ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
1021 NORTH GRAND AVENUE EAST, P.O. BOX 19276, SPRINGFIELD, ILLINOIS 62794-9276 • (217) 782-3397
BRUCE RAUNER, GOVERNOR ALEC MESSINA, ACTING DIRECTOR

Project Summary for a Construction Permit Application from Invenergy Nelson Expansion LLC, for Two Additional Electrical Generating Units at the Nelson Energy Center Near Rock Falls

Source Identification No.:	103814AAC
Application No.:	15060042

<u>Schedule</u>

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<u>Illinois EPA Contacts</u>

Permit Analyst:	Bob Smet
Community Relations Coordinator:	Brad Frost

I. INTRODUCTION

Invenergy Nelson Expansion LLC (Invenergy Nelson Expansion) has requested a construction permit for two new electrical generating units at its existing electricity power plant near Rock Falls. The new units will be installed to serve as peaking units. Peaking units are installed to provide electricity during periods of high demand and other periods when electrical generating units that operate more routinely cannot meet the demand for electricity. Natural gas will be the principal fuel for the new units. Ultra-low sulfur diesel (ULSD) will be used during periods when natural gas is in short supply, such as during the winter months, and for periodic operational testing to confirm the ability to burn ULSD.

The Illinois EPA has reviewed the construction permit application for the proposed project and made a preliminary determination that it meets applicable air pollution control requirements.

The Illinois EPA has prepared a draft of the construction permit that it would propose to issue for the proposed project. Prior to issuing any construction permit for this project, the Illinois EPA is holding a public comment period to receive comments on the proposed issuance of a permit for the project and the terms and conditions of the draft permit.

II. PROJECT DESCRIPTION

Invenergy Nelson Expansion operates the Nelson Energy Center, a natural gas-fired power plant at Nelson, near Rock Falls.[1] This plant has two combined cycle combustion turbine generating units that were developed to serve as intermediate load units rather than peaking units.[2]

The proposed project involves the construction at this power plant of two simple-cycle combustion turbine generators to act as peaking units. Peaking units supply electricity to the grid to meet peak load electrical power demands. The nominal summer-time rated electrical output of each turbine would be 150 MWe (combined output of 300 MWe).[3] The turbines would be equipped with evaporative cooling systems for the inlet air to enhance output during hot summer weather.

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[1] This application has actually been submitted by Invenergy Nelson II LLC, a separate company organized by Invenergy Nelson II LLC for the proposed project that is organizationally distinct from Invenergy Nelson, which operates the existing Nelson Energy Center.

[2] As intermediate load units, the existing turbines have heat recovery steam generators (HRSG) to produce steam from the hot exhaust for the turbines. This steam is then used to generate electricity in a steam turbine generator. Because electricity is produced both by the generators powered by the turbines and by a steam turbine generator, the existing turbine generator are classified as "combined-cycle" units. Simple-cycle turbines only generate power from the turbines and do not have HRSGs.

[3] The winter time rating of the turbines would be about 190 MWe (combined capacity of 380 MWe). The rating of turbines varies significantly based on the season because generating capacity increases with lower air temperature.

Natural gas would be the principal fuel for the two new combustion turbines. Ultra-low sulfur diesel (ULSD) would be a backup fuel in case the supply of natural gas is restricted or curtailed. Emissions from the combustion turbines would be controlled or minimized by using good combustion practices, low-NOx combustors and, for ULSD, water injection.

The proposed project would also include construction of a small natural gas-fired fuel heater. This unit will heat the natural gas burned in the new turbines to prevent condensation in the fuel piping due to the cooling that occurs when the pressure of the gas is reduced to the operating pressure of the burners in the turbines.

The proposed project would also include construction of a storage tank for ULSD.[4] Like the existing roadways at the plant, the new roadways to serve this tank will also be paved.

III. EMISSIONS

The potential emissions of the proposed project are listed below. Potential emissions reflect an annual heat input limit for the turbines serving as peaking units. Actual emissions are expected to typically be much less as peaking turbines operate at less than their annual permitted capacity.

Potential Emissions from the Project (tons/year)[5]

Pollutant	Emissions
Nitrogen Oxides (NOx)	277.5
Carbon Monoxide (CO)	96.7
Particulate Matter (PM), Filterable	28.8
Particulate $Matter_{10}$ (PM_{10})[6]	38.2
Particulate $Matter_{2.5}$ ($PM_{2.5}$)[3]	38.2
Greenhouse Gases (GHG), as carbon dioxide equivalents	610,755
Volatile Organic Material (VOM)	13.2
Sulfur Dioxide (SO_2)	7.0

IV. APPLICABLE EMISSION STANDARDS

All emission units in Illinois must comply with state emission standards adopted by the Pollution Control Board. The state's emission standards

[4] Invenergy Nelson Expansion does not plan to construct a new tank for de-mineralized water for water injection. This water will be handled in an existing storage tank that serves the existing combined cycle turbines.

[5] The project will not be a major source of emissions of hazardous air pollutants (HAPs) since its potential annual emissions of HAPs are less than 25 tons in aggregate and less than 10 tons for any single HAP.

[6] The potential emissions of PM_{10} and $PM_{2.5}$ are greater than the potential emissions of PM because, as now provided by 40 CFR 52.21(b)(50)(i)(*a*), both filterable and condensable particulate are included when determining emissions of PM_{10} and $PM_{2.5}$. Only filterable particulate is addressed when determining PM emissions.

represent the basic requirements for sources in Illinois. The Board has standards or requirements for emissions of NOx, SO_2 and opacity that apply to the proposed turbines. The proposed turbines should readily comply with these applicable standards and requirements (35 Illinois Administrative Code Subtitle B).

The proposed turbines are subject to federal New Source Performance Standards (NSPS) for stationary gas turbines, 40 CFR 60 Subpart KKKK. The Illinois EPA administers NSPS for sources in Illinois on behalf of the USEPA under a delegation agreement. This NSPS sets emission limits for NOx and SO_2 from the two turbines. For NOx, these standards are 15 ppm and 42 ppm, both at 15 percent O_2, for natural gas and ultra-low-sulfur diesel (ULSD), respectively.[7] The proposed turbines should readily comply with these limits. The application indicates that the NOx emissions of the turbines when operating in the normal load range would be no more than 9 ppm at 15% O_2 for natural gas and 42 ppm at 15% O_2 for ULSD. The SO_2 emissions from natural gas and ULSD also comply with the requirements of this NSPS.

The proposed fuel heater is subject to the NSPS for Small Industrial-Commercial-Institutional Steam Generating Units, 40 CFR 60 Subpart Dc. Because this heater would only burn natural gas, this NSPS only requires that the heater be operated and maintained in a manner consistent with good air pollution control practices for minimizing emissions.

V. PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

a. Introduction

The proposed project is a major modification subject to the federal rules for Prevention of Significant Deterioration of Air Quality (PSD), 40 CFR 52.21. The proposed project is major for emissions of NOx, PM, PM_{10} and $PM_{2.5}$, with potential annual emissions of each of these pollutants that are significant (i.e., more than 40 tons for NOx, 25 tons for PM, 15 tons for PM_{10} and 10 tons for $PM_{2.5}$). The proposed project is also significant for emissions of greenhouse gases (GHG), with potential annual emissions of more than 75,000 tons, as carbon dioxide equivalents (CO_2e).[8] Because potential emissions of other regulated PSD pollutants, including CO, SO_2 and VOM, from the project will be below their applicable significant emission rates, PSD will not apply for these other pollutants.

b. Best Available Control Technology (BACT)

Under the PSD rules, a source or project that is subject to PSD must use BACT to control emissions of pollutants subject to PSD. The application includes BACT demonstration addressing emissions

[7] Applicable limits from Table 1 of 40 CFR 60 Subpart KKKK — Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines, for turbines with a heat input capacity greater than 850 mmBtu/hour, that fire natural gas and fuels other than natural gas.
[8] Because the proposed project is subject to PSD for regulated NSR pollutants other than GHG, PSD may also be triggered GHG if the project's potential GHG emissions are significant, i.e., 75,000 tons or more per year, as CO_2e.

of pollutants that are subject to PSD, i.e., NOx, $PM/PM_{10}/PM_{2.5}$ and GHG.

BACT is defined by Section 169(3) of the federal Clean Air Act as:

> An emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental and other costs, determines is achievable for such facility through application of production processes and available methods, systems and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant.

BACT is generally set by a "Top-Down Process." In this process, the most effective control option that is available[9] and technically feasible[10] is assumed to constitute BACT for a particular unit, unless the energy, environmental and economic impacts associated with that control option are found to be excessive. An important resource for BACT determinations is USEPA's *RACT/BACT/LAER Clearinghouse* (Clearinghouse of RBLC), a national compendium of control technology determinations maintained by USEPA. Other documents that are consulted include general information in the technical literature and information on other similar or related projects that are proposed or have been recently permitted.

A demonstration of BACT was provided for the project in the permit application for emissions for the pollutants that are subject to PSD from the various emission units for the project. The Illinois EPA's proposed determinations of BACT for the turbines and fuel heater are discussed, respectively, in Attachments A and B of this Project Summary. The draft permit includes proposed BACT requirements and limits for emissions of the pollutants that are subject to PSD. These proposed limits have generally been determined based on the following:

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[9] As discussed by USEPA in its *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA-457/B-11-001, March 2011 (GHG Permitting Guidance), "Available control options are those air pollution control technologies or techniques (including lower-emitting processes and practices) that have the potential for practical application to the emissions unit and the regulated pollutant under evaluation." GHG Permitting Guidance, p. 24.

As previously discussed by USEPA in in its *New Source Review Workshop Manual*, Draft, October 1990 (NSR Workshop Manual, "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice." NSR Manual, p. B.12.

[10] In its GHG Permitting Guidance, USEPA indicates that a technology should be considered "to be technically feasible if it 1) has been demonstrated and operated successfully on the same type of source under review, or 2) is available and applicable to the source under review." GHG Permitting Guidance, p. 33.

- Emission data provided by the applicant;
- The demonstrated ability of similar equipment to meet the proposed emission limits or control requirements;
- Compliance periods associated with limits that are consistent with guidance issued by USEPA;
- Emission limits that account for normal operational variability based on the equipment and control equipment design, when properly operated and maintained;
- USEPA draft permit review comments on recent PSD permits;
- Permit applications and GHG BACT reports for recent projects;
- Gas Turbine World 2015 Performance Specifications; and
- Review of emission limits and control efficiencies required of other new simple cycle combustion turbines as reported in the USEPA's *Clearinghouse*.

The roadways at the plant will be extended to serve the new storage tank for ULSD. Emissions of particulate from truck traffic on this roadway will be addressed by paving and periodic cleaning. The projected PM emissions from these roadways, considering that ULSD will be a backup fuel, will be less than 0.02 tons/year. BACT for roadways is proposed to be paving and periodic cleaning, consistent with the current practices for plant roadways.

