.582	0.572	0.646	0.002	1.802
Indeno(1,2,3-c,d)pyrene	193-39-5*				0.00000004	0.00000004
Methanol	67-56-1			0.096		0.096
Methylene Chloride	74-87-3			0.001		0.001
Naphthalene	91-20-3	0.001	0.001	0.003	0.00001	0.005
n-Hexane	110-54-3				0.040	0.040
PAH	130498-29-2*	0.002	0.002	0.004		0.008
Phenanthrene	85-01-8*				0.0000004	0.0000004
Propylene Oxide	75-56-9	0.024	0.023			0.047
Pyrene	129-00-0*				0.0000001	0.0000001
Styrene	100-42-5			0.0004		0.0004
Toluene	108-88-3	0.107	0.105	0.018	0.00008	0.229
Vinyl Chloride	75-01-4			0.0002		0.0002
Xylene	1330-20-7	0.052	0.052	0.006		0.110

* Polycyclic Organic Matter (POM)

Total HAP (tpy)	2.73	
Single HAP Emitted in Largest Amount (tpy)	1.802	Formaldehyde

Appendix E - Table 3 - 2012 Actual Emissions of Criteria and Hazardous Air Pollutants

For EPA Part 71 Form FEE Part D.

Criteria Pollutant	NOx	VOC	SO2	PM10	CO	Lead	HAP
Turbine Unit 401 (EU 001)	0.22	0.002	0.003	0.006	0.52	n/a	0.0009
Turbine Unit 402 (EU 002)	0.50	0.002	0.003	0.006	0.03	n/a	0.0009
Standby Generator (EU 003)	0.48	0.02	0.0005	0.02	3.12	n/a	0.03
Boiler (EU 004)	0.06	0.003	0.0004	0.005	0.05	n/a	0.001
Total 2012 Actual Emissions (tpy)2	1.26	0.03	0.007	0.03	3.72	n/a	0.03

For EPA Part 71 Form FEE Part E. HAP Identification

Hazardous Air Pollutant (HAP)	CAS Number	HAP Number	Turbine Unit 401 (EU 001)	Turbine Unit 402 (EU 002)	Standby Generator (EU 003)	Boiler (EU 004)	Total 2012 Actual Emissions (tpy)
1,1,2,2-Tetrachloroethane	79-34-5	HAP 1			2.12E-05		2.12E-05
1,1,2-Trichloroethane	79-00-5	HAP 2			1.28E-05		1.28E-05
1,3-Butadiene	106-99-0	HAP 3	3.80E-07	3.59E-07	5.55E-04		5.56E-04
1,3-Dichloropropene	542-75-6	HAP 4			1.06E-05		1.06E-05
2-Methylnaphthalene	91-57-6*	HAP 6				1.43E-08	1.43E-08
3-Methylchloranthrene	56-49-5*	HAP 7				1.08E-09	1.08E-09
7,12-Dimethylbenz(a)anthracene	57-97-6*	HAP 8				9.56E-09	9.56E-09
Acenaphthene	83-32-9*	HAP 9				1.08E-09	1.08E-09
Acenaphthylene	203-96-8*	HAP 10				1.08E-09	1.08E-09
Acetaldehyde	75-07-0	HAP 11	3.53E-05	3.34E-05	2.34E-03		2.41E-03
Acrolein	107-02-8	HAP 12	5.65E-06	5.34E-06	2.20E-03		2.21E-03
Anthracene	120-12-7*	HAP 13				1.43E-09	1.43E-09
Benz(a)anthracene	56-55-3*	HAP 14				1.08E-09	1.08E-09
Benzene	71-43-2	HAP 15	1.06E-05	1.00E-05	1.32E-03	1.25E-06	1.35E-03
Benzo(a)pyrene	50-32-8*	HAP 16				7.17E-10	7.17E-10
Benzo(b)fluoranthene	205-99-2*	HAP 17				1.08E-09	1.08E-09
Benzo(g,h,i)perylene	191-24-2*	HAP 19				7.17E-10	7.17E-10
Benzo(k)fluoranthene	205-82-3*	HAP 20				1.08E-09	1.08E-09
Carbon Tetrachloride	56-23-5	HAP 22			1.48E-05		1.48E-05
Chlorobenzene	108-90-7	HAP 23			1.08E-05		1.08E-05
Chloroform	67-66-3	HAP 24			1.15E-05		1.15E-05
Chrysene	218-01-9*	HAP 25				1.08E-09	1.08E-09
Dibenzo(a,h)anthracene	53-70-3*	HAP 26				7.17E-10	7.17E-10
Dichlorobenzene	25321-22-6	HAP 27				7.17E-07	7.17E-07
Ethylbenzene	100-41-4	HAP 28	2.83E-05	2.67E-05	2.08E-05		7.58E-05
Ethylene Dibromide	106-93-4	HAP 29			1.78E-05		1.78E-05
Fluoranthene	206-44-0*	HAP 30				1.79E-09	1.79E-09
Fluorene	86-73-7*	HAP 31				1.67E-09	1.67E-09
Formaldehyde	50-00-0	HAP 32	6.27E-04	5.93E-04	1.72E-02	4.48E-05	1.84E-02
Indeno(1,2,3-c,d)pyrene	193-39-5*	HAP 33				1.08E-09	1.08E-09
Methanol	67-56-1	HAP 34			2.56E-03		2.56E-03
Methylene Chloride	74-87-3	HAP 35			3.45E-05		3.45E-05
Naphthalene	91-20-3	HAP 36	1.15E-06	1.09E-06	8.13E-05	3.64E-07	8.39E-05
n-Hexane	110-54-3	HAP 37				1.08E-03	1.08E-03
PAH	130498-29-2*	HAP 38	1.94E-06	1.84E-06	1.18E-04		1.22E-04
Phenanthrene	85-01-8*	HAP 39				1.02E-08	1.02E-08
Propylene Oxide	75-56-9	HAP 41	2.56E-05	2.42E-05			4.98E-05
Pyrene	129-00-0*	HAP 42				2.99E-09	2.99E-09
Styrene	100-42-5	HAP 43			9.97E-06		9.97E-06
Toluene	108-88-3	HAP 45	1.15E-04	1.09E-04	4.67E-04	2.03E-06	6.93E-04
Vinyl Chloride	75-01-4	HAP 46			6.01E-06		6.01E-06
Xylene	1330-20-7	HAP 47	5.65E-05	5.34E-05	1.63E-04		2.72E-04
Total 2012 Actual HAP Emissions			0.0009	0.0009	0.027	0.001	0.030

* Polycyclic Organic Matter (POM)

Appendix E - Table 4 - 2012 Actual and Potential Emissions of Criteria and Hazardous Air Pollutants for Natural Gas-Fired Turbine Unit 401

For EPA Part 71 Form EMISS, Unit EU 001

Equipment Information	
Facility:	Deer River CS4
AQD Emission Unit ID:	001
Unit No.	401
Make:	Rolls Royce/Avon
Model Number:	101G
Installation Date:	1971
AQD Stack Number:	SV001
Stack Height (feet):	48.08
Stack Diameter (feet):	5.8
Fuel Burned:	Natural Gas
Assumptions:	
Turbine Rated Capacity, (hp):	18,000
PTE Hours of Operation:	8,760
Brake-Specific Fuel Consumption (Btu/hp-hr):	10,400
2012 Actual Fuel Use (MMscf/year):	1.73
Calculated Max. Annual Fuel Use (MMscf/year):	1,607.72
Calculated Max. Hourly Fuel Use (MMscf/hour):	0.184
Calculated Max. Heat Input (MMBtu/hr):	187.2
Fuel Heat Content (Btu/scf):	1,020

Potential Emissions - Criteria Pollutants

Criteria Pollutant	Notes	Emission Factor (lb/MMBtu)	Stack Test Emission Factor plus 20% Safety Factor (lb/MMBtu)	Emission Factor on Fuel Use Basis (lb/MMscf)	2012 Actual Emissions (tpy)	PTE Hourly Emissions (lb/hr)	PTE Annual Emissions (tpy)
NOx	1	2.1E-01	2.46E-01	250.920	0.22	46.05	201.70
VOC	2	2.1E-03	n/a	2.142	0.002	0.39	1.72
SO2	2,3	3.4E-03	n/a	3.468	0.003	0.64	2.79
PM (PM10)	2,4	6.6E-03	n/a	6.732	0.006	1.24	5.41
CO	1	4.9E-01	5.92E-01	603.432	0.52	110.75	485.07
Lead	2	--	n/a	n/a	n/a	n/a	n/a

