Appendix E. Air Permit Amendment Application

This appendix contains a portion of the applicant's air permit amendment application. The entire application includes a large amount of data and air modeling information in a variety of file formats and is not reproduced here. The application is available upon request from the Minnesota Pollution Control Agency, www.pca.state.mn.us.

WENCK File #1294-0035
November 2015

Air Emissions Permit Major Amendment Application

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Executive Summary

Mankato Energy Center, LLC (MEC I) currently owns one (1) 1 X 1 combined cycle power block consisting of one combustion turbine, one heat recovery steam generator (HRSG), and one steam turbine (referred to herein as the Existing Facility). The existing unit in combined cycle mode is capable of producing approximately 375 MW at peak load at winter conditions. The Existing Facility is operated by Calpine Operating Services Company, Inc. (COSCI). All entities are wholly owned indirect subsidiaries of Calpine Corporation (Calpine).

The current combustion turbine is fired primarily by natural gas with distillate fuel oil as a backup fuel. The combustion turbine exhausts to a separate HRSG having supplementary duct firing capacity of 800 MMBtu/hr. The steam generated in the HSRG exhausts in to the steam turbine. The unit is equipped with dry low-NO_x (DLN) burners and a selective catalytic reduction (SCR) system to reduce nitrogen oxides (NO_x) emissions and a catalyst oxidation system to control carbon monoxide (CO) and volatile organic compound (VOC) emissions from the combustion turbine and duct burner exhaust.

Calpine is proposing to install a new combustion turbine/HRSG train (referred to herein as the Expansion Project), converting the Existing Facility to a 2 X 1 combined cycle power block (referred to herein as the Combined Facility). The proposed Expansion Project will be owned by Mankato Energy Center II, LLC (MEC II) and operated by COSCI. The new combustion turbine/HRSG train will generate an additional 345 MW at peak load at winter conditions. The proposed combustion turbine will be fired with natural gas only and will exhaust to the new HRSG having a supplementary duct firing capacity of 824 MMBtu/hr. The duct burners will also be fired only with natural gas. The steam generated by the new HRSG will exhaust into the existing steam turbine.

MEC II will install SCR and DLN burners to reduce NO_x emissions and a catalyst oxidation system to control CO and VOC emissions from the proposed combustion turbine. The HRSG duct burner exhaust will be controlled by the proposed SCR and catalyst oxidation system and low-NO_x burners. The equipment selection is not yet final. The proposed new combustion turbine will be an F-Class turbine with similar characteristics to the existing unit. The new HRSG will also be designed to produce steam conditions matching the existing equipment. In order to provide additional cooling due to the increased steam flow to the steam turbine, four new cells will be added to the existing cooling tower. A new anhydrous ammonia tank will be installed to provide the reagent to the new SCR.

Secondary combustion sources at the Combined Facility include the existing natural gas fired auxiliary boiler with a rated heat input of 70 MMBtu/hr, the existing diesel fired fire pump engine, the existing bath heater, and a proposed diesel fired emergency generator. Other non-combustion related sources include storage tanks and the new and existing cooling tower cells.

The project site is located in Mankato, MN. The location is shown in Figures 2-1 and 2-2 at the end of Section 2.

The Expansion Project is subject to review under the federal Prevention of Significant Deterioration (PSD) rules for emissions of NO_x, CO, VOCs, particulate matter (PM), PM with diameter less than 10 microns (PM_{10}), PM less than 2.5 microns ($PM_{2.5}$), and greenhouse gases (GHGs).

MEC II will apply Best Available Control Technology (BACT) to control emissions. As mentioned above, exhaust from the proposed combustion turbine will be controlled using SCR and DLN burners to control NO_x emissions and a catalytic oxidizer to control CO and VOC emissions. Emissions from the proposed HRSG low-NO_x duct burners will be controlled using an SCR and catalytic oxidizer. The proposed diesel fired emergency generator will be limited to 100 hours of non-emergency operation annually and will be operated and maintained in accordance with manufacturers' specifications to ensure low emissions. The additional cooling tower cells will incorporate a mist eliminator having a 0.0005% tower drift rate. Additional details are provided in Section 5.

An Additional Impacts Analysis shows that no adverse impacts on soils, vegetation, and visibility will be caused by emissions from the Expansion Project and from associated growth. An Endangered Species Act (ESA) analysis shows that there are no federal endangered species in the area. In addition, a National Historical Preservation Act (NHPA) analysis shows that no historical buildings or artifacts will be affected by the Expansion Project. Section 6 provides additional details.

Air dispersion modeling was performed to demonstrate that the Existing Facility and Expansion Project emissions do not cause or contribute to a violation of the Minnesota and National Ambient Air Quality Standards (MAAQS and NAAQS) and PSD increment standards. The modeling demonstration was conducted in the following three steps. Additional details are provided in Section 7.

1. Preliminary modeling of the emissions from the Expansion Project alone shows that the maximum downwind ambient concentrations are less than the PSD significant impact level (SIL) for 1-hour CO, annual NO_2, PM_{10} and the vacated SIL for $PM_{2.5}$. Therefore, no further analysis of 1-hour CO, an annual NO_2, PM_{10} emissions was required. No further NAAQS analysis of $PM_{2.5}$ emissions was required but a $PM_{2.5}$ Increment screening analysis was still required.
2. Refined modeling of the Combined Facility shows that predicted concentrations of 1-hour NO_2 and 8-hour CO comply with the respective NAAQS and MAAQS. There are no PSD increments for these pollutants and averaging periods.
3. $PM_{2.5}$ Increment screening modeling shows that the Combined Facility will be a small consumer of increment. The analysis also determined that monitored background concentrations in the area have improved significantly over the past several years, increasing the amount of "headroom" between the project impacts and the PSD Class II increment standards.

This application identifies the state and federal air quality requirements that apply to the Expansion Project and the testing, monitoring, recordkeeping, and reporting procedures that will be utilized to demonstrate compliance. The Existing Facility currently operates under a "synthetic" limit on formaldehyde, hexane and total HAP emissions, equivalent to the recently promulgated Maximum Achievable Control Technology Standard for combustion turbines (40 CFR 63, Subp. YYYY), to ensure that the Facility qualified as a non-major source of hazardous air pollutants. The Expansion Project will not change the current "synthetic" limit on formaldehyde, hexane and total hazardous air pollutants (HAPs). The Expansion Project proposes the use of continuous emission monitors (CEMS) to demonstrate compliance with the BACT emission limits on NO_x and CO emissions from the proposed combustion turbine/duct burner stack.

1.0 Prevention of Significant Deterioration Applicability

MEC I is currently subject to state and federal PSD requirements because the facility qualifies as a major stationary source under the PSD rules, defined in 40 CFR 52.21(b)(1)(i). The Existing Facility potential emissions of PM, PM_{10}, $PM_{2.5}$, SO_2, NO_x, VOC, and CO are greater than the PSD major source threshold of 100 tons/yr. The Existing Facility potential GHG emissions are greater than the PSD major source threshold of 100,000 tons/yr.

If emissions of one or more regulated pollutants from a project at an existing major facility exceed the major modification thresholds, the project is subject to PSD review. Potential emissions of PM, PM_{10}, $PM_{2.5}$, NO_x, VOC, CO, and carbon dioxide equivalent (CO_2e) exceed the PSD major modification thresholds for the Expansion Project. Additional discussion on emission calculation methodology is included in Section 5.

Table 1-1 shows a comparison of the total potential emissions from the Expansion Project with the PSD major modification threshold for each pollutant. The Combined Facility post project total emissions are also provided in Table 1-1.

Table 1-1 Potential Emissions and PSD Applicability Thresholds

Pollutant	Combined Facility Post Project Total Potential Emissions (tpy)	Expansion Project Potential Emissions (tpy)	PSD Major Modification Threshold (tpy)
PM	189.05	68.00	25
PM_{10}	175.88	54.83	15
$PM_{2.5}$	173.20	52.15	10
SO_2	98.58	30.46	40
NO_x	354.01	167.44	40
VOC	647.01	382.58	40
CO	1,266.03	768.64	100
Lead	0.026	6.61E-03	0.6
CO_2e	3,100,582	1,585,055	75,000
Asbestos	NA	NA	0.007
Beryllium	3.92E-04	4.24E-05	0.004
Mercury	3.07E-03	9.20E-04	0.1
Vinyl chloride	NA	NA	1
Hydrogen sulfide	NA	NA	10
Sulfuric acid mist	14.88	4.58	7
Total reduced sulfur	NA	NA	10
Reduced sulfur compounds	NA	NA	10

As a major stationary source subject to PSD review, the Expansion Project must satisfy the following requirements specified in 40 CFR 52.21, which include the following:

- Apply BACT to control emissions of each regulated pollutant for which the potential emissions exceed the PSD major modification threshold: the evaluation of BACT for each pollutant and emission source is detailed in Section 3.

- Evaluate the impact of air, ground, and water pollution on soils, vegetation, and visibility caused by emissions from the Expansion Project and from associated growth; these additional impacts are summarized in Section 6 and are described in more detail in the Environmental Assessment (EA) and questionnaire submitted to the Public Utilities Commission (PUC). Projects are also required to evaluate the impact on endangered species and national historical sites. These impacts are also summarized in Section 6.
- Perform air dispersion modeling to demonstrate that the potential emissions will not cause or contribute to an exceedance of the NAAQS or PSD Increment Standard; the modeling methodology and results are summarized in Section 7. A modeling report is provided in Appendix H.
- Perform an air emissions risk analysis (AERA) to determine cumulative impacts of the Combined Facility. Results of this analysis are summarized in Section 8 and a full report and application forms are provided in Appendix I.

2.0 Project Description

2.1 PROJECT SITE

The project site is located in the Mankato City limits. The Existing Facility site is approximately 25 acres in size. The Expansion Project will be located on the Existing Facility site. The project location is shown in Figures 2-1 and 2-2.

2.2 GENERATING TECHNOLOGY

A combined cycle facility refers to a power block arrangement with at least one combustion turbine generator, 1 HRSG that may be equipped with duct burners, and 1 steam turbine-generator. Two combustion turbine/HRSG trains will provide steam to 1 steam turbine-generator at the Combined Facility. The power block configuration is shown in Figure 2-3 at the end of this section.

The current and proposed combustion turbines are F-Class models which utilize compressed air and fuel to produce electricity and high temperature exhaust gas. The proposed combustion turbine will be fired by natural gas only.

Each combustion turbine consists of the following equipment in series:

- an inlet air filter;
- a compressor, where air is drawn in and compressed;
- a combustor, where fuel is mixed with the compressed air and burned;
- a power turbine, where the combusted gases expand to rotate a turbine; and
- an electric generator.

The HRSG recovers waste heat from the exhaust gases of the combustion turbine. The waste heat is used to produce steam, creating additional power generation in combination with a steam turbine. Inside the HRSGs, the hot exhaust gases are directed across the heat transfer tube surface causing the water in the tubes to boil and change phase into steam. The steam turbine receives the steam produced by the two HRSGs. The steam will expand through the steam turbine and cause the turbine shaft to rotate. This drives the generator to produce electrical power.

Air pollution control equipment for the current and proposed combustion turbine includes DLN burners and SCR for NO_x control; catalytic oxidization system for CO and VOC control. The current and proposed HRSG low-NO_x duct burners will also be controlled by the existing and proposed SCR and catalytic oxidizer. Natural gas combustion produces minimal particulate and SO_2 emissions. Thus, no specific control equipment is required for either pollutant.

DLN burners limit the production of NO_x by premixing the compressed air and natural gas prior to injection into staged lean combustors. This results in a relatively cool combustion zone. More NO_x is produced in high-temperature zones; therefore, the lower temperature in the combustion zone reduces the NO_x produced. The SCR uses anhydrous ammonia and a catalyst to convert NO_x emissions to elemental nitrogen and water.

As mentioned previously, a catalytic oxidizer is employed on the existing equipment and will be installed on the new unit to reduce emissions of CO and VOC emissions.

The proposed and existing combined cycle units have the ability to operate with and without duct burners. The duct burners utilize excess oxygen in the exhaust gas to combust additional natural gas increasing steam production. The HRSG duct burners for the proposed unit will add approximately 824 MMBtu/hr (HHV) of heat input.

The current combustion turbine is a Siemens F-Class model which is no longer manufactured. Since the existing and new combustion turbine/HRSG trains will be operating in parallel to supply steam to the existing steam turbine, it is preferred that the proposed unit be of similar performance and exhaust gas characteristics to ensure a stable combined cycle operation. In order to obtain a combustion turbine with compatible characteristics, MEC II will purchase either: 1) a grey market version, 2) an off-market version, or 3) a newer version but de-rated combustion turbine.

2.3 ANCILLARY EQUIPMENT

New emission sources for the Expansion Project will also include a proposed diesel-fired emergency generator, four additional cooling tower cells, natural gas piping, and electrical equipment insulated with sulfur hexafluoride (SF_6). MEC II also plans to install an anhydrous ammonia tank, a water tank, condensate tank and a small diesel tank for the proposed diesel fired emergency generator.

MEC I installed an indirect-gas fired bath heater as part of the Existing Facility. The bath heater is a small natural gas combustion source at 2.87 MMBtu/hr. The bath heater qualified as a Minn. R. 7007.1300, Subpart 4 insignificant activity during the original permitting. However, the bath heater can no longer qualify as an insignificant activity under Subpart 4 because this is not an initial Title V permit. The source is included in the application as an emission unit.

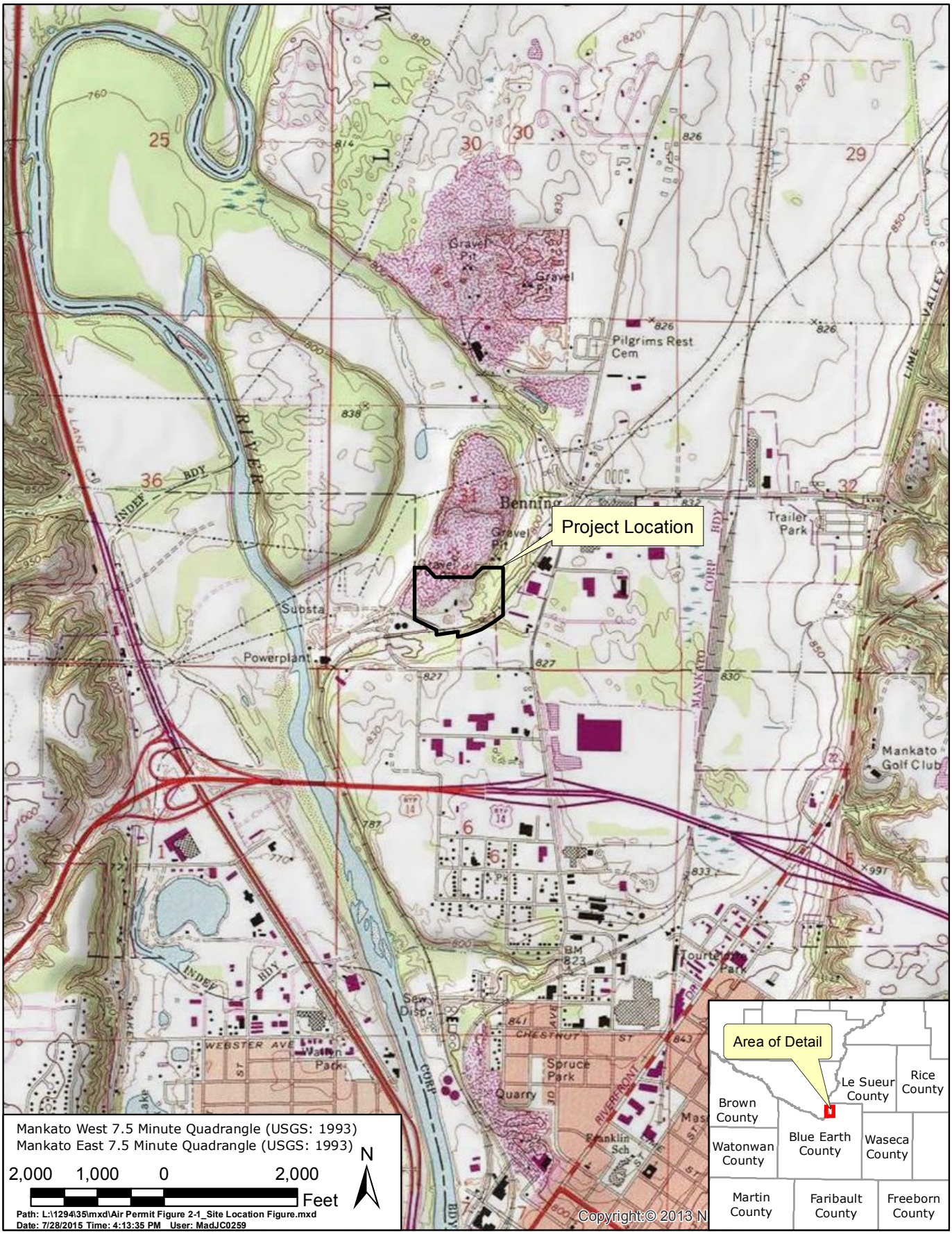
2.4 PROPOSED EQUIPMENT SUMMARY

Below is a summary of the proposed and existing equipment at the facility and relation to control equipment and stack vents. This equipment schedule is included in the attached form for the proposed equipment and the current permit for the existing equipment. A process flow diagram is also provided below for the Expansion Project equipment in Figure 2-4 and included with Form GI-02 in Appendix A.1.