VI. OTHER APPLICABLE REGULATIONS

a. Acid Rain Program

The new combustion turbines are affected units for Acid Deposition: Title IV of the Clean Air Act, and regulations promulgated thereunder. For combustion turbines, these provisions establish requirements for affected sources related to control of emissions of SO_2, a pollutant that contributes to acid rain. Under the Acid Rain program, SO_2 allowances will have to be held for the actual SO_2 emissions from the affected units. Another requirement of the Acid Rain program is to operate pursuant to an Acid Rain permit. An Acid Rain permit was issued for the existing plant in 2008 in conjunction with the issuance of the construction permit for the existing plant. The Illinois EPA is proposing to issue an Acid Rain Permit, that addresses the new two peaking turbines, in conjunction with the issuance of the construction permit for this project.[11]

b. Cross State Air Pollution Rule (CSAPR)

Combustion turbines used to produce electricity generally qualify as Electrical Generating Units (EGU) for purposes of the NOx and SO_2 Allowance Programs for Electrical Generating Units - Cross State Air Pollution Rule (CSAPR). As such, the Permittee will have to hold

[11] The Permittee for this Acid Rain Permit, as drafted, would be Invenergy Nelson expansion LLC. The two proposed combustion turbines would be addressed as Unit 3 (U3) and Unit 4 (U4) in the Acid Rain Permit.

allowances for the NOx and SO_2 emissions of the combustion turbines during each calendar year and seasonal control period (NOx only).

c. Clean Air Act Permit Program (CAAPP)

The existing plant is a major source under Illinois' Clean Air Act Permit Program (CAAPP) pursuant to Title V of the Clean Air Act, because it is a major source for purposes of the PSD Rules. The operation of the proposed facility will also have to be addressed under the CAAPP.

VII. AIR QUALITY IMPACT ANALYSIS

a. Introduction

The previous discussions addressed emissions and emission standards. Emissions are the quantity of pollutants emitted by a source, as they are released to the atmosphere from various emission units. Standards are set limiting the amount of these emissions as a means to address the presence of contaminants in the air. The quality of air that people breathe is known as ambient air quality. Ambient air quality considers the emissions from a particular source after they have dispersed from the source following release from a stack or other emission point, in combination with pollutants emitted from other nearby sources and background pollutant levels. The level of pollutants in ambient air is typically expressed in terms of the concentration of the pollutant in the air. One form of this expression is parts per million. A more common scientific form for measuring air quality is "micrograms per cubic meter", which are millionths of a gram by weight of a pollutant contained in a cubic meter of air.

The USEPA has standards for the level of various pollutants in the ambient air. These ambient air quality standards are based on a broad collection of scientific data to define levels of ambient air quality where adverse human health impacts and welfare impacts may occur. As part of the process of adopting air quality standards, the USEPA compiles scientific information on the potential impacts of the pollutant into a "criteria" document. Hence the pollutants for which air quality standards exist are known as criteria pollutants. Based upon the nature and effects of a pollutant, appropriate numerical standards(s) and associated averaging times are set to protect against adverse impacts. For some pollutants several standards are set, for others only a single standard has been established.

Areas can be designated as attainment, nonattainment or unclassified for criteria pollutants, based on the existing air quality. In an attainment area, the goal is to generally preserve the existing clean air resource and prevent increases in emissions which would result in nonattainment. In a nonattainment area efforts must be taken to reduce emissions to come into attainment. An area can be attainment for one pollutant and nonattainment for another. The plant, located in Lee County, is in a location classified as an attainment or unclassified for all criteria pollutants.

Compliance with air quality standards is determined by two techniques, monitoring and modeling. In monitoring one actually samples the levels of pollutants in the air on a routine basis. This is particularly valuable as monitoring provides data on actual air quality, considering actual weather and source operation. The Illinois EPA operates a network of ambient air monitoring stations across the state.

Monitoring is limited because one cannot operate monitors at all locations. One also cannot monitor to predict the effect of a future source or project, which has not yet been built, or to evaluate the effect of possible regulatory programs to reduce emissions. Modeling is used for these purposes. Modeling uses mathematical equations to predict ambient concentrations based on various factors, including the height of a stack, the velocity and temperature of exhaust gases, and weather data (speed, direction and atmospheric mixing). Modeling is performed by computer, allowing detailed estimates to be made of air quality impacts over a range of weather data. Modeling techniques are well developed for essentially stable pollutants like particulate matter, NOx and CO, and can readily address the impact of individual sources. Modeling techniques for reactive pollutants, e.g., ozone, are more complex and have generally been developed for analysis of entire urban areas. As such, these modeling techniques are not applied to a single source with small amounts of emissions.

Air quality analysis is the process of predicting ambient concentrations in an area as a result of a project, and comparing the concentration to the air quality standard or other reference level. Air quality analysis uses a combination of monitoring data and modeling as appropriate.

b. Air Quality Analysis for NO_2, PM_{10}, $PM_{2.5}$, CO and SO_2

An ambient air quality analysis was conducted by Invenergy Nelson Expansion to assess the impact of the emissions of the proposed project compared to the NAAQS and PSD Increments. The analysis addressed operation of the turbines on both natural gas and ultra-low-sulfur diesel (ULSD) and both for normal operation and for startup and tuning. This analysis also addressed the impacts of emissions of CO and SO_2 although the project would not be a significant for CO or SO_2.[12] This analysis determined that the proposed project will not cause or contribute to a violation of the applicable National Ambient Air Quality Standards (NAAQS) for NO_2, $PM_{10,}$ $PM_{2.5}$ CO and SO_2 or to a violation of the applicable PSD Increments. This analysis is discussed in further detail in Attachment C of this Project Summary.

Results of the Significance Analysis Compared to NAAQS			
Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
NO_2	1-hour	11.3*	188
	Annual	0.48	100
PM_{10}	24-hour	0.78	150
$PM_{2.5}$	24-hour	0.38	35
	Annual	0.04	12
SO_2	3-Hour	0.16	25
	24-Hour	0.057	5

[12] The current NAAQS for particulate address particulate as PM_{10} and $PM_{2.5}$ and not PM. USEPA has not adopted a NAAQS for GHGs or CO_2.

Results of the Significance Analysis Compared to NAAQS			
Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
CO	1-Hour	10.7	40,000
	8-Hour	6.8	10,000

* The maximum predicted 1-hour NO_2 impact is above the Significant Impact Level (SIL) so further analysis was conducted for the hourly impacts of the plant on NO_2 air quality, as discussed in Attachment C.

c. Air Quality Analysis for Ozone

The analysis of potential impacts of the project on ozone air quality conducted by Invenergy Nelson Expansion used the screening method formulated by the USEPA and Illinois EPA for analysis of ozone air quality impacts for purposes of PSD permitting. This methodology predicts increases in 1-hour ozone concentrations from the increases in emissions from a project, using conservative assumptions concerning baseline conditions for VOM and NOx emissions in an area.[13]

Based on the analysis provided by Invenergy Nelson Expansion, the increase in the 8-hour ozone concentration resulting from the proposed project will be 0.4 ppb. Adding a background concentration of 62.0 ppb yields a total 8-hour ozone concentration of 62.4 ppb. As this is below the current 8-hour ozone standard 70 ppb, the proposed project is not expected to threaten ozone air quality.

The screening methodology entails an evaluation of the impact of a proposed project on ozone air quality, 8-hour average, considering the potential emissions of ozone precursors from the proposed project, the current levels of precursor emissions in the region in which the plant is located and monitored ozone air quality for the region. The most recent data for existing emissions in the region that is available is from 2012 through 2014, as presented in annual Air Quality Reports. Information on current ozone air quality in the region is available from the Illinois EPA's ambient monitoring station in Rock Island. The design value for the Rock Island monitoring station for 2012 through 2014, 0.062 ppm, 8-hour average, confirmed that ozone air quality in the region complied with the current ozone NAAQS.[14] The evaluation of the project's potential impact on ozone air quality then considered the increase in regional NOx and VOM emissions that would potentially accompany the proposed project. The total annual emissions in the region surrounding the project site, (Bureau, Henry, Whiteside, Carroll, Ogle and Rock Island Counties in Illinois and Clinton and Scott Counties in Iowa) were on the order of 38,364 and 30,195 tons for NOx and VOM, respectively, with a VOM-to-NOx ratio of 0.79. The project's potential emissions are 274.2 and 8.0 tons/year for NOx and VOM, respectively, with a VOM-to-NOx ratio of 0.029. Since the VOM-to-NOx ratios are not similar, in this analysis, the VOM

[13] The 1-hour ozone impacts based on this methodology can also be used to address the 8-hour ozone NAAQS.

[14] The design value is a metric that expresses the maximum level of ozone air quality over a three year period in terms that are consistent with the form of the current ozone NAAQS, which addresses the maximum levels of ozone over a three year period. A 2014 design value for ozone addresses the ozone air quality for the period of 2012 through 2014.

emissions of the proposed project were assumed to be higher, reflecting the existing VOM-to-NOx ratio in region. Using that adjusted VOM value, the future ozone impacts due to the emissions of the proposed project can be very conservatively predicted by applying the increase in emissions to the monitored design value. The result is a predicted design value of 0.0624 ppm, 8-hour average, which continues to be below the 8-hour ozone NAAQS, 0.070 ppm. The proposed project will potentially increase the emissions of NOx and VOM in the region in which the plant is located by 0.71 percent. Assuming, very conservatively, that the ozone air quality in this region is only caused by regional emissions of ozone precursors, the result is at most a less than 1 percent increase in ozone levels or a future design value of at most 0.062 ppm ($0.062 \times 1.0071 = 0.0624$, ≈ 0.062). This assessment confirms that the proposed project will not threaten ambient air quality for ozone.

d. Vegetation and Soils Analysis

Predominant land use in the vicinity of the project site is agricultural production (cultivated crops) followed by low to medium intensity development. The majority of the area surrounding the site is used overwhelmingly for agriculture, followed by recreation and residential purposes.

Included in the vegetation analysis are potential impacts to vegetation with significant commercial or recreational value. For the purpose of this analysis, only agricultural commodity crops (primarily corn and soybeans) were evaluated because the study area is predominately agricultural based. Forest products were not considered since essentially no commercial forestry occurs within the modeled pollutant impact area of the plant.

Invenergy Nelson Expansion provided an analysis of the impacts of the proposed project on vegetation and soils. The first stage of this analysis focused on the use of modeled air concentrations and published screening values for evaluating exposure to flora from the relevant pollutants (NOx, $PM_{10}/PM_{2.5}$, SO_2 and CO). For NOx, the analysis showed that the maximum 1-hour and annual NOx concentration from the project will be well less than the secondary NAAQS, which are protective of the adverse health effect impact levels for typical row crop agriculture (corn, soybeans) which predominates in the vicinity of the proposed plant. Predicted concentrations from the project of $PM_{10}/PM_{2.5}$ are well below secondary NAAQS established to protect vegetative species. In addition, as only small amounts of SO_2 will potentially be emitted from the proposed project (less than the significant emission rate under the PSD rules), no negative impacts to flora will occur.

Hazardous Air Pollutants (HAPs) include both particulate metals and VOM. Total HAP emissions for the project are estimated at 3.04 tons/year, well below the major source thresholds of 10 tons/year for an individual HAP and 25 tons/year for all HAPs. The two relevant families of HAPs for this project are particulate metals and organic HAPs, as discussed below.

Particulate Metals - Particulate emissions from the proposed project are from fuel combustion, both of natural gas and of backup ULSD. PM_{10} and $PM_{2.5}$ air dispersion modeling that was conducted indicates that ambient air concentrations at the property boundary are below the PSD significant impact level (SIL). The SIL analysis not only demonstrates a de minimis impact to ambient air concentrations, but by extension the SIL analysis also demonstrates insignificant impact to soils and vegetation (NSR Workshop Manual, Section D.II.C.).

Because potential impacts from modeled PM_{10} and $PM_{2.5}$ air concentrations are de minimis, potential deposition of particulate metals is also considered de minimis as deposition is related to the concentration of a pollutant in the air (USEPA 2001; Janhäll 2015). An insignificant ambient air concentration (i.e., air concentration below a SIL) indicates insignificant potential deposition of that pollutant, which is a consistent interpretation with SIL modeling results. Therefore, potential deposition-related impacts from particle-bound pollutants are expected to be insignificant. Therefore, no adverse effects to ecological receptors are expected from particulate metal emissions associated with the proposed project.

