TECHNICAL SUPPORT DOCUMENT
For
DRAFT/PROPOSED AIR EMISSION PERMIT NO. 0850034-002

This technical support document (TSD) is intended for all parties interested in the draft/proposed permit and to meet the requirements that have been set forth by the federal and state regulations (40 CFR § 70.7(a)(5) and Minn. R. 7007.0850, subp. 1). The purpose of this document is to provide the legal and factual justification for each applicable requirement or policy decision considered in the preliminary determination to issue the draft/proposed permit.

1. General Information

1.1 Applicant and Stationary Source Location:

Table 1. Applicant and Source Address

Applicant/Address	Stationary Source/Address (SIC Code: 4911)
Hutchinson Utilities Commission 225 Michigan Street Hutchinson, Minnesota 55350	Hutchinson Utilities Commission – Plant 2 1100 Industrial Boulevard Hutchinson, Minnesota 55350
Contact: Mr. Steve Lancaster Phone: (320) 587-4746	

1.2 Facility Description

Hutchinson Utilities Commission (HUC) Plant No. 2 is an existing municipal electric generation. The primary responsibility of HUC is to provide electrical power to the City of Hutchinson. HUC purchases some of its power from other sources, and produces its own power when:

1) their contracted power supplier requests them to generate;
2) power is interrupted; or
3) economical power is not available through MidContinent Area Power Pool.

Emission units at the facility include a GE LM 6000 52-megawatt (MW) combined cycle combustion turbine restricted to combusting natural gas (EU001) and a GE Frame 5 22- MW simple cycle combustion turbine restricted to combusting natural gas (EU004) and one steam boiler that combusts natural gas (EU003). HUC uses water injection to control nitrogen oxides (NO_X) emissions from the two turbines.

Because the combined cycle combustion turbine uses a recovered heat steam boiler to power an additional generator, HUC is considered one of the 28 named source categories listed in 40 CFR § 52.21, making its major source threshold for New Source Review (NSR) 100 tons per year (tpy). The Permittee is considered a non-major source for NSR through federally enforceable synthetic minor limits previously of 99 tons per year of NO_X and carbon monoxide (CO), along with the requirement to operate air pollution control equipment. These limits are being changed to 95 tpy – see further explanation in sections 1.3 and 2.1 of this document. This stationary source is located in an area which is designated attainment (or unclassifiable) for all criteria pollutants. Limitation of the remaining criteria pollutants is not required, since the potential emissions of these pollutants are under major source thresholds listed in 40 CFR § 52.21.

The facility was previously and continues to be considered a major source under Part 70 because it is subject to the Acid Rain regulations. The facility is now also considered a major source for Title V purposes because of potential greenhouse gas (GHG) emissions.

Table 3. Facility Classification

Classification	Major/Affected Source	Synthetic Minor/Area	Minor/Area
PSD		NO_X and CO	PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, and Lead
Part 70 Permit Program	CO_2e	NO_X and CO	PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, and HAPs
Part 63 NESHAP			Area

2. Regulatory and/or Statutory Basis

2.1 New Source Review (NSR)

The facility belongs to one of the 28 source categories for which the NSR major source threshold is 100 tpy. The facility is considered an existing minor source for NSR due to federally enforceable permit conditions limiting the emissions of all regulated pollutants to below 100 tpy. Even through GHG emissions, are greater than 100,000 tpy of carbon dioxide equivalents (CO_2e), GHG is not subject to regulation (40 CFR § 52.21(b)(49)) at the time of reissuance, and therefore is not a regulated pollutant subject to the 100 tpy major source threshold (40 CFR § 52.21(b)(50)).

NO_X and CO emissions from the three primary emission sources are each limited to 95 tpy. The previous permit contained limits of 99 tpy for NO_X and CO, placed as a total facility limit, implying the applicability of the limit to the entire facility, including insignificant activities. However, because emissions from insignificant activities were not included in the compliance calculations for the limits, it is assumed that the limits were meant to apply only to the three primary emission sources. Therefore, a new group was created and the NO_X and CO limits were relocated to that group. Furthermore, the limits were changed from 99 tpy to 95 tpy (as described above in Section 1.3). The Title I citation for each limit was changed to "limit to avoid classification as a major source and modification under 40 CFR Section 52.21 and Minn. R. 7007.3000." This is because in 2000, the facility was permitted as a minor NSR source, a modification was made, and the then-new EU004 was incorporated into the existing synthetic minor limit. Thus, the project itself was limited to minor source status, and the facility remained a minor source.