Table 2-1 Equipment Summary

Emission Unit Description	EU Number	Control Equipment Description	Control Equipment Number	Stack Vent Number
Proposed Equipment as part of the Expansion Project				
Combustion Turbine #1	EU 008	Dry Low-NOx Burner SCR Catalytic Oxidizer	CE 010 CE 011 CE 012	SV 007
Duct Burners (Combustion Turbine #1)	EU 009	SCR Catalytic Oxidizer	CE 011 CE 012	SV 007
Diesel Fired Emergency Generator	EU 010	NA	NA	SV 008
Cooling Tower*	FS 001	NA	NA	NA
Natural Gas Fugitives	FS 002	NA	NA	NA
Breaker Fugitives	FS 003	NA	NA	NA
Current Equipment as part of the Existing Facility				
Combustion Turbine #2	EU 002	Dry Low-NOx Burner Water Injection SCR Catalytic Oxidizer	CE 002 CE 004 CE 006 CE 008	SV 002
Duct Burners (Combustion Turbine #2)	EU 004	SCR Catalytic Oxidizer	CE 006 CE 008	SV 002
Auxiliary Boiler	EU 005	NA	NA	SV 003
Diesel Fired Fire Pump Engine	EU 007	NA	NA	SV 005
Bath Heater	EU 011	NA	NA	SV 009

* Calpine is proposing to install 4 additional cooling tower cells to existing FS001.



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Site Location Map

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Figure 2-1

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Aerial Photograph Site Location Map

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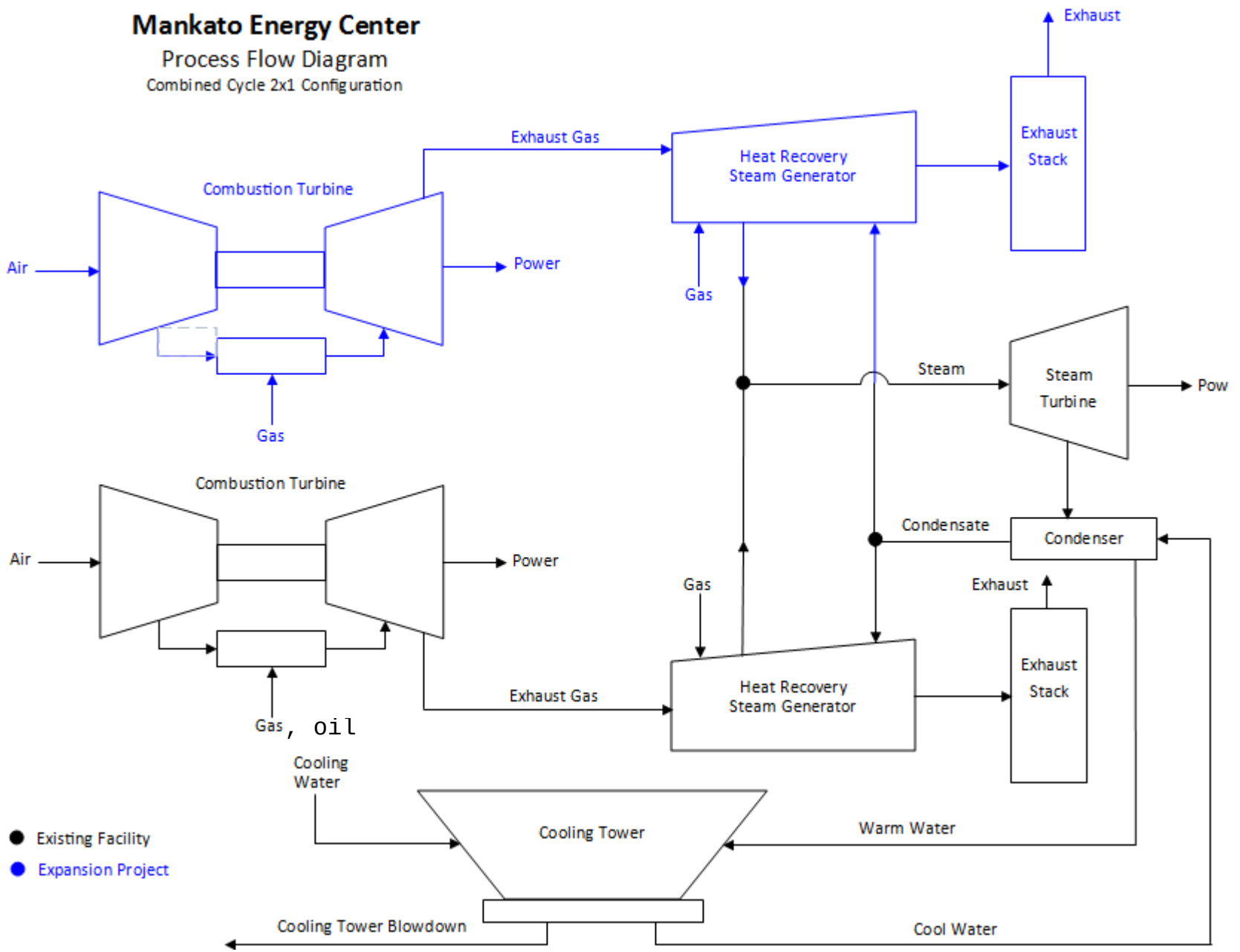
Figure 2-2



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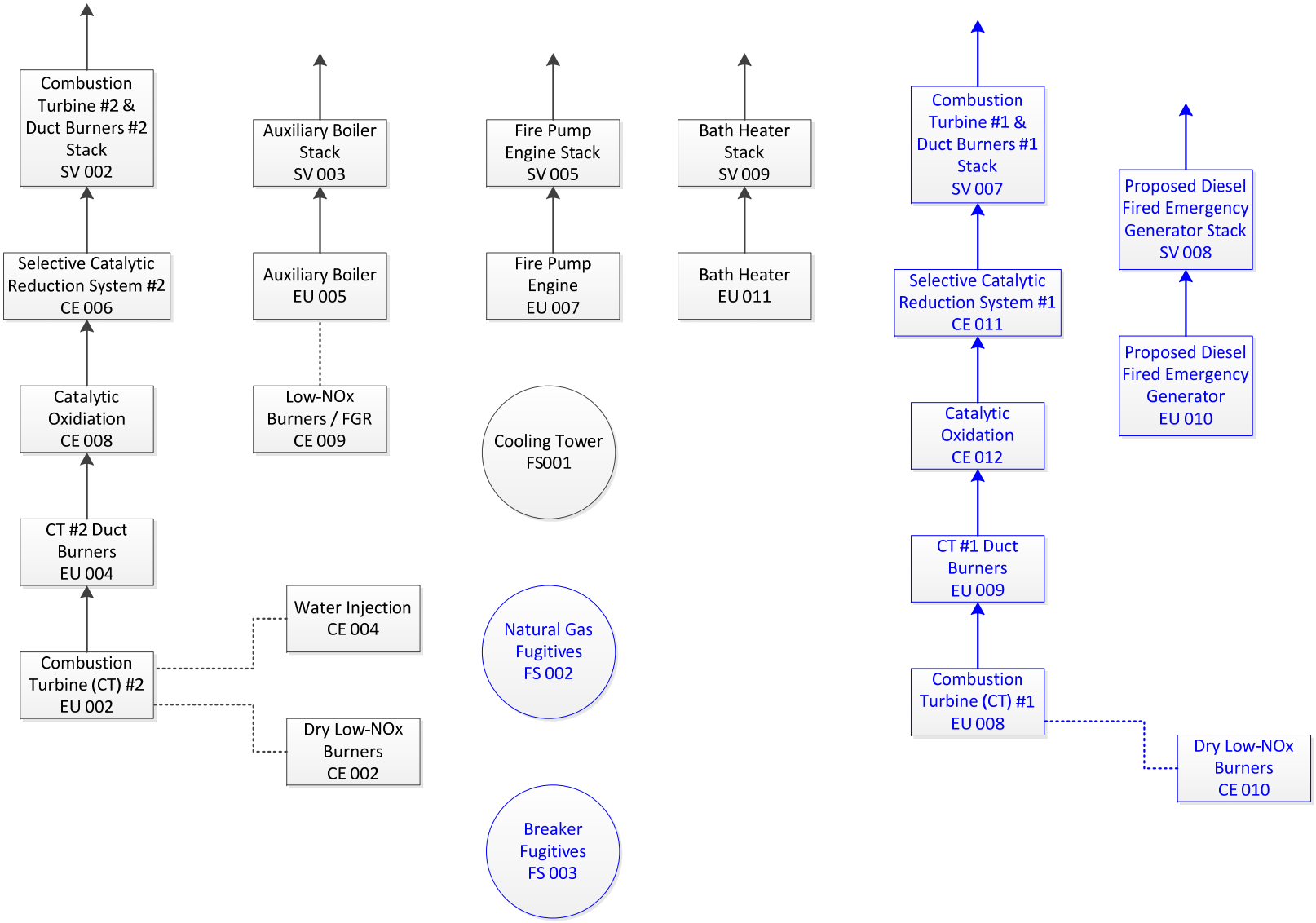
Process Flow Diagram		Figure 2-3

Figure 2-4 Equipment Summary Diagram



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3.0 Best Available Control Technology Determination

The Expansion Project is subject to PSD review for emissions of NO_x, CO, $PM/PM_{10}/PM_{2.5}$, VOC and GHG. These regulations require MEC II to complete a case-by-case BACT determination for each piece of equipment associated with the Expansion Project that has the potential to emit air pollutants subject to PSD.

This section documents the BACT determination for each piece of equipment associated with the Expansion Project that has the potential to emit NO_x, CO, $PM/PM_{10}/PM_{2.5}$, VOC and GHG.

3.1 BACT DEFINITION

BACT is defined in 40 CFR 52.21(j) BACT as follows:

> "an emission limitation (including a visible emission standard) based on the maximum degree of reduction of each air pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant…"

BACT has been determined using Environmental Protection Agency's (EPA's) top-down approach. Following the top-down approach, progressively less stringent control technologies are analyzed until a level of control considered BACT is reached on the basis of environmental, energy, and economic impacts. The steps involved, include:

- Step 1 - Identify applicable options;
- Step 2 - Eliminate technically infeasible options;
- Step 3 - Rank remaining alternatives by control effectiveness;
- Step 4 - Evaluate most effective controls; and
- Step 5 - Select BACT

In determining BACT for the emission units included this project, information from the following sources were evaluated:

- On-line EPA RACT/BACT/LAER Clearinghouse (RBLC) System and other state BACT control technology databases;
- EPA/State/Local Air Quality Permits and Applications;
- Control Technology Vendors;
- AP-42-Section 3.1 Stationary Gas Turbines for Electricity Generation; and
- Alternative Control Techniques Document – NO_x emissions form Stationary Gas Turbines EPA-453/R-93-007.

The following sections outline the results of the evaluations to determine BACT for the various emissions units associated with the Expansion Project.

3.2 BACT DETERMINATION FOR COMBINED CYCLE COMBUSTION TURBINE/HRSG OPERATION

The Expansion Project will install an additional natural gas fired combustion turbine equipped with DLN burners. The turbine will exhaust to a separate HRSG which is equipped with an 824 MMBtu/hr natural gas only duct burner. MEC II is proposing to install downstream from the HRSG an SCR system to reduce NO_x emissions, and a catalytic oxidizer to reduce CO and VOC emissions. A summary of recent BACT determinations, including those for ancillary equipment, is included in Appendix B.

3.2.1 Control of Oxides of NO_x Emissions

A top-down evaluation of NO_x control technologies revealed that DLN burners and SCR are equivalent to the best available control alternatives for natural gas-fired combined cycle units. Both of these technologies will be applied to the proposed expansion at MEC II. The proposed NO_x emission performance levels are as follows:

- 3.0 ppmvd @ 15% O_2 for natural gas combustion with DLN burner technology, low-NO_x duct burners and SCR technology.

The operating temperatures within combustion turbine burner systems result in the formation of NO_x emissions. Thermal NO_x and fuel NO_x are the two primary NO_x formation mechanisms in combustion turbines. Thermal NO_x is formed by the dissociation of atmospheric nitrogen and oxygen in the turbine combustor and the subsequent formation of NO_x. When fuels containing nitrogen are combusted this additional source of nitrogen results in fuel NO_x formation. Thermal NO_x is the dominant mechanism for NO_x emissions for the proposed turbine because natural gas fuel contains little or no nitrogen. The formation rate of thermal NO_x increases exponentially with an increase in temperature.

The following technologies were identified as potentially able to control NO_x emissions from stationary combined-cycle combustion turbines:

- DLN burner technology;
- Wet controls – water and steam injection;
- Rich/Quench/Lean (RQL) combustion;
- SCR;
- Selective Non-catalytic reduction (SNCR);
- EMx, formerly SCONOX™ catalytic oxidation/absorption; and
- Catalytic combustion – XONON™

3.2.1.1 Technical Feasibility of NO_x Control Alternatives

The previously referenced information resources were consulted to determine the extent of applicability or each identified control alternative.

<u>Combustion Turbine DLN Burner Technology</u>
DLN burners use an advanced combustion design to suppress NO_x formation and/or promote CO burnout while firing natural gas. The technology can include a lower combustion temperature with lean mixtures of air and fuel, staged premix combustion, or decreased residence time. For turbines such as those proposed for the Expansion Project, DLN burners can achieve 25 ppm NO_x without the addition of any further controls. As

discussed earlier, MEC II is proposing a turbine equipped with the DLN burner technology, which will be utilized while firing natural gas.

Wet Combustion – Water or Steam Injection

Water or steam injection into the flame area of the turbine combustor lowers the flame temperature and reduces the formation of thermal NO_x. A water injection system consists of a water treatment system, pump(s), water metering valves and instrumentation, turbine-mounted injection nozzles, and piping. Water or steam injection can control NO_x concentrations to 25 ppm at 15 percent O_2 for natural gas combustion and 42 ppm for distillate fuel oil combustion. The water-to-fuel ratio (WFR) is the most important factor affecting performance of this control technology and varies by manufacturer and model.

Because the proposed turbine will be equipped with DLN burners that generate NO_x levels equivalent to what is attainable with wet control, this control technology will be eliminated from further consideration in the BACT determination for natural gas firing. The existing combustion turbine utilizes water injection to control NO_x emissions when combusting distillate fuel oil. Because the proposed turbine will only fire natural gas, water injection is not required and would not provide any additional control.

Rich/Quench/Lean (RQL) Combustion

RQL combustors burn fuel-rich in the primary zone and fuel-lean in the secondary zone. Incomplete combustion under fuel-rich conditions in the primary zone produces an atmosphere with a high concentration of CO and hydrogen. The CO and hydrogen replace some of the oxygen normally available for NO_x formation and also act as reducing agents for any NO_x formed in the primary zone. Thus fuel nitrogen is released with minimal conversion to NO_x. The lower peak flame temperatures due to partial combustion also reduce the formation of thermal NO_x. As the combustion products leave the primary zone, they are cooled through rapid dilution and combustion is completed under fuel-lean conditions. Thermal NO_x is minimized during lean combustion because of the low flame temperature.

As indicated in the Alternative Control Techniques (ACT) document, RQL combustors are not commercially available for most turbine designs. Therefore because it is not technically feasible, this control alternative utilizing RQL combustion is eliminated from further consideration in this BACT determination.

Selective Catalytic Reduction (SCR)

SCR can be installed in HRSGs to control NO_x emissions from the combustion turbines and duct burners. Anhydrous ammonia is injected into the flue gas stream, upstream of the SCR catalyst bed, where it mixes with the NO_x to form molecular nitrogen and water. The reactions take place on the surface of the catalyst. The function of the catalyst is to effectively lower the activation energy required for the NO_x decomposition reactions.

Depending on system design and the inlet NO_x level, NO_x removal of up to 70-90 percent is achievable at optimum theoretical conditions. Depending on the catalyst, NO_x reduction occurs within a reaction window of 400 to 1100 degrees Fahrenheit. The design of the HRSG allows for catalyst installation in the optimum temperature zone. As stated earlier MEC II is proposing to install SCR to reduce NO_x emissions from the combustion turbine and duct burner system.

Selective Non-Catalytic Reduction (SNCR)

SNCR technology involves using ammonia or urea injection similar to SCR technology but at a higher temperature window of 1600 to 2200 degrees Fahrenheit, without the use of a

catalyst. In certain applications the low end of the operating temperature window can be reduced from 1600 to 1300 degrees Fahrenheit. However, outside of the temperature limits the ammonia can be converted to NO_x, resulting in an increase in NO_x emissions.

Because the exhaust temperatures in combustion turbines typically do not exceed 1250 degrees Fahrenheit, the operative temperature window of this control alternative is not technically feasible in this application. The exhaust temperature is typically around 1150 degrees Fahrenheit at the combustion turbine exit during steady state conditions and 200 degrees Fahrenheit at the exhaust stack, which is less than the acceptable range for SNCR application. Additionally, this technology requires a residence time of approximately 100 milliseconds. This is relatively slow for exhaust gas operating velocities. Thus there may not be adequate residence time for the NO_x destruction chemical reaction. Furthermore, a review of the RBLC database for recent BACT/Lowest Achievable Emission Rate (LAER) determinations did not indicate that SNCR systems have been successfully installed for NO_x control for similar combined-cycle units. For the above reasons, SNCR will no longer be considered for this analysis because it is not technically feasible for the size of the proposed unit.

<u>EM_x™ (Formerly SCONOx™) Catalytic Oxidation/Absorption</u>
EM_x™ is a trade name for a proprietary experimental NOx control technology being marketed by EmeraChem, LLC (formerly Goal Line Technologies). EM_x™ guarantees NO_x emission concentration of 2 ppmv based on an inlet NO_x concentration of 25 ppm. The technology works by allowing the exhaust gases to react with potassium carbonate that is coated on a platinum catalyst surface. The CO is oxidized to CO_2 and exhausted out the stack. The NO is oxidized to NO_2 and then reacts with the potassium carbonate absorber coating on the catalyst to form potassium nitrites and nitrates at the catalyst surface until the catalyst requires regeneration.

The EPA Region IX issued a letter dated March 23, 1998, indicating that emissions data from Sunlaw's Federal Cogeneration facility in Vernon, California has "demonstrated in practice" NO_x emissions at or below 2.0 ppm (3-hour average) using SCONOx™. Although this letter is not a Federal LAER determination, the letter does state that future projects subject to LAER should evaluate this technology for feasibility of application. The South Coast Air Quality Management District (SCAQMD) of California also adopted (effective June 12, 1998) a "BACT" guideline for gas turbines less than 50 MW equal to 2.5 ppm at 15 percent O_2 (1-hour average corrected for efficiency) based on SCONOx™ technology.