Potential Emissions - HAPs

Hazardous Air Pollutant (HAP)	Notes	AP-42 Emission Factor (lb/MMBtu)	Emission Factor on Fuel Use Basis (lb/MMscf)	2012 Actual Emissions (tpy)	PTE Hourly Emissions (lb/hr)	PTE Annual Emissions (tpy)
1,3-Butadiene	5	4.3E-07	4.39E-04	0.00	0.00	0.00
Acetaldehyde	5	4.0E-05	4.08E-02	0.00	0.01	0.03
Acrolein	5	6.4E-06	6.53E-03	0.00	0.00	0.01
Benzene	5	1.2E-05	1.22E-02	0.00	0.00	0.01
Ethylbenzene	5	3.2E-05	3.26E-02	0.00	0.01	0.03
Formaldehyde	5	7.1E-04	7.24E-01	0.00	0.13	0.58
Naphthalene	5	1.3E-06	1.33E-03	0.00	0.00	0.00
PAH	5,6	2.2E-06	2.24E-03	0.00	0.00	0.00
Propylene Oxide	5	2.9E-05	2.96E-02	0.00	0.01	0.02
Toluene	5	1.3E-04	1.33E-01	0.00	0.02	0.11
Xylene	5,8	6.4E-05	6.53E-02	0.00	0.01	0.05
			Total HAP	0.00	0.19	0.84

Notes
1. NOx and CO Emission Factors from Stack test (March 29, 2005). Emission factors have a 20% safety factor that was added to each emission factor to account for operational variability.
2. VOC, SO2, PM, and Lead Emission factors from AP-42 Table 3.1-2a. Emission factor for lead listed as "ND = No Data".

3. SO2 emissions factor from AP-42 Table 3.1-2a (0.94S). Emission Factor footnote h: "...If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines…."
4. It is assumed that Total PM = PM10,
5. HAP emission factors from AP-42, Table 3.1-3, April, 2000.
6. For inventory purposes, assume Polycyclic Aromatic Hydrocarbons (PAH) is the same as Polycyclic Organic Matter (POM).
7. Emission factors converted from Ib/MMBtu to lb/MMscf using the AP-42 Emission Factor footnote "To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020."
8. Mixed xylenes

Appendix E - Table 4 - 2012 Actual and Potential Emissions of Criteria and Hazardous Air Pollutants for Natural Gas-Fired Turbine Unit 402

For EPA Part 71 Form EMISS, Unit EU 002

Equipment Information	
Facility:	Deer River CS4
AQD Emission Unit ID:	EU 002
Unit No.	402
Make:	General Electric
Model Number:	LM1600
Installation Date:	1993
AQD Stack Number:	SV002
Stack Height (feet):	40.0
Stack Diameter (feet):	6.60
Fuel Burned:	Natural Gas
Assumptions:	
Turbine Rated Capacity, (hp):	23,000
PTE Hours of Operation:	8,760
Brake-Specific Fuel Consumption (Btu/hp-hr):	8,000
2012 Actual Fuel Use (MMscf/year):	1.64
Calculated Max. Annual Fuel Use (MMscf/year):	1,580.24
Calculated Max. Hourly Fuel Use (MMscf/hour):	0.180
Calculated Max. Heat Input (MMBtu/hr):	184.0
Fuel Heat Content (Btu/scf):	1,020

Potential Emissions - Criteria Pollutants

Criteria Pollutant	Notes	Emission Factor (lb/MMBtu)	Stack Test Emission Factor plus 20% Safety Factor (lb/MMBtu)	Emission Factor on Fuel Use Basis (lb/MMscf)	2012 Actual Emissions (tpy)	PTE Hourly Emissions (lb/hr)	PTE Annual Emissions (tpy)
NOx	1	5.0E-01	6.00E-01	612.000	0.50	110.40	483.55
VOC	2	2.1E-03	n/a	2.142	0.002	0.39	1.69
SO2	2,3	3.4E-03	n/a	3.468	0.003	0.63	2.74
PM (PM10)	2,4	6.6E-03	n/a	6.732	0.006	1.21	5.32
CO	1	3.0E-02	3.60E-02	36.720	0.03	6.62	29.01
Lead	2	--	n/a	n/a	n/a	n/a	n/a

Potential Emissions - HAPs

Hazardous Air Pollutant (HAP)	Notes	AP-42 Emission Factor (lb/MMBtu)	Emission Factor on Fuel Use Basis (lb/MMscf)	2012 Actual Emissions (tpy)	PTE Hourly Emissions (lb/hr)	PTE Annual Emissions (tpy)
1,3-Butadiene	5	4.3E-07	4.39E-04	0.00	0.00	0.00
Acetaldehyde	5	4.0E-05	4.08E-02	0.00	0.01	0.03
Acrolein	5	6.4E-06	6.53E-03	0.00	0.00	0.01
Benzene	5	1.2E-05	1.22E-02	0.00	0.00	0.01
Ethylbenzene	5	3.2E-05	3.26E-02	0.00	0.01	0.03
Formaldehyde	5	7.1E-04	7.24E-01	0.00	0.13	0.57
Naphthalene	5	1.3E-06	1.33E-03	0.00	0.00	0.00
PAH	5,6	2.2E-06	2.24E-03	0.00	0.00	0.00
Propylene Oxide	5	2.9E-05	2.96E-02	0.00	0.01	0.02
Toluene	5	1.3E-04	1.33E-01	0.00	0.02	0.10
Xylene	5,8	6.4E-05	6.53E-02	0.00	0.01	0.05
			Total HAP	0.00	0.19	0.83

Notes
1. NOx and CO Emission Factors from Stack test (February 16, 2010). Emission factors have a 20% safety factor that was added to each emission factor to account for operational variability.
2. VOC, SO2, PM, and Lead Emission factors from AP-42 Table 3.1-2a. Emission factor for lead listed as "ND = No Data".

3. SO2 emissions factor from AP-42 Table 3.1-2a (0.94S). Emission Factor footnote h: "...If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines…."
4. It is assumed that Total PM = PM10,
5. HAP emission factors from AP-42, Table 3.1-3, April, 2000.
6. For inventory purposes, assume Polycyclic Aromatic Hydrocarbons (PAH) is the same as Polycyclic Organic Matter (POM).
7. Emission factors converted from Ib/MMBtu to lb/MMscf using the AP-42 Emission Factor footnote "To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020."
8. Mixed xylenes

Appendix E - Table 4 - 2012 Actual and Potential Emissions of Criteria and Hazardous Air Pollutants for Natural Gas-Fired Standby Electrical Generator

For EPA Part 71 Form EMISS, Unit EU 003

Equipment Information	
Facility:	Deer River CS4
AQD Emission Unit ID:	EU 003
Unit No.	N/A
Make:	Waukesha
Model Number:	L36GL (4SRB)
Installation Date:	1997
AQD Stack Number:	SV003
Stack Height (feet):	24.4
Stack Diameter (feet):	0.67
Fuel Burned:	Natural Gas
Assumptions:	
Rated Capacity, (hp):	899
2012 Actual Hours of Operation:	233.0
PTE Hours of Operation:	8,760
Brake-Specific Fuel Consumption (Btu/hp-hr):	8,000
Calculated 2012 Actual Fuel Use (MMscf/year):	1.643
Calculated Max. Annual Fuel Use (MMscf/year):	61.77
Calculated Max. Hourly Fuel Use (MMscf/hour):	0.007
Calculated Max. Heat Input (MMBtu/hr):	7.2
Fuel Heat Content (Btu/scf):	1,020

Potential Emissions - Criteria Pollutants

Criteria Pollutant	Notes	Emission Factor (lb/MMBtu)	Emission Factor on Fuel Use Basis (lb/MMscf)	2012 Actual Emissions (tpy)	PTE Hourly Emissions (lb/hr)	PTE Annual Emissions (tpy)
NOx	7	5.74E-01	585.480	0.48	4.13	18.08
VOC	1	2.96E-02	30.192	0.02	0.21	0.93
SO2	1	5.88E-04	0.600	0.00	0.00	0.02
PM10	1,3	1.94E-02	19.798	0.02	0.14	0.61
CO	1,2	3.72E+00	3794.400	3.12	26.75	117.18
Lead	1	not listed	n/a	n/a	n/a	n/a