Organic HAPs — the potential VOM emissions of the proposed project are below the PSD significant emission rate. Because the project's VOM emissions are not significant, the potential increase in emissions of VOM and organic HAPs from the project is considered to be negligible with regard to potential effects to vegetation and soils. Therefore, the organic emissions from the project are expected to have no effect on ecological receptors. Potential deposition is expected to be small due to both the level of emissions from the proposed project and the fact that VOM generally remains in air and does not deposit locally to terrestrial or aquatic ecosystems to any measurable extent (e.g., environmental fate of benzene air emissions is that 99+ percent remain in air and that atmospheric deposition of benzene usually only results in trace concentrations in surface waters; California State Water Resources Board, 2010; ATSDR 2007). Based on the relatively small emissions level from the proposed project and the small and likely trace (non-measurable) potential deposition from VOM, no impacts to federal listed species or other ecological receptors near the project are expected.

For NOx, the potential emissions of this proposed project are above the PSD significant emission rate, but air dispersion modeling results indicate that annual air concentrations are below the SIL at the property boundary. Annual emission rates and annual modeling results are used to assess potential nitrogen deposition to compare to background and guideline deposition values. The SIL modeling results indicate the project will not have any direct effects on soil or vegetation and is not expected to increase local deposition of nitrogen. Krupa (2003) suggests that the "most vulnerable terrestrial ecosystems (heaths, bogs, cryptogams)" would be protected at total nitrogen deposition rates of 5 to 10 kilograms nitrogen per hectare[15] per year (kg N/ha/yr).

Invenergy Nelson Expansion estimated the potential nitrogen deposition to be 0.13 kg N/ (ha/yr) based on a modeled annual NOx ambient air concentration of 0.05 microgram per cubic meter ($\mu g/m^3$). Background deposition from the National Atmospheric Deposition Program (NADP) (site IL18, Shabbona, Illinois) is estimated to average 5.4 kg N/(ha/yr) (2010 to 2014 time period). Background plus project deposition = 5.56 kg N/(ha/yr), which is within the deposition thresholds of 5 to 10 kg N/(ha/yr) proposed by Krupa (2003).

[15] A hectare is an area of 107,639 square feet, slightly less than 2.5 acres.

e. Construction and Growth Analysis

Invenergy Nelson Expansion provided a discussion of the emissions impacts resulting from residential and commercial growth associated with construction of the proposed project. Anticipated emissions resulting from residential, commercial, and industrial growth associated with construction and operation of the proposed project are expected to be very low. Emissions associated with new residential construction, commercial services, and supporting secondary industrial services are not expected to be significant. This is because the project will draw from the large existing work force located within commuting distance of the plant that are already supported by the existing infrastructure. Thus, impacts would be minimal and distributed throughout the region.

f. Visibility Analysis

There are no national or state forests and no areas that can be described as scenic vistas in the immediate vicinity of the site. The nearest state park is Prophetstown State Park about 18 miles southwest of the project site.

Based upon the maximum modeled concentrations being within the immediate vicinity of the plant, and significant impacts of NO_2 being measured out to less than two kilometers from the site, the project will not have a significant effect on visibility in the Prophetstown State Park. Further, a Level 1 Screening Analysis using USEPA's VISCREEN Model for worst-case emissions demonstrated insignificant impacts on visibility at Prophetstown.

VIII. CONSULTATIONS FOR THE PROJECT

a. Federal Endangered Species Act

As required under the federal Endangered Species Act, Invenergy Nelson Expansion has initiated consultation with USEPA. As part of this consultation, USEPA reviewed the analysis of air quality impacts of the proposed project and determined that the project may affect, but is not likely to adversely affect, any federally listed species of endangered plants and animals that are present in the area. USEPA is consulting with the United States Fish and Wildlife Service on its findings. The proposed construction permit will only be issued once it is determined that there will be no adverse effects on these species.

b. Illinois Endangered Species Act

Consultation between the Illinois EPA and the Illinois Department of Natural Resources (Illinois DNR), as required under Illinois' Endangered Species Protection Act, has been completed The IDNR has indicated that no adverse impacts are expected from this proposed facility on species of plants and animals that are considered endangered under state law.

c. National and State Historic Preservation Acts

USEPA considered the potential effects of this permit action on historic properties eligible for inclusion in the National Register of Historic Places consistent with the requirements of the National Historic Preservation Act. The USEPA and the Illinois State Historic Preservation Agency found that there were no historic properties located within the Area of Potential Effects of the proposed project. The USEPA has provided a copy of its determination to the State Historic Preservation Officer for consultation and concurrence with its determination. The State Historic Preservation Officer provided concurrence on the determination that issuance of the permit will not affect historic properties eligible for inclusion in the National Register of Historic Places.

IX. DRAFT PERMIT

The Illinois EPA has prepared a draft of the construction permit that it would propose to issue for this project. The conditions of the permit set forth the emission limits and the air pollution control requirements that the proposed new units must meet. These requirements include the applicable emission standards that apply to the various units. They also include the measures that must be used and the emission limits that must be met for emissions of different regulated pollutants from the units.

Limits are set for the emissions of various pollutants from the new units. In addition to annual limits on emissions, the permit includes short-term emission limits and operational limits, as needed to provide practical enforceability of the annual emission limits. As previously noted, actual emissions of the proposed project would be less than the permitted emissions to the extent that the proposed project operates at less than capacity and control equipment normally operates to achieve emission rates that are lower than the applicable standards and limits.

The permit would also establish appropriate compliance procedures for the new units, including requirements for emission testing, required work practices, operational and emissions monitoring, recordkeeping, and reporting. For the combustion turbines, continuous fuel flow and emissions monitoring would be required for NOx, CO and O_2. Testing of emissions or performance testing would be required for emissions of other pollutants from these units. These measures are imposed to assure that the operation and emissions of the project are appropriately tracked to confirm compliance with the various limits and requirements established for individual units.

X. REQUEST FOR COMMENTS

It is the Illinois EPA's preliminary determination that the application for the proposed project meets applicable state and federal air pollution control requirements. The Illinois EPA is therefore proposing to issue a construction permit for the proposed project. Comments are requested on this proposed action by the Illinois EPA and the conditions of the draft permit.

ATTACHMENT A

Best Available Control Technology (BACT) for the Proposed Turbines

INTRODUCTION

This attachment discusses the Illinois EPA's analysis of Best Available Control Technology (BACT) and proposed determinations of BACT for emissions of nitrogen oxides (NOx), particulate (PM, PM_{10} and $PM_{2.5}$) and greenhouse gases (GHGs) from the two turbines that would be constructed in this project.

The project will consist of two simple cycle combustion turbine generators (turbines) that will serve as peaking electrical generating units. Peaking units serve a critical role for the electrical power system or grid as they serve as the "backup power supply." They operate to provide electricity when base load and intermediate load generating units cannot meet the demand for electricity, most commonly during extremely hot or cold weather when the demand for electricity is high.[16] To support such operation when it is needed, peaking units must also be operated periodically to confirm readiness and for the purpose of emission testing. Otherwise, peaking units in Illinois stand in reserve for when there is need for them to operate.[17]

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[16] In its application, Invenergy Nelson Expansion requested that each turbine be permitted to operate for 2400 hours annually. This would accommodate operation in a year in which there was a high call for peaking electricity from the proposed units. The application also indicated that it would be more typical that each turbine would operate for no more than 1,275 hours annually. Compared to the current operation of peaking units in Illinois, this is a conservative, high projection for the typical operation of the turbines at this proposed facility. For example, in 2015, the turbines at the LSP-University Park peaking plant in University Park, Illinois, averaged about 600 hours of operation; the turbines at the Elwood Energy peaking plant near Elwood, averaged about 500 hours of operation.

[17] The proposed facility would be located in the upper portion of Illinois where PJM is the regional transmission system operator that oversees the electric power system or "grid." As such, PJM manages a competitive wholesale market for electricity to assure that there is a reliable, cost-efficient supply of electricity to meet the demand in the area of the grid that it oversees. Based on the prices for electricity at which the owners of generating units are prepared to operate, this market functions both on an annual and short-term basis, hour by hour, to determine which available electrical generating units operate and the amount of electricity that each such unit should be operated to produce. When lower-price base load and intermediate load units that are available to provide power are not sufficient to meet the demand for electricity, peaking units are called upon to operate to provide the additional power that is needed. In addition, if a lower price generating unit that is operating experiences a breakdown or there is an interruption of a key power transmission line, peaking units will be called upon to quickly begin operation to make up for this loss in generation and to maintain the supply of electricity.

The function of peaking units for the grid is facilitated as peaking units are able to rapidly startup when needed. In this regard, the turbines at the proposed facility would be designed to able to typically startup and begin supplying power within 30 minutes. The turbines would only operate when called upon by PJM to provide power or, otherwise, as needed for reliability or emissions testing to support their role as peaking units. The turbines at the proposed facility would not need to operate at low loads at other times in anticipation of being called upon by PJM to actually provide power. When there is no longer a need for power from the turbines, they would be shutdown, a process that would typically take no more than 15 minutes.

Since Invenergy Nelson Expansion has proposed to develop a peaking power facility, it is not appropriate for the BACT determination for this facility to consider whether electrical power should be supplied by another type of project, e.g., a wind farm, energy conservation or an energy storage facility. Under the PSD program, the scope of the BACT determination is appropriately focused on alternative processes, raw materials and emission control techniques that would be consistent with the design or fundamental business objectives of the project that the applicant has proposed. Moreover, the proposed fuel-fired peaking units would provide a reliable backup, reserve source of electrical power for the grid. Other types of projects would not necessarily provide the same role or functionality for the grid as the proposed project.[18] Likewise, the proposed facility also would not substitute for other types of power projects that might be developed by other entities to provide or expand base load or intermediate load generation of power.

PART 1: USE OF CLEAN FUELS

Proposal

Invenergy Nelson Expansion has proposed to use natural gas as the primary fuel for the turbines. Natural gas is considered the "cleanest" commercially available fuel. That is, compared to other fuels, natural gas provides for lower emission rates for NOx, PM, PM_{10}, $PM_{2.5}$ and GHGs. As such, alternatives to use of natural gas in the turbines do not need to be evaluated as BACT.

However, it is necessary to conduct a BACT evaluation for ultra-low-sulfur diesel (ULSD), which is proposed to be used as the backup fuel for the turbines.[19] A backup fuel will enable Invenergy Nelson Expansion to supply electrical power when the supply of natural gas to the turbines is constrained. In this regard, the applicable regional transmission organization, PJM,[20] effectively requires that new peaking power facilities be developed to

[18] For example, the electrical output of a wind farm is constrained by the actual wind speed. One cannot be assured that the wind speed will be sufficient to supply additional power at times when there is a need for additional power. Moreover, as wind farms routinely operate when there is enough wind to operate, they are not available to supply additional power in extreme situations like peaking units.

The circumstances of energy conservation and energy storage projects are similar to those of wind farms. One cannot be assured that such projects will be able to free up or store enough power for times when additional power is needed. Also, once such projects are undertaken, they are routinely implemented on an ongoing basis. For example, power storage projects are operated to enable base load units to store power from "off hours" and displace the operation of intermediate load units that would have otherwise had to provide such power. They are not held in reserve to take the place of peaking units.