2.2 Part 70 Permit Program

The facility is a major source under the Part 70 permit program due to applicable acid rain requirements and the potential emissions of greenhouse gases. At the time of permit issuance, the GHG Tailoring Rule is in Step 2; therefore a facility with potential CO_2e emissions greater than 100,000 tpy is classified as major under Part 70.

2.3 New Source Performance Standards (NSPS)

40 CFR 60 Subpart GG -- HUC is subject to the Standards of Performance for Stationary Gas Turbines, 40 CFR 60 Subpart GG. The NSPS requires a NO_X emission limit, an initial performance test for NO_X, and periodic monitoring of the fuel nitrogen and sulfur content as described below.

40 CFR § 60.332(b) sets NO_X emission limits of 114 ppmv for EU001 during simple cycle operation, 141 ppmv for EU001 during combined cycle operation, and 75 ppmv for EU00. HUC uses water injection to control NO_X emissions from the turbines to meet the limits. HUC does not claim an allowance for fuel bound nitrogen (F = 0), so according to 40 CFR § 60.334(h)(2), monitoring of the nitrogen content in the fuel combusted is not required. An initial NO_X performance test was done on EU001 on November 3, 1994 where compliance with the 40 CFR pt. 60, subp. GG limit was demonstrated.

40 CFR § 60.333(b) sets a sulfur content limit of 0.8 percent by volume. Under the provisions of 40 CFR § 60.334(h)(3), sulfur content is not required to be monitored provided the fuel used meets the definition of gaseous fuel, demonstrated by maintaining records of 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 standard cubic feet (scf) or less. The Permittee burns only pipeline quality natural gas.

As such, EU004 is exempt from CAM [40 CFR §64.2(b)(2)].

2.6 Acid Rain

EU001, Combined Cycle 52-MW Combustion Turbine is a gas-fired unit subject to Acid Rain provisions. It qualifies as a 'new unit' and is subject to Phase II SO_2 program requirements. The facility does not qualify for exemption under 40 CFR 72.7. The Acid Rain rules require that the facility holds allowances not less than the total annual SO_2 emissions for the previous calendar year. The facility must continuously monitor SO_2 emissions, but is allowed to use fuel sulfur contents to calculate emissions from low sulfur fuels. The facility uses the procedures in 40 CFR pt. 75, Appendix D to measure SO_2 emissions. Appendix D, Part 2.3.2 allows use of a default SO_2 emission rate of 0.0006 lb/MMBtu for calculating SO_2 emissions if the fuel combusted is pipeline quality natural gas.

The facility is not subject to Acid Rain provisions for NO_X emission reduction, but must continuously monitor NO_X emissions per 40 CFR 75. The Permittee operates a continuous emissions monitoring system (CEMS) to measure NO_X emissions on a continuous basis in accordance with 40 CFR § 75.10(a)(2). The system consists of NO_X pollutant concentration and CO_2 diluent gas monitors, with calculations performed by an automated Data Acquisition and Handling System (DAHS). A performance test was conducted to calibrate the NO_X CEMS and to verify an emission factor used to calculate emissions from the facility to demonstrate compliance with a NO_X limit of 90 tons/year.

EU001 burns only pipeline quality natural gas, and is therefore exempt from the opacity monitoring requirements under 40 CFR § 75.14(c).

EU001 has both a primary stack (SV001) and a bypass stack (SV002). An exhaust gas diverter directs flow into either the bypass stack or through the combined cycle's heat recovery boiler and out the primary stack. During start-up all exhaust flow is directed to the bypass stack. When the turbine operation becomes stable, usually within minutes of start-up, the diverter directs a portion of the exhaust gas through the boiler and out the primary stack. When the boiler reaches operating temperature, typically within three hours of start-up, the diverter directs all exhaust gas through the boiler and out the primary stack. During the three-hour boiler warm up period, the turbine can only be operated at ten percent of its rated capacity due to exhaust turbulence associated with the partially open diverter.

Previously, the flow monitor, CO_2 diluent monitor, and continuous NO_X CEMS were only on the primary stack; a position switch monitored the diverter, and for all hourly periods when the diverter was directing a portion of the exhaust gases through the bypass stack, the monitors recorded and reported maximum potential flow and maximum potential emission data for NO_X , CO_2 and heat input. However, the Permittee reports that the CEMS probes have been relocated such that all emissions are now recorded and reported, regardless of whether the main stack or bypass stack is used.