However in Appendix B of a document titled Supporting Material for BACT Review for Electrical Generation Technologies (July 23, 2001), SCAQMD recognized that this technology has not been applied to larger turbines such as those proposed by MEC II when the agency stated the following:

> *"Because the technology has not been demonstrated for all sizes of turbines, the ARB staff is not considering the SCONOx technology for the purposes of establishing guideline levels".*

In preparation of the Existing Facility 2004 PSD application, ABB Alstom Power was contacted as the license holder of this technology for turbines of similar size to those proposed for the Expansion Project. According to Noel Kuch of ABB Alstom, the largest turbine that this technology has been commercially installed on is 43 MW.

In addition to the scale-up concern, there is also significant energy impacts associated with this application of EM_x™ technology. There is a power output penalty, and a fuel penalty associated with the use of the catalyst. The increased backpressure in the turbine from the catalyst installation increases the heat input required and reduces the power output of the turbine. EM_x™ technology has been used to define LAER in non-attainment areas in smaller (32 MW systems). EM_x™ can match the performance of SCR without the ammonia slip; however, catalyst must be regenerated periodically while online using hydrogen produced by a natural gas reforming unit, making this technology not cost effective when compared to SCR. No RBLC entries for permits issued after 2006 have listed SCONOx™ as BACT. The proposed unit will be equipped with a combination DLN Combustor technology as well as SCR (equivalent control technology) which is capable of reducing emissions to an equivalent level; therefore EM_x™ will be eliminated from consideration in the BACT analysis.

Catalytic Combustion – XONON™

Another new NO_x control technology being developed is catalytic combustion. Catalytic combustion minimizes peak temperatures and NO_x formation. The XONON™ system is being developed for commercial application by Catalytic Combustion Systems to utilize this technology. Their system includes a pre-burner, a fuel injection and mixing system, a flameless catalyst module and a flameless burnout zone. The pre-burner starts the turbine and a fuel injection system provides a uniform fuel and air mixture to the catalyst, where a portion of the fuel is combusted at reduced temperature to reduce thermal NO_x emissions. The remainder of the fuel is combusted in the burnout zone with minimal NO_x emissions.

The technology has only been tested in small turbines (less than 10 MW) and it is not commercially available for the proposed turbine size. Although the vendor is in the process of developing the technology for larger units, the complete application is believed to be years away from development. Until such time that the technology is commercially available, catalytic combustors are not considered technically feasible. In view of this limitation, utilizing catalytic combustor control is eliminated from further consideration in this BACT determination.

3.2.1.2 Proposal for NO_x BACT for the Combustion Turbine/HRSG

Various control alternatives were reviewed for technical feasibility in controlling NO_x emissions from the proposed combustion turbine/HRSG train. Combustion control utilizing the DLN combustor technology based on lean premix combustion controls and SCR (both of which are proposed for implementation) is equivalent to the highest ranking control technology.

As stated previously, the existing technology for MEC I is a Siemens Westinghouse FD-2 combustion turbine which is no longer a standard offering from the manufacturer. It is preferable that the Expansion Project use a gas turbine technology with similar performance and exhaust gas characteristics to provide stable and reliable combined cycle operation, since the existing and new combustion turbine/HRSG trains will be operating in parallel to supply steam to the existing steam turbine. In order to provide a combustion turbine with comparable operating characteristics, MEC II has the following procurement options:

- a unit from the gray market,
- an original manufacturer equipment (OEM) off-market unit built from spare components, or
- a newer unit, slightly de-rated to the match the performance of the existing unit.

Each of these options has long term reliability concerns which could affect the emissions performance. A combustion gas turbine with latest available technology could offer lower emissions, supporting a BACT limit of 2 ppm NO_x at the stack. However, the turbine would have to be significantly de-rated to match the existing equipment, negating the performance and efficiency benefits that would otherwise justify its purchase. In addition, operating a modern combustion turbine at a significant de-rating could cause stability and reliability issues when in parallel with the existing combustion turbine/HRSG train.

Calpine believes that using a combustion turbine technology similar to the existing equipment for the new expansion is an economically viable option that will provide reliable operation over the life of the plant.

In conclusion, BACT for the proposed natural gas-fired combustion turbine/HRSG is the following:

- 3.0 ppmvd using a 3-hour block average @ 15% O_2 for natural gas combustion with DLN burner technology, low NO_x duct burners, and SCR technology. This limit does not apply during startup, shutdown, malfunction, tuning, and combustion turbine shakedown

MEC II is proposing BACT limits that apply during startup and shutdown operation. These limits are described in further detail in Section 4. Definitions for combustion turbine shakedown and tuning are also provided in Section 4.

3.2.2 Control of CO Emissions

MEC II proposes to install a catalytic oxidizer to decrease CO emissions. The proposed CO emission rates for the combustion turbine/HRSG emission source including the duct burner are as follows:

- 4 ppmvd using a 3-hour block average @ 15% O_2 (while operating at normal turbine base load capacity) and 4.7 ppmvd using a 3-hour block average @ 15% O_2 (while operating at load conditions less than the turbine base load capacity) for natural gas combustion with DLN burner technology, low NO_x duct burners, and catalytic oxidizer.

Normal turbine base load capacity is defined as 90% or greater of capacity for the ambient conditions. Less than turbine base load capacity is defined as greater than or equal to 60% capacity to less than 90% of rated capacity for the ambient conditions.

CO emissions from any combustion process are formed due to incomplete combustion of the fuel. Typically, CO emissions from combustion sources depend on the oxidation efficiency of the fuel. By controlling the combustion process carefully, CO emissions can be minimized. The DLN system used during natural gas firing achieves low NO_x emissions at high efficiency and with no water consumption by optimizing the combustion to produce a lower flame temperature. CO emissions are also reduced through more thorough mixing of fuel and air in the DLN burner, which promotes more complete combustion. Additionally, the HRSG duct burners employ good combustion practices to further minimize the formation of CO emissions.

A review of the RBLC database shows that two types of CO control technologies have been proposed for combined-cycle applications. The technologies available include the following:

- Combustion control, and
- Catalytic oxidizer.

3.2.2.1 Technical Feasibility of CO Control Alternatives

Combustion Control
CO is formed due to incomplete combustion or inefficient combustion of the fuel. Improperly tuned turbines operating at off-design levels decrease combustion efficiency, increasing CO emissions. By controlling the combustion process carefully, the generation of CO emissions can be minimized. Improved mixing of fuel and air in the proposed DLN combustors and HRSG duct burners promotes complete combustion of the fuel, which minimizes CO emissions.

Catalytic Oxidizer In addition to good combustion control the proposed HRSG will be equipped with a catalytic oxidizer. A catalytic oxidizer removes CO from the combustion turbine and duct burner exhaust gas. The technology does not require introduction of additional chemicals for the reaction to proceed. The oxidation of CO to CO_2 uses the excess air present in the turbine exhaust and the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. The catalytic oxidizer is considered the most stringent level of control for combustion turbines similar to the proposed MEC II turbine—capable of oxidizing 80 to 90 percent of the inlet CO concentration.

3.2.2.2 Proposal for CO BACT for the Combustion Turbine/HRSG

Both of the available alternatives for controlling CO emissions will be applied to the proposed combustion turbine/HRSG train. The catalytic oxidizer represents the most effective level of control. Furthermore, it will not result in any significant impacts of unregulated air pollutants or unreasonable impacts in other media. Because MEC II is proposing to install a catalytic oxidizer to control CO emissions from the combustion turbine and duct burner, and a catalytic oxidizer results in the greatest control effectiveness, no further analysis is required under a top down BACT analysis. BACT for controlling CO emissions is proposed as follows:

- 4 ppmvd using a 3-hour block average @15% O_2 (while operating at normal base load conditions) and 4.7 ppmvd using a 3-hour block average @ 15% O_2 (while operating at load conditions less than the turbine base load capacity) for natural gas combustion with DLN technology, low NO_x duct burners, and catalytic oxidizer. This limit does not apply during startup, shutdown, malfunction, tuning, and combustion turbine shakedown.

MEC II is proposing BACT limits that apply during startup and shutdown operation. These limits are described in further detail in Section 4.

Similar to the discussion in the NO_X BACT section above, the existing technology for MEC I is a Siemens Westinghouse FD-2 combustion turbine which is no longer a standard offering from the manufacturer. It is preferable that the Expansion Project use a gas turbine technology with similar performance and exhaust gas characteristics to provide stable and reliable combined cycle operation, since the existing and new combustion turbine/ HRSG trains will be operating in parallel to supply steam to the existing steam turbine.

A combustion gas turbine with latest available technology could offer lower emissions, supporting a lower BACT limit at the stack. However, the turbine would have to be significantly de-rated to match the existing equipment, negating the performance and efficiency benefits that would otherwise justify its purchase. In addition, operating a modern combustion turbine at a significant de-rating could cause stability and reliability issues when in parallel with the existing combustion turbine/HRSG train.

3.2.3 Control of VOC Emissions

Similar to CO emissions, VOC emissions are formed in any combustion process due to incomplete combustion of the fuel. The VOCs may consist of a wide spectrum of volatile and semi-volatile organic compounds. By controlling the combustion process carefully, VOC emissions can be minimized. As stated earlier, MEC II is proposing to install a catalytic oxidizer to reduce CO emissions from the turbines. These systems will also reduce VOC emissions from the turbine.

The proposed VOC emission rates for the turbine/HRSG emission source are as follows:

- 3.4 ppmvd using a 3-hour block average @ 15% O_2 for natural gas combustion with DLN burner technology, low NO_x duct burners, and catalytic oxidizer.

Based on a review of the RBLC database, it was shown that two types of VOC control technologies have been proposed for combined-cycle applications. The technologies available include the following:

- Combustion control, and
- Catalytic oxidizer.

3.2.3.1 Technical Feasibility of VOC Control Alternatives

<u>Combustion Control</u>
VOCs are formed due to incomplete combustion or inefficient combustion of the fuel. Improperly tuned turbines operating at off-design levels decrease combustion efficiency, increasing VOC emissions. By controlling the combustion process carefully, the generation VOC emissions can be minimized.

Catalytic Oxidizer In addition to good combustion control the proposed turbines will be equipped with a catalytic oxidizer. A catalytic oxidizer serves to remove VOCs from the combustion turbine/duct burner exhaust gas. The technology does not require introduction of additional chemicals for the reaction to proceed. The oxidation of VOCs uses the excess air present in the turbine exhaust and the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. The catalytic oxidizer is considered the most stringent level of control for turbines similar to the proposed MEC II turbine.

3.2.3.2 Proposal for VOC BACT for the Combustion Turbine/HRSG

Both of the available control alternatives for controlling VOC emissions will be applied to the proposed combustion turbine/HRSG train. The catalytic oxidizer represents the most effective level of control. Furthermore, it will not result in any significant impacts of unregulated air pollutants or unreasonable impacts in other media. Because MEC II is proposing to install a catalytic oxidizer to control CO and VOC emissions from the new

combustion turbine and duct burner, and an oxidation catalyst systems results in the greatest control effectiveness, no further analysis is required under a top down BACT analysis. BACT for controlling VOC emissions is proposed as:

- 3.4 ppmvd using a 3-hour block average @ 15% O_2 for natural gas combustion with DLN burner technology, low NOx duct burners, and catalytic oxidizer. This limit does not apply during startup, shutdown, malfunction, tuning, and combustion turbine shakedown.

MEC II is proposing BACT limits that apply during startup and shutdown operation. These limits are described in further detail in Section 4.

3.2.4 Control of $PM/PM_{10}/PM_{2.5}$ Emissions

PM may be formed from non-combustible constituents in fuel or combustion air, from products of incomplete combustion, or from post-combustion formation of ammonium sulfates in units with an SCR. All of the particulate emissions from the combustion turbine are assumed be in the form of PM_{10} and $PM_{2.5}$.

The proposed PM emission limits are based on vendor data and operating experience at MEC and other units in Calpine's fleet. Good combustion control is regarded as BACT for $PM/PM_{10}/PM_{2.5}$. Add-on controls are technically and economically infeasible due to the high flow rates, very low concentrations of $PM/PM_{10}/PM_{2.5}$, and the extremely small particle diameters. Mankato Energy is not aware of any combined cycle project that has been required to install add-on $PM/PM_{10}/PM_{2.5}$ controls.

The proposed $PM/PM_{10}/PM_{2.5}$ emission rate for the proposed combustion turbine/HRSG emission source is 11.9 lb/hr using a 3-hour block average for natural gas firing.

<u>Potential Combined Cycle Unit $PM/PM_{10}/PM_{2.5}$ Control Alternatives</u>
Based on a review of the RBLC database and the references listed earlier the following $PM/PM_{10}/PM_{2.5}$ control technologies are available to potentially control emissions from combined cycle units:

- Fuel specifications: clean burning fuel;
- Good combustion practices/combustion control; and
- Low-sulfur fuel.

3.2.4.1 Technical Feasibility of $PM/PM_{10}/PM_{2.5}$ Control Alternatives

<u>Fuel Specifications: Clean Burn Fuel</u>
MEC II is proposing to burn pipeline-quality natural gas. Among traditional fuels natural gas is considered a clean burning fuel since it has a very low potential for generating particulates. The RBLC database indicates that pipeline-quality natural gas is the clean burning fuel of choice for similar combined cycle applications.

<u>Good Combustion Practice/Combustion Control</u>
Based upon a review of the RBLC, good combustion practice is listed as a control alternative for many similar combined cycle applications. MEC II will maintain the combustion turbines in good working order in accordance with manufacturers' guidance and implement good combustion practices to minimize particulate emissions. As discussed earlier, the proposed

combustion turbine will be equipped with DLN burners that will also contribute towards good combustion practice and further help lower particulate emissions.

The Expansion Project's combustion turbine will burn natural gas only. The sulfur content of natural gas will not exceed 0.8 grains per 100 standard cubic feet of gas.

3.2.4.2 Proposed $PM/PM_{10}/PM_{2.5}$ BACT for the Combustion Turbine/HRSG

Various control alternatives were reviewed for technical feasibility in controlling $PM/PM_{10}/PM_{2.5}$ emissions from the proposed turbine/HRSG. The proposed combustion turbine will use a combination of all of the above control alternatives in order to provide the best available particulate control.

In conclusion, BACT for controlling $PM/PM_{10}/PM_{2.5}$ emissions from the proposed turbine is proposed as the maintenance of the turbine/HRSGs in good working order, implementation of good combustion practices with DLN burner technology, and use of clean-burning natural gas fuel as the only fuel to meet a $PM/PM_{10}/PM_{2.5}$ emission rate of 11.9 lb/hr using a 3 hour block average. This limit will apply at all times including during startup, shutdown, or malfunction. This limit will not apply prior to combustion turbine shakedown which is further defined in Section 4.

3.2.5 Control of Greenhouse Gas (GHG) Emissions

3.2.5.1 Available GHG Control Technologies

<u>Inherently Lower-Emitting Processes/Practices/Designs</u>

MEC II performed a search of the EPA's RACT/BACT/LAER Clearinghouse for natural gas fired combustion turbine generators in combined cycle operation and found no entries which address BACT for GHG emissions. Calpine has permitted several units under GHG BACT regulations. Those analyses determined that BACT for GHG emissions was maintenance of the high energy efficiency that is inherent with natural gas fired combined cycle power plants. GHG BACT permit conditions were established which set an efficiency limit (also referred to as heat rate) appropriate for each particular combination of gas turbine, heat recovery steam generator, and steam turbine model. The net heat rate was based on a design base load rate, without duct firing with factors added to account for a design margin and degradation.

A summary of available, lower greenhouse gas emitting processes, practices, and designs for combined cycle units is presented below.

3.2.5.1.1 Combined Cycle Energy Efficiency Processes, Practices, and Combustion Turbine Design

CO_2 is a product of combustion of fuels containing carbon, which is inherent in any power generation technology using fossil fuel. It is not possible to reduce the amount of CO_2 generated from combustion, as CO_2 is the essential product of the chemical reaction between the fuel and the oxygen in which it burns, not a byproduct caused by imperfect combustion. As such, there is no technology available that can effectively reduce CO_2 generation by adjusting the conditions in which combustion takes place.

The only effective means to reduce the amount of CO_2 generated by a fuel-burning power plant is to generate as much electric power as possible from the combustion, thereby reducing the amount of fuel needed to meet the plant's required power output. This result is obtained by using the most efficient generating technologies available, so that as much of the energy content of the fuel as possible goes into generating power.

The most efficient way to generate electricity from a natural gas fuel source is the use of a combined cycle design. For fossil fuel technologies, efficiency ranges from approximately 30-50% (higher heating value [HHV]). A typical coal-fired Rankine cycle power plant has a base load efficiency of approximately 30% (HHV), while a modern F-Class natural gas fired combined cycle unit operating under optimal conditions has a baseload efficiency of approximately 50% (HHV).

Combined cycle units operate based on a combination of two thermodynamic cycles: the Brayton and the Rankine cycles. A combustion turbine operates on the Brayton cycle and the HRSG and steam turbine operate on the Rankine cycle. The combination of the two thermodynamic cycles allows for the high efficiency associated with combined cycle plants. The technology proposed for the additional combustion turbine at MEC II has not been chosen but will be "F" Class combustion turbine technology. In addition to the high-efficiency primary components of the turbine, there are a number of other design features employed within the combustion turbine that can improve the overall efficiency of the machine. These additional features include those summarized below.

Periodic Burner Tuning
Modern F-Class combustion turbines have regularly scheduled maintenance programs. These maintenance programs are important for the reliable operation of the unit, as well as to maintain optimal efficiency. As the combustion turbine is operated, the unit experiences degradation and loss in performance. The combustion turbine maintenance program helps restore the recoverable lost performance. The maintenance program schedule is determined by the number of hours of operation and/or turbine starts. There are three basic maintenance levels, commonly referred to as combustion inspections, hot gas path inspections, and major overhauls. Combustion inspections are the most frequent of the maintenance cycles. As part of this maintenance activity, the combustors are tuned to restore highly efficient low-emission operation.