Potential Emissions - HAPs

Hazardous Air Pollutant (HAP)	Notes	AP-42 Emission Factor (lb/MMBtu)	Emission Factor on Fuel Use Basis (lb/MMscf)	2012 Actual Emissions (tpy)	PTE Hourly Emissions (lb/hr)	PTE Annual Emissions (tpy)
1 1,2,2-Tetrachloroethane	4	2.53E-05	2.58E-02	0.00002	0.0002	0.0008
1 1,2-Trichloroethane	4	1.53E-05	1.56E-02	0.00001	0.0001	0.0005
1 3-Butadiene	4	6.63E-04	6.76E-01	0.0006	0.005	0.021
1,3-Dichloropropene	4	1.27E-05	1.30E-02	0.00001	0.00009	0.0004
Acetaldehyde	4	2.79E-03	2.85E+00	0.002	0.020	0.088
Acrolein	4	2.63E-03	2.68E+00	0.002	0.019	0.083
Benzene	4	1.58E-03	1.61E+00	0.001	0.011	0.050
Carbon Tetrachloride	4	1.77E-05	1.81E-02	0.00001	0.0001	0.0006
Chlorobenzene	4	1.29E-05	1.32E-02	0.00001	0.00009	0.0004
Chloroform	4	1.37E-05	1.40E-02	0.00001	0.0001	0.0004
Ethylbenzene	4	2.48E-05	2.53E-02	0.00002	0.0002	0.0008
Ethylene Dibromide	4	2.13E-05	2.17E-02	0.00002	0.0002	0.0007
Formaldehyde	4	2.05E-02	2.09E+01	0.017	0.147	0.646
Methanol	4	3.06E-03	3.12E+00	0.003	0.022	0.096
Methylene Chloride	4	4.12E-05	4.20E-02	0.00003	0.0003	0.001
Naphthalene	4	9.71E-05	9.90E-02	0.00008	0.0007	0.003
PAH	4,5	1.41E-04	1.44E-01	0.0001	0.001	0.004
Styrene	4	1.19E-05	1.21E-02	0.00001	0.00009	0.0004
Toluene	4	5.58E-04	5.69E-01	0.0005	0.004	0.018
Vinyl Chloride	4	7.18E-06	7.32E-03	0.000006	0.00005	0.0002
Xylene	4	1.94E-04	1.98E-01	0.0002	0.001	0.006
			Total HAP	0.027	0.233	1.021

Notes
1. VOC, SO2, PM, and CO Emission factors from AP-42 Table 3.2-3 for 4-stroke rich burn engines.
2. CO factor is for 90-105% load.
3. PM10 is the sum of the emission factors for PM10 (filterable) and PM Condensable.
4. HAP emission factors from AP-42, Table 3.2-3, July 2000.
5. For inventory purposes, assume PAH is the same as Polycyclic Organic Matter (POM).
6. Emission factors converted from lb/MMBtu to lb/MMscf using the AP-42 Emission Factor Table footnote "To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020."
7. NOx emission factor from manufacturers specifications: 2.0 gm/hp-hr18000 btu/hp-hr 1435.6 gmab x 1,000,000 btu/MMBtu = 0.574 lb/MMBtu NOx

Appendix E - Table 4 - 2012 Actual and Potential Emissions of Criteria and Hazardous Air Pollutants for Natural Gas-Fired Boiler

For EPA Part 71 Form EMISS, Unit EU 004

Equipment Information	
Facility:	Deer River CS4
AQD Emission Unit ID:	EU 004
Unit No.	N/A
Make:	Kewanee
Model Number:	L3W125-G
Installation Date:	1993
Fuel Burned:	Natural Gas
Assumptions:	
Maximum Firing Rate (MMBtu/hr):	5.23
2012 Actual Hours of Operation:	233.0
PTE Hours of Operation:	8,760
Calculated 2012 Actual Fuel Use (MMscf/year):	1.194
Calculated Max. Annual Fuel Use (MMscf/year):	44.92
Calculated Max. Hourly Fuel Use (MMscf/hour):	0.005
Fuel Heat Content (Btu/scf):	1,020

Potential Emissions - Criteria Pollutants

Criteria Pollutant	Notes	Emission Factor (lb/MMscf)	2012 Actual Emissions (tpy)	PTE Hourly Emissions (lb/hr)	PTE Annual Emissions (tpy)
NOx	1	100	0.06	0.51	2.25
VOC	2	5.5	0.00	0.03	0.12
SO2	2	0.6	0.00	0.00	0.01
PM10	2	7.6	0.00	0.04	0.17
CO	1	84	0.05	0.43	1.89

Potential Emissions - HAPs

Hazardous Air Pollutant (HAP)	Notes	AP-42 Emission Factor (lb/MMscf)	2012 Actual Emissions (tpy)	PTE Hourly Emissions (lb/hr)	PTE Annual Emissions (tpy)
2-Methylnaphthalene	3	2.40E-05	0.00	0.00	0.00
3-Methylchloranthrene	3	1.80E-06	0.00	0.00	0.00
7,12-Dimethylbenz(a)anthracene	3	1.60E-05	0.00	0.00	0.00
Acenaphthene	3	1.80E-06	0.00	0.00	0.00
Acenaphthylene	3	1.80E-06	0.00	0.00	0.00
Anthracene	3	2.40E-06	0.00	0.00	0.00
Benz(a)anthracene	3	1.80E-06	0.00	0.00	0.00
Benzene	3	2.10E-03	0.00	0.00	0.00
Benzo(a)pyrene	3	1.20E-06	0.00	0.00	0.00
Benzo(b)fluoranthene	3	1.80E-06	0.00	0.00	0.00
Benzo(g,h,i)perylene	3	1.20E-06	0.00	0.00	0.00
Benzo(k)fluoranthene	3	1.80E-06	0.00	0.00	0.00
Chrysene	3	1.80E-06	0.00	0.00	0.00
Dibenzo(a,h)anthracene	3	1.20E-06	0.00	0.00	0.00
Dichlorobenzene	3	1.20E-03	0.00	0.00	0.00
Fluoranthene	3	3.00E-06	0.00	0.00	0.00
Fluorene	3	2.80E-06	0.00	0.00	0.00
Formaldehyde	3	7.50E-02	0.00	0.00	0.00
Hexane	3	1.80E+00	0.00	0.01	0.04
Indeno(1,2,3-cd)pyrene	3	1.80E-06	0.00	0.00	0.00
Naphthalene	3	6.10E-04	0.00	0.00	0.00
Phenanathrene	3	1.70E-05	0.00	0.00	0.00
Pyrene	3	5.00E-06	0.00	0.00	0.00
Toluene	3	3.40E-03	0.00	0.00	0.00
		Total HAP	0.00	0.01	0.04

Notes
1. NOx and CO Emission factors from AP-42 Emission Factor Table 1.4-1 for natural gas combustion boilers < 100 MMBtu/hr, July 1998.
2. VOC, SO2, and PM emission factor are from AP-42 Emission Factor Table 1.4-2, July 1998.
3. HAP emission factors are from AP-42 Emission Factor Table 1.4-3, July 1998.

APPENDIX F:

EPA COMPILATION OF AIR POLLUTANT EMISSION FACTORS, AP-42, SUPPLEMENT F, EMISSION FACTOR INFORMATION

- Chapter 1.4 Natural Gas Combustion
- Chapter 3.1 Stationary Gas Turbines
- Chapter 3.2 Natural Gas-Fired Reciprocating Engines
- Chapter 3.3 Gasoline and Diesel Industrial Engines

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO_x[b]		CO	
	Emission Factor (lb/10^6 scf)	Emission Factor Rating	Emission Factor (lb/10^6 scf)	Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)[c]	280	A	84	B
Uncontrolled (Post-NSPS)[c]	190	A	84	B
Controlled - Low NO_x burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO_x burners	50	D	84	B
Controlled - Low NO_x burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	B	40	B

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from lb/10^6 scf to kg/10^6 m^3, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from 1b/10^6 scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Expressed as NO_2. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO_X emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate NO_X emission factor.