The Permittee uses the procedure outlined in 40 CFR pt. 75, Appendix F to meet the heat input measurement requirement in 40 CFR § 75.10(c). Hourly exhaust gas concentration and a carbon-based F-factor for natural gas (see Appendix F, Part 3.3.5., Table 1) is used to determine hourly heat input as specified in Appendix F, Part 5.3.1., Equation F-15.

40 CFR § 72.7 allows new utility units with a total nameplate electricity generating capacity of 25 MW or less burning only fuels with sulfur content of 0.05 percent or less by weight to be exempted from the Acid Rain Program. The facility applied to the Director of the U.S. Environmental Protection Agency's (EPA) Acid Rain Division for an exemption from the program in late 1999. The facility has since received confirmation from U.S. EPA Headquarters that EU004, simple cycle 22-MW turbine is not subject to the Acid Rain Program.

2.7 Environmental Review & AERA

No changes are authorized through this permit, therefore Environmental Review and Air Emissions Risk Analysis are not required at this time.

2.8 Minnesota State Rules

Portions of the facility are subject to the following Minnesota Standards of Performance:

Interpoll Laboratories, Inc.
4500 Ball Road N.E.
Circle Pines, Minnesota 55014-1819

TEL: (612) 786-6020
FAX: (612) 786-7854

RESULTS OF THE NOVEMBER 3, 1994 NO_x EMISSION TESTS ON THE UNIT 1 GAS TURBINE AT THE HUTCHINSON UTILITIES PLANT IN HUTCHINSON, MINNESOTA

Submitted to:

ASSOCIATED CONSULTANTS ENGINEERS, INC.
3131 Fernbrook Lane North
Minneapolis, Minnesota 55447

Attention:

Paul Meyer

Approved by:

Daniel Despen
Manager
Stationary Source Testing Department

Report Number 4-4251C
December 6, 1994
SB/sab

Table 1. Summary of the Results of the November 3, 1994 **Oxides of Nitrogen** Determinations on the Unit 1 Gas Turbine at the Hutchinson Utilities Plant in Hutchinson, Minnesota.

		LOAD	NOx Concentration (ppm,d)		
Test/Run	Fuel	(%)	Actual	@15%O2	ISO
2/1	ng	40	23.5	31.5	58.0
2/2	ng	40	23.6	31.7	58.1
2/3	ng	40	23.8	31.8	58.6
3/1	ng	60	25.2	29.2	61.2
3/2	ng	60	25.4	29.2	61.1
3/3	ng	60	25.1	29.1	60.9
4/1	ng	80	24.4	26.0	55.9
4/2	ng	80	24.3	25.9	55.6
4/3	ng	80	24.2	25.8	55.5
5/1	ng	100	24.7	23.6	55.4
5/2	ng	100	25.0	24.5	57.7
5/3	ng	100	24.9	24.3	57.3

ng = natural gas

Table 2. Summary of the Results of the November 3, 1994 **Oxides of Nitrogen** Determinations on the Unit 1 Gas Turbine at the Hutchinson Utilities Plant in Hutchinson, Minnesota.

Test/Run	LOAD (%)	Conc. ppm,d	Emission Rate LB/HR	Emission Factor LB/MMBTU
2/1	40	23.5	27.1	0.116
2/2	40	23.6	27.2	0.117
2/3	40	23.8	27.4	0.117
3/1	60	25.2	34.4	0.107
3/2	60	25.4	34.7	0.108
3/3	60	25.1	34.3	0.107
4/1	80	24.4	38.3	0.096
4/2	80	24.3	38.1	0.095
4/3	80	24.2	38.0	0.095
5/1	100	24.7	42.3	0.087
5/2	100	25.0	42.8	0.090
5/3	100	24.9	42.6	0.090

Test No. 2
Unit 1 Gas Turbine Stack - **40% Load**

Results of Oxides of Nitrogen Determinations - EPA Method 20.

	Run 1	Run 2	Run 3
Date	11-03-94	11-03-94	11-03-94
Time of Run (HRS)	0927-0941	0951-1005	1020-1034
Load (MW)	3.7	3.7	3.7
Fuel Type	ng	ng	ng
Ambient Temp (°F)	44	45	44
Ambient Pressure (IN.HG.)	28.79	28.79	28.79
Gas Composition			
CO_2 (%v/v, d)	2.48	2.49	2.49
O_2 (%v/v, d)	16.5	16.5	16.5
NO_x (ppm, d)			
measured	23.5	23.6	23.8
@ 15% oxygen	31.5	31.7	31.8
@ 15% oxygen - ISO	58.1	58.1	58.6
Emission Rate (LB/HR)	27.1	27.2	27.4
Emission Factor (LB/MMBTU)	0.116	0.117	0.117

Test No. 3
Unit 1 Gas Turbine Stack - **60% Load**

Results of Oxides of Nitrogen Determinations - EPA Method 20.