Reduction in Heat Loss
Modern F-Class combustion turbines have high operating temperatures. The high operating temperatures are a result of the heat of compression in the compressor along with the fuel combustion in the burners. To minimize heat loss from the combustion turbine and protect the personnel and equipment around the machine, insulation blankets are applied to the combustion turbine casing. These blankets minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine.

Instrumentation and Controls
Modern F-Class combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system is a digital type and is supplied with the combustion turbine. The distributed control system (DCS) controls all aspects of the turbine's operation, including the fuel feed and burner operations, to achieve efficient low-NO_X combustion. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency low-emission performance for full-load and part-load conditions.

3.2.5.2 Heat Recovery Steam Generator Energy Efficiency Processes, Practices, and Designs

The HRSG takes waste heat from the combustion turbine exhaust and uses it to convert boiler feed water to steam. Duct burning involves burning additional natural gas in the ducts to the heat recovery boiler, which increases the temperature of the exhaust coming from the combustion turbines and thereby creates additional steam for the steam turbine.

The modern F-Class combustion turbine-based combined cycle HRSG is generally a horizontal natural circulation drum-type heat exchanger designed with three pressure levels of steam generation, reheat, split superheater sections with interstage attemperation, post-combustion emissions control equipment, and condensate recirculation. The HRSG is designed to maximize the conversion of the combustion turbine exhaust gas waste heat to steam for all plant ambient and load conditions. Maximizing steam generation will increase the steam turbine's power generation, which maximizes plant efficiency.

Heat Exchanger Design Considerations
HRSGs are heat exchangers designed to capture as much thermal energy as possible from the combustion turbine exhaust gases. This is performed at multiple pressure levels. For a drum type configuration, each pressure level incorporates an economizer section(s), evaporator section, and superheater section(s). These heat transfer sections are made up of many thin walled tubes to provide surface area to maximize the transfer of heat to the working fluid. Most of the tubes also include extended surfaces (e.g., fins). The extended surface optimizes the heat transfer, while minimizing the overall size of the HRSG. Additionally, flow guides are used to distribute the flow evenly through the HRSG to allow for efficient use of the heat transfer surfaces and post-combustion emissions control components. Low-temperature economizer sections employ recirculation systems to minimize cold-end corrosion, and stack dampers are used for cycling operation to conserve the thermal energy within the HRSG when the unit is off line.

Insulation
HRSGs take waste heat from the combustion turbine exhaust gas and uses that waste heat to convert boiler feed water to steam. As such, the temperatures inside the HRSG are nearly equivalent to the exhaust gas temperatures of the turbine. For F-Class combustion turbines, these temperatures can approach 1250°F. HRSGs are designed to maximize the conversion of the waste heat to steam. One aspect of the HRSG design in maximizing this waste heat conversion is the use of insulation. Insulation minimizes heat loss to the surroundings, thereby improving the overall efficiency of the HRSG. Insulation is applied to the HRSG panels that make up the shell of the unit, to the high-temperature steam and water lines, and typically to the bottom portion of the stack.

Minimizing Fouling of Heat Exchange Surfaces
HRSGs are made up of a number of tubes within the shell of the unit that are used to generate steam from the combustion turbine exhaust gas waste heat. To maximize this heat transfer, the tubes and their extended surfaces need to be as clean as possible. Fouling of the tube surfaces impedes the transfer of heat. Fouling occurs from the constituents within the exhaust gas stream. To minimize fouling, filtration of the inlet air to the combustion turbine is performed. Additionally, cleaning of the tubes is performed during periodic outages. By reducing the fouling, the efficiency of the unit is maintained.

Minimizing Vented Steam and Repair of Steam Leaks
As with all steam-generated power facilities, minimization of steam vents and repair of steam leaks is important in maintaining the plant's efficiency. A combined cycle facility has just a few locations where steam is vented from the system, blowdown tank vents and vacuum pumps/steam jet air ejectors. These vents are necessary to improve the overall heat transfer within the HRSG and condenser by removing solids and air that potentially blankets the heat transfer surfaces lowering the equipment's performance. Additionally, power plant operators are concerned with overall efficiency of their facilities. Therefore, steam leaks are repaired as soon as possible to maintain facility performance. Minimization of vented steam and repair of steam leaks will be performed for this project.

3.2.5.2.1 Plant-wide Energy Efficiency Processes, Practices, and Designs

There are a number of other components within the combined cycle plant that help improve overall efficiency, including:

- **Fuel gas preheating** – The overall efficiency of the combustion turbine is increased with increased fuel inlet temperatures. For the F-Class combustion turbine based combined cycle unit, the fuel gas is generally heated with high temperature water from the HRSG. This improves the efficiency of the combustion turbine.
- **Drain operation** – Drains are required to allow for draining the equipment for maintenance (i.e., maintenance drains), and also to allow condensate to be removed from the steam piping and drains for operation (i.e., operation drains). Operation drains are generally controlled to minimize the loss of energy from the cycle. This is accomplished by closing the drains as soon as the appropriate steam conditions are achieved.
- **Multiple combustion turbine/HRSG trains** – Multiple combustion turbine/HRSG trains help with part-load operation. The multiple trains allow the unit to achieve higher overall plant part-load efficiency by shutting down trains operating at less efficient part-load conditions and ramping up the remaining train(s) to high-efficiency full-load operation.
- **Boiler feed pump fluid drives** – The boiler feed pumps are used as the means to impart high pressure on the working fluid. The pumps require considerable power. To minimize the power consumption at part-loads, the use of fluid drives or variable-frequency drives can be employed. For this project, fluid drives are being used to minimize power consumption at part-load, improving the facility's overall efficiency.

3.2.5.2.2 Add-On Controls

In addition to power generation process technology options discussed above, it is appropriate to consider add-on technologies as possible ways to capture GHG emissions that are emitted from natural gas combustion in the proposed Expansion Project's CTG/HRSG unit and to prevent them from entering the atmosphere. These emerging carbon capture and storage (CCS) technologies generally consist of processes that separate CO_2 from combustion process flue gas, and then inject it into geologic formations such as oil and gas reservoirs, unmineable coal seams, and underground saline formations. Of the emerging CO_2 capture technologies that have been identified, only amine absorption is currently commercially used for state-of-the-art CO_2 separation processes. Amine absorption has been applied to processes in the petroleum refining and natural gas processing industries and for exhausts from gas-fired industrial boilers. Other potential absorption and membrane technologies are currently considered developmental.

The U.S. Department of Energy's National Energy Technology Laboratory (DOE-NETL) provides the following brief description of state-of-the-art post-combustion CO_2 capture technology and related implementation challenges:

> …In the future, emerging R&D will provide numerous cost-effective technologies for capturing CO_2 from power plants. At present, however, state-of-the-art technologies for existing power plants are essentially limited to amine absorbents. Such amines are used extensively in the petroleum refining and natural gas processing industries… Amine solvents are effective at absorbing CO_2 from power plant exhaust streams—about 90 percent removal—but the highly energy-intensive process of regenerating the solvents decreases plant electricity output…[1]

The DOE-NETL adds:

> …Separating CO_2 from flue gas streams is challenging for several reasons:
> - CO_2 is present at dilute concentrations (13-15 volume percent in coal-fired systems and 3-4 volume percent in gas-fired turbines) and at low pressure (15-25 pounds per square inch absolute [psia]), which dictates that a high volume of gas be treated.
> - Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes.
> - Compressing captured or separated CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall power plant system…[2]

If CO_2 capture can be achieved at a power plant, it would need to be routed to a geologic formation capable of long-term storage. The long-term storage potential for a formation is a function of the volumetric capacity of a geologic formation and CO_2 trapping mechanisms within the formation, including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock. The DOE-NETL describes the geologic formations that could potentially serve as CO_2 storage sites as follows:

"Geologic carbon dioxide (CO_2) storage involves the injection of supercritical CO_2 into deep geologic formations (injection zones) overlain by competent sealing formations and geologic traps that will prevent the CO_2 from escaping. Current research and field studies are focused on developing better understanding of 11 major types of geologic storage reservoir classes, each having their own unique opportunities and challenges. Understanding these different storage classes provides insight into how the systems influence fluids flow within these systems today, and how CO_2 in geologic storage would be anticipated to flow in the future. The different storage formation classes include: deltaic, coal/shale, fluvial, alluvial, strandplain, turbidite, eolian, lacustrine, clastic shelf, carbonate shallow shelf, and reef.

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[1] DOE-NETL, *Carbon Sequestration: FAQ Information Portal*, http://extsearch1.netl.doe.gov/search?q=cache:e0yvzjAh22cJ:www.netl.doe.gov/technologies/carbon_seq/FAQs/tech-status.html+emerging+R%26D&access=p&output=xml_no_dtd&ie=UTF-8&client=default_frontend&site=default_collection&proxystylesheet=default_frontend&oe=ISO-8859-1 (last visited Aug. 8, 2011).

[2] *Id.*

Basaltic interflow zones are also being considered as potential reservoirs. These storage reservoirs contain fluids that may include natural gas, oil, or saline water; any of which may impact CO_2 storage differently…"[3]

3.2.5.3 Step 2: Eliminate Technically Infeasible Options

In this section, Mankato Energy addresses the potential feasibility of implementing CCS technology as BACT for GHG emissions from the proposed project's gas turbine/HRSG train. Each component of CCS technology (i.e., capture and compression, transport, and storage) is discussed separately.

3.2.5.3.1 CO_2 Capture and Compression

Though amine absorption technology for CO_2 capture has been applied to processes in the petroleum refining and natural gas processing industries and to exhausts from gas-fired industrial boilers, it is not yet commercially available for power plant gas turbine exhausts, which have considerably larger flow volumes and considerably lower CO_2 concentrations. The Obama Administration's Interagency Task Force on Carbon Capture and Storage confirms this in its recently completed report on the current status of development of CCS systems:

"Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."[4]

3.2.5.3.2 CO_2 Transport

Even if it is assumed that CO_2 capture and compression could feasibly be achieved for the proposed project, the high-volume CO_2 stream generated would need to be transported to a facility capable of storing it. There are no potential geologic storage sites in in Minnesota or the Midwest to which CO_2 could be transported if a pipeline was constructed. The current CO_2 pipelines are shown in Figure 3-1 on the map found at the end of Section 3.[5] Therefore, in order to access any potentially large-scale storage capacity site, assuming that it is eventually demonstrated to indefinitely store a substantial portion of the large volume of CO_2 generated by the proposed project, a very long and sizable pipeline would need to be constructed to transport the large volume of high-pressure CO_2 from the plant to the storage facility, thereby rendering implementation of a CO_2 transport system infeasible.

3.2.5.3.3 CO_2 Storage

Even if it is assumed that CO_2 capture and compression could feasibly be achieved for the proposed project and that the CO_2 could be transported economically, the feasibility of CCS technology would still depend on the availability of a suitable sequestration site. The

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[3] DOE-NETL, **Carbon Sequestration:** Geologic Storage Focus Area, http://www.netl.doe.gov/technologies/carbon_seq/corerd/storage.html (last visited Aug.8, 2011)
[4] *Report of the Interagency Task Force on Carbon Capture and Storage* at 50 (Aug. 2010).
[5] Denbury Resources, 2012, "CO2 Transportation," Investor Slides, April, 2012, 25p.

suitability of potential storage sites is a function of volumetric capacity of their geologic formations, CO_2 trapping mechanisms within formations (including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock), and potential environmental impacts resulting from injection of CO_2 into the formations. Potential environmental impacts resulting from CO_2 injection that still require assessment before CCS technology can be considered feasible include:

- uncertainty concerning the significance of dissolution of CO_2 into brine,
- risks of brine displacement resulting from large-scale CO_2 injection, including a pressure leakage risk for brine into underground drinking water sources and/or surface water,
- risks to fresh water as a result of leakage of CO_2, including the possibility for damage to the biosphere, underground drinking water sources, and/or surface water,[6] and
- potential effects on wildlife.

Potentially suitable storage sites, including EOR sites and saline formations, exist in Iowa and Illinois. Figure 3-2 shows possible storage sites[7]. However, there are no pipelines that connect to these formations.

Based on the reasons provided above, Calpine believes that CCS technology should be eliminated from further consideration as a potential feasible control technology for purposes of this BACT analysis. However, to answer possible questions that the public or the EPA may have concerning the relative costs of implementing hypothetical CCS systems, Calpine has estimated such costs. Those cost estimates are presented on Table 3-1 at the end of Section 3.

3.2.5.4 Step 3: Rank Remaining Control Technologies

As documented above, implementation of CCS technology is currently infeasible, leaving energy efficiency measures as the only technically feasible emission control options. As all of the energy efficiency related processes, practices, and designs discussed in Section 3.2.5.1 of this application are being proposed for this project, a ranking of the control technologies is not necessary for this application.

3.2.5.5 Step 4: Evaluate Most Effective Controls and Document Results

As all of the energy efficiency related processes, practices, and designs discussed in Section 3.2.5.1 of this application are being proposed for this project, an examination of the energy, environmental, and economic impacts of the efficiency designs is not necessary for this application. Because the CCS add-on control option discussed in Section 3.2.5.2 was determined to be technically infeasible, an examination of the energy, environmental, and economic impacts of that option is not necessary for this application. However, MEC II is including estimated costs for implementation of CCS.

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[6] *Id.*

[7] Exhibit 36, Current State and Future Direction of Coal-fired Power in the Eastern Interconnection, Final Study Report June 2013

3.2.5.6 Step 5: Select BACT

MEC II proposes as BACT for this project, the following energy efficiency processes, practices, and designs for the proposed combined cycle combustion turbine:

- Use of Combined Cycle Power Generation Technology
- Combustion Turbine Energy Efficiency Processes, Practices, and Designs
  - Efficient turbine design
  - Turbine inlet air cooling
  - Periodic turbine burner tuning
  - Reduction in heat loss
  - Instrumentation and controls
- HRSG Energy Efficiency Processes, Practices, and Designs
  - Efficient heat exchanger design
  - Insulation of HRSG
  - Minimizing fouling of heat exchange surfaces
  - Minimizing vented steam and repair of steam leaks
- Plant-wide Energy Efficiency Processes, Practices, and Designs
  - Fuel gas preheating
  - Drain operation
  - Multiple combustion turbine/HRSG trains
  - Boiler feed pump fluid drive design

Calpine calculated the design base load net heat rate without duct firing for the 1 x 1 Expansion Project combined cycle plant using the new CTG/HRSG train and the existing steam turbine. A compliance margin was applied based upon reasonable degradation factors that may foreseeably reduce efficiency under real world conditions. The design base load net heat rate for the proposed 1 X 1 combined cycle unit without duct firing is 7,075 Btu/kW-hr (HHV) without the application of degradation factors. Note that this rate reflects the facility's "net" power production, meaning the denominator is the amount of power provided to the grid; it does not reflect the total amount of energy produced by the plant, which also includes auxiliary load consumed by operation of the plant.

To determine an appropriate heat rate, the following compliance margins are added to the base heat rate value:

- A 3.3% design margin reflecting the possibility that the constructed facility will not be able to achieve the design heat rate.
- A 6% performance margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls.
- A 3% degradation margin reflecting the variability in operation of auxiliary plant equipment due to use over time.

These factors are consistent with the compliance margin factors used in previous Calpine GHG BACT analyses. As a result of these adjustments, MEC II is proposing a BACT net heat rate for the Project of 7,979 Btu/kWh (HHV), corrected to the following conditions of:

- Ambient Dry Bulb Temperature: 6ºF
- Ambient Relative Humidity: 59%
- Barometric Pressure: 14.28 psia
- Fuel Lower Heating Value: 21,500 Btu/lb
- Fuel HHV/LHV Ratio: 1.109

A GHG BACT limit of 1,000 lb/MW-hr on a gross power production basis is proposed based on 1 X 1 combined cycle operation. Calpine is proposing a heat rate demonstration test 180 days after first fire and again prior to obtaining a new permit to verify compliance with the heat rate limit. Although derived from a slightly less efficient operating mode, this limit will account for the range of possible MEC operating scenarios. The calculation of the net heat rate is provided on Table 3-2 at the end of this section.

3.3 BACT DETERMINATION FOR THE DIESEL ENGINE-DRIVEN EMERGENCY EQUIPMENT

The proposed diesel fired emergency generator will be used for emergency situations, if any. However, the diesel engine-driven equipment will be operated for a minimal period on a bi-weekly basis for testing.

3.3.1 Control of NO_x Emissions from Emergency-Use Diesel Engines

As a result of the intended use of the proposed diesel fired emergency generator and subsequent limited operation, allowable NO_x emissions from these units are minimal with an emission rate of 0.66 tons/yr. Based on a review of similar emission sources associated with recent power plant projects, these types of emission sources typically do not have add-on controls but should be operated according to the manufacturer's specifications. Therefore, for the proposed diesel fired emergency equipment, BACT for controlling NO_x emissions is proposed as maintenance in good working order, operation according to the manufacturer's specifications and limiting non-emergency operation of the diesel engine to 100 hours per year.

3.3.2 Control of CO Emissions from Emergency-Use Diesel Engines

Again, as a result of the intended use of the proposed diesel fired emergency generator and subsequent limited operation, allowable CO emissions from these units are minimal with an emission rate of 0.66 tons/yr. Based on a review of similar emission sources associated with recent power plant projects, these types of emission sources typically do not have add-on controls but should be operated according to the manufacturer's specifications. Therefore, for the proposed diesel fired emergency equipment, BACT for controlling CO emissions is proposed as maintenance in good working order, operation according to the manufacturer's specifications, and limiting non-emergency operation of the diesel engine to 100 hours per year.

3.3.3 Control of VOC Emissions from the Emergency-Use Diesel Engines

The allowable VOC emissions from the proposed diesel fired emergency generator are minimal with a limited emission rate of 0.04 tons/yr. MEC II completed a review of similar emission sources associated with recent power plant projects. It was determined that these types of emission sources typically do not have add-on controls but should be operated according to the manufacturer's specifications. Therefore, for the proposed diesel fired emergency generator, BACT for controlling VOC emissions is proposed as maintenance in good working order, operation according to the manufacturer's specifications, and limiting non-emergency operation of the diesel engine to 100 hours per year.