[c] NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. $CO_2[lb/10^6$ scf] = (3.67) (CON) (C)(D), where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, $4.2x10^4$ $lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2.
Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
91-57-6	2-Methylnaphthalene[b, c]	2.4E-05	D
56-49-5	3-Methylchloranthrene[b, c]	<1.8E-06	E
	7,12-Dimethylbenz(a)anthracene[b,c]	<1.6E-05	E
83-32-9	Acenaphthene[b,c]	<1.8E-06	E
203-96-8	Acenaphthylene[b,c]	<1.8E-06	E
120-12-7	Anthracene[b,c]	<2.4E-06	E
56-55-3	Benz(a)anthracene[b,c]	<1.8E-06	E
71-43-2	Benzene[b]	2.1E-03	B
50-32-8	Benzo(a)pyrene[b,c]	<1.2E-06	E
205-99-2	Benzo(b)fluoranthene[b,c]	<1.8E-06	E
191-24-2	Benzo(g,h,i)perylene[b,c]	<1.2E-06	E
205-82-3	Benzo(k)fluoranthene[b,c]	<1.8E-06	E
106-97-8	Butane	2.1E+00	E
218-01-9	Chrysene[b,c]	<1.8E-06	E
53-70-3	Dibenzo(a,h)anthracene[b,c]	<1.2E-06	E
25321-22-6	Dichlorobenzene[b]	1.2E-03	E
74-84-0	Ethane	3.1E+00	E
206-44-0	Fluoranthene[b,c]	3.0E-06	E
86-73-7	Fluorene[b,c]	2.8E-06	E
50-00-0	Formaldehyde[b]	7.5E-02	B
110-54-3	Hexane[b]	1.8E+00	E
193-39-5	Indeno(1,2,3-cd)pyrene[b,c]	<1.8E-06	E
91-20-3	Naphthalene[b]	6.1E-04	E
109-66-0	Pentane	2.6E+00	E
85-01-8	Phenanathrene[b,c]	1.7E-05	D

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION (Continued)

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
74-98-6	Propane	1.6E+00	E
129-00-0	Pyrene[b, c]	5.0E-06	E
108-88-3	Toluene[b]	3.4E-03	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $1b/10^6$ scf to lb/MMBtu, divide by 1,020. Emission Factors preceeded with a less-than symbol are based on method detection limits.

[b] Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.

[c] HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of the Clean Air Act.

[d] The sum of individual organic compounds may exceed the VOC and TOC emission factors due to differences in test methods and the availability of test data for each pollutant.

TABLE 1.4-4. EMISSION FACTORS FOR METALS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
7440-38-2	Arsenic[b]	2.0E-04	E
7440-39-3	Barium	4.4E-03	D
7440-41-7	Beryllium[b]	<1.2E-05	E
7440-43-9	Cadmium[b]	1.1E-03	D
7440-47-3	Chromium[b]	1.4E-03	D
7440-48-4	Cobalt[b]	8.4E-05	D
7440-50-8	Copper	8.5E-04	C
7439-96-5	Manganese[b]	3.8E-04	D
7439-97-6	Mercury[b]	2.6E-04	D
7439-98-7	Molybdenum	1.1E-03	D
7440-02-0	Nickel[b]	2.1E-03	C
7782-49-2	Selenium[b]	<2.4E-05	E
7440-62-2	Vanadium	2.3E-03	D
7440-66-6	Zinc	2.9E-02	E

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. Emission factors preceeded by a less-than symbol are based on method detection limits. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by l6. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020.

[b] Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

Table 3.1-2a. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors[a] - Uncontrolled				
Pollutant	Natural Gas-Fired Turbines[b]		Distillate Oil-Fired Turbines[d]	
	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[e] (Fuel Input)	Emission Factor Rating
CO_2[f]	110	A	157	A
N_2O	0.003[g]	E	ND	NA
Lead	ND	NA	1.4 E-05	C
SO_2	0.94S[h]	B	1.01S[h]	B
Methane	8.6 E-03	C	ND	NA
VOC	2.1 E-03	D	4.1 E-04[j]	E
TOC[k]	1.1 E-02	B	4.0 E-03[l]	C
PM (condensible)	4.7 E-03[l]	C	7.2 E-03[l]	C
PM (filterable)	1.9 E-03[l]	C	4.3 E-03[l]	C
PM (total)	6.6 E-03[l]	C	1.2 E-02[l]	C

[a] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

[b] SCCs for natural gas-fired turbines include 2-01-002-01, 2-02-002-01 & 03, and 2-03-002-02 & 03.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60^{o}F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. Similarly, these emission factors can be converted to other natural gas heating values.

[d] SCCs for distillate oil-fired turbines are 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[e] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[f] Based on 99.5% conversion of fuel carbon to CO_2 for natural gas and 99% conversion of fuel carbon to CO_2 for distillate oil. CO_2 (Natural Gas) [lb/MMBtu] = (0.0036 scf/Btu)(%CON)(C)(D), where %CON = weight percent conversion of fuel carbon to CO_2, C = carbon content of fuel by weight, and D = density of fuel. For natural gas, C is assumed at 75%, and D is assumed at 4.1 E+04 lb/10^6scf. For distillate oil, CO_2 (Distillate Oil) [lb/MMBtu] = (26.4 gal/MMBtu) (%CON)(C)(D), where C is assumed at 87%, and the D is assumed at 6.9 lb/gallon.

[g] Emission factor is carried over from the previous revision to AP-42 (Supplement B, October 1996) and is based on limited source tests on a single turbine with water-steam injection (Reference 5).

[h] All sulfur in the fuel is assumed to be converted to SO_2. S = percent sulfur in fuel. Example, if sulfur content in the fuel is 3.4 percent, then S = 3.4. If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines, and 3.3 E-02 lb/MMBtu for distillate oil turbines (the equations are more accurate).

[j] VOC emissions are assumed equal to the sum of organic emissions.

[k] Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.

[l] Emission factors are based on combustion turbines using water-steam injection.

Table 3.1-3. EMISSION FACTORS FOR HAZARDOUS AIR POLLUTANTS FROM NATURAL GAS-FIRED STATIONARY GAS TURBINES[a]

Emission Factors[b] - Uncontrolled		
Pollutant	Emission Factor (lb/MMBtu)[c]	Emission Factor Rating
1,3-Butadiene[d]	< 4.3 E-07	D
Acetaldehyde	4.0 E-05	C
Acrolein	6.4 E-06	C
Benzene[e]	1.2 E-05	A
Ethylbenzene	3.2 E-05	C
Formaldehyde[f]	7.1 E-04	A
Naphthalene	1.3 E-06	C
PAH	2.2 E-06	C
Propylene Oxide[d]	< 2.9 E-05	D
Toluene	1.3 E-04	C
Xylenes	6.4 E-05	C

[a] SCC for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. Hazardous Air Pollutants as defined in Section 112 (b) of the *Clean Air Act*.
[b] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".
[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60^{o}F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. These emission factors can be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this heating value.
[d] Compound was not detected. The presented emission value is based on one-half of the detection limit.
[e] Benzene with SCONOX catalyst is 9.1 E-07, rating of D.
[f] Formaldehyde with SCONOX catalyst is 2.0 E-05, rating of D.

Table 3.2-3. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE RICH-BURN ENGINES[a]
(SCC 2-02-002-53)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO_x[c] 90 - 105% Load	2.21 E+00	A
NO_x[c] <90% Load	2.27 E+00	C
CO[c] 90 - 105% Load	3.72 E+00	A
CO[c] <90% Load	3.51 E+00	C
CO_2[d]	1.10 E+02	A
SO_2[e]	5.88 E-04	A
TOC[f]	3.58 E-01	C
Methane[g]	2.30 E-01	C
VOC[h]	2.96 E-02	C
PM10 (filterable)[i,j]	9.50 E-03	E
PM2.5 (filterable)[j]	9.50 E-03	E
PM Condensable[k]	9.91 E-03	E
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane[l]	2.53 E-05	C
1,1,2-Trichloroethane[l]	<1.53 E-05	E
1,1-Dichloroethane	<1.13 E-05	E
1,2-Dichloroethane	<1.13 E-05	E
1,2-Dichloropropane	<1.30 E-05	E
1,3-Butadiene[l]	6.63 E-04	D
1,3-Dichloropropene[l]	<1.27 E-05	E
Acetaldehyde[l,m]	2.79 E-03	C
Acrolein[l,m]	2.63 E-03	C
Benzene[l]	1.58 E-03	B
Butyr/isobutyraldehyde	4.86 E-05	D
Carbon Tetrachloride[l]	<1.77 E-05	E

Table 3.2-3. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE RICH-BURN ENGINES (Concluded)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Chlorobenzene[l]	<1.29 E-05	E
Chloroform[l]	<1.37 E-05	E
Ethane[n]	7.04 E-02	C
Ethylbenzene[l]	<2.48 E-05	E
Ethylene Dibromide[l]	<2.13 E-05	E
Formaldehyde[l,m]	2.05 E-02	A
Methanol[l]	3.06 E-03	D
Methylene Chloride[l]	4.12 E-05	C
Naphthalene[l]	<9.71 E-05	E
PAH[l]	1.41 E-04	D
Styrene[l]	<1.19 E-05	E
Toluene[l]	5.58 E-04	A
Vinyl Chloride[l]	<7.18 E-06	E
Xylene[l]	1.95 E-04	A

[a] Reference 7. Factors represent uncontrolled levels. For NO_x, CO, and PM-10, "uncontrolled" means no combustion or add-on controls; however, the factor may include turbocharged units. For all other pollutants, "uncontrolled" means no oxidation control; the data set may include units with control techniques used for NOx control, such as PCC and SCR for lean burn engines, and PSC for rich burn engines. Factors are based on large population of engines. Factors are for engines at all loads, except as indicated. SCC = Source Classification Code. TOC = Total Organic Compounds. PM10 = Particulate Matter $\leq$ 10 microns (μm) aerodynamic diameter. A "<" sign in front of a factor means that the corresponding emission factor is based on one-half of the method detection limit.