	Run 4	Run 5	Run 6
Date	11-03-94	11-03-94	11-03-94
Time of Run (HRS)	1125-1139	1150-1204	1215-1229
Load (MW)	5.8	5.8	5.8
Fuel Type	ng	ng	ng
Ambient Temp (°F)	45	46	46
Ambient Pressure (IN.HG.)	28.79	28.79	28.79
Gas Composition			
CO_2 (%v/v, d)	2.83	2.85	2.85
O_2 (%v/v, d)	15.8	15.8	15.8
NO_x (ppm, d)			
measured	25.2	25.4	25.1
@ 15% oxygen	29.2	29.2	29.1
@ 15% oxygen - ISO	61.2	61.1	60.1
Emission Rate (LB/HR)	34.4	34.7	34.3
Emission Factor (LB/MMBTU)	0.107	0.108	0.107

Test No. 4
Unit 1 Gas Turbine Stack - **80% Load**

Results of Oxides of Nitrogen Determinations - EPA Method 20.

	Run 7	Run 8	Run 9
Date	11-03-94	11-03-94	11-03-94
Time of Run (HRS)	1320-1334	1345-1359	1410-1424
Load (MW)	7.4	7.4	7.4
Fuel Type	ng	ng	ng
Ambient Temp (°F)	46	46	46
Ambient Pressure (IN.HG.)	28.78	28.78	28.78
Gas Composition			
CO_2 (%v/v, d)	3.05	3.05	3.06
O_2 (%v/v, d)	15.4	15.4	15.4
NO_x (ppm, d)			
measured	24.4	24.3	24.2
@ 15% oxygen	26.0	25.9	25.8
@ 15% oxygen - ISO	55.9	55.6	55.5
Emission Rate (LB/HR)	38.3	38.1	38.0
Emission Factor (LB/MMBTU)	0.096	0.095	0.095

Test No. 5
Unit 1 Gas Turbine Stack - **100% Load**

Results of Oxides of Nitrogen Determinations - EPA Method 20.

	Run 10	Run 11	Run 12
Date	11-03-94	11-03-94	11-03-94
Time of Run (HRS)	1500-1514	1816-1830	1841-1855
Load (MW)	10.0	10.0	10.0
Fuel Type	ng	ng	ng
Ambient Temp (°F)	44	43	43
Ambient Pressure (IN.HG.)	28.78	28.78	28.78
Gas Composition			
CO_2 (%v/v, d)	3.45	3.55	3.51
O_2 (%v/v, d)	14.7	14.9	14.9
NO_x (ppm, d)			
measured	24.7	25.0	24.9
@ 15% oxygen	23.6	24.5	24.3
@ 15% oxygen - ISO	55.4	57.7	57.3
Emission Rate (LB/HR)	42.3	42.8	42.6
Emission Factor (LB/MMBTU)	0.087	0.090	0.090

OPERATING DATA SUMMARY FOR COMBUSTION SOURCES

05/17/94

Company Name: Hutchinson Utilities Commission
Date of Performance Test: November 3, 1994
Summary prepared by: _____ (Signature)

A. Fuel Input

1. Itemize all fuels and materials that are added to the combustion process during the test period. Attach ultimate/proximate analysis of the fuel. List the specific fuel (list ratios if applicable) used during testing (e.g., Western sub-bituminous coal (Antelope mines) topped with natural gas (70/30 ratio).

Natural Gas - 40% of full load

Gas Turb.

TEST	RATE OF FUEL INPUT (list units)	MOISTURE CONTENT (as received)	HEAT CONTENT (e.g. Btu/lb, Btu/gal- as received)	HEAT INPUT (x 10^6 Btu/hr)	MW Production	Steam Load (x 10^3 lbs/hr)	Steam Turbine MW Prod
Run 1	183.3 MCF/HR		1013 BTU/CF	185.68	17.2	41.6	3.7
Run 2	183.3 MCF/HR		1013 BTU/CF	185.68	17.2	41.6	3.7
Run 3	183.3 MCF/HR		1013 BTU/CF	185.68	17.2	41.6	3.7