[19] Consistent with the USEPA's Guidance for GHG Permitting, clean fuels that reduce GHG emissions should be considered as a control technology, understanding that the BACT analysis does not need to include a clean fuel option that would fundamentally redefine or alter the nature of a proposed project. (USEPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA-457/B-11-001, March 2011, p. 27)

[20] PJM is the Regional Transmission Organization whose jurisdiction includes Northern Illinois. Regional Transmission Organizations coordinate and supervise the generation of electricity and the operation of the power transmission grid in a particular area. PJM supervises part of the Eastern Interconnection grid that serve all or parts of

be able to operate on a backup fuel.[21] This assures that these facilities will be able to provide power even when the supply of natural gas to the facilities is restricted or curtailed , thereby enhancing the reliability of the electrical grid. Invenergy Nelson Expansion plans to meet this requirement with ULSD. The emissions of NOx, PM, PM_{10}, $PM_{2.5}$ and GHGs from use of ULSD will be higher than those of natural gas. However, as a backup fuel, ULSD would only be used during periods when the supply of natural gas is constrained, e.g., unusually cold weather, and for emission and operational testing. The permit would limit the use of ULSD to use as a backup fuel.

Step 1: Identify Available Control Technologies

The available alternative to use of ultra-low-sulfur diesel (ULSD) as a backup fuel is use of a gaseous fuel, i.e., propane or liquefied petroleum gas (LPG).[22,23] While not having any backup fuel is the theoretically possible for the turbines, it would not be consistent with Invenergy Nelson Expansion’s intent for the proposed turbines to supply electrical power when other generating units are unable to meet the need for electricity. It would also be inconsistent with public policy, as reflected in PJM’s requirements, that the electrical grid is able to reliably supply electrical power.

Step 2: Eliminate Technically Infeasible Options

Gaseous fuel is not a feasible backup fuel for the turbines. A large quantity of propane or LPG would need to be stored at the plant to be available as a backup fuel. The storage of this quantity of a compressed, flammable gas at the plant would pose an unacceptable safety risk. In contrast, ultra-low-sulfur diesel may be readily stored at the plant with minimal safety risk.

Step 3: Rank the Remaining Alternative by Effectiveness

There is not a feasible alternative to ultra-low-sulfur diesel as a backup fuel for the turbines.

Step 4: Evaluate the Most Effective Controls

As there is not an alternative to use of ultra-low-sulfur diesel as the

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Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

[21] The presence of backup fuel capability is necessary to respond to PJM’s October 7, 2014 PJM Capacity Performance Updated Proposal capacity market rules, which would impose strict penalties for capacity resources that are unable to deliver when called upon, and provide no relief for gas resources whose fuel supply is unavailable due to supply interruptions. (PJM, “PJM Capacity Performance Updated Proposal”, Available at: https://pjm.com/~/media/documents/reports/20141007-pjm-capacity-performance-proposal.ashx. See pg. 11 for penalty specifications.

[22] USEPA’s *Compilation of Air Pollutant Emission Factors*, AP-42, indicates that the CO_2 emissions of propane are 148 pounds/mmBtu, compared to 167 pounds/mmBtu for ULSD.

[23] While fuel oils other than ULSD could be used as the backup fuel for the turbines, e.g., conventional distillate fuel oil, Invenergy Nelson Expansion has proposed to use ULSD as a backup fuel. ULSD would be a cleaner fuel compared to conventional fuel oils.

backup fuel for the turbines, an evaluation of alternatives is not needed.

Step 5: Select BACT

Ultra-low-sulfur diesel is proposed as BACT for the backup fuel for the turbines.

PART 2: **TYPE OF TURBINE**

When determining BACT, one must consider alternative production processes, methods, systems, and techniques as a means to reduce emissions of the subject pollutants. For this project, Invenergy Nelson Expansion is proposing to use simple-cycle combustion turbines to generate peaking electrical power. Simple-cycle combustion turbines are routinely used at peaking facilities. As a general matter, combustion turbines are compact and can provide relatively large amounts of electrical power for their size. They have a long-life, especially when used infrequently as is typically the case with peaking turbines. They are simple and reliable, with the amount of maintenance being directly related to the number of hours that they are actually operated. As such, it is both entirely understandable and reasonable that Invenergy Nelson Expansion has proposed to construct simple cycle turbines for this project.[24, 25]

Combined-cycle configurations of turbines, with heat recovery steam generators (HRSG), are not used for peaking generating units. . Combined-cycle turbines are used to meet intermediate, or in some cases, base load electrical needs. Adding HRSGs, steam turbines and the associated equipment would fundamentally change the nature of the proposed project. Combined-cycle turbines cannot startup as quickly as simple-cycle turbines. Combined-cycle turbines are installed with the goal and purpose of meeting the demand for intermediate electrical power, relying on much higher levels of annual operation, as needed to support the costs of the HRSG and other additional equipment that is part of a combined cycle turbine.

For the proposed project, Invenergy Nelson Expansion has selected so-called “frame turbines.” Frame turbines are designed for land-based use. They are heavier than “aero-derivative turbines,” which are adapted from designs of turbines that are used in jet airplanes. As such, frame turbines can be larger and have generating capacities that are much greater than available with aero-derivative turbines. Invenergy Nelson Expansion has selected two frame turbines for this project because it would meet Invenergy Nelson Expansion’s objectives for this project. It would enable 300 MW to be generated with these two turbines during hot summer weather, when the demand for electrical power is commonly

[24] The essential attribute of a peaking generating unit is to be able to startup quickly so as to quickly respond to a need for power. This capability is not present for technologies that generate electricity form steam. This is because the steam tubes in the boiler and surrounding refractory must be gradually heated to avoid thermal stresses and metal fatigues. While these phenomena are also a concern for turbines, the durations of startups for startups of turbines are measured in minutes rather than in hours.

[25] Installation of turbines in a configuration for “combined heat and power” or cogeneration is not a feasible measure to improve the energy efficiency and reduce emissions of the proposed peaking units. Cogeneration involves base load operation to match the base steam needs of the partner facility. As such, peaking plants are incompatible with cogeneration.

Moreover, the Nelson Energy Center is not located near any facilities that could serve as the partner for a cogeneration project. The siting of the Nelson Energy Center was based on development of a power plant. First, the plant needed to be located near an interstate natural gas pipeline that would be able to supply fuel for the facility. Second, the plant needed to be located near high-voltage power lines that would be able to carry power to areas where it was needed.

greatest due to use of electricity for air conditioning.[26] It would also take advantage of the existing infrastructure of the Nelson Energy Center. This plant was originally developed for four frame turbines, all as combined cycle turbines. Only construction of the two existing turbines at the plant was completed. However, much of the infrastructure for the two other turbines was completed, including foundations and electrical switch gear. As such, additional frame turbines of the same model as originally planned for the plant will be able to be readily worked into the existing operation of the plant. The new turbines will share spare parts with the existing frame turbines at the plant. The operational control for the existing turbines will also be expanded to address the new turbines.

Frame turbines are commonly used at peaking power facilities. This is because fewer units are needed to provide the same level of generating capacity. Even using the largest aero-derivative turbines currently available, four turbines would need to be installed in this project to provide the generating capacity that will available with the two proposed frame turbines.[27] As such, there are obvious economies to proposed projects from installing significantly fewer generating units. There are further economies as aero-derivative turbines are significantly more expensive than frame turbines on a per MW basis.

However, the choice of frame turbines for this project must be further examined as part of the BACT determination for this project. This is because aero-derivative turbines are generally more energy efficient than frame turbines. As such, their emissions of GHGs are generally less per MWe of electricity generated. The higher energy efficiency of aero-derivative turbines is reflected in lower exhaust temperatures, which makes them more amenable to use of selective catalytic reduction (SCR) for control of NOx emissions.[28]

Invenergy Nelson Expansion conducted a cost evaluation for use of aero-derivative turbines for this project. This evaluation shows that the cost of requiring use of aero-derivative turbines for this project would be excessive. As addressed in Appendix G Table G-1 of the application, the capital cost of four GE Model LMS100 aero-derivative turbines is estimated to be more than $180 million greater than the cost for two GE Model 7FA.03 frame turbines. Even after accounting for lower fuel costs from better efficiency, the calculated cost-effectiveness of using aero-derivative turbines with SCR to reduce NOx to 2.5 and 15 ppm for natural gas and ultra-low-sulfur diesel (ULSD), respectively,

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[26] Invenergy Nelson Expansion has indicated that the demand and supply-side analyses, which it completed, identified peaking resources specifically designed for that purpose were the most effective available resource to meet the peaking power market.

[27] The largest aero-derivative turbine (the GE LMS100) has a winter capacity of approximately 100 MW. Four such units would be needed to meet the project's design winter capacity of approximately 380 MW.

[28] The NOx emissions of aero-derivative turbines in the absence of SCR are significantly higher than those of frame turbines. For example, GE's aero-derivative turbines are designed to comply with a NOx emission limit of 15 ppm on natural gas whereas the proposed frame turbines would comply with a limit of 9 ppm. This is because frame turbines are larger, with proportionately larger burners. The larger burners provide more room for manipulation of the combustion process to reduce generation of NOx.

However, the temperature of the exhaust of aero-derivative turbines is lower than that of frame turbines. The temperature is in the range at which SCR systems high-temperature catalysts are feasible. With SCR systems, it is reasonable to assume that an aero-derivative turbine might comply with a NOx emission rate of 2.5 ppm during normal operation (nominal 85 percent control efficiency).

would range from $76,392 per ton of NOx removed (maximum annual operation) to $207,150 per ton of NOx removed (expected annual operation). These costs are clearly excessive for NOx BACT, especially as some significant costs were not quantified. First, aero-derivative turbines would not make use of existing infrastructure at the site, requiring significant construction of additional foundations and major retrofit to the switchyard to accommodate more than two units. Second, aero-derivative turbines are more expensive to maintain. Even without quantification of these specific additional costs, the analysis demonstrated that costs would be excessive for NOx BACT, adding a layer of conservatism to the analysis. Lastly, aero-derivative turbines need higher pressure natural gas than frame turbines (typically 800-900 psi compared to 450-550 psi). The minimum pressure of the gas supply at Nelson is insufficient for aero-derivative turbines. Use of aero-derivative turbines would require the installation of natural gas compressors. This would be both costly and energy-intensive.

Invenergy Nelson Expansion also conducted an evaluation for the cost of using newer GE Model 7FA.04 or 7FA.05 frame turbines for this project (Tables 7 and 8 of the application). The GE Model 7FA.04 would provide a nominal 2.5 percent improvement in thermal efficiency and the same NOx emission rates in ppm. The increase in capital cost would be $10 million per unit. The calculated cost-effectiveness for NOx would be $134,242 per ton of NOx reduced (maximum annual operation) or $520,629 per ton of NOx reduced (expected annual operation). The GE Model 7FA.05 turbines would provide a nominal 6.5 percent improvement in thermal efficiency for natural gas. They would also have a lower NOx emission rate, 5 ppm, than the GE Model 7FA.03 turbines, 9 ppm. (For ULSD, the emission rate would be the same, 42 ppm.) There would be an increase in direct capital cost of over $74.8 million. The calculated cost-effectiveness for NOx would be $90,199 per ton of NOx reduced (maximum annual operation) or $255,231 per ton of NOx reduced (expected annual operation). These cost impacts for both GE Model 7FA.04 or 7FA.05 turbines are clearly excessive.

PART 3: TURBINE BACT LIMITS FOR NOx, PM AND GHG

Subpart A: BACT for NOx for Normal Operation

Proposal

As BACT for NOx for normal operation of the turbines, Invenergy Nelson Expansion proposed use of Dry Low-NOx combustion and, when using ultra-low-sulfur diesel (ULSD), water injection, as well as turbine design, with installation of turbines that will comply with emission limits of 9 ppmvd for natural gas and 42 ppmvd for ULSD, both limits corrected to 15 percent oxygen. The BACT limits for NOx emissions from startup and shutdown cycles (SU/SD cycles)and from tuning would be separately addressed. In addition, the BACT limits for NOx emissions of the turbines during the initial shakedown or "commissioning" of the facility would also be addressed separately.