[b] Emission factors were calculated in units of (lb/MMBtu) based on procedures in EPA Method 19. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by the heat content of the fuel. If the heat content is not available, use 1020 Btu/scf. To convert from (lb/MMBtu) to (lb/hp-hr) use the following equation:

$$\text{lb/hp-hr} = (\text{lb/MMBtu})(\text{heat input, MMBtu/hr})(\text{1/operating HP, 1/hp})$$

[c] Emission tests with unreported load conditions were not included in the data set.

[d] Based on 99.5% conversion of the fuel carbon to CO_2. CO_2 [lb/MMBtu] = (3.67)(%CON)(C)(D)(1/h), where %CON = percent conversion of fuel carbon to CO_2,

C = carbon content of fuel by weight (0.75), D = density of fuel, 4.1 E+04 lb/10^6 scf, and h = heating value of natural gas (assume 1020 Btu/scf at 60°F).

[e] Based on 100% conversion of fuel sulfur to SO_2. Assumes sulfur content in natural gas of 2,000 gr/10^6scf.

[f] Emission factor for TOC is based on measured emission levels from 6 source tests.

[g] Emission factor for methane is determined by subtracting the VOC and ethane emission factors from the TOC emission factor.

[h] VOC emission factor is based on the sum of the emission factors for all speciated organic compounds. Methane and ethane emissions were not measured for this engine category.

[i] No data were available for uncontrolled engines. PM10 emissions are for engines equipped with a PCC.

[j] Considered ≤ 1 μm in aerodynamic diameter. Therefore, for filterable PM emissions, PM10(filterable) = PM2.5(filterable).

[k] No data were available for condensable emissions. The presented emission factor reflects emissions from 4SLB engines.

[l] Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

[m] For rich-burn engines, no interference is suspected in quantifying aldehyde emissions. The presented emission factors are based on FTIR and CARB 430 emissions data measurements.

[n] Ethane emission factor is determined by subtracting the VOC emission factor from the NMHC emission factor.

Table 3.3-1. EMISSION FACTORS FOR UNCONTROLLED GASOLINE AND DIESEL INDUSTRIAL ENGINES[a]

Pollutant	Gasoline Fuel (SCC 2-02-003-01, 2-03-003-01)		Diesel Fuel (SCC 2-02-001-02, 2-03-001-01)		EMISSION FACTOR RATING
	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	
NO_x	0.011	1.63	0.031	4.41	D
CO	6.96 E-03[d]	0.99[d]	6.68 E-03	0.95	D
SO_x	5.91 E-04	0.084	2.05 E-03	0.29	D
PM-10[b]	7.21 E-04	0.10	2.20 E-03	0.31	D
CO_2[c]	1.08	154	1.15	164	B
Aldehydes	4.85 E-04	0.07	4.63 E-04	0.07	D
TOC					
Exhaust	0.015	2.10	2.47 E-03	0.35	D
Evaporative	6.61 E-04	0.09	0.00	0.00	E
Crankcase	4.85 E-03	0.69	4.41 E-05	0.01	E
Refueling	1.08 E-03	0.15	0.00	0.00	E

[a] References 2,5-6,9-14. When necessary, an average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. To convert from lb/hp-hr to kg/kw-hr, multiply by 0.608. To convert from lb/MMBtu to ng/J, multiply by 430. SCC = Source Classification Code. TOC = total organic compounds.

[b] PM-10 = particulate matter less than or equal to 10 μm aerodynamic diameter. All particulate is assumed to be $\leq$ 1 μm in size.

[c] Assumes 99% conversion of carbon in fuel to CO_2 with 87 weight % carbon in diesel, 86 weight % carbon in gasoline, average BSFC of 7,000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb, and gasoline heating value of 20,300 Btu/lb.

[d] Instead of 0.439 lb/hp-hr (power output) and 62.7 lb/mmBtu (fuel input), the correct emissions factors values are 6.96 E-03 lb/hp-hr (power output) and 0.99 lb/mmBtu (fuel input), respectively. This is an editorial correction. March 24, 2009

Table 3.3-2. SPECIATED ORGANIC COMPOUND EMISSION FACTORS FOR UNCONTROLLED DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

Pollutant	Emission Factor (Fuel Input) (lb/MMBtu)
Benzene[b]	9.33 E-04
Toluene[b]	4.09 E-04
Xylenes[b]	2.85 E-04
Propylene	2.58 E-03
1,3-Butadiene[b,c]	<3.91 E-05
Formaldehyde[b]	1.18 E-03
Acetaldehyde[b]	7.67 E-04
Acrolein[b]	<9.25 E-05
Polycyclic aromatic hydrocarbons (PAH)	
Naphthalene[b]	8.48 E-05
Acenaphthylene	<5.06 E-06
Acenaphthene	<1.42 E-06
Fluorene	2.92 E-05
Phenanthrene	2.94 E-05
Anthracene	1.87 E-06
Fluoranthene	7.61 E-06
Pyrene	4.78 E-06
Benzo(a)anthracene	1.68 E-06
Chrysene	3.53 E-07
Benzo(b)fluoranthene	<9.91 E-08
Benzo(k)fluoranthene	<1.55 E-07
Benzo(a)pyrene	<1.88 E-07
Indeno(1,2,3-cd)pyrene	<3.75 E-07
Dibenz(a,h)anthracene	<5.83 E-07
Benzo(g,h,l)perylene	<4.89 E-07
TOTAL PAH	1.68 E-04

[a] Based on the uncontrolled levels of 2 diesel engines from References 6-7. Source Classification Codes 2-02-001-02, 2-03-001-01. To convert from lb/MMBtu to ng/J, multiply by 430.
[b] Hazardous air pollutant listed in the *Clean Air Act*.
[c] Based on data from 1 engine.

APPENDIX G:

EMISSION UNIT HEAT RATE FACTOR (Btu/hp-hr)

CALCULATION SPREADSHEET

Emission Unit Btu/hp-hr Calculations

Unit No.	Make/Model	Test 1 Btu/hp-hr	Test 2 Btu/hp-hr	Test 3 Btu/hp-hr	Test 4 Btu/hp-hr
401	Avon 101G	9754	9839	9453	9331
201	Avon 101G	9351	9260	9573	9699
601	Avon 101G	10217	10592	10237	10861
303	LM1600	6950	6930	6998	6999
505	LM1600	7104	7160	7277	7277

Average for all like units operated at 100% load:

	Tested Btu/hp-hr
Avon 101G	9847.3
LM1600	7086.9

Student's t Distribution = Average + [t value*(std.dev./sqrt n)]

	n	n-1	sqrt of n	t value (99%)
Avon 101G	12	11	3.46	3.106
LM1600	8	7	2.83	3.499

	Tested (Btu/hp-hr) Avon 101G	LM1600
Standard deviation	521.3	139.8

Student's t Distribution (@ 99% confidence interval)

	Tested
Avon 101G	10314.7
LM1600	7259.9

Use 10,400 Btu/hp-hr for Avon 101G
Use 8,000 Btu/hp-hr for General Electric LM1600.