3.3.4 Control of $PM/PM_{10}/PM_{2.5}$ Emissions from the Emergency-Use Diesel Engines

The allowable $PM/PM_{10}/PM_{2.5}$ emissions from the proposed diesel fired emergency generator are minimal with a limited emission rate of 0.01 tons/yr. Based on a review of similar emission sources associated with recent power plant projects, these types of emission sources typically do not have add-on controls but should be operated according to the manufacturer's specifications. Therefore, for the proposed diesel fired emergency generator, BACT for controlling particulate matter emissions is proposed as maintenance in good working order, operation according to the manufacturer's specifications, and limiting non-emergency operation of the diesel engine to 100 hours per year.

3.3.5 Control of GHG Emissions from the Emergency-Use Diesel Engines

Similar to the pollutants above, as a result of the intended use of the proposed diesel fired emergency generator and subsequent limited operation, allowable CO_2e emissions from these units are minimal with an emission rate of 208 tons/yr. Generators of this size typically do not have add-on controls but should be operated according to the manufacturer's specifications. Therefore, for the proposed diesel fired emergency equipment, BACT for controlling greenhouse gas emissions is proposed as maintenance in good working order, operation according to the manufacturer's specifications, and limiting non-emergency operation of the diesel engine to 100 hours per year.

3.4 BACT DETERMINATION FOR THE COOLING TOWER

The existing cooling tower is used for temperature management of process water for the installation. The 4 new cells will accommodate the additional cooling requirements of the expanded combined cycle unit. Projected annual emissions are minimal with an estimated emission rate of 6.58 tons per year for total particulate, 0.64 tons per year for PM_{10}, and 0.01 tons per year for $PM_{2.5}$ for the 4 additional cells. Based on a review of similar projects, cooling towers associated with combined cycle power plants are equipped with high efficiency mist eliminators. The existing cooling tower and proposed additional cooling tower cells will incorporate a mist eliminator (0.0005% tower drift rate).

In conclusion, BACT for controlling $PM/PM_{10}/PM_{2.5}$ emissions for the proposed additional cooling tower cells is the use of a mist eliminator and maintenance of the fans and equipment in good working order and operation according to the manufacturer's specifications with an estimated $PM/PM_{10}/PM_{2.5}$ emissions rates of 6.58 tons per year, 0.64 tons per year, and 0.01 tons per year, respectively.

3.5 BACT DETERMINATION FOR THE DIESEL FUEL STORAGE TANKS

The proposed diesel fired emergency generator will be equipped with its own diesel storage tank. The tank will have a capacity of less than 6,000 gallons and will be used to store diesel fuel. Due to the low volatility of this material, potential VOC emissions are anticipated to be negligible. Based on a search of the RBLC, no control is proposed for this source. BACT is proposed as using a fixed roof tank and maintaining the tank in good working condition.

3.6 BACT DETERMINATION FOR NATURAL GAS PIPING FOR GHG EMISSIONS

Natural gas is delivered to the site via pipeline. Gas will be metered and piped to the new combustion turbine and duct burner. Project GHG fugitive emissions from the natural gas

piping components associated with the new CT/HRSG train will include emissions of methane (CH_4) and carbon dioxide (CO_2).

3.6.1 Step 1: Identify All Available Control Technologies

The following technologies were identified as potential control options for piping fugitives:

- Implementation of leak detection and repair (LDAR) program using a hand held analyzer;
- Implementation of alternative monitoring using a remote sensing technology such as infrared cameras; and
- Implementation of audio/visual/olfactory (AVO) leak detection program.

The use of instrument LDAR and remote sensing technologies are technically feasible. Since pipeline-quality natural gas is odorized with a small amount of mercaptan, an AVO leak detection program for natural gas piping components is technically feasible.

3.6.2 Step 2: Eliminate Technically Infeasible Options

There are no technically infeasible control options.

3.6.3 Step 3: Rank Remaining Control Technologies

The use of a LDAR program with a portable gas analyzer meeting the requirements of 40 CFR 60, Appendix A, Method 21, can be effective for identifying leaking methane. The U.S. EPA has allowed the use of an optical gas imaging instrument as an alternative work practice for a Method 21 portable analyzer for monitoring equipment for leaks in 40 CFR 60.18(g). For components containing inorganic or odorous compounds, periodic AVO walk-through inspections provide predicted control efficiencies of 97% control for valves, flanges, relief valves, and sampling connections, and 95% for compressors.

3.6.4 Step 4: Evaluate Most Effective Controls and Document Results

The frequency of inspection and the low odor threshold of mercaptans in natural gas make AVO inspections an effective means of detecting leaking components in natural gas service. The predicted emission control efficiency is comparable to the LDAR programs using Method 21 portable analyzers.

3.6.5 Step 5: Select BACT

Any leak detection program implemented would be solely due to potential greenhouse gas emissions. Since the uncontrolled CO_2e emissions from the natural gas piping represent approximately 0.01% of the total site-wide CO_2e emissions, any emission control techniques applied to the piping fugitives will provide minimal CO_2e emission reductions. Quarterly AVO inspections are proposed as BACT.

3.7 BACT DETERMINATION FOR ELECTRICAL EQUIPMENT INSULTATED WITH SF_6

The generator circuit breakers associated with the proposed unit will be electrically insulated using SF_6 gas. SF_6 is a colorless, odorless, non-flammable, and non-toxic synthetic gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF_6 make it an efficient electrical insulator. The gas is used for

electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF_6 is only used in sealed and safe systems which under normal circumstances do not leak gas. As part the Expansion Project, two new SF_6 breakers will be installed. The new combustion turbine generator circuit breaker will contain approximately 35 lbs of SF_6 gas. An additional breaker containing approximately 72 lbs of SF_6 will be installed between the combustion turbine generator step-up transformer and the 115kV transmission line. Both proposed circuit breakers will be equipped with low pressure alarms and low pressure lockouts. The alarms will alert operating personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of "quenching and cooling" SF_6 gas.

3.7.1 Step 1: Identify All Available Control Technologies

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies. One technology is the use of state-of-the-art SF_6 technology with leak detection to limit fugitive emissions. In comparison to older SF_6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

One alternative considered in this analysis is to substitute another, non-greenhouse-gas substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 were addressed in the National Institute of Standards and Technology (NTIS) Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6.*[8]

3.7.2 Step 2: Eliminate Technically Infeasible Options

According to the report NTIS Technical Note 1425, SF_6 is a superior dielectric gas for nearly all high voltage applications.[9] It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF_6 -insulated equipment. The report concluded that although "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture… it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Therefore, there are currently no technically feasible options besides use of SF_6.

3.7.3 Step 3: Rank Remaining Control Technologies

The use of state-of-the-art SF_6 technology with leak detection to limit fugitive emissions is the highest ranked control technology that is technically feasible for this application.

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[8] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF6,* NIST Technical Note 1425, Nov.1997.
[9] *Id.* at 28 – 29.

3.7.4 Step 4: Evaluate Most Effective Controls and Document Results

Energy, environmental, or economic impacts were not addressed in this analysis because the use of alternative, non-greenhouse-gas substance for SF_6 as the dielectric material in the breakers is not technically feasible.

3.7.5 Step 5: Select BACT

Based on this top-down analysis, MEC II concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection would be the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers.[10] The proposed circuit breakers at the generator output and the step-up transformer output will have low pressure alarms and low pressure lockouts. These alarms will function as early leak detectors that will bring potential fugitive SF_6 emissions problems to light before a substantial portion of the SF_6 escapes. The lockouts prevent any operation of the breakers due to lack of "quenching and cooling" SF_6 gas. The Expansion Project will also complete monthly inspections of the pressure of the breakers.

3.8 BACT DETERMINATION FOR THE CONDENSATE TANK

The Expansion Project is proposing to install a small condensate tank. The condensate tank will emit a small amount of VOC. The use of the condensate tank will be minimal and on a batch cycle. The tank will have a capacity of less than 50 gallons. Due to the low volatility of this material; potential VOC emissions are anticipated to be negligible. Based on a search of the RBLC, no control is proposed for this source. BACT is proposed as maintaining the tank in good working condition.

3.9 BACT SUMMARY

The emission limitations that are proposed to represent BACT for the emission units associated with the Facility are summarized in Table 3-1.

[10] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current*

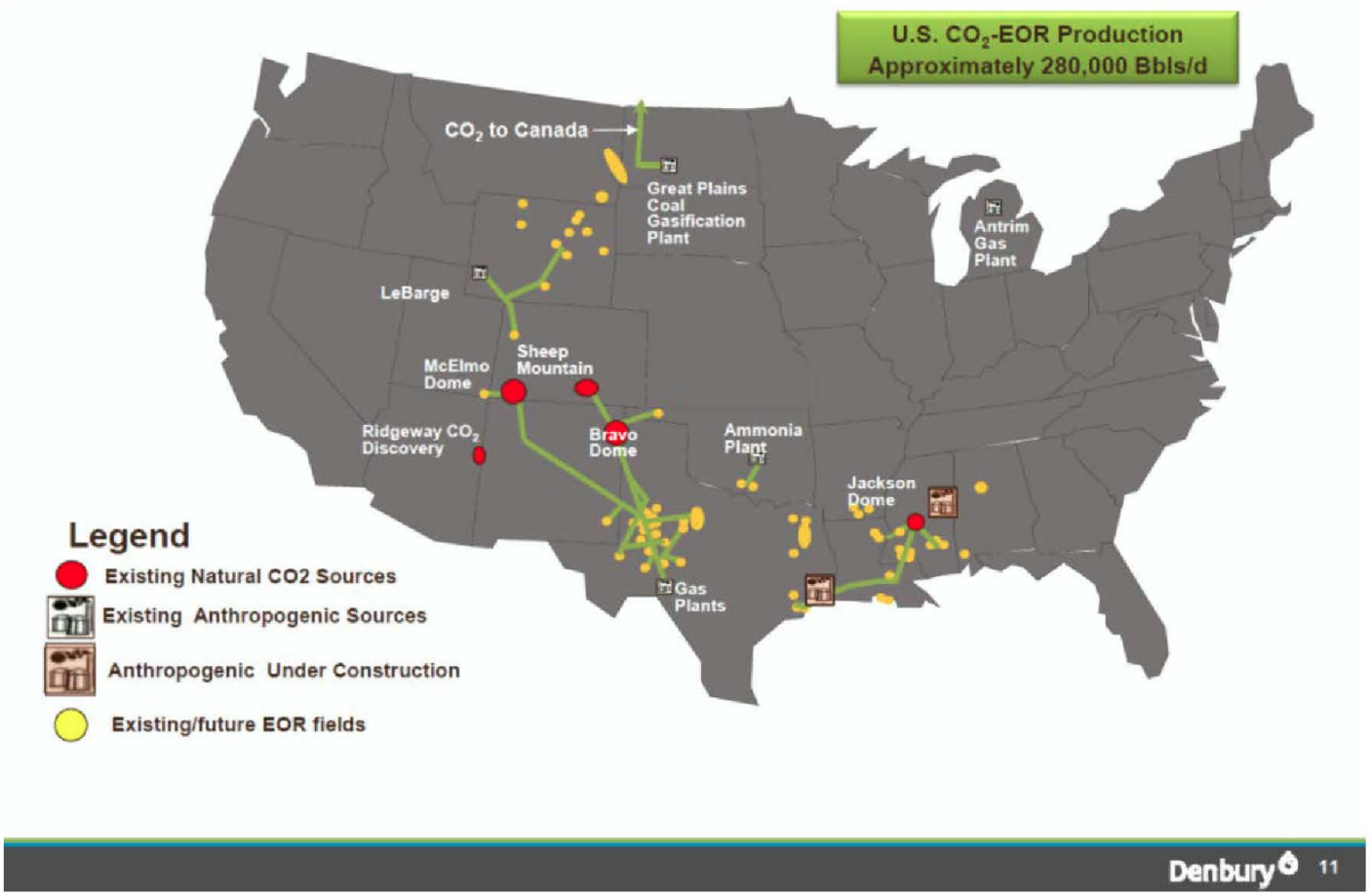
Table 3-1 BACT Summary

Proposed Equipment	BACT Limitation				
	NO_x	**CO**	**$PM/PM_{10}/ PM_{2.5}$**	**VOC**	**GHG**
Combined Cycle Combustion System – Natural Gas	3.0 ppmvd using a 3-hour block average @ 15% O_2 [2]	4.0 ppmvd using a 3-hour block average @15% O_2 (while operating at normal turbine base load conditions), 4.7 ppmvd using a 3-hour block average @15% O_2 (while operating at load conditions less than the turbine base load capacity)[1, 2]	11.9 lb/hr using a 3-hour block average. This limit applies at all times including startup, shutdown, tuning or malfunction.	3.4 ppmvd using a 3-hour block average @15% O_2 [2]	1,000 lb CO_2e/MWhr (gross) And Expansion Project net heat rate of 7,979 Btu/kWh (HHV) without duct firing
Proposed Diesel Fired Emergency Generator	Limiting hours of non-emergency operation to less than 100 hr/yr	Limiting hours of non-emergency operation to less than 100 hr/yr	Limiting hours of non-emergency operation to less than 100 hr/yr	Limiting hours of non-emergency operation to less than 100 hr/yr	Energy Efficiency Measures
Diesel Storage Tank	NA	NA	NA	Fixed Roof Tank	NA
Cooling Tower	NA	NA	Mist eliminator with 0.0005% drift	NA	NA
Natural Gas Piping	NA	NA	NA	N/A	Quarterly AVO Inspections
Electrical Equipment Insulated with SF_6	NA	NA	NA	NA	State-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection and monthly pressure inspections.
Condensate Tank	NA	NA	NA	Maintaining the tank in good working condition	NA

[1] For the CO limit applicability, full load is all operation at 90% or greater of rated capacity for the ambient conditions and less than full load is all operation greater than or equal to 60% load and less than 90% of the rated capacity for the ambient conditions.
[2] The limit does not apply during startup, shutdown, malfunction, tuning, and combustion turbine shakedown.

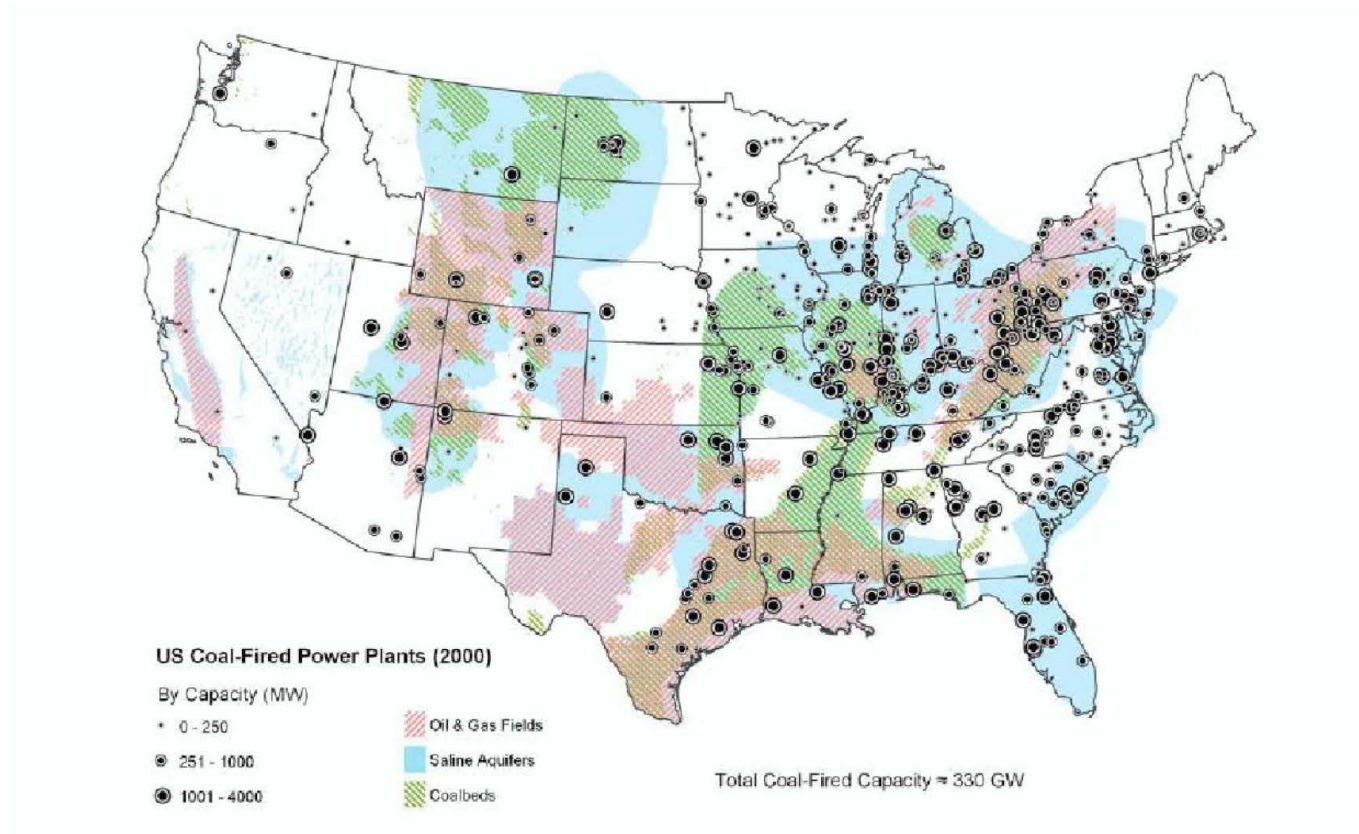
Table 3-2 Net Heat Rate Calculation

Operating Mode		Net Plant Output - KW	Net Heat Rate (HHV)		Heat Input (HHV)	
CTG		200,826			2,056	
Duct Burner					824	
STG		96,392				
Total Auxiliary Load		6,648				
Total Net Output - Base Operations with Duct Burning		290,570	7,075	Btu/kWh	2,056	MMBtu/hr
Weighted Average Heat Rate		**7075**				
Design Margin		3.3%				
Performance Margin		6.0%				
Degradation Margin		3.0%				
Calculated Weighted Average Heat Rate with Compliance Margins		**7979**				



Source: Current State and Future Direction of Coal-fired Power in the Eastern Interconnection, ICF Incorporated, June 2013.