Invenergy Nelson Expansion has selected GE Model 7FA.03 turbines for the project because they best meet its business plan and project operational criteria to address electricity for peaking purposes. Business plan considerations for combustion turbine selection included combustion efficiency, size range, economics and operational capabilities.

The Illinois EPA is also proposing that BACT for NOx for normal operation of the turbines be the use of low-NOx combustion and, for ULSD, water injection and turbine design, subject to the proposed NOx limits of 9 ppmvd for natural gas and 42 ppmvd for ULSD, both corrected to 15 percent oxygen.

Step 1: Identify Available Control Technologies

For the turbines, the following control technologies for NOx are available:

1. Selective Catalytic Reduction (SCR);
2. Selective Non-Catalytic Reduction (SNCR);
3. SCONOX;
4. Dry Low-NOx combustors (without water injection);
5. Low-NOx combustors and water injection;
6. Turbine design accompanied by good operating practices.

Step 2: Eliminate Technically Infeasible Options

1. Selective Catalytic Reduction (SCR)

SCR involves injection of ammonia into the flue gas and then passing the flue gas through a catalyst to chemically reduce NOx to nitrogen and water. Under ideal conditions, SCR has removal efficiencies of over 90% when used on steady state processes. The efficiency of removal is lower for processes that are variable or entail frequent changes in the mode of operation. The key factor affecting SCR efficiency is the temperature of the flue gas. SCR generally operates in a window ranging from 500°F to 875°F, with the exact temperature range depending on the type of catalyst and the composition of the flue gas. Outside the ideal temperature range, catalyst activity is lower. Until the flue gas reaches the minimum temperature, the SCR is not operated, i.e., ammonia is not injected. If ammonia is injected above the temperature range, the ammonia will oxidize to create additional NOx. SCR is technically feasible for the turbines if dilution air was added to lower the flue gas temperature from 1200°F to less than 875°F or the temperature of the flue gas is otherwise cooled.

2. Selective Non-Catalytic Reduction (SNCR)

With selective non-catalytic reduction (SNCR), NOx is selectively removed by the injection of ammonia or urea into the flue gas in the appropriate temperature window of 1600°F to 2000°F in the absence of a catalyst. Because SNCR does not involve a catalyst, it does not present the concerns for fouling of the catalyst that may be present with SCR. It is also less effective than SCR. As such, the temperature window and residence time are critical for the desired reaction to occur. At higher temperatures, the oxidation of ammonia actually creates NOx. At lower temperatures, the reaction rate slows resulting in slip, i.e., emissions of unreacted reagent. Effective implementation of SNCR requires an injection system that can thoroughly mix reagent with the flue gas within the temperature window while accommodating variability in the temperature and flow rate of the flue gas stream due to variation in the operating load of a unit.

SNCR is commonly used on new cement kilns and coal-fired fluidized bed boilers. The uncontrolled NOx emissions of those units are high enough (typically 200 to 400 ppm) that NOx reduction with SNCR is possible. The uncontrolled emissions of combustion turbines (now less than 15 or 42 ppm) are too low for SNCR to be practical for achieving additional control. The designs of cement kilns and coal-fired fluidized bed boilers also inherently provide the appropriate conditions for SNCR technology relative to the location of the reaction temperature range and steady operation within that temperature window. These circumstances are not present for the turbines. The temperature of the turbine exhaust is a nominal 1100 to 1225 °F with virtually no residence time in the unit. In order to utilize SNCR, the configuration of the turbines would have to be changed so that additional fuel could be burned in ductwork after the turbines to heat the exhaust gas stream to the 1600 to 2000 °F temperature range of SNCR. Such changes have never been implemented for combustion turbines. Moreover, as the additional fuel that would be burned to enable use SNCR would not contribute to the generation of electricity, BACT requirements would not be met for GHG emissions. As will be discussed, BACT for GHG involves design and operation of the turbines for efficient generation of electricity.[29] Accordingly, SNCR is not considered technically feasible.

3. SCONOX

SCONOX is a post-combustion, multi-pollutant (NOx, CO and VOM) control

[29] The "add-on" NOx control technology that is pursued for combustion units whose design does not inherently provide the condition necessary for SNCR is SCR. As discussed, use of SCR would involve cooling of the exhaust streams from the proposed turbines. As such, it would not entail a direct increase in fuel consumption.

technology capable of reducing emissions by approximately 90 to 95 percent for NOx. It uses a single catalyst to remove NO and other pollutants in the turbine exhaust gas by oxidizing NOx to NO_2 and then absorbing NOx onto the catalytic surface using a potassium carbonate absorber coating. This coating reacts with the NO_2 to form potassium nitrates and nitrites which are deposited onto the catalyst surface. The temperature window for operation of the SCONOX system is 300 to 700°F. As a consequence, SCONOX systems are not feasible for the proposed turbines since the normal exhaust temperatures (1100 to 1225°F) of the turbines are above this temperature window.[30] Therefore, SCONOX is not technically feasible.

4. Dry Low-NOx combustors

Dry Low-NOx combustion reduces combustion temperatures by providing a lean pre-mixed air-fuel mixture, where air and fuel are combined before entering the combustors. This technology minimizes fuel-rich pockets and facilitates the action of excess air to act as a heat sink and moderate temperatures. This lowers the peak combustion zone temperatures reducing the formation of thermal NOx. For natural gas-firing, modern dry-low-NOx combustion or lean pre-mixed combustion is very effective in reducing NOx emissions. Because oil is burned as discrete atomized droplets, rather than in the gaseous state, this technology is not as effective for combustion of oil. Dry low-NOx combustion is an available control technology.

5. Low-NOx combustors and water injection

Low-NOx combustion and water injection also reduce NOx emissions by the design of the combustor. In addition to managing the mixing of fuel and combustion air, water or steam is injected with the fuel to provide a heat sink, which lowers the combustion zone temperature to further reduce formation of thermal NOx formation. In modern turbines, this technology is commonly used for burning of oil. For burning of natural gas, the combination of low-NOx combustion and water injection is not a feasible technology. It would cause unstable combustion and increase CO emissions.[31] Low-NOx combustors and water injection are an available technology for the turbines for ULSD but not natural gas.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The feasible control options, ranked in order of performance are:

1. SCR (2.5 ppm and 15 ppm);
2. Dry Low-NOx combustion for natural gas (9 ppm) and low-NOx

[30] Cooling of the exhaust gas would require dilution of the exhaust gas with several million pounds per hour of ambient air, which would result in cost prohibitive increases in project capital costs and maintenance, as well as a large increase in particulate matter emissions.

[31] It should be recognized that the proposed NOx emissions of the turbines when burning ultra-low-sulfur diesel with use of low-NOx combustors and water injection is much higher than the NOx emission rate for natural gas with use of only dry-low NOx technology, i.e., 42 ppm compared to 9 ppm. This difference in the NOx emission rates that are achievable based on the fuel that is burned is also reflected in the NSPS, 40 CFR 60 Subpart KKKK, which sets limits of 42 and 15 ppm for oil and natural gas, respectively.

combustors and water injection for ULSD (42 ppm).

Step 4: Evaluate the Most Effective Controls

The cost for use of SCR for the turbines would be excessive. This is due to the capital cost of Hot SCR systems, which rely upon dilution air to cool the exhaust, and the amount of NOx that would be controlled since the turbines would be in peaking service and not routinely operate.[32] The capital cost for the Hot SCR system with cooling equipment is over $8 million dollars as addressed in Table 7 of the application. The cost-effectiveness of the use of Hot SCR to reduce NOx emissions from 9 and 42 ppm for natural gas and ULSD to 2.5 and 15 ppm would range from $58,420 per ton of NOx removed (maximum unit operation) to $115,045 per ton of NOx removed (expected unit operation). This is well above the range of costs considered to be excessive for NOx BACT.

Step 5: Select BACT

Previous BACT determinations for NOx for similar frame simple cycle turbines are listed in Table A1. These determinations confirm that BACT for NOx is dry low NOx combustion for natural gas and low-NOx combustion and water injection for ULSD, with limits of 9 and 42 ppmvd, respectively.

As discussed, the Illinois EPA is proposing that BACT for NOx for each turbine be use of dry low NOx combustion for natural gas and low-NOx combustion and water injection for ULSD, to comply with limits of 9 and 42 ppmvd, respectively.

[32] The expected reduction in annual NOx emissions with SCR assuming operation at maximum permitted limits would be 186.2 tons per year, while the reduction at the expected or typical operating case would be 93.1 tons per year. For the expected case, Invenergy Nelson Expansion conservatively assumed that the proposed turbines would typically operate for at most 1,275 hours/year, about half the permitted level of operation. For peaking units, it is very reasonable that the evaluation of BACT address the expected utilization of the turbines rather than the permitted level of operation. In fact, based on experience with existing peaking plants in Illinois, the proposed turbines would typically operate for less than 1,000 hours/year.

Table A1: Previous BACT Determinations for NOx, PM and GHG for Simple Cycle Combustion Turbines							
RBLC ID	**Facility**	**Issue Date**	**Turbine Model**	**Capacity (MW)**	**Pollutant**	**BACT Limit(s)**	**Control Measure(s)***
TX-0764	Southern Power Co. Nacogdoches	10/14/15	Siemens F5 2,500 hr/yr	232 MW	NOx	9 ppmvd @ 15% O_2	DLN, GCP & Limited Operation
					PM/PM_{10}	12.1 lb/hr	PQNG & GCP
TX-0735 TX-0733 (Draft)	Antelope Elk Energy Center	5/19/15 5/12/15	GE 7FA03 4,572 hr/yr	202 MW	GHG	1304 lb CO_2/MW-hr	EE & GCP
TX-0734	Navasota South Peakers	5/8/15	GE 7FA.04 2500 hr/yr	183 MW 550 MW total	NOx	9 ppmvd @15% O_2 3-hr avg	DLN
TX-0694 TX-0757 (draft)	Indeck Wharton	2/2/15	GE 7FA03 or Siemens TBD, evaporative cooling	215-225 MW	NOx (TX-0694)	9 ppmvd @ 15% O_2, 24 hr avg	DLN
					GHG (TX-0757)	1276 lb CO_2/MWh or 1337 lb CO_2 /MWh	EE, GCP & Proper Maintenance
TX-0753 (Draft)	Guadalupe Power Partners	12/2/14	GE7FA.05 5,000 hr/yr & 300 hr/yr of startup & shutdown	227 MW	GHG, as CO_2e	1293 lb CO_2/MWh, 12 month avg	-
TX-0696	Tenaska Roan's Prairie	9/22/14	GE 7FA.04** each 2,920 hr/yr at full load	600 MW	NOx	9 ppmvd @ 15% O_2	DLN and limited operation
					$PM_{2.5}$	---	PQNG
TX-0758 TX-0695 (draft) TX-0701 (draft)	Invenergy Ector County Energy	8/1/14	GE 7FA.03 2,500 hr/yr	180 MW	GHG (TX-0758)	1393 lb CO_2/MWh (Gross); 239,649 tpy CO_2e	DLN
					NOx (TX-0695)	9 ppmvd @ 15% O_2 24 hr	DLN
FL-0310	Shady Hills	1/12/09	GE 7FA	170 MW	NOx	9 ppmvd @ 15% O_2 24 hr	DLN
					PM_{10}	10% Opacity, 6 min.	Efficient Design

* Abbreviations for control measures: DLN - Dry Low-NOx; NG - Natural Gas; PQNG - Pipeline Quality Natural Gas; GCP - Good Combustion Practices; ULSD - ultra-low-sulfur diesel; WI - Water Injection; and EE - Energy Efficiency.