1-Aug-95

APPENDIX H:

ANNUAL EMISSIONS INVENTORY

Great Lakes Gas Transmission
Deer River Compressor Station 4

Operator ID	Emission Unit Description	Annual Operating Hours	Days Operated per Year	Actual Gas Usage (MMscf)	Annual Tank Thruput (1000 gal)	NOx Emission Factor (lb/MMscf)	CO Emission Factor (lb/MMscf)	VOC Emission Factor (lb/MMscf or lb/1000 gal	Ammonia Emission Factor (lb/MMscf)	PM10 Emission Factor (lb/MMscf)	SOx Emission Factor (lb/MMscf)	NOx Emissions (lbs/yr)	CO Emissions (lbs/yr)	VOC Emissions (lbs/yr)	Ammonia Emissions (lbs/yr)	PM10 Emissions (lbs/yr)	SOx Emissions (lbs/yr)	NOx Emissions (tpy)	CO Emissions (tpy)	VOC Emissions (tpy)	Ammonia Emissions (tpy)	PM10 Emissions (tpy)	SOx Emissions (tpy)
UNIT401	Rolls Royce Avon Turbine	11	0	1.73								362.11	870.82	3.71	--	11.66	6.01	0.18	0.44	0.00	--	0.01	0.00
UNIT402	GE LM1600 Turbine	15	1	1.64		**See attached tables for EF information**						835.04	50.10	3.51	--	11.02	5.68	0.42	0.03	0.00	--	0.01	0.00
											Total	**1197.14**	**920.92**	**7.22**	**0.00**	**22.68**	**11.68**	**0.60**	**0.46**	**0.00**	**0.00**	**0.01**	**0.01**

Emissions Calculated as follows:

Engines (Actual Annual Gas Usage, MMscf) * (Emission Factor, lb/MMscf) = Emissions, lbs/yr)

NOTES

Great Lakes Gas Transmission
Deer River Compressor Station 4

Engine Data from COMET Database 1/1/2012 - 12/31/2012

Unit	Manufacturer	Model	Fuel Usage (MMcf/yr)
Unit 401	ROLLS ROYCE	AVON	1.732
Unit 402	GENERAL ELECTRIC	LM 1600	1.637

Emission Factors to be used for reporting for engines

Unit	NO_X (lb/MMscf)	CO (lb/MMscf)	VOC (lb/MMscf)	PM (lb/MMscf)	SO_2 (lb/MMscf)
Unit 401	209.100	502.860	2.142	6.732	3.468
Unit 402	510.000	30.600	2.142	6.732	3.468

	Unit 401	Unit 402
NO_X	March 29, 2005 stack test. Stack test report submitted to EPA May 11, 2005.	Emissions Test 2/16/2010; g/hp-hr calculated based on Fuel Flow (scfh) from stack test (102,603 scfh)
CO	March 29, 2005 stack test. Stack test report submitted to EPA May 11, 2005.	Emissions Test 2/16/2010; g/hp-hr calculated based on Fuel Flow (scfh) from stack test (102,603 scfh)
VOC	April 2000 EPA AP-42 Table 3.1-2a, Supplement F. (0.0021 lb/MMBtu)(1020 MMBtu/MMCF)= 2.142 lb/MMCF	April 2000 EPA AP-42 Table 3.1-2a, Supplement F. (0.0021 lb/MMBtu)(1020 MMBtu/MMCF)= 2.142 lb/MMCF
PM	PM Total from April 2000 AP-42, Table 3.1-2a, Supplement F. (0.0066 lb/MMBtu)(1020 MMBtu/MMCF) = 6.732 lb/MMCF.	PM Total from April 2000 AP-42, Table 3.1-2a, Supplement F. (0.0066 lb/MMBtu)(1020 MMBtu/MMCF) = 6.732 lb/MMCF.
SO_2	Based on a max. value of 0.205 gr/100 scf from TGP	Based on a max. value of 0.205 gr/100 scf from TGP

TOTAL FACILITY HAP EMISSIONS

HAP	Emission Rate (tpy)
Acetaldehyde	0.000
Acrolein	0.000
1,3-Butadiene	0.000
Benzene	0.000
Ethylbenzene	0.000
Formaldehyde	0.001
Naphthalene	0.000
PAH	0.000
Propylene Oxide	0.000
Toluene	0.000
Xylene	0.000
Total (lb/yr) =	**3.530**
Total (tons/year) =	**0.002**

UNIT 1 - TURBINE

HAP	Emission Factor (lb/MMBTU)	Emission Rate (lb/hr)	Emission Rate (tpy)
Acetaldehyde	4.00E-05	8.07E-06	0.000
Acrolein	6.40E-06	1.29E-06	0.000
1,3-Butadiene	4.30E-07	8.67E-08	0.000
Benzene	1.20E-05	2.42E-06	0.000
Ethylbenzene	3.20E-05	6.45E-06	0.000
Formaldehyde	7.10E-04	1.43E-04	0.001
Naphthalene	1.30E-06	2.62E-07	0.000
PAH	2.20E-06	4.44E-07	0.000
Propylene Oxide	2.90E-05	5.85E-06	0.000
Toluene	1.30E-04	2.62E-05	0.000
Xylene	6.40E-05	1.29E-05	0.000
		Total (tons/year) =	**0.001**

UNIT 2 - TURBINE

HAP	Emission Factor (lb/MMBTU)	Emission Rate (lb/hr)	Emission Rate (tpy)
Acetaldehyde	4.00E-05	7.63E-06	0.000
Acrolein	6.40E-06	1.22E-06	0.000
1,3-Butadiene	4.30E-07	8.20E-08	0.000
Benzene	1.20E-05	2.29E-06	0.000
Ethylbenzene	3.20E-05	6.10E-06	0.000
Formaldehyde	7.10E-04	1.35E-04	0.001
Naphthalene	1.30E-06	2.48E-07	0.000
PAH	2.20E-06	4.19E-07	0.000
Propylene Oxide	2.90E-05	5.53E-06	0.000
Toluene	1.30E-04	2.48E-05	0.000
Xylene	6.40E-05	1.22E-05	0.000
		Total (tons/year) =	**0.001**

NOTES:

HAP emission factors derived from AP-42 Table 3.1-3 (Turbines)
Facility must report any emission of a single HAP for any unit >0.5 tpy

APPENDIX I:

INSIGNIFICANT ACTIVITIES

- Table 1 – Potential Emissions from Insignificant Activities

Minnesota Pollution Control Agency
520 Lafayette Road North
St. Paul, MN 55155-4194

IA-01

Insignificant Activities Required to be Listed

Air Quality Permit Program

Doc Type: Permit Application

Instructions on Page 2

1a) AQ Facility ID No.: N/A **1b)** AQ File No.:

2) Facility Name: Deer River Compressor Station No. 4

3) Check and describe insignificant activities:

	Rule Citation	Description of activities at the facility
☐	7007.1300, subp. 3(A)	
☐	7007.1300, subp. 3(B)(1)	
☒	7007.1300, subp. 3(B)(2)	Residential hot water heater, natural gas-fired, 0.033 MMBtu/hr
☐	7007.1300, subp. 3(C)	
☐	7007.1300, subp. 3(D)	
☐	7007.1300, subp. 3(E)(1)	
☒	7007.1300, subp. 3(E)(2)	One diesel aboveground storage tank with dispensing nozzle, approximately 400 gallon
☐	7007.1300, subp. 3(F)	
☐	7007.1300, subp. 3(G)	
☐	7007.1300, subp. 3(H)(1)	
☐	7007.1300, subp. 3(H)(2)	
☒	7007.1300, subp. 3(H)(3)	Arc welding torches (3) and oxy-acetylene welding (1) or approximately 20 hr/yr.
☐	7007.1300, subp. 3(H)(4)	
☐	7007.1300, subp. 3(H)(5)	
☐	7007.1300, subp. 3(H)(6)	

	Rule Citation	Description of activities at the facility
☐	7007.1300, subp. 3(H)(7)	
☒	7007.1300, subp. 3(I)	Gasoline-powered portable electrical generator, Honda GX100 engine, 2.8 hp
		Gasoline-powered portable water pump, Honda GX120 engine, 3.5 hp
☐	7007.1300, subp. 3(J)	
☐	7007.1300, subp. 3(K)	
☒	7007.1300, subp. 4	Three Reznor Space Heaters, 200,000 Btu/hr each, total capacity 600,000 Btu/hr
☐	7008.4100	
☒	7008.4110	Abrasive cleaning operation with hood that filters air and exhausts indoors.

Form IA-01 Instructions

Four tables of insignificant activities are provided below.