2. Are the above fuels substantially the same as those normally burned ? Yes
   If not, explain _____

3. Are the above fuels normally burned in the proportions shown above ? Yes
   If not, explain _____

4. Describe any changes anticipated for procurement of fuels within the next twelve (12) months.
   None

B. Equipment & Operating Data:

1. ~~Furnace~~ Turbine No. LM-6000 Gas Turbine
2. ~~Furnace~~ Turbine Manufacturer: General Electric
3. Type of Firing: Natural Gas
4. Was the ~~furnace~~ turbine operated under normal operating conditions? NO
   If not, explain typical loading on the gas turbine will be 80-100% of full load
5. Specify normal soot blowing frequency:
   a) source operating time blowing soot: N/A minutes/shift
   b) number of shifts per day N/A

OPERATING DATA SUMMARY FOR COMBUSTION SOURCES

05/17/94

Company Name: Hutchinson Utilities Commission
Date of Performance Test: November 3, 1994
Summary prepared by: Paul Meyer (Signature)

A. Fuel Input

1. Itemize all fuels and materials that are added to the combustion process during the test period. Attach ultimate/proximate analysis of the fuel. List the specific fuel (list ratios if applicable) used during testing (e.g., Western sub-bituminous coal (Antelope mines) topped with natural gas (70/30 ratio).

Natural Gas - 60% of full load

Gas Turb.

TEST	RATE OF FUEL INPUT (list units)	MOISTURE CONTENT (as received)	HEAT CONTENT (e.g. Btu/lb, Btu/gal- as received)	HEAT INPUT (x 10^6 Btu/hr)	MW Production	Steam Load (x 10^3 lbs/hr)	Steam T MW
Run 1	241 MCF/Hr		1013 BTU/CF	244.13	25.8	59.2	5.8
Run 2	241 MCF/Hr.		1013 BTU/CF	244.13	25.8	59.2	5.8
Run 3	241 MCF/Hr.		1013 BTU/CF	244.13	25.8	59.2	5.8

2. Are the above fuels substantially the same as those normally burned ? Yes
   If not, explain

3. Are the above fuels normally burned in the proportions shown above ? Yes
   If not, explain

4. Describe any changes anticipated for procurement of fuels within the next twelve (12) months.
   None

B. Equipment & Operating Data:

1. Furnace No. LM-6000 Gas turbine
2. Furnace Manufacturer: General Electric
3. Type of Firing: Natural Gas
4. Was the furnace operated under normal operating conditions? No
   If not, explain Typical loading on the gas turbine will be 80-100% of full loa.
5. Specify normal soot blowing frequency:
   a) source operating time blowing soot: N/A minutes/shift
   b) number of shifts per day N/A

OPERATING DATA SUMMARY FOR COMBUSTION SOURCES

05/17/94

Company Name: Hutchinson Utilities Commission
Date of Performance Test: November 3, 1994
Summary prepared by: Paul Meyer (Signature)

A. Fuel Input

1. Itemize all fuels and materials that are added to the combustion process during the test period. Attach ultimate/proximate analysis of the fuel. List the specific fuel (list ratios if applicable) used during testing (e.g., Western sub-bituminous coal (Antelope mines) topped with natural gas (70/30 ratio).

Natural Gas - 80% of full load

Gas Turb.

TEST	RATE OF FUEL INPUT (list units)	MOISTURE CONTENT (as received)	HEAT CONTENT (e.g. Btu/lb, Btu/gal- as received)	HEAT INPUT (x 10^6 Btu/hr)	MW Production	Steam Load (x 10^3 lbs/hr)	Steam Turb. MM Prod
Run 1	311.2 MCF/Hr		1013 BTU/CF	315.25	34.4	72.6	7.4
Run 2	311.2 MCF/Hr		1013 BTU/CF	315.25	34.4	72.6	7.4
Run 3	311.2 MCF/Hr		1013 BTU/CF	315.25	34.4	72.6	7.4

2. Are the above fuels substantially the same as those normally burned ? Yes
   If not, explain

3. Are the above fuels normally burned in the proportions shown above ? Yes
   If not, explain

4. Describe any changes anticipated for procurement of fuels within the next twelve (12) months.
   None

B. Equipment & Operating Data:

1. Furnace No. LM-6000 Gas Turbine
2. Furnace Manufacturer: General Electric
3. Type of Firing: Natural Gas
4. Was the ~~furnace~~ turbine operated under normal operating conditions? Yes
   If not, explain
5. Specify normal soot blowing frequency:
   a) source operating time blowing soot: N/A minutes/shift
   b) number of shifts per day N/A