** Alternatively, GE FA.05 or Siemens SGT6-5000F turbines may be installed.

Subpart B: BACT for NOx for Startup/Shutdown, Tuning and Commissioning

Introduction

The BACT limits for the NOx emissions of the turbines discussed earlier are primary BACT limits for the normal operation of the turbines. These limits, which are expressed in ppmvd at 15 percent O_2, reflect the achievable emission rates using the applicable control technology during periods of normal, steady-state turbine operation. However, these emission limits are not appropriate for other modes of operation, i.e., startup and shutdown, tuning and commissioning. In these modes of operation, the combustors in the turbines do not operate in the same way as during normal operation. When firing natural gas, NOx emissions are higher until the turbines reach a load at which the burners can transitions from diffusion flame combustion to lean pre-mixed low-NOx combustion. When firing oil, emissions are higher until water injection is at design levels. As such, the turbines cannot comply with BACT limits for NOx that have been set to address normal operation during startup and shutdown.

USEPA guidance for BACT provide that a BACT limit must be set at a level that is achievable with proper installation, operation and maintenance of the control technology that has been selected as BACT. Therefore, in order for Invenergy Nelson Expansion to propose limits that are both "achievable" and keep the turbines under a high degree of control during normal steady-state operation, BACT limits applicable to normal steady state operations must not be applied to startup and shutdown. Separate "secondary" limits for these periods have been set other power generating projects. Some examples of such permit approvals issued in the last two years for natural gas-fired power projects are Moxie Liberty (Combined Cycle) and Patriot Generating Stations (Plan Approval Nos. 08-00045A and 41-00084A) (PA-0286)and the LS Power Hickory Run (Combined Cycle) project (Plan Approval No. 37-337A) (PA-0291)in Pennsylvania and the Oregon Clean Energy Center (Combined Cycle)(PTI P0110840) (OH-0352) and Carroll County Energy project (Combined Cycle)(PTI P0113762) in Ohio.[33]

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[33] For example, the permit for the Moxie facility limits startup and shutdown emissions as part of the plant's total annual emissions as follows. The other permits for projects in Pennsylvania have similar provisions and do not set short-term NOx emission limits applicable to startups and shutdowns.

Terms and conditions of the permit for the Moxie project for emissions:

> At all times, including startup and shutdown, emissions from each combined cycle combustion turbine, Source IDs 201 and 202, shall not exceed the following on a 12-month rolling basis:
> (a) Nitrogen Oxides (NOx): 106.2 tpy
> (b) Carbon Monoxide (CO): 105.1 tpy
> (c) Volatile Organic Compounds (VOC): 38.5 tpy
> (d) Total Particulate Matter (PM): 58.0 tpy
> (e) Total Particulate Matter with an aerodynamic diameter less than 10 microns (PM_{10}): 58.0 tpy
> (f) Total Particulate Matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$): 58.0 tpy
> (g) Sulfuric Acid Mist (H_2S0_4): 12.5 tpy.

The permit for Moxie further limits total startup/shutdown hours per year as follows:

> (a) The durations of startups and shutdowns shall be minimized to the maximum extent possible.

The recent Ohio combined cycle combustion turbine permits do have startup emission limits for NOx. The Oregon Clean Energy Center and Carroll County Energy LLC also have separate limits for startup.[34]

Secondary BACT limits are justified and, in cases such as the proposed turbines, are required to ensure with a necessary degree of confidence that the "primary" BACT limits, as previously discussed in the sections, are achievable for those pollutants with continuous compliance demonstration methods. This is consistent with the above-referenced permits.

Startup and Shutdown

Startups and shutdowns of turbines are managed to minimize the time outside of the normal operating load range of the turbines (50 to 100 percent load). This is implicit in the operation of the turbines, as they do not generate significant amounts of electricity or revenue during startup and shutdown. Startups are tuned, working with the turbine manufacturer, to ensure proper operation of the combustion controls as rapidly as possible without damage to a turbine. Advancements in the design of combustion turbines and their operational control systems enable sources to continuously monitor unit operation and identify conditions that could interfere with or prolong startups. Turbines readily achieve the "normal" operating range in less than one hour. Likewise, shutdowns are accomplished as quickly as possible. Startup and shutdowns, with higher NOx emission rates, are inherent in the operation of turbines. As the normal NOx emission rates are achieved with combustion technology that is only feasible or effective when the turbines are in their normal load range, there not alternatives to higher NOx emissions during startup.

Conservative estimates of the pounds per startup and shutdown cycle[35] and the duration of startups/shutdowns, based on vendor data, have been provided in the application and were addressed in the air quality modeling analysis. The highest NOx emission rate modeled for the proposed turbines was 275 lb/cycle, which addressed both turbines starting up on ultra-low-sulfur diesel at the

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(b) Total startup and shutdown duration for each combined cycle combustion turbine shall not exceed the following:
For Mid-Range Dispatch
(i) Mid Range Cold Startups 15 hours in any consecutive 12-month period.
(ii) Mid Range Warm Startups 50 hours in any consecutive 12-month period.
(iii) Mid Range Hot Startups 155 hours in any consecutive 12-month period.
(iv) Mid Range shutdowns 220 hours in any consecutive 12-month period.
For Baseload assumes no lag between CT starts
(i) Baseload Cold Startups 5 hours in any consecutive 12-month period.
(ii) Baseload Warm Startups 25 hours in any consecutive 12-month period.
(iii) Baseload Hot Startups 50 hours in any consecutive 12-month period.
(iv) Baseload shutdowns 80 hours in any consecutive 12-month period.

(c) Each startup event shall not exceed one hour in duration.

[34] The numerical limits for startup at the Oregon Clean Energy Center and Carroll County Energy, i.e., 188 and 124.1 pounds/hour, respectively, are not relevant for the proposed turbines. This is because neither facility has GE Frame 7FA.03 turbines.

[35] Each startup of a turbine must eventually be followed by a shutdown. Accordingly, BACT for NOx emissions from startups and shutdowns of the turbines has been addressed in terms of startup/shutdown cycles, i.e., the combination of a startup and the subsequent shutdown, rather than with separate limits for startups and for shutdowns.

same time.[36] The air quality impacts during startups and shutdowns did not adversely impact continued attainment of the annual and 1-hour NO_2 NAAQS.

Consistent with the emission data in the application, BACT for NOx for startup and shutdown of the turbines is proposed to be emissions of 110 pounds for natural gas and 275 pounds for ultra-low-sulfur diesel.[37] Compliance with these limits will be determined via continuous monitoring. Operation of the turbines in a manner consistent with the good combustion practice to minimize NOx emissions would also be required during startup and shutdown, including operation in accordance with the manufacturer's written instructions or other written instructions developed by the permittee.

Combustor Tuning

Combustor tuning is performed periodically to adjust or tune the turbines for efficient operation. Tuning is performed to address drift in operational instrumentation, variations in the heat content of natural gas, and seasonal changes in ambient temperature and absolute humidity. Tuning is only performed with natural gas, i.e., the primary fuel of the turbines. The turbines will be subject to BACT limits for startups and shutdowns in addition to BACT limits for normal operation, so providing an allowance for tuning with alternative limits is necessary to assure compliance during the rest of the year.

Tuning of a turbine may take up to 8 hours to complete. During tuning, the operating rate or load of the turbine during the tuning is brought up slowly, approximately 5 MW at a time, and tuning is performed at each MW level. The turbines are held at each load level while settings are adjusted to tune a turbine. The complexity of the model-based operating control system requires tuning the turbine at each operating level, which establishes tuning set points. These set points are saved in the automated operating control system for the turbines and then relied upon for normal operation. Each turbine would need to be tuned up to two times per year. The two turbines would not be tuned simultaneously.

Tuning has traditionally been performed during startups. Startups involve bringing the turbine load up slowly and, therefore, provide an appropriate opportunity to conduct tuning. Recently, permits have started to impose more stringent emission or time limits on startups. As a consequence, sources cannot complete tuning within the limits set for startup. Recent permits have, therefore, had to include specific provisions allowing for tuning outside of startups. Because tuning were originally conducted under startup limits, these provisions have typically provided for tuning to be subject to the same emissions limits applicable for startups. These limits are also generally appropriate for tuning because tuning includes low-load operation where emissions controls are not as effective, as is the case with startups. Tuning takes longer than a startup, however, because the turbine must be kept

[36] The permits would also be set limits for the annual emissions from startups and shutdowns of the turbines. These limits would be based on information in the application for the greatest numbers and types of startups and shutdowns for different operating scenarios.

In addition, the number of startup/shutdown cycles would be limited to 360 per year (total for the two turbines).

[37] Each startup of a turbine must eventually be followed by a shutdown. Accordingly, BACT for NOx emissions from startups and shutdowns of the turbines has been addressed in terms of startup/shutdown cycles rather than with separate limits for startup and for shutdown.

at each load level for a period of time while it is tuned, instead of progressing through the standard sequence for startup.

Tuning of the turbines, with higher NOx emission rates, is inherent in the proper operation of turbines. As the normal NOx emission rates are achieved with combustion technology that is only feasible or effective when the turbines are in their normal load range, there not alternatives to higher NOx emissions during tuning. As turbines do not provide generate peaking power during tuning, there is not any benefit to Invenergy Nelson Expansion to performing tuning more frequently than needed.

Conservative estimates of the emissions associated with tuning were included in the application based on vendor data. This indicates that the NOx emissions of the turbines during tuning may be 65 percent higher than during normal operation. Consistent with this data, the proposed alternative BACT limit for NOx for tuning is 15 ppmvd at 15 percent O_2. In addition, tuning would only be allowed on one turbine at a time.

Commissioning of the Turbines

The turbines and associated generators and electrical equipment are sophisticated equipment and will have to be carefully tested, adjusted, and tuned after construction is complete. These activities are generally referred to as shakedown or "commissioning." During commissioning, each of the turbines needs to be fine-tuned at for proper performance. The combustors also need to be tuned to ensure that the turbines run efficiently and meet the guarantees for both operational and emissions performance. .

The turbines will not be able to meet the BACT limits for normal operation or startup during commissioning for a number of reasons. First, each turbine needs to be operated for a break-in period to evaluate the control system logic. In addition, the equipment needs to be tuned in order to assure proper performance. Until the equipment is tuned, it will not be able to achieve the levels of NOx emissions reflected in the BACT limits for normal operations. Because the BACT limits for NOx for normal operations will not be achievable during commissioning, alternate limits must be established for commissioning.

The electricity generated during commissioning is not purchased by PJM as peaking power so there is not any benefit to Invenergy Nelson Expansion to prolonging commissioning for any longer than needed. The commissioning process will be carried out as quickly as possible so that the turbines are available for dispatch by PJM. There are not any additional control equipment options or work practices available for commissioning. Since the normal NOx emission rates of the turbines are achieved with dry-low-NOx combustion technology that will only be fully effective when commissioning has been completed, the normal NOx emission rates will not be achievable during commissioning. Similarly, for ultra-low-sulfur diesel, the normal emission rates are based on the performance of water injection following commissioning. The operational considerations for commissioning are similar to those for tuning. Accordingly, the numerical NOx BACT limit for tuning is also proposed for operation during commissioning.

Subpart C: BACT for Particulate (PM, PM_{10} and $PM_{2.5}$)

Proposal

For the turbines as BACT for PM, PM_{10} and $PM_{2.5}$, Invenergy Nelson Expansion proposed limits of 0.005 lb/mmBtu for natural gas and 0.02 lb/mmBtu for ULSD. These limits are consistent with recent BACT determinations for simple cycle turbines, as provided in Table A1. Unlike BACT for NOx, only a single set of BACT limits is proposed for particulate to address all operation of the turbines. Secondary BACT limits are not proposed for other periods of operation.