- **Table IA-01.1, Insignificant Activities Not Required to be Listed**, specifies those activities that **do not** need to be included in your permit application.
- **Table IA-01.2**, **Insignificant Activities Required to be Listed, and Table IA-01.4, Conditionally Insignificant Activities**, specify those activities that must be included in your application, on the **IA-01** form.
- **Table IA-01.3, Insignificant Activities Required to be Listed for Part 70 Sources**, specifies insignificant activities which are required to be listed in part 70 permit applications but do not qualify as insignificant activities for state permits.
- If your facility has a Plantwide Applicability Limit (PAL), or you are applying for a PAL, all activities from Tables IA-01.2, 3, and 4 that emit the PAL pollutant no longer qualify as Insignificant Activities and must be included in your permit application as emitting equipment using the appropriate forms (e.g., GI-04, GI-05B, GI-05C, GI-07, CD-01, etc.).
- Any activity that requires a permit under 40 CFR § 52.21 (e.g., it is included in a previous Best Available Control Technology [BACT] determination or is subject to conditions to avoid New Source Review), no longer qualifies as Insignificant Activity and must be included in your permit application on the appropriate forms (e.g., GI-04, GI-05B, GI-05C, GI-07, CD-01, etc.).
- It is possible that activities listed on this form may be included in your permit with applicable requirements and associated periodic monitoring.

1a) **AQ Facility ID No**. – Fill in your Air Quality (AQ) Facility Identification (ID) Number (No.) as listed on Form GI-01, item 1a.

1b) **AQ File No.** -- Fill in your AQ File Number as listed on Form GI-01, item 1b.

2) **Facility Name --** Enter your facility name as listed on Form GI-01, item 2.

3) **Description of Activities -** Check the boxes for the insignificant activities listed in Tables IA-01.2, IA-01.3, and IA-01.4 that take place at your stationary source. For each checked activity, provide a brief description of the activity taking place at your stationary source. Fill out a separate row for each listed activity. Provide enough detail in your description so it is clear how the emission unit(s) at your source meet the definition of the insignificant activity. For example, insignificant activity subpart 3(E)(1) corresponds to gasoline storage tanks with a combined total tankage capacity of not more than 10,000 gallons. If you have gasoline storage tanks that meet this definition, indicate the total capacity of your tanks to show that it is under 10,000 gallons. If you run out of room on the table, make additional copies of the form.

Appendix I, Insignificant Activities - Table 1: 2.8 horsepower Honda GX100 electrical generator

Equipment Information	
Facility:	Deer River CS4
Make:	Honda
Model Number:	GX100
Fuel Burned:	Gasoline
Assumptions:	
Rated Capacity, (hp):	2.8
PTE Hours of Operation:	8,760

Potential Emissions - Criteria Pollutants

Criteria Pollutant	Emission Factor (lb/hp-hr)	PTE Hourly Emissions (lb/hr)	PTE Annual Emissions (tpy)
NOx	0.011	0.03	0.13
VOC	2.16E-02	0.06	0.26
SO2	5.91E-04	0.002	0.007
PM10	7.21E-04	0.002	0.009
CO	6.96E-03	0.02	0.09

Note:
Emission Factors are from AP-42, Table 3.3-1: Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines (10/96).

Appendix I, Insignificant Activities - Table 2: 3.5 horsepower Honda GX120 water pump

Equipment Information	
Facility:	Deer River CS4
Make:	Honda
Model Number:	GX120
Fuel Burned:	Gasoline
Assumptions:	
Rated Capacity, (hp):	3.5
PTE Hours of Operation:	8,760

Potential Emissions - Criteria Pollutants

Criteria Pollutant	Emission Factor (lb/hp-hr)	PTE Hourly Emissions (lb/hr)	PTE Annual Emissions (tpy)
NOx	0.011	0.04	0.17
VOC	2.16E-02	0.08	0.33
SO2	5.91E-04	0.002	0.009
PM10	7.21E-04	0.003	0.01
CO	6.96E-03	0.02	0.11

Note:
Emission Factors are from AP-42, Table 3.3-1: Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines (10/96).

Table 3.3-1. EMISSION FACTORS FOR UNCONTROLLED GASOLINE AND DIESEL INDUSTRIAL ENGINES[a]

	Gasoline Fuel (SCC 2-02-003-01, 2-03-003-01)		Diesel Fuel (SCC 2-02-001-02, 2-03-001-01)		
Pollutant	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	EMISSION FACTOR RATING
NO_x	0.011	1.63	0.031	4.41	D
CO	6.96 E-03[d]	0.99[d]	6.68 E-03	0.95	D
SO_x	5.91 E-04	0.084	2.05 E-03	0.29	D
PM-10[b]	7.21 E-04	0.10	2.20 E-03	0.31	D
CO_2[c]	1.08	154	1.15	164	B
Aldehydes	4.85 E-04	0.07	4.63 E-04	0.07	D
TOC					
Exhaust	0.015	2.10	2.47 E-03	0.35	D
Evaporative	6.61 E-04	0.09	0.00	0.00	E
Crankcase	4.85 E-03	0.69	4.41 E-05	0.01	E
Refueling	1.08 E-03	0.15	0.00	0.00	E

[a] References 2,5-6,9-14. When necessary, an average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. To convert from lb/hp-hr to kg/kw-hr, multiply by 0.608. To convert from lb/MMBtu to ng/J, multiply by 430. SCC = Source Classification Code. TOC = total organic compounds.

[b] PM-10 = particulate matter less than or equal to 10 µm aerodynamic diameter. All particulate is assumed to be ≤ 1 µm in size.

[c] Assumes 99% conversion of carbon in fuel to CO_2 with 87 weight % carbon in diesel, 86 weight % carbon in gasoline, average BSFC of 7,000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb, and gasoline heating value of 20,300 Btu/lb.

[d] Instead of 0.439 lb/hp-hr (power output) and 62.7 lb/mmBtu (fuel input), the correct emissions factors values are 6.96 E-03 lb/hp-hr (power output) and 0.99 lb/mmBtu (fuel input), respectively. This is an editorial correction. March 24, 2009

APPENDIX J:

EMISSION FACTORS FROM EMISSIONS TEST REPORT

Great Lakes Gas Transmission
Deer River Compressor Station 4

Emission Factors to be used for reporting for engines

Unit	NO_X (lb/MMscf)	CO (lb/MMscf)	VOC (lb/MMscf)	PM (lb/MMscf)	SO_2 (lb/MMscf)
Unit 401	209.100	502.860	2.142	6.732	3.468
Unit 402	510.000	30.600	2.142	6.732	3.468

	Unit 401	Unit 402
NO_X	March 29, 2005 stack test. Stack test report submitted to EPA May 11, 2005.	Emissions Test 2/16/2010; g/hp-hr calculated based on Fuel Flow (scfh) from stack test (102,603 scfh)
CO	March 29, 2005 stack test. Stack test report submitted to EPA May 11, 2005.	Emissions Test 2/16/2010; g/hp-hr calculated based on Fuel Flow (scfh) from stack test (102,603 scfh)
VOC	April 2000 EPA AP-42 Table 3.1-2a, Supplement F. (0.0021 lb/MMBtu)(1020 MMBtu/MMCF)= 2.142 lb/MMCF	April 2000 EPA AP-42 Table 3.1-2a, Supplement F. (0.0021 lb/MMBtu)(1020 MMBtu/MMCF)= 2.142 lb/MMCF
PM	PM Total from April 2000 AP-42, Table 3.1-2a, Supplement F. (0.0066 lb/MMBtu)(1020 MMBtu/MMCF) = 6.732 lb/MMCF.	PM Total from April 2000 AP-42, Table 3.1-2a, Supplement F. (0.0066 lb/MMBtu)(1020 MMBtu/MMCF) = 6.732 lb/MMCF.
SO_2	Based on a max. value of 0.205 gr/100 scf from TGP	Based on a max. value of 0.205 gr/100 scf from TGP

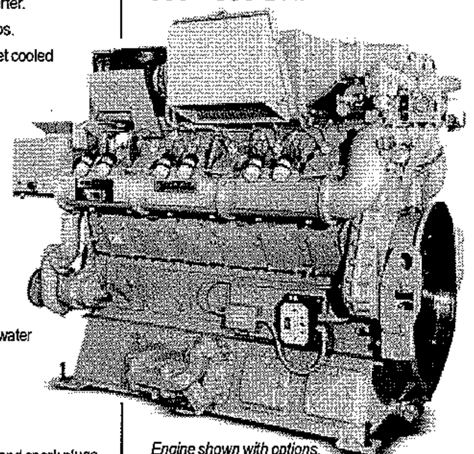
APPENDIX K:

WAUKESHA GENERATOR SPECIFICATION SHEET

Waukesha VGF

L36GL

VGF™ Series Gas Engine
500 - 880 BHP



Engine shown with options.

Model L36GL Turbocharged and Intercooled, Lean Combustion, Twelve Cylinder, Four-Cycle Gas Engine

BASE ENGINE

CONNECTING RODS – Drop forged alloy steel, angle split, serrated joint, oil jet piston pin lubrication.