Current CO_2 Pipeline Map	WENCK ASSOCIATES Responsive partner. Exceptional outcomes.	Nov 2015 Figure 3-1



Source: Current State and Future Direction of Coal-fired Power in the Eastern Interconnection, ICF Incorporated, June 2013.

Possible CO_2 Storage Sites

WENCK ASSOCIATES

Responsive partner. Exceptional outcomes.

Nov 2015

Figure 3-2

4.0 Requested Permit Changes

The following section addresses the requested changes to the current permit as a result of the Expansion Project. These proposed changes are also included in the required Forms CD-01s included in Appendix A.1.

4.1 PERMIT OWNERS

As mentioned previously, MEC I currently owns the Existing Facility. The Existing Facility is operated by COSCI. All entities are wholly owned indirect subsidiaries of Calpine Corporation (Calpine). The proposed Expansion Project will be owned by MEC II and also operated by COSCI. Calpine would like both owners listed on the air permit. Below is an example of the ownership and operator agreement that Calpine is requesting for the air permit title page.

AIR EMISSION PERMIT NO. 01300098-003
Total Facility Operating Permit
IS ISSUED TO
MANKATO ENERGY CENTER
for their facility
located at
1 Fazio Lane
Mankato, Blue Earth County, Minnesota 56001

4.2 STARTUP/SHUTDOWN EMISSION LIMITS

As part of the permitting for the current permit number 01300098-002, Calpine revised the SUSD limits to reflect a lb/event and tons/yr basis. MPCA advised Calpine that, because the SUSD limits serve as BACT limits, a time-based annual limit (or 12-Month Rolling Sum limit) alone is not workable for federal-enforceability considerations. Instead, MPCA requested that alternative limits be proposed that effectively limit emissions on both a short-term (e.g., hourly) and long-term (i.e., annual) basis. Based on permit requirements applicable to several other Calpine facilities, in 2010 Calpine proposed to limit SUSD emissions on a "Lb/Event" and "Tons/Yr (12-Month Rolling Sum)" basis. Calpine believed that limiting SUSD emissions in this manner allows for sufficient operating flexibility and meets MPCA's requirements for short-term BACT limitations. Therefore, the current permit includes SUSD limit for the current turbine in units of worst case lb/event and tons/yr.

The current permit includes "Lb/Event" limits and annual (12-Month Rolling Sum) limits for each of Warm/Cold start scenarios on Natural Gas and Distillate Fuel Oil. Note that explicit limits on the number of startups and/or the length of startups are not required. The limits on maximum emissions per startup/shutdown event in conjunction with 12-Month limits serve to effectively limit emissions to BACT levels for short-term and long-term periods.

Startup and shutdown operating mode is all operation of SV 002 or SV 007 at less than 60 percent of the CTG maximum potential load based on ambient conditions at the time of operation when combusting natural gas for fuel oil as applicable. The steam turbine is online when any steam is fed to the steam turbine.

A unit startup is considered a cold start if **either** of the following conditions exist:

1. The steam turbine first stage inter-metal temperature is less than 650°F, or
2. The HRSG high pressure steam drum is below 212°F (i.e. there is no positive pressure in the steam drum).

A unit startup is considered a warm start if **both** of the following conditions exist:

1. The steam turbine first stage inter-metal temperature is at least 650°F, and
2. The HRSG high pressure steam drum pressure is at least 212°F.

Calpine is proposing the following SUSD limits for the Combined Facility in GP 005.

Table 4-1 Summary of SUSD Proposed Limits for the Combined Facility

Pollutant	CT #1 SV 007 Lb/Event (Natural Gas)*	CT #2 SV 002 Lb/Event (Natural Gas)*	SV 002 Lb/Event (Fuel Oil)*	Annual SUSD Emissions for the Combined Facility (tpy)
NO_x	414	323.5	459.3	≥ 66.8
VOC	2,959.5	2,693.8	749.1	≥ 547
CO	5,919	5,387.6	1,498.2	≥ 1,093.9

* The worst case lb/event values are based on the highest lb/event for cold, warm or shutdown event for SV 007, SV 002 combusting natural gas and SV 002 combusting fuel oil.

The annual limits are based on projected number of cold and warm starts and shutdown events for each unit and the lb/event values for each type of start and fuel for SV 002 and SV 007. The per event limits above were determined for each pollutant using manufacturer predictions and data from the existing combustion turbine. The VOC startup and shutdown emissions are based on one half of the CO estimates. Additional details on the annual startup and shutdown emission calculations are included in Appendix C and described in Section 5.1.

Operation of the DLN, SCR and catalytic oxidizer are not available during initial startup of SV 002 or SV 007, but will come on-line as soon as combustion turbine exhaust conditions support operations. During shutdown, control equipment operation shall continue as long as physically possible.

As described in Section 3.2.1.2, in order to provide a combustion turbine with comparable operating characteristics, MEC II has the following procurement options:

- a unit from the gray market,
- an original manufacturer equipment (OEM) off-market unit built from spare components, or
- a newer unit slightly de-rated to the match the performance of the existing unit.

The SV007 startup emissions represent the worst case startup emissions from three combustion turbine options listed above.

Occasionally a combustion turbine, without warning, automatically initiates a shutdown and drops out of steady state operation. Potential reasons for unplanned shutdowns include but are not limited to a drop in natural gas supply pressure or sensor malfunction where there is no operational issue with the unit. During this time the Facility may determine that the unit is functioning properly and it can return to steady state operation without ceasing operation.

On other occasions the facility may commence shutdown and, for a reason unknown to the Facility, be asked by the grid operator to come back to steady state prior to shutting down completely. A turbine runback shall be defined as the period of time during which a turbine is returned to steady state operation after the initiation of a shutdown without ceasing operation. Calpine is proposing that these situations be considered SUSD operation and not included in compliance for the normal operating mode.

4.3 FACILITY SHAKEDOWN AND TUNING DEFINITIONS

Calpine is proposing that the lb/event SUSD limits proposed in Section 4.2 above and the normal operating load BACT limits included in Section 3 will not be in effect until after shakedown occurs for the proposed unit.

The Expansion Project shakedown is defined as the period of time commencing on the day of initial start-up of the new unit and terminating on the earlier of the following three dates:

1. 180 days after initial start-up of CT#1, or
2. 60 days after achieving maximum production of CT#1, or
3. Submittal of successful Compliance Test and CEMS Certification reports of the new unit.

Calpine is also proposing that the normal operating load BACT limits will not be applicable during times of combustion turbine tuning. Tuning is adjustment of the equipment for optimization of combustion and/or emissions performance. Maintenance and testing, like tuning, are required, to maintain and maximize the equipment's availability and reliability, which in turn reduce unscheduled repairs and breakdown.

4.4 FACILITY FORMALDEHYDE, HEXANE AND TOTAL HAP EMISSION LIMITS

As noted previously, the Existing Facility currently operates under a "synthetic" limit on formaldehyde, hexane and total combined HAP emissions to ensure that the Existing Facility qualified as a non-major source of hazardous air pollutants. The Expansion Project will not change the current "synthetic" limit on formaldehyde, hexane, or total combined HAP emissions. Rather, Calpine is proposing to add a new group in the permit that addresses synthetic minor limits for both the Existing Facility and Expansion Project. The proposed limits are provided below. The new group is listed as GP 004 in the attached Form CD-01s in Appendix A.1.

Formaldehyde	Less than or equal to 9.0 tons per year on a 12-month rolling sum, regardless of fuel type. This limit applies to the total emissions from SV 002, SV 003, SV 005, SV 007, SV 008 and SV 009, and at all times including startup, shutdown, and malfunction
Hexane	Less than or equal to 9.0 tons per year on a 12-month rolling sum, regardless of fuel type. This limit applies to the total emissions from SV 002, SV 003, SV 005, SV 007, SV 008 and SV 009, and at all times including startup, shutdown, and malfunction
Total HAPs	Less than or equal to 22.5 tons per year on a 12-month rolling sum, regardless of fuel type. This limit applies to the total emissions from SV 002, SV 003, SV 005, SV 007, SV 008 and SV 009, and at all times including startup, shutdown, and malfunction

4.5 PROPOSED DIESEL FIRED EMERGENCY GENERATOR BEST MANAGEMENT PRACTICES

As specified previously, a proposed diesel fired emergency generator is proposed as part of the Expansion Project. In addition, a fire pump was installed as part of the original permitting and is located at the Existing Facility. These emission sources are for emergency purposes only and they are tested once per month. MEC I and MEC II will follow best management practices (BMPs) for both pieces of equipment.

The existing diesel fired fire pump and proposed diesel fired generator both employ BMPs and therefore do not need to be included in the modeling demonstration based on MPCA's Modeling Guidance (2014). Calpine will select four of the BMPs listed below in lieu of including the existing diesel fired fire pump and proposed diesel fired emergency generator in the modeling analysis.

The proposed BMPs for the existing diesel fired fire pump and proposed diesel fired emergency generator are the following:

a. Select a generator that operates on “ultra-low” sulfur diesel fuel.
b. Build the stack high enough to ensure good dispersion.
c. Vent the emissions upward.
d. Install the generator in a location that doesn’t affect “fresh air.”

5.0 Emission Calculations

This section discusses the emissions associated with the individual emission units that will be installed as part of the Expansion Project. This discussion supplements the emission calculations included later in this section. The Expansion Project will include the following emission unit groupings:

A. Natural Gas-Fired Combined Cycle Equipment (Combustion Turbine and HRSG Equipped with Duct burners)
B. Diesel Fired Emergency Generator with associated Fuel Oil Storage Tank
C. New Cooling Tower Cells
D. Natural Gas Piping
E. Electrical Equipment Insulated with SF_6
F. Condensate Tank

5.1 GAS-FIRED COMBINED CYCLE EQUIPMENT

A manufacturer has not yet been selected for the proposed combustion turbine. However, operational and emissions data have been provided for the potential F-Class turbine with similar characteristics to the existing unit. This data includes operational and emissions data for natural gas, different load scenarios, various ambient temperatures, and operating scenarios. The data also includes the contribution from the HRSG duct burners in the appropriate emissions cases. The calculations based on the worst-case operational and emissions data calculations have been included in Appendix C.

Potential NO_x, CO, and VOC emissions were calculated for the combined cycle system (both combustion turbine and HRSG duct burners) using the worst-case emission rates derived from the data of potential turbines, all ambient temperatures, and all load and operating scenarios. The emission values represent the calculated maximum controlled emissions from data at ambient conditions for the combined cycle system. The maximum controlled emissions include the combustion turbine and duct burners, and incorporate the proposed combustion turbine BACT limits (See Section 3.2 for combined cycle combustion turbine/HRSG operation).

Potential PM, PM_{10}, and $PM_{2.5}$ emissions were based on vendor data, operating experience and stack tests from other similar Calpine facilities. SO_2 emissions are based on a grain loading limit of 0.8 grains of sulfur/100 standard cubic feet.

Annual emissions for NO_x, CO and VOC include the contribution of emissions from startup and shutdown events. The worst case emissions based on a per event basis were determined for each pollutant using manufacturer predictions and data from the existing combustion turbine. The lb/event values were determined using the highest lb/event value from cold start, warm start or shutdown events. The annual emissions were then calculated based on the worst case annual number of events and the duration of each event type. These startup and shutdown emission quantities were added to steady state emissions for the remaining operating hours of the year, for a combined total of 8760 hours. The VOC startup and shutdown emissions are based on ½ of the CO estimates. Equation 5.1 below shows an example of the annual emissions calculation for the proposed combustion turbine. Additional information on the calculation methodology is provided in the data calculation

sheets included in Appendix C. Limits for the startup and shutdown emissions for the Combined Facility are included in the Forms in Appendix A.

$$Equation\ 5.1$$

$$Maximum\ Hours\ of\ SUSD\ \left(\frac{hrs}{yr}\right) = 50\ \frac{cold\ starts}{yr} * 5\frac{hrs}{start} + 250\ \frac{warm\ starts}{yr} * 3.5\frac{hrs}{start} + 300\ \frac{shutdowns}{yr} * 1\frac{hrs}{shutdown} = 1425\ hrs/yr$$

$$Annual\ NOx\ SUSD\ Emissions\ (tpy) = 414\frac{lb}{coldSUevent} * 50\frac{events}{yr} + 220\frac{lb}{warmSUevent} * 250\frac{events}{yr} + 27\frac{lb}{SDevent} * 300\frac{events}{yr} = 41.9\frac{tons}{yr}$$

$$Annual\ NOx\ Normal\ Operation\ Emissions\ (tpy) = 34.1\ \frac{lb\ NOx}{hr} * 7335\frac{hrs}{yr} = 124.9\ \frac{tons}{yr}$$

$$Annual\ NOx\ Total\ Emissions\ (tpy) = 41.9\ SUSD\frac{tons}{yr} + 124.9\ Normal\ Operation\frac{tons}{yr} = 166.8\ \frac{tons}{yr}$$

Greenhouse gas emissions are based on emission factors from 40 CFR Part 98 Subpart C (GHG Mandatory Reporting Rule, Combustion); converted from kg/MMBtu to lb/MMBtu based on 2.2046 lb/kg. GWP Conversion factors are from Table A–1 to Subpart A of Part 98—Global Warming Potentials.

All combustion turbine Hazardous Air Pollutant (HAP) emissions, except for formaldehyde and hexane were calculated using the maximum manufacture heat input capacity and emission factors taken from AP-42, Chapter 3.1, Station Gas Turbines, (4/00). Formaldehyde and hexane emissions were calculated using emission factors from natural gas stack test data for MEC I and the projected maximum turbine heat input capacity for natural gas for the proposed combustion turbine. The limited annual emissions for formaldehyde will remain at the current permit limit of 9 tons/yr for the Combined Facility. The limited annual emissions for hexane will remain at the current permit limit of 9 tons/yr for the Combined Facility. The limited annual emissions for total HAP emissions will remain at the current permit limit of 22.5 tons/yr for the Combined Facility.

Potential duct burner criteria pollutant emissions are included in the uncontrolled, controlled, and limited combined cycle system criteria pollutant emission calculations. HAP emissions from the duct burners were calculated using the maximum designed heat input capacity for the duct burners and emission factors taken from AP-42, Chapter 1.4 "Natural Gas Combustion" (7/98) for Boilers greater than 100 MMBtu/hr. Greenhouse gas emissions are based on emission factors from 40 CFR Part 98 Subpart C (GHG Mandatory Reporting Rule, Combustion); converted from kg/MMBtu to lb/MMBtu based on 2.2046 lb/kg. GWP Conversion factors are from Table A–1 to Subpart A of Part 98—Global Warming Potentials.

5.2 PROPOSED DIESEL FIRED EMERGENCY GENERATOR

Worst-case vendor emission factors were used to calculate all criteria pollutant emissions. HAP emissions are based on emission factors from AP-42 Section 3.4 “Large Stationary Diesel and All Stationary Dual-fuel Engines” (10/96). Greenhouse gas emissions are based on emission factors from 40 CFR Part 98 Subpart C (GHG Mandatory Reporting Rule,

Combustion); converted from kg/MMBtu to lb/MMBtu based on 2.2046 lb/kg. GWP Conversion factors are from Table A–1 to Subpart A of Part 98—Global Warming Potentials.

This proposed diesel fired generator unit will be used for emergency purposes only, during equipment testing, if there is an equipment failure, or electricity is not available from the electric grid. MEC II is proposing to limit the maximum non-emergency engine usage to 100 hours of operation per year. This is appropriate based on historical power outage data and expected maintenance operation.

5.3 PROPOSED DIESEL FIRED EMERGENCY GENERATOR FUEL TANK

The proposed diesel fired emergency generator will have a 6,000 gallon fuel oil tank. The tank will be a horizontal fixed roof tank. VOC emissions from the fire pump fuel tank are based on Tanks 4.09D. Tanks 4.09D is a Windows-based computer software program that estimates VOC and HAP emissions from fixed- and floating-roof storage tanks. Tanks 4.09D is based on the emission estimation procedures from AP-42 Chapter 7.

5.4 COOLING TOWER

Potential PM was calculated using the calculation methods used in AP-42, Chapter 13.4 "Wet Cooling Towers", (01/95). Potential PM_{10} and $PM_{2.5}$ emissions were derived from the calculated PM emissions using the calculation procedure in "Calculating Realistic PM_{10} Emissions form Cooling Towers", by Reisman and Frisbie, Environmental Progress, Vol. 21, No.2 along with the proposed drift rate of 0.0005%, flow rate of the cooling tower, total dissolved solids (TDS) for the make-up water and number of cycles of the make-up water.

5.5 NATURAL GAS PIPING

As mentioned previously, natural gas is delivered to the site via pipeline. Gas will be metered and piped to the new combustion turbine and HRSG duct burner. Greenhouse gas fugitive emissions from the natural gas pipeline system associated with the Expansion Project are calculated. Emissions for the total facility fugitive emissions for the Combined Facility are also calculated.

Emission factors are provided for valves, flanges/connectors, relief valves, and open-ended lines. Emissions factors for valves, flanges/connectors, relief valves, and open-ended lines were obtained from 40 CFR Part 98 Subpart W "Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems; Final Rule" Table W-7.

Emissions from sampling connections are based MPCA Form EC-14, Table EC-14.1. MPCA obtained the SOCMI emissions factors from "Protocol for Equipment Leak Emissions Estimates" (EPA-453/R-95-017), Table 2-1.

5.6 ELECTRICAL EQUIPMENT INSULATED WITH SF_6

SF_6 emissions from the new generator and step-up transformer circuit breakers associated with the Expansion Project are calculated using a predicted SF_6 maximum annual leak rate of 0.5% by weight as specified by the vendor. The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting

Rules.[11] In addition, SF_6 emissions from the Existing Facility breakers were also calculated using the methodology above. The emissions from the Existing Facility are included in the total Combined Facility emissions totals.