The Illinois EPA is proposing that BACT for particulate for the turbines be turbine design, with installation of turbines that comply with a limit of 0.0051 lb/mmBtu for natural gas and 0.02 lb/mmBtu for ULSD. Use of good operating practices would also be required.

Step 1: Identify Available Control Technologies

The available control technologies for particulate for the turbines are turbine design accompanied by good operating practices. Add-on controls, such as baghouses or electrostatic precipitators (ESPs) are not available technologies for turbines due to the very low concentration of particulate present in the exhaust stream from units firing natural gas and ULSD.

Step 2: Eliminate Technically Infeasible Options

Turbine design for lower particulate emissions and good operating practices to facilitate conformance with that design is feasible for the turbines. Use of the manufacturer's operating procedures for efficient combustion reduces the potential for soot formation that would contribute to particulate emissions. For particulate, as part of the design, turbines also utilize inlet air filtration systems to minimum the potential for particulates to be drawn into the combustion zone and pass through to the stack. ULSD is filtered prior to use to ensure negligible particulate contamination during storage. These devices are part of the design of new turbines as they facilitate reliable operation and reduce maintenance and wear.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There is only one feasible control option, turbine design and good operating practices. Accordingly, a ranking is not needed.

Step 4: Evaluate the Most Effective Controls

The only feasible control option, turbine design and good operating practices, has been selected. Accordingly, no further evaluation is needed.

Step 5: Select BACT

Previous BACT determinations for particulate for similar turbines are listed in Table A1. These determinations confirm that add-on particulate control technology is not used on turbines. Particulate emissions are addressed by turbine design and good operating practices. As already indicated, the Illinois EPA is proposing that BACT for each turbine for particulate be limits for total PM of 0.0051 lb/mmBtu for natural gas and 0.02 lb/mmBtu for ULSD. Because it is expected that all or most particulate emissions will constitute $PM_{2.5}$, separate limits are not proposed for PM or PM_{10}.[38]

[38] In its *Compilation of Air Pollutant Emission Factors*, AP-42, USEPA observes that particulate from natural gas combustion generally constitutes $PM_{2.5}$. Based on the very low sulfur content of ultra-low-sulfur diesel, it is also reasonable to assume that the majority of particulate from combustion of ultra-low-sulfur diesel is also $PM_{2.5}$.

Subpart D: BACT for GHG

Introduction

The turbines emit GHGs from combustion of fuel. The principal GHG emitted is carbon dioxide (CO_2). Methane (CH_4) and nitrous oxide (N_2O) are also emitted from combustion but account for much less than 1 percent of the total GHG emissions, as CO_2e.[39] For this reason, the BACT review for GHG focuses on CO_2 but the proposed BACT limits are expressed in terms of CO_2e, to also account for CH_4 and N_2O.

Proposal

For the turbines, Invenergy Nelson Expansion proposes two GHG BACT limits on a 12-month rolling average basis, a limit 1,367 lb CO_2e per MWh gross output for natural gas fuel and a limit of, 1,934 lb CO_2e per MWh gross output for ULSD.

The Illinois EPA is proposing that BACT for GHG for each turbine be energy efficient design and operation to comply with a single GHG BACT limit on a 12-month rolling-average basis. This BACT limit would be a weighted average of the two limits proposed by Invenergy Nelson Expansion based on the amounts of electrical output from natural gas and ULSD during 12 consecutive operating months. This limit will appropriately constrain the GHG emissions of these turbines for efficient operation consistent with their function as peaking units.

Step 1: Identify Available Control Technologies

The first step in the top-down BACT process is to identify all "available" emission control technologies. Available control options are technologies or techniques, including lower-emitting processes and practices, with the potential for practical application to the emission unit and the regulated pollutant under evaluation. In its *PSD and Title V Permitting Guidance for Greenhouse Gases* (GHG Permitting Guidance),[40] pages 28 through 32, the USEPA emphasizes the existence of two basic approaches to control of emissions of CO_2: 1) Process design and operational practices for energy efficiency; and 2) Add-on control technologies or "carbon capture and storage" (CCS).[41]

The "available" emission control technology options for GHG emissions of the turbines that have been addressed for the determination of BACT are listed below (Table A2).[42]

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[39] The CO_2 emission factor for natural gas combustion is 24.0 lb/mmBtu (40 CFR 98 Table C-1). The combined CO_2e emissions from CH_4 and N_2O from natural gas combustion (based on 40 CFR 98 Table C-2 emission factors and Table A-1 global warming potentials), is 0.023 lb/mmBtu. This is approximately 0.1 percent of the total GHG emissions as CO_2e.

[40] USEPA, PSD and Title V Permitting Guidance for Greenhouse Gases, Office of Air and Radiation, March 2011, EPA-457/B-11-001 http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

[41] The combination of these two basic approaches to control of the GHG emissions of the turbines also results in a third approach to control of their GHG emissions, i.e., the combinations of the two basic approaches. However, this third approach only needs to be considered later in the BACT determination, after both basic approaches to control have been determined to be feasible.

[42] Pairing energy storage with the turbines is not an available technology to reduce GHG emissions of the turbines. This is because the proposed facility is being

<table>
<tr><th colspan="3">Table A2: Greenhouse Gas Control Technologies.</th></tr>
<tr><th colspan="2">Control Technology</th><th>Key Technical Characteristics</th></tr>
<tr><td colspan="2">Inherently Lower Polluting Design</td><td>Utilizing the properly designed turbine to address the purpose of their intended use.</td></tr>
<tr><td colspan="2">Design and Operational Energy Efficiency Measures</td><td>Energy efficiency measures include energy efficiency equipment design, minimizing heat loss, waste heat recovery and good operating and maintenance practices. These energy efficiency measures minimize GHG emissions by reducing fuel consumption.</td></tr>
<tr><td colspan="2">Clean Fuels</td><td>ULSD is proposed as a necessary back-up fuel, so alternatives to ULSD must be reviewed.[43]</td></tr>
<tr><td rowspan="2">Carbon Capture and Storage (CCS)</td><td>Carbon Capture</td><td>Carbon capture system produces a concentrated and pressurized stream of CO_2 which is then compressed for transport and/or storage.</td></tr>
<tr><td>Carbon Transport and Storage</td><td>Carbon transport and storage involves compressing and transporting captured CO_2 to a suitable disposal site for deep underground storage in geological formations.</td></tr>
</table>

Equipment Selection

The design of turbines continues to evolve, with newer models of turbines becoming available. As energy efficiency is often an important consideration in the selection of a turbine, in addition to other improvements, new models of turbines are commonly more energy efficient that older models of turbines.

Clean Fuels

Use of clean fuels, e.g., natural gas and ULSD, in the turbines is an available technique to reduce GHG emissions from the turbines, as already addressed in Part 1 of this attachment. As it is proposed for the project by Invenergy Nelson Expansion, use of clean fuels need not be discussed further here.

Carbon Capture and Storage (CCS)

To be successful, CCS technology must be capable of capturing CO_2 from the exhaust stream of an emission unit, transporting it to a storage site, and permanently storing and sequestering it. Therefore, to be considered an

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developed so that the turbines would only need to be operated when called upon by PJM or for operational and emission testing to support such operation. The turbines would not operate on low load for extended periods of time in anticipation of being called upon to provide power. As such, the proposed facility is distinguishable from the peaking turbines proposed by Arizona Public Service Company at its Ocotillo plant, as described in filings before the USEPA's Environmental Appeals Board. In those filings, the operation of those proposed turbines would include operation at low loads for extended periods of time, during which periods the efficiency of the turbines would be lower than at normal loads and GHG emissions in lb/MW-hour, would be higher. This manner of operation would be needed because that facility would be designed to compensate for the short-term variability in the amount of power that is provided to Arizona Public Service by solar power facilities in the region that it serves.

[43] Clean fuels are generally considered as a component of a BACT determination. However, since natural gas will be the primary fuel for the proposed turbines, the use of natural gas as an alternative clean fuel need not to be examined.

available CO_2 control option for BACT, each of the following must be found to be available for the proposed project:

- Technology for removing CO_2 from the exhaust stream, also referred to as a carbon capture technology
- A feasible means of transporting the quantities of CO_2 generated to the storage site
- A viable place for permanent storage of the CO_2 given its physical form after removal (i.e., gas, liquid, or solid); this is often referred to as carbon sequestration.

In its GHG Permitting Guidance, page 32, USEPA classifies CCS as an add-on pollution control technology that is available for facilities emitting CO_2 in large quantities, including fossil fuel–fired power plants, as well as for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). The proposed turbines under evaluation in this analysis emit relatively small amounts of CO_2, and the concentration of CO_2 in the exhaust is highly diluted. According to the Interagency Task Force on CCS, the exhaust from natural gas-fired turbines contains only 3 to 4 percent CO_2.[44]

Design and Operational Energy Efficiency Measures

Energy efficiency focuses on reducing the amount of energy/fuel used in the process. Reducing energy is considered a key solution to reducing GHG emissions. Energy efficiency measures can include making improvements, installing process-monitoring and process-control systems (e.g., adjusting the fuel-air mixture in the combustion zone), and/or implementing heat or steam recovery.

Cogeneration is the production of electricity and useful thermal energy simultaneously from a common fuel source, in this case, the turbines. The rejected heat from the turbines can be used to provide heat for beneficial use, such as for off-site processes, or for heating purposes elsewhere. A cogeneration system using waste heat from the turbines would be technically possible at the proposed plant.

Step 2: Eliminate Technically Infeasible Options

The technical feasibility of potential control technology options for GHG emissions from the proposed turbines is summarized below (Table A3).

Table A3: Technical Feasibility of Potential GHG Control Technologies

Technology Option	Demonstrated in Practice?	Technically Feasible?
Inherently Lower Polluting Processes	Yes	Yes
Carbon Capture and Storage	Yes	No
Clean Fuels	Yes	Yes
Design and Operational Energy Efficiency Measures	Yes	Yes

Equipment Selection

[44] USEPA, Report of the Interagency Task Force on Carbon Capture and Storage, 2010.

Invenergy Nelson Expansion is proposing to install two simple-cycle frame-type turbines. As already discussed, GE Model 7FA.03 turbines best meet Invenergy Nelson Expansion's business design and objectives for this project. Business plan considerations for turbine-generator selection included thermal efficiency, size range, economics and operational capabilities.

In support of the selected turbines, a summary of design efficiency data for GE Model 7FA.03 turbines and several comparative simple-cycle turbines, in the same size range, and their associated gross operating efficiency (LHV basis) is provided below (Table A4). The data in the table is based on standard equipment performance data at standard conditions[45] from Gas Turbine World's 2015 Performance Specification. The data does not reflect project-specific conditions. Actual output and efficiency may be significantly lower due to actual ambient pressure and temperature (altitude), type of inlet air cooling and parasitic loads.