CRANKCASE – Alloy cast iron, fully ribbed, integral with cylinder frame.

CRANKSHAFT – Drop forged alloy steel, dynamically balanced and fully counterweighted. Viscous vibration dampener.

CYLINDERS – Removable wet type liners of centrifugally cast alloy iron.

CYLINDER HEADS – Twelve interchangeable, valve-in-head type, with two hard faced intake and two hard faced exhaust valves per cylinder. Replaceable intake and exhaust valve seats. Mechanical valve lifters with pivoted roller followers.

FLYWHEEL – With 165 tooth ring gear (for Delco electric and I–R air/gas starters). Flywheel machined to accept SAE 620D-21, 21″ (533 mm) diameter clutch, or SAE J927B–210 flywheel converter.

FLYWHEEL HOUSING – SAE #00, nodular iron housing. Provision for two magnetic pickups.

PISTONS – Aluminum alloy, three ring, with patented high turbulence combustion bowl. Oil jet cooled with full floating piston pin. 11:1 compression ratio pistons.

STANDARD ACCESSORIES

AIR CLEANER – Dual two stage, dry panel type with rain shield and service indicator. Engine mounted.

BARRING DEVICE – Manual.

BREATHER – Crankcase, open type.

CARBURETOR – Two natural gas Impco 600 Varifuel downdraft.

CONTROLS – Local shutdown switch, engine mounted.

COOLING SYSTEM – Jacket water: gear driven jacket water pump, thermostatically controlled, full flow bypass type with nominal 180° F (82° C) outlet temperature. 4″ ANSI flange connection. Auxiliary water: thermostatically controlled, gear driven pump supplies water to intercooler and oil cooler circuit. 2″ special companion flanges supplied.

EXHAUST SYSTEM – Water cooled exhaust manifolds. Single outlet flange for ANSI 10″ 125# flange.

GOVERNOR – Woodward PSG hydraulic.

IGNITION – Waukesha Custom Engine Control electronic ignition system with coils, cables and spark plugs. Non-shielded. 24V DC power required.

INTERCOOLER – Two pass, fin and tube, air-to-water.

LIFTING EYES – For engine only.

LUBRICATION SYSTEM – Gear type pump, two replaceable element filters and industrial base type oil pan, 86 gallon (326 litres) capacity. Engine mounted shell and tube oil cooler, thermostatic valve for oil temperature control.

MOUNTING – Base type oil pan.

PAINT – Oilfield orange.

TURBOCHARGER – Two exhaust driven, dry type with wastegate. For 1400 – 1800 rpm applications.

WAUKESHA CUSTOM ENGINE CONTROL DETONATION SENSING MODULE (DSM) – Includes engine mounted detonation sensors, DSM, filter and wiring. Operation of DSM requires Waukesha CEC Ignition Module (IM), which is standard equipment. 24V DC power supply is required for IM and DSM. DSM meets CSA Class 1, Group D, Division 2, hazardous location requirements.

RECOMMENDED GENERATOR SET SPECIFICATION

BREATHER – Crankcase, closed.

GOVERNOR – Woodward EPG.

INSTRUMENT PANEL/ENGINE PROTECTION SHUTDOWNS – Engine mounted; includes high jacket water temperature and low oil pressure switchgages.

REGULATOR – Fisher model Y692, mounted. A fuel shutoff valve must be provided to positively stop gas flow to the engine for both normal and emergency shut down.

RECOMMENDED COMPRESSOR SPECIFICATION

INSTRUMENT PANEL/ENGINE PROTECTION SHUTDOWNS – Engine mounted; includes high jacket water temperature and low oil pressure switchgages. Also includes intake manifold pressure gauge.

REGULATOR – Fisher model Y692, mounted with mechanical fuel shutoff valve.

SPECIFICATIONS

Cylinders
V 12

Piston Displacement
2193 cu. in. (36 L)

Bore & Stroke
5.98″ x 6.5″
(152 x 165 mm)

Compression Ratio
11:1

Jacket Water System Capacity
44 gal. (166 L)

Lube Oil Capacity
86 gal. (326 L)

Fuel Pressure Range
25 - 50 psi
(172 - 345 kPa)

Starting System
150 psi max. air/gas
24V DC electric

Dry Weight
11,200 lb. (5171 kg)

Cooling Water Flow at	1500 rpm	1800 rpm
Jacket Water gpm (l/m)	184 (697)	218 (825)
Aux. Water gpm (l/m)	52 (197)	62 (235)

ISO 9001 CERTIFIED

POWER RATINGS: L36GL VGF SERIES GAS ENGINES

Model	I.C. Water Inlet Temp.	C.R.	Bore & Stroke in. (mm)	Displ. cu. in. (litres)	Brake Horsepower 1200 rpm[1] I	1200 rpm[1] C	1400 rpm[1] I	1400 rpm[1] C	1500 rpm I	1500 rpm C	1600 rpm I	1600 rpm C	1800 rpm I	1800 rpm C
L36GL	130° F (54° C)	11:1	5.98 x 6.5 (152 x 165)	2193 (36)	585	530	685	620	735	670	780	710	880	800
L36GL*	130° F (54° C)	11:1	5.98 x 6.5 (152 x 165)	2193 (36)	550	500	640	580	690	625	735	665	825	750
L36GL***	130° F (54° C)	11:1	5.98 x 6.5 (152 x 165)	2193 (36)	—	585	—	685	—	735	—	780	—	880

[1] *Low speed turbocharger required for operation form 1100 - 1600 rpm.*

**These power ratings are for engines applied at elevated jacket water temperatures 210° - 265° F (99° - 129° C).*

****These power ratings require Price Book Code 1100, and are available continuously when applied per WKI™ power and timing curve S7090-14. It is permissible to operate at up to 5% overload for two hours in each 24 hour period.*

Rating Standard: All models; Ratings are based on ISO 3046/1-1995 with mechanical efficiency of 90% and Tcra (clause 10.1) as specified limited ±10° F (±5° C). Ratings are also valid for SAE J1349, BS5514, DIN6271 and AP17B-11C standard atmospheric conditions.

Intermittent Power Rating: The highest load and speed which can be applied in variable speed mechanical system application only. Operation at this rating is limited to a maximum of 3500 hours per year.

ISO Standard Power/Continuous Power Rating: The highest load and speed which can be applied 24 hours a day, seven days a week, 365 days per year except for normal maintenance, it is permissible to operate the engine at up to 10% overload, or maximum load indicated by the intermittent rating, whichever is lower, for two hours in each 24 hour period.

Standby Power Rating: This rating applies to those systems used as a secondary source of electrical power. This rating is the output the system will produce continuously (no overload), 24 hours per day for the duration of the prime power source outage.

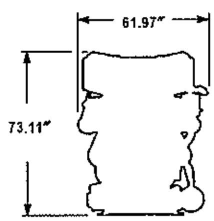
All natural gas engine ratings are based on a fuel of 900 Btu/ft³ (35.3 MJ/nm³) SLHV value, with a 91 WKI. For conditions or fuels other than standard, consult the Waukesha Engine Sales Engineering Department.

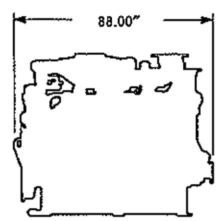
PERFORMANCE: L36GL VGF SERIES GAS ENGINES

130° F (54° C) Intercooler Water Temp		1800 rpm	1500 rpm
Low NO_x Settings	Power	800	670
	BSFC (Btu/bhp-hr)	7720	7300
	NOx (grams/bhp-hr)	1.00	1.05
	CO (grams/bhp-hr)	1.30	1.30
	NMHC (grams/bhp--hr)	0.40	0.40
Low Fuel Consumption Settings	BSFC (Btu/bhp-hr)	6985	6765
	NOx (grams/bhp-hr)	2.00	2.33
	CO (grams/bhp-hr)	1.75	1.52
	NMHC (grams/bhp--hr)	0.75	0.65

NOTES:

1) Performance ratings are based on ISO 3046/1-1995 with mechanical efficiency of 90% and Tcra limited to ± 10° F.
2) Fuel consumptions based on ISO 3046/1-1995 with a +5% tolerance for commercial quality natural gas having a 900 Btu/ft³ saturated low heat value.
3) Data based on standard conditions of 77° F (25° C) ambient temperature, 29.53 inches Hg (100kPa) barometric pressure, 30% relative humidity (0.3 inches Hg/1 kPa water vapor pressure).
4) Data will vary due to variations in site conditions. For conditions and/or fuels other than standard, consult the Waukesha Engine Sales Engineering Department.





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