5.7 CONDENSATE TANK

The Expansion Project is proposing to install a 50 gallon condensate tank. The tank will be a horizontal fixed roof tank. VOC emissions from the condensate tank are based on Tanks 4.09D. Tanks 4.09D is a Windows-based computer software program that estimates VOC and HAP emissions from fixed- and floating-roof storage tanks. Tanks 4.09D is based on the emission estimation procedures from AP-42 Chapter 7. The tank will be used minimally and the majority of the time will be empty. Calpine used an estimated tank volume of 10% for the calculations. This is a conservative estimate and results in negligible emissions. The proposed condensate tank qualifies as an insignificant activity under Minn. R. 7007.1300, Subpart 3(I) but was included in the PSD netting analysis and Form CH-04a.

5.8 SUMMARY OF PSD NETTING EMISSION CALCULATIONS

In order to determine if the Expansion Project is subject to PSD review, netting calculations were performed for the units described in Sections 5.1 through 5.7. In general, two tests are available to determine PSD applicability:

- Past actual to future potential emissions; and
- Past actual to future projected actual emissions.

The Expansion Project involves the installation of new emission units, not modification of existing units; therefore, only the past-actual-to-future-potential test is applied. There are no emission units that will be removed as part of the project. Only future potential emissions will be evaluated to determine the net emissions increase for the Expansion Project. Table 5-1 provides a summary of the PSD applicability test for the Expansion Project. Emission calculations are provided in Appendix C. As shown below, the Expansion Project is subject to PSD for PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC and GHG. This analysis is also shown on the required forms in Appendix A.

[11] Global Warming Potentials, 40 C.F.R. Pt. 98, Subpt. A, Tbl. A-1.

Table 5-1 Expansion Project Potential Emissions and PSD Applicability Thresholds

Pollutant	CT/HRSG# 1 (tpy)	Proposed Diesel Fired Emergency Generator / Fuel Oil Tank/Condensate Tank (tpy)	Cooling Tower* (tpy)	Fugitive/ SF6 Emissions (tpy)	Project Potential Emissions (tpy)	PSD Major Modification Threshold (tpy)
PM	52.12	0.01	15.87	NA	68.00	25
PM_{10}	52.12	0.01	2.70	NA	54.83	15
$PM_{2.5}$	52.12	0.01	0.02	NA	52.15	10
SO_2	30.20	0.26	NA	NA	30.46	40
NO_x	166.78	0.66	NA	NA	167.44	40
VOC	382.54	0.20	NA	NA	382.58	40
CO	767.98	0.66	NA	NA	768.64	100
Lead	6.61E-03	NA	NA	NA	6.61E-03	0.6
CO_2e	1,578,145	208.1	NA	6,702	1,585,055	75,000
Asbestos	NA	NA	NA	NA	NA	0.007
Beryllium	4.24E-05	NA	NA	NA	4.24E-05	0.004
Mercury	9.20E-04	NA	NA	NA	9.20E-04	0.1
Vinyl chloride	NA	NA	NA	NA	NA	1
Hydrogen sulfide	NA	NA	NA	NA	NA	10
Sulfuric acid mist	4.58	NA	NA	NA	4.58	7
Total reduced sulfur	NA	NA	NA	NA	NA	10
Reduced sulfur compounds	NA	NA	NA	NA	NA	10

* Cooling tower emissions are based on the total cells (12 cells). However, Calpine is proposing to only install 4 new cells. This is a conservative assumption.

6.0 Additional Impacts Analysis

This section describes the impacts on soils, vegetation, and visibility caused by emissions from the Expansion Project and from associated growth.

The Expansion Project site is located in the City of Mankato boundary within Lime Township and Blue Earth County. The Expansion Project site is located approximately one-quarter mile east of Nicollet County and approximately three miles south of Le Sueur County and is located within the boundary of the Existing Facility. The Existing Facility site was recently annexed by the City of Mankato, with a population of 55,941 (U.S. Census Bureau, 2000). The Existing Facility location is shown in Section 2, Figures 2-1 and 2-2.

Approximately 25 acres of land was developed as part of the original project. Access to the facility is provided from the south off Summit Avenue. To the south, across Summit Avenue is an industrial park for light industrial and services. Undeveloped woodlands bound the proposed site to the west. The adjoining property to the east consists of woodlands interspersed with several small-to-medium sized businesses. A closed construction-demolition waste landfill and yard waste composting facility border the site to the north.

The site is located within an established industrial and manufacturing area and lies within an exhausted limestone quarry currently being utilized as a construction-demolition waste landfill and yard waste composting facility. The nearest residential areas are approximately one mile to the north of the site, approximately one-half mile to the south of the site, approximately one mile to the east of the site, and approximately one and 1/4 miles to the west of the site in North Mankato. Highway 169 is located approximately one half mile west of the site, and Highway 14 is located approximately one-half mile south of the site.

As described previously, the Expansion Project involves construction of a second combustion turbine/HRSG train that will be fueled with natural gas only. The Expansion Project will add approximately 290 MW of baseload capacity and 55 MW of peaking capacity at winter conditions. In addition to the combustion turbine/HRSG train, the Expansion Project includes a proposed diesel fired emergency diesel generator, 4 additional cooling tower cells, and a new anhydrous ammonia tank.

Electricity from the facility is currently interconnected directly into Xcel Energy's (Xcel's) Wilmarth Substation, which is located just to the west of the Existing Facility.

Cooling water is supplied by effluent taken from the municipal wastewater treatment system, located approximately 1 mile due south of the site on the east bank of the Minnesota River. The water is treated prior to delivery. The effluent is discharged back to the City of Mankato wastewater treatment plant. Potable and process water is supplied from the City of Mankato.

6.1 GROWTH ANALYSIS

Construction of the Expansion Project will require a work force of 250 people over a period of 24 to 27 months. This represents the number of construction workers working at the plant over the duration of the project, not necessarily a peak number on a given day. It is anticipated that workers commuting to the site from throughout the three-county area will

fill most of the construction jobs available. In 2010, the total civilian labor force for Blue Earth, Le Sueur, and Nicollet Counties was 43,378 with an unemployment rate for the surrounding area of 3.4 percent (Minnesota Department of Employment and Economic Development Website, June 2015). Following construction activities, the Combined Facility expects to employ an additional 2 full time employee equivalents for day-to-day operations and maintenance, for a total of approximately 19 full time employees. The Expansion Project will not require an increase in small support industries.

No related industrial growth is expected to accompany the Expansion Project. Emergency and full maintenance capacity is contained within the plant. With no associated commercial or industrial growth projected, it then follows that there will be no growth-related air pollution impacts.

6.2 SOILS AND VEGETATION

The New Source Review Workshop Manual (USEPA OAQPS, Draft October 1990, Chapter D, Section II.C) specifies that the analysis of soils and vegetation should be based on an inventory of the soils and vegetation types found within the impact area of the proposed project. The impact area is defined as the circular area with a radius extending from the source to the most distant point where dispersion modeling predicts that a significant ambient impact level will occur. As documented in Section 7 of this application, compliance with the secondary NAAQS will ensure that there are no adverse impacts to the types of soils and vegetation in the vicinity of the Expansion Project. Therefore, no adverse impacts to soils and vegetation are expected to occur as a result of the Expansion Project.

Despite the low predicted ambient air concentrations resulting from the Expansion Project emissions, information was acquired on the soil and vegetation types at and in the vicinity of the proposed project. The Existing Facility site has been previously disturbed during facility construction and prior to that, by activities associated with past gravel and limestone mining activities and the demolition landfill. The disturbance for the construction of the Expansion Project will take place entirely within the boundaries of the Existing Facility. Wooded areas exist on the east edge of the site along a drainage ditch, which receives stormwater runoff from the site and surrounding areas and flows northerly to the Minnesota River. Wooded areas also exist along the south side of the site along the railroad tracks. The construction of the Expansion Project or operation of the Combined Facility will not result in significant changes in land cover or land use at the facility.

6.3 RARE AND UNIQUE NATURAL RESOURCES

A review of the Minnesota Natural Heritage Information System (NHIS) database was requested from the Minnesota DNR to determine if rare plant communities or animal species, unique resources, or other significant natural features are known to occur on or near the site of the facility.

<u>Federally Listed Species</u>
No federally listed endangered or threatened species were identified by the NHIS search. The NHIS letter mentions that the U.S. Fish and Wildlife Service listed the Northern Long-eared Bat (*Myotis septentrionalis)* as threatened under the Endangered Species Act and implemented an interim 4(d) rule effective May 4, 2015, which generally prohibits purposeful taking of northern long-eared bats throughout the species' range. The Northern Long-eared Bat is also a state-listed species of special concern in Minnesota. The bat hibernates in caves and mines during the winter and roosts underneath bark or in cavities

and crevices of trees. The northern long-eared bat was not identified as being in the vicinity of the facility in the NHIS query results. There will only be very limited clearing of trees (less than one acre) during the construction of the Expansion Project. Therefore no impacts to the northern long-eared bat are anticipated.

Calpine submitted an Endangered Species Act (ESA) consultation request to US EPA Region 5. A copy of the request is included in Appendix E along with additional supporting documentation.

6.4 ARCHAEOLOGICAL AND HISTORIC RESOURCES

The Expansion Project will include the construction of one additional CTG/HRSG, four new cooling tower cells, and related auxiliary equipment within the fence line of the Existing Facility. Information was requested from the State Historic Preservation Office (SHPO) about possible archeological, historical, or architectural resources located on or near the proposed project site. A response letter dated April 2, 2015 was received from SHPO indicating that no known or suspected archeological resources are present in the area that would be affected by the Expansion Project. Two historic architectural structures (farmsteads) were identified within Section 31. The Expansion Project will take place within the fence line of the Existing Facility which is within a developed industrial area of the City of Mankato and would not impact either of these identified resources. Less than 15 acres of land will be leased from a local land owner for construction laydown space. This temporary space will not be in close proximity to the historic properties. Based on these findings and due to the disturbed nature of the site from the previous construction activity for the Existing Facility, construction of the Expansion Project and operation of the Combined Facility will have no impact on archeological, historical, or architectural resources.

Calpine submitted a National Historical Preservation Act consultation request to US EPA Region 5. A copy of the request is included in Appendix F along with additional supporting documentation.

6.5 WATER USAGE AND WATER QUALITY

The majority of water that will be utilized at the Combined Facility will be cooling water supplied by the City of Mankato WWTP plant. A small amount of service water (approximately five percent of the total water utilized) from the City of Mankato will also be utilized by the facility. The Combined Facility will be designed to maximize the existing water reuse and recycling measures and to minimize wastewater discharges. The Existing Facility has two separate discharge points – one each for process and domestic wastewater. Both discharge points ultimately end up at the City of Mankato WWTP. Process wastewater consisting of cooling tower blowdown, reverse osmosis reject, and other minor low volume waste streams are all ultimately discharged to the City WWTP. The City WWTP discharges to the Minnesota River. The Combined Facility will continue to operate in the same manner as existing conditions and will not add or change wastewater flow pathways or discharge points.

The majority of process water that has been utilized is lost to the atmosphere through evaporation, which will account for approximately 75 percent of all water that comes into the Combined Facility. The remaining process water is discharged back to the City WWTP. As part of the original construction of the Existing Facility, MEC I constructed a process water treatment system including a phosphorus removal and dechlorination system prior to discharge to the City WWTP. This system is located at the City's WWTP site and will continue

to be utilized during operation of the Combined Facility. MEC II will install upgrades as required at the WWTP to accommodate the Expansion Project.

Cooling water from the Mankato WWTP that is treated and routed to the Combined Facility would otherwise be discharged directly to the Minnesota River under the Mankato WWTP's existing NPDES permit. The wastewater generated from the Combined Facility will continue to be treated for phosphorus and chlorine removal prior to discharge, and as a result it is anticipated that phosphorus and total suspended solids loads to the Minnesota River will be reduced as a direct result of the Combined Facility's water use and discharge.
Domestic wastewater generated from the Existing Facility (i.e., bathrooms and sink areas in the administrative building and water treatment building) is discharged directly to the City of Mankato sanitary sewer system. This discharge is authorized by the City of Mankato and subject to appropriate discharge limits and monitoring requirements. No significant changes to sanitary discharge are expected as a result of the Expansion Project.

6.6 VISIBILITY ANALYSIS

MPCA guidance, "MPCA Air Dispersion Modeling Guidance", July 2014, was consulted in determining if a visibility analysis is required for the Expansion Project. The guidance indicates that all major sources or major modifications within 300 km of a Class I area should conduct an impact analysis for the Class I area.

There are no Class I areas within 300 kilometers (km) of the Combined Facility. The closest Class I area is Rainbow Lake Wilderness Area, located northeast of the Combined Facility in northern Wisconsin. Below is a summary of the nearest Class I areas with approximate distances and direction from the Combined Facility.

- Rainbow Lake Wilderness Area, WI – 320.6 km Northeast
- Boundary Water Canoe Wilderness Area, MN – 432.6 km North
- Voyageurs National Park, MN – 471.8 km North
- Isle Royale National Park, MI – 537.3 km Northeast
- Badlands National Park, SD – 644.8 km West
- Seney Wilderness Area, MI – 647.6 km Northeast

It was determined that a Class I increment analysis is not required for the Expansion Project because the Combined Facility is further than 300 km from Rainbow Lake Wilderness Area.

Although not required by MPCA guidance, PSD rules or the 2008 FLAG guidance, a visibility analysis was performed for the nearest Class I Area (Rainbow Lake Wilderness) in order to show the minimal impact the Combined Facility will have on the Class I areas. The screening procedure consisted of the methodology outlined in the EPA document Workbook for Estimating Visibility Impairment.

The Draft Federal Land Managers' Air Quality Related Values Workgroup (FLAG) guidance (June 27, 2008) contains an initial screening criteria to determine if a project causes or contributes to an impairment on visibility or air quality related values (AQRV) within a Class I area. The guidance states:

> *"… the Agencies are using a fixed Q/D factor of 10 as a screening criteria for sources locating greater than 50 km from a Class I area. Furthermore, the Agencies are expanding the screening criteria to include all AQRVs, not just visibility. Therefore, the Agencies will consider a source locating greater than*

50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if its total SO_2, NO_x, PM_{10} and H_2SO_4 annual emissions (in tons per year, based on 24-hour maximum allowable emissions, divided by the distance (km) from the Class I area (Q/D) is 10 or less. The Agencies would not request any further Class I AQRV impact analyses from such sources.

The total emissions from the Combined Facility of SO_4, NO_x, PM and soot are as follows:

- PM = 192.91 tons/year
- NO_x (as NO_2) = 354.01 tons/year
- Soot = 0 tons/year
- Primary SO_4 = 0 tons/year
- Total = 546.92 tons/year

The closest Class I area to the Combined Facility is Rainbow Lake Wilderness, WI:

- Q = 546.92 tons/year
- D = 320.6 km
- Q / D = 546.92 / 320.6 = 1.71

Following the procedures documented in the 2008 FLAG guidance results in a Q/D value less than 10. Therefore, it is concluded that the Expansion Project would not be considered to cause or contribute to impairment on visibility or an AQRV within a Class I area.

A visibility screening analysis was also performed for Rainbow Lake Wilderness. The screening procedure is divided into three levels. Each level represents a screening technique for an increasing possibility of visibility impairment. A Level 1 analysis involves a series of conservative tests that help to identify sources having little potential for adverse or significant visibility impairment of a potentially affected Class I Area. These calculations were performed for the distance from the Combined Facility to Rainbow Lake Wilderness using the EPA VISCREEN model. The PM and NO_x emissions used in this visibility analysis are conservatively assumed to be for the Combined Facility. The results of the VISCREEN run are shown in Table 6-1.

Table 6-1 Level 1 VISCREEN Analysis for Rainbow Lake Wilderness

Background	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Critical	Plume (project Results)	Critical	Plume (project Results)
Maximum Visual Impacts INSIDE Class I Area								
Sky	10	85	321.3	84	2.0	0.001	0.05	0
Sky	140	85	321.3	84	2.0	0	0.05	0
Terrain	10	92	329.2	77	2.0	0	0.05	0
Terrain	140	92	329.2	77	2.0	0	0.05	0
Maximum Visual Impacts OUTSIDE Class I Area								
Sky	10	80	315.8	89	2.0	0.001	0.05	0
Sky	140	80	315.8	89	2.0	0	0.05	0
Terrain	10	65	299.1	104	2.0	0	0.05	0
Terrain	140	65	299.1	104	2.0	0	0.05	0

The results for the Rainbow Lake Wilderness VISCREEN analysis are well below the Delta E critical value of 2.0. The results are no greater than approximately 0.05% of the Delta E critical thresholds. In addition, the plume contrast values are zero for all scenarios indicating that the proposed project will not impair visibility in Rainbow Lake Wilderness. As shown from the VISCREEN analysis the Expansion Project will not impair visibility in Rainbow Lake Wilderness. Detailed VISCREEN results are included in Appendix G.

Long-range transport modeling would not be appropriate for the Expansion Project. Guidance provided in the Interagency Work-group for Air Quality Modeling (IWAQM) report on long-range transport modeling for Class I impact analyses states that CALPUFF and other long-range assessment methodologies are not reliable beyond a distance of approximately 200 km. As indicated above, it is the policy of the USEPA that Class I impacts are normally not considered to be of concern beyond 300 km from a proposed source.

7.0 Ambient Air Quality Analysis

An air dispersion modeling analysis was performed for the Expansion Project. The purpose of the modeling analysis was to demonstrate that the emissions from the Combined Facility would not cause or contribute to a violation of the MAAQS and NAAQS and PSD increment standards. The modeling demonstration was conducted in two steps:

1. Preliminary modeling was conducted to determine whether emissions from the Expansion Project alone would result in any predicted maximum ambient concentrations of criteria pollutants above the PSD significant ambient impact levels.

2. The predicted concentrations for 1-hour nitrogen dioxide (NO_2) exceeded the respective significant ambient impact levels. Additional modeling for this pollutant and averaging time was performed to demonstrate compliance with NAAQS and MAAQS. PSD increment standards have not yet been developed for 1-hour NO_2.

7.1 SIL ANALYSIS

A SIL analysis was completed as part of the Expansion Project. Pollutants modeled in this SIL analysis were PM_{10}, $PM_{2.5}$, NO_2, and CO. The modeled concentrations of each pollutant were compared to their respective SIL value using High First High (H1H) modeled impacts. The SIL modeling analysis was completed for the following averaging periods with the following results:

Table 7-1 Class II Significant Impact Level Modeling Results

Pollutant	Averaging Period	Modeled Impact H1H ($\mu g/m^3$)	SILs ($\mu g/m^3$) *As of 10/26/2010	Percent of SIL (%)	Exceed SIL?	Radius of Impact (if exceeds SIL)
PM_{10}	24-Hour	1.42	5	28.30	No	--
	Annual	0.15	1	14.85	No	--
$PM_{2.5}$	24-Hour	0.78	1.2	65.31	No	--
	Annual	0.05	0.3	17.71	No	--
NO_2	1-Hour	27.61	7.52	367.00	Yes	50 km
	Annual	0.65	1	65.00	No	--
CO	1-Hour	755.10	2000	37.76	No	--
	8-Hour	468.00	500	93.60	No	

Based on the results above, further modeling is not required for PM_{10}, $PM_{2.5}$, CO, and annual NO_2. However, cumulative modeling is required for 1-hour NO_2 emissions as modeled concentrations for that pollutant and averaging period are greater than the SIL. Additionally a $PM_{2.5}$ PSD Increment screening analysis was completed.

The radius of impact listed in Table 7-1 is based on the distance from the site to the furthest receptor greater than the SIL. It was common practice in the past to reduce the extent of the receptor grid used in SIL modeling down to the radius of impact for cumulative modeling. EPA's March 1, 2011 memo entitled "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard" states on page 3:

> "*…we deem it appropriate and acceptable in most cases to limit the cumulative impact analysis to only those receptors that have been shown to have significant impacts from a proposed new source based on the initial SIL analysis…*"

Based on this statement from EPA, the size of the receptor grid used in the SIL model runs was reduced to include only those receptors with modeled concentrations greater than the 1-hour NO_2 SIL. Separate receptor grids were created for receptors inside and outside the nearby ADM facility.

7.2 NAAQS

Under the federal Clean Air Act (CAA) and the PSD regulation, a Class II area is a geographic area other than national parks, monuments and wilderness areas that are classified as Class I. Most of Minnesota is Class II. To receive a PSD permit in a Class II area, the Permittee must demonstrate that the NAAQS and MAAQS are protected, but less stringent standards are in place for a Class II area than a Class I area. A Class II air quality analysis was completed for the project as part of the air permit application.

The Expansion Project includes both fugitive sources and stacks, as well as nearby industrial background sources for the NO_x modeling only. The modeled fugitive sources include the cooling towers. The facility stacks include the facility combustion turbine stacks, the auxiliary boiler stack, bath heater stack, fire pump stack, and the proposed diesel fired emergency generator stack. The existing diesel fired fire pump and proposed diesel fired emergency generator are not required to be modeled as indicated in Section 7.6 below. Air pollution control equipment efficiencies and proposed air permit limits are included in the air emission estimates that were used in the modeling. Haul roads were not required to be included in the modeling analysis because predicted concentrations from the Expansion Project were less than the SIL for PM_{10} and $PM_{2.5}$. No changes to the haul roads are proposed as part of the Expansion Project.

The AERMOD air dispersion model was used to estimate Class II ambient air concentrations. The USEPA recommends AERMOD as a "Preferred Model" for Class II air quality analyses. Building downwash was predicted for the facility stacks using the BPIP-PRIME downwash model. Both AERMOD and BPIP-PRIME were developed by USEPA.

As shown in Table 7-2 below, the Class II air quality analysis showed a small modeled exceedance of NO_2 over the 1-hour averaging period. A culpability analysis of the modeled exceedance shows that the Combined Facility does not contribute more than a SIL toward the exceedance, which indicates that the Combined Facility is not a significant contributor to the exceedance.

Table 7-2 Maximum Predicted Ambient Air Concentrations

Pollutant	Averaging Period	Modeled Impact ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Predicted Ambient Air Concentration ($\mu g/m^3$)	MAAQS ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Percent of Standard (%)
NO_2	1-Hour (H8H)	189.69	54.56[a]	189.69	-	188[b]	100.9

[a] Background level is 3-year average of maximum monitored observations for FHR 423 monitor (2011-2013).
[b] Not to be exceeded more than the three-year average of the 98th percentile of 1-hour concentrations.

An ozone impacts analysis is also required of any major PSD modification where there is an increase in NO_x and VOC emissions which exceeds the significance threshold for ozone (40 tpy) because NO_x and VOCs are precursors to ozone. A quantitative modeling analysis for ozone has not yet been developed to be used for this permit. Therefore a qualitative analysis was decided to be used. In this analysis, data from the Blaine ozone monitor was used. This data shows that the monitoring station has recorded average ozone concentrations at or below 89% of the NAAQS standard during 2012-2014. NO_x and VOC emissions from the Combined Facility account for less than 0.04% of the stationary source emissions in the state according to the 2012 Criteria Point Air Emissions by Facility summary. This data indicates there is no reason to expect emissions from the Combined Facility would alter the compliance status with respect to the ozone standard.

7.3 PSD INCREMENTS

PSD allows facilities to construct emission units, but restricts the amount of additional pollution an area can receive. It does this by imposing "PSD increments," or limits on the concentration of air pollution since a certain date.

There are increments that apply in normal (or Class II) areas as well as increments for protected (Class I) areas such as National Parks and Wilderness areas. The allowed increase in a concentration of a pollutant is lower in a Class I area than in a Class II area.

As part of this modeling analysis, MEC II conducted a $PM_{2.5}$ Increment Screening Analysis. This screening process was completed for the purpose of demonstrating compliance and screening out of a cumulative air dispersion modeling analysis. In the past it has been acceptable to demonstrate that project impacts were below the SIL and background concentration was at least one SIL below the NAAQS. However, in the EPA's most recent guidance on $PM_{2.5}$ modeling, that approach was deemed unacceptable when screening out of a $PM_{2.5}$ increment analysis.

The $PM_{2.5}$ Increment Screening Analysis ultimately determined that the Expansion Project impact will be a small consumer of increment. The analysis also determined that monitored background concentrations in the area have improved significantly over the past several years, increasing the amount of "headroom" between the Expansion Project impacts and the PSD Class II increment standards. These results indicate that further refined increment modeling is not required. For a detailed report of the techniques used and complete results of this analysis, please see Appendix H.

7.4 CLASS I INCREMENT ANALYSIS

As outlined in the MPCA's Air Dispersion Modeling Guidance (July 2014), source applicability to complete a Class I increment analysis is based on a source's proximity to a Class I area. The most current recommendation is that all major sources or major modifications within 300 km of a Class I area should conduct an impact analysis of the affected Class I area(s).

As described in Section 6.6, there are no Class I areas within 300 kilometers (km) of the facility. The closest Class I area is Rainbow Lake Wilderness Area, located northeast of the Combined Facility in northern Wisconsin. Below is a summary of the nearest Class I areas with approximate distances and direction from the Combined Facility.

- Rainbow Lake Wilderness Area, WI – 320.6 km Northeast
- Boundary Water Canoe Wilderness Area, MN – 432.6 km North
- Voyageurs National Park, MN – 471.8 km North
- Isle Royale National Park, MI – 537.3 km Northeast
- Badlands National Park, SD – 644.8 km West
- Seney Wilderness Area, MI – 647.6 km Northeast

It was determined that a Class I increment analysis is not required for the project because the Combined Facility is more than 300 km from Rainbow Lake Wilderness Area.

8.0 Applicable Requirements

The significant applicable state and federal air quality regulations are summarized in this section. The MPCA forms that identify all applicable requirements are included as Appendix A.

8.1 PSD APPLICABILITY

The Expansion Project is subject to PSD for PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC, and GHG emissions as shown in Table 5-1. PSD requires installation of BACT for new emission units. A BACT limit for PM, PM_{10}, $PM_{2.5}$, NO_x, CO, VOC, and GHG emissions are proposed for each new emission unit as described in Section 3. The Expansion Project does not trigger PSD for SO_2 because the combustion turbine will be fired with natural gas only.

8.2 MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY

The project includes equipment governed by Maximum Achievable Control Technology (MACT) standards specified in 40 CFR 63. The Combined Facility is a synthetic minor source with respect to HAPs. Highlighted regulations are included in Appendix A.2.

- The existing fire pump is an existing source at an area source with respect to MACT. The unit is rated at less than 500 hp. The unit is subject to 40 CFR Part 63 Subpart ZZZZ. Requirements are already listed in the current permit.
- The proposed diesel fired emergency engine will be a new source, rated at greater than 500 hp, located at an area source of HAP. It will comply with 40 CFR 63 Subpart ZZZZ through compliance with 40 CFR 60, Subpart IIII.
- As noted above, the Combined Facility is not a major source with respect to HAPs and will continue to be a minor source following the Expansion Project. 40 CFR Part 63 Subpart YYYY is only applicable to major sources of HAPs and therefore is not applicable to the proposed combustion turbine.
- The existing and proposed duct burners are classified as Electric Utility Steam Generating Units (EUSGUs). The proposed Electric Utility Steam Generating Unit source category definition published in 67 FR 6521, Table 1 includes coal-fired and oil-fired EUSGUs. Because the existing duct burners burn natural gas and the duct burners will fire natural gas, the proposed 40 CFR 63 Subpart UUUUU and 112(g), Case-by-Case MACT requirements are not applicable to these units.

8.3 NEW SOURCE PERFORMANCE STANDARDS (NSPS)

The Expansion Project will have equipment subject to the following New Source Performance Standards (NSPS). Highlighted NSPS Standards are included in Appendix A.2 of this application.

- The proposed combustion turbine and duct burners will be subject to 40 CFR 60 Subpart KKKK: Standards of Performance for Stationary Combustion Turbines. According to the applicability of NSPS KKKK, the proposed combustion turbine will be exempt from 40 CFR 60 Subpart GG and the associated proposed duct burner will be exempt from NSPS Subpart Da: Standards of Performance for Electric Utility Steam Generating Units.

- The existing combustion turbine and its associated existing duct burners are not subject to NSPS KKKK. NSPS Subpart KKKK is only applicable to units that have commenced construction, modification or reconstruction after February 18, 2005. Calpine commenced construction on the existing combustion turbine and duct burners on November 1, 2004.
- The proposed combustion turbine and duct burners will be subject to 40 CFR 60 Subpart TTTT: Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units.
- The proposed diesel fired emergency generator will be subject to 40 CFR 60 Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

8.3.1 NSPS Subpart KKKK

The proposed combustion turbine and duct burners will be subject to 40 CFR 60 Subpart KKKK: Standards of Performance for Stationary Combustion Turbines. As noted previously, the proposed combustion turbine will be exempt from 40 CFR 60 Subpart GG: Standards of Performance for Electric Utility Steam Generating Units. The proposed HRSG and duct burners are exempt from 40 CFR Part 60 Subpart Da: Standards of Performance for Electric Utility Steam Generating Units.

The Expansion Project will install a NO_x CEMS on CT #1 in accordance with §60.4345, to demonstrate compliance with the NSPS KKKK limits of 15 ppm at 15% O_2, or 0.43 lb NO_x/MWh. The NO_x limit includes startup and shut down emissions and is demonstrated on a 4 hour rolling average. Consistent total SO_2 composition of the combustion fuel will be demonstrated either by fuel purchase contract specifications, or through representative fuel sampling in accordance with §60.4365.

8.3.2 NSPS Subpart TTTT

The proposed CT#1 and duct burners will be subject to 40 CFR 60 Subpart TTTT: Standards of Performance for Greenhouse Gas Emissions. Based on this regulation, a heat output based limit of 1000 lb CO_2/MWh is required for the CT as the combustion turbine will supply more than its design efficiency times the potential electric output as net electric sales and the unit will burn natural gas only (Table 2 of Subpart TTTT).

The projected design LHV efficiency of the unit is 45 percent. The air permitting for the unit is based on 100 percent capacity factor (or no requested annual capacity factor for the unit). Therefore, this unit will be subject to the output based limit in Table 2 of Subpart TTTT. The BACT limit results in emissions below this limit. This is lower than the NSPS and will ensure compliance with the standard. A copy of 40 CFR 60 Subpart TTTT highlighted for applicability for the proposed CT is included in Appendix A.2.

8.4 STATE RULES

8.4.1 Air Emission Standards

In addition to the generally applicable state requirements, the Expansion Project will install equipment subject to unit-specific standards.

- The proposed combustion turbine will be subject to Minn. R. 7011.2350 Stationary Gas Turbines for the Combustion Turbines.

- The proposed fuel oil tank for the proposed diesel fired emergency generator will be subject to Minn. R. 7011.1500 through 7011.1520 for the Fuel Oil Tanks.
- The cooling towers will be subject to the Industrial Process Equipment rule, Minn. R. 7011.0715 Standards of Performance For Post-1969 Industrial Process Equipment.
- The proposed diesel fired emergency generator will be subject to Minn. R. 7011.2300 Standards of Performance For Stationary Internal Combustion Engines.

8.4.2 Environmental Review

Calpine has applied to the Minnesota Public Utilities Commission for a Site Permit in accordance with the Minnesota Power Plant Siting Act (Minnesota Statutes Chapter 216E and Minnesota Rules 7850) on August 5, 2015. The Site Permit application contains environmental information as specified by Minnesota Rules 7850.1900, Subpart 3. Data and other information on air impacts is one area that are covered in the Site Permit application.

8.4.3 Air Emissions Risk Analysis

MEC I completed an Air Emissions Risk Analysis ("AERA") in accordance with MPCA technical guidance (Facility Air Emissions Risk Analysis Guidance; Version 1.0; September 2003) as part of the 2004 Site Permit. The results of the 2004 analysis demonstrated compliance with all applicable standards.

MPCA guidance no longer exempts natural gas-fired combustion units from review. Therefore, the AERA addressed emissions resulting from combustion of the natural gas combustion in the proposed combustion turbine and associated proposed duct burners.

An AERA was conducted as part of the Expansion Project. The purpose of the AERA is to assess the potential health risk attributed to air emissions from a given source. The AERA includes both quantitative and qualitative analyses. In the quantitative portion of the analysis, the potential incremental cancer risks and non-cancer hazard indices are estimated using procedures outlined in MPCA guidance. The qualitative portion of the analysis identifies and discusses items of potential interest that cannot be easily quantified.

The MPCA's AERA guidance allows for a preliminary assessment based on the use of screening level air dispersion modeling to predict exposure levels. Maximum one-hour impacts for each pollutant were determined for assessing acute exposures. The maximum annual impacts for each pollutant were determined for assessing chronic exposures and/or cancer risk. These exposures were then compared with pollutant-specific toxicity values supplied by the MPCA. Hazard indices and cancer risks were then calculated. A detailed summary of the AERA and its findings are presented in Appendix I.

8.5 COMPLIANCE ASSURANCE MONITORING (CAM)

Compliance Assurance Monitoring (CAM) applies on a pollutant specific basis to emissions units that:

1. Are subject to an emission limit or standard, and
2. use add-on pollution control to achieve compliance with the applicable limit or standard, and
3. have pre-controlled potential emissions greater than the Part 70 major source level for that pollutant.

There are also many exemptions from CAM, such as being subject to an emission limit or standard proposed by the EPA after April 15, 1990, under Sections 111 or 112 of the Clean Air Act.

Proposed pollution control equipment at MEC II includes DLN burners for the combustion turbine and SCR and oxidation catalyst for the combustion turbine and duct burners. DLN burners do not meet the definition of add-on controls under the CAM regulation.

SCR reduces NO_x emissions, and the combined cycle unit is subject to a NSPS standard promulgated after April 15, 1990, which exempts them from CAM for the NSPS limits. MEC II is also proposing a NO_x BACT limit, which does not qualify for an exemption, making the combustion turbine and duct burners subject to CAM for NO_x. MEC II is installing a NO_x CEMS to demonstrate compliance with the proposed emission limitation. A CAM plan has been prepared for the NO_x CEMS and is included in Appendix A.3 of this application.

The catalytic oxidizer reduces emissions for both CO and VOC. MEC II will use a CO CEMS to comply with the CO emission limit. The CAM rule indicates that the use of a CEMS or PEMS meets the requirements of the CAM rule, so a CAM plan has been prepared for the CO CEMS and is included in Appendix A.3 of this application. The CO CEMS is proposed as a surrogate for VOC emissions as well.

8.6 PRE-CONSTRUCTION MONITORING REQUEST

On January 22, 2013, the United States Court of Appeals for the District of Columbia Circuit (Court) granted a request from the EPA to vacate and remand portions of two PSD $PM_{2.5}$ rules. The Court vacated the portion of the PSD rules that established a $PM_{2.5}$ SIL. The Court also vacated the portion of the PSD rules that established a $PM_{2.5}$ Significant Monitoring Concentration (SMC), finding that EPA was precluded from using the $PM_{2.5}$ SMC to exempt permit applicants from the statutory requirement to compile preconstruction monitoring data. Therefore, all applicants for a federal PSD permit should include ambient $PM_{2.5}$ monitoring data as part of the application process.

EPA issued guidance that addressed EPA's recommendations for completing an air quality analysis for $PM_{2.5}$ following the Court's decision. The May 20, 2014 Guidance for $PM_{2.5}$ Permit Modeling, provides additional information on how a permitting should select and include ambient $PM_{2.5}$ monitoring data.

The guidance indicates that even though the PSD application must include ambient monitoring data representative of the area of concern, this data need not be collected by the PSD applicant if existing data is determined by the permitting authority to represent the air quality in the area of concern over the 12-month period prior to the submittal of a complete PSD application.

Currently, there are no $PM_{2.5}$ ambient monitors located at the Existing Facility. However, there are several $PM_{2.5}$ monitors located in Minnesota that are operated and maintained by either the Minnesota Pollution Control Agency (MPCA) or other permitees. MEC II is proposing to use a representative existing monitor to supply ambient $PM_{2.5}$ monitoring data for the Expansion Project. The memorandum located in Appendix D documents the selection criteria and justification for using an existing $PM_{2.5}$ monitoring data as a representation of the current $PM_{2.5}$ emission levels at the Existing Facility.