Table A4: Summary of Simple Cycle Turbine Efficiencies – Vendor Information

Turbine	Net Output (kW)	Net Heat Rate (Btu/kWh)	Net Efficiency LHV %
Alstom			
GT11N2	115,400	10,066	33.9
GT24	230,700	8,066	40.0
Ansaldo Energia			
AE94.2	185,300	9,421	36.2
AE94.2K	170,000	9,348	36.5
Bharat Heavy Electricals			
PG9171(E)	128,700	9,952	34.3
V94.2	157,000	9,920	34.4
EthosEnergy			
TG50D5U	144,500	9,850	34.6
GE Energy Oil and Gas (Frame Units)			
MS9001E	126,100	10,094	33.8
GE Power and Heavy Duty			
7FA.03*	**172,590**	**9,230**	**37.0**
7F.04	198,000	8,840	38.6
7F.05	231,000	8,640	39.5
MAPNA Group			
MGT-70(2)	170,160	9,862	34.6
Mitsubishi Hitachi Power Systems			
H-100(100)	101,320	9,036	37.8
H-100(110)	116,200	8,792	38.8
M501DA	113,950	9,780	34.9
M501F3	185,400	9,230	37.0
Siemens Energy			
SGT6-2000E	114,000	9,949	34.3
Average Performance	**154,592**	**9,358**	**36.2**

* Gas Turbine World 2015 does not include specifications for GE Model 7FA.03 turbines, as planned for this project. Invenergy Nelson Expansion's project-

[45] "Standard conditions" for combustion turbines are 59 °F, 60 percent relative humidity, and 14.7 PSI barometric pressure, as set by the International Standards Organization. Because the performance of turbines may vary with ambient conditions and site elevation (which affects ambient pressure), performance specifications are provided for operation at standard conditions to enable accurate comparisons.

specific performance specifications are provided. As these specifications are based on actual site elevation above sea-level, they provide a conservative basis for comparison with other models of turbines.

At standard ambient conditions, the energy efficiency of the proposed GE Model 7FA.03 units is estimated at 37 percent on a LHV basis. Therefore, based on the above, the energy efficiency of the project's selected turbine is slightly higher than average performance of similar style units in its size class, 36.2 percent.

Additionally, to support equipment comparisons, Invenergy Nelson Expansion searched the USEPA's *RACT/BACT LAER Clearinghouse* (Clearinghouse) and a review of other recently issued permits was made for frame-type simple-cycle turbine projects similar to the proposed project. The following table, Table A5, provides the energy efficiency (HHV basis) of turbines having an electric output in the range of the proposed units. The calculated energy efficiencies Table A5 are based on actual plant conditions and are in terms of the higher heating value (HHV) of the fuel. Given the range of efficiencies, this data clearly does not represent design data, as are provided in the above table. It is expected that the information in this table would be more representative of actual (or worst case) operating conditions. However, Unlike Table A4, this data does not provide a basis to directly compare different models of turbines.

At worst-case, summer ambient conditions, the efficiency of the proposed GE Model 7FA.03 units has been calculated at 33 percent. Recognizing that efficiency would be better at other ambient conditions, the information in Table A5 shows that the energy efficiency of the proposed units is similar to that of other simple-cycle combustion turbine projects listed in the Clearinghouse and addressed in recent permit actions.

The turbine selection was based on the project's purpose as already discussed. While slight efficiency increases may be achieved through the selection of an alternative turbine, it does not necessitate its selection as BACT. BACT should not be used to regulate the applicant's purpose or objective for a proposed project or redefine the project. Selection of an alternative turbine would go against the project purpose of serving peaking capacity needs using existing plant infrastructure. Nevertheless, Invenergy Nelson Expansion has included a cost-effectiveness evaluation for an alternate model of turbine under Step 4 of the BACT analysis.

Table A5: Data for Efficiencies of Simple Cycle Turbines from Recent Permits and Applications					
Facility	**Turbine Type**	**Application/ Permit Date**	**Production (kW)**	**Heat Input (mmBtu/hr) HHV**	**Calculated Efficiency HHV**
Duke Energy, Suwannee River Plant	GE 7FA.03	Application April 2014	178,000	1,938	31%
Southern Power, Nacogdoches Facility	Siemens F5	Application February 2014	232,000	2,146	37%
Ector County Energy Center	GE 7FA.03	8/1/2014	165,000	1,932(4)	30%
Indeck Wharton Energy Center	GE 7FA or Siemens SGT-5000F	5/12/2014	215,000 - 225,000	2,146 - 2,354	33 - 34%
Florida Power & Light, Lauderdale Plant	GE 7FA or Siemens SGT-5000F	4/22/2014	200,000	2,224	31%
Shady Hills Station	GE 7FA.05	4/6/2014	218,000	2,135	35%
Puget Sound Energy	Varies	10/24/2013	181,000 - 207,000	1,858 - 2,124	32-33%
Montana Dakota Utilities, R.M. Heskett Station	GE 7EA DLN	3/22/2013	88,000	986	30%
Entergy Gulf States, LLC, Calcasieu Plant	Siemens 501F	12/21/2011	160,000	1,900	29%
East Texas Electric Coop, San Hardin County	GE 7EA	7/24/2008	73,000	766.5	33%
Great River Energy, Elk River Station	Siemens 5000F	7/1/2008	175,000	2,169	28%
East Texas Electric Coop, San Jacinto	GE 7EA	6/26/2008	73,000	766.5	33%
Platte River Power Authority, Rawhide Plant	GE 7FA	8/31/2007	150,000	1,400	24%
Progress Energy, Bartow Plant	SW 6-5000F	1/26/2007	195,000	1,972	34%
Jackson Electric Authority	GE PG7241 FA	12/22/2006	172,000	1,804	33%
Oleander Power Project	GE PG7241 FA	11/17/2006	190,000	1,909	34%
NRG Texas Power Generation, San Jacinto	GE Frame 7EA	4/19/2006	80,000	840	33%

Carbon Capture and Storage

The USEPA determined that CCS represents the best system of GHG emission reduction for new coal-fired electric generating units but not for natural gas–fired turbines. Reasons cited by the USEPA in support of this determination include the lower concentration and overall amount of CO_2 in natural gas–fired turbine exhaust, the lack of sufficient demonstration of CCS at natural gas–fired turbines, the risk of delaying projects due to the shorter construction period for turbines, and the relatively larger impact on water-use requirements. Imposition likely would cause the project to become uneconomical, unreliable, and untimely.

In addition, geologic CO_2 storage is still in the developmental phase and is being tested by the U.S. Department of Energy (USDOE) at a number of sites. The National Energy Technology Laboratory (NETL) Carbon Storage Program, which is part of the DOE's national laboratory system, is in the process of developing and evaluating technologies that will not be available for commercial deployment until 2020. Large-scale carbon storage projects, i.e., greater than 1 million metric tons CO_2 injected, are in the very early stages of testing and development and it is unclear at this time what the long-term outcomes will be. The NETL is currently working on, and in some instances economically supporting, a number of large scale field tests in different geologic storage formations to confirm that CO_2 capture, transportation, injection, and storage can be achieved safely, permanently, and economically for extended periods of time.

Although a number of USDOE funded large scale storage projects have taken the first steps (i.e., injection of CO_2) to demonstrate CO_2 storage technology, it has not yet been proven that these injection sites will be able to provide long-term storage of CO_2. According to NETL's February 2011 report "Carbon Sequestration Program: Technology Program Plan," implementation of large scale field demonstration projects consists of three phases (site characterization, operations, and closure) and typically take at least eight years.[46] Considering that demonstration projects like the ones listed above are only in the site characterization or operation phase, carbon storage will still not be fully tested for many years. This is consistent with the estimated timeline provided by NETL.

Carbon storage poses a number of issues that must be resolved before the technology can be safely and effectively deployed at a commercial scale. For example, according to the NETL, the following items still need to be proven and documented to validate that CCS can be conducted at a commercial scale.19

- Permanent storage must be proven viable by verifying that CO_2 will be contained in the target formations
- Technologies and protocols must be developed to quantify potential releases and ensure that the projects do not adversely affect underground sources of drinking water or cause CO_2 to be released to the atmosphere
- Long-term monitoring (including tracking of a CO_2 plume to ensure it stays within the intended containment zone) of the migration of CO_2 during and

[46] NETL, "Carbon Sequestration Program: Technology Program Plan", February 2011. Available at www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf.

after project completion must be completed to show that permanent containment has been achieved

- Methodologies to determine the presence or absence of release pathways must be developed
- An effective regulatory and legal framework must be developed for the safe, long-term injection and storage of CO_2 into geological formations; this framework must include clarity with respect to long-term liability, including stewardship responsibilities after closure, along with a permitting system and the public education and outreach needed for community support

For purposes of this analysis, storage techniques are only being considered with the purpose of long-term storage as BACT-qualifying GHG storage technologies. While enhanced oil recovery (EOR) is currently being tested and evaluated for long-term storage, existing practices are not considered to demonstrate permanent sequestration.

An alternative to geologic storage is the beneficial utilization of CO_2 in aboveground applications where the gas can be immobilized, such as cement production or mineralization. NETL is supporting the research and development of six projects to demonstrate innovative concepts for beneficial CO_2 use. However, these projects are all characterized as pilot scale, with the purpose of evaluating the technical and economic feasibility of applying the techniques commercially. Since beneficial utilization of CO_2 is in the very early stages of development, it is not considered feasible currently.

CCS is not considered to be feasible control option for this project but, for discussion purposes, CCS has been included as a potential control option in the subsequent steps of this top-down BACT analysis.

As discussed above, technology that captures CO_2 from an emission unit but does not lead to viable long-term storage will not accomplish the goal of preventing CO_2 from entering the atmosphere. Therefore, in order for carbon capture technology to be considered a technically feasible control option for consideration as BACT, carbon capture with an option for transport and storage must be examined and deemed available and technically feasible for the proposed project.

In this case, the project site is located within the Midwest Geological Sequestration Consortium region and just north of the northern edge of the Illinois Basin. According to the NETL's carbon utilization and storage atlas, the closest possible location for which there is a reasonable level of confidence that CO_2 storage is feasible is located in the Illinois Basin.[47] The Illinois Basin is believed to hold potential for CO_2 storage in oil fields, un-mineable coal and shale basins, as well as deep saline formations. The closest oil fields would be over 100 miles from the project site and the nearest existing CO_2 injection well is in Decatur, Illinois, which is approximately 140 miles from the plant. However, there are small coal or shale basins and deep saline formations within 30 miles of the plant.

Before CCS could be implemented for the turbines, significant logistical issues would have to be overcome, many of which are not within the control of

[47] NETL. "2012 United States Carbon Utilization and Storage Atlas – Fourth Edition." Available at http://www.netl.doe.gov/research/coal/carbon-storage/atlasiv. See CO_2 storage resource estimates in Appendix D.

Invenergy Nelson Expansion, such as successful permitting, right-of-way for a new supercritical CO_2 pipeline, securing of project funding (including potential government funding), identification of a suitable CO_2 storage site, and securing of a lease or title to that site. Funding for CCS is a considerable logistical hurdle because the estimated cost of CCS (a voluntary cost estimate is provided in Step 4) exceeds the cost of the proposed project. The USEPA's GHG Permitting Guidance states that:

> While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases. As noted above, to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller sources will likely be more constrained in this regard. Based on these considerations, a permitting authority may conclude that CCS is not applicable to a particular source, and consequently not technically feasible, even if the type of equipment needed to accomplish the compression, capture, and storage of GHGs are determined to be generally available from commercial vendors.
> GHG Permitting Guidance, page 36

For the reasons discussed here, and in Step 1 above, CCS is not considered to be a technically feasible control technology for the proposed project. Again, this conclusion is consistent with the USEPA's recently adopted New Source Performance Standard (NSPS) for CO_2 emissions from new power plants, where the USEPA concluded that CCS is not technically feasible for natural gas-fired turbines.[48] The USEPA's rationale shares many of the same reasons stated here, including the lack of demonstration of CCS for natural gas–fired turbines, the lower CO_2 concentration in the exhaust, and the long development timeline for carbon transport and capture.

While CCS is not a feasible technology for the project, it has nevertheless been carried through to Step 4 of the top-down analysis. A cost-effectiveness evaluation for implementing CCS technology for peaking units is included in Step 4 of this BACT analysis.

Clean Fuels
As already discussed, gaseous fuels are not a feasible alternative to use of ULSD as a back-up fuel.

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[48] USEPA, *Standards of Performance for Greenhouse Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Utility Generating Units*, 80 FR 64509 (Oct 23, 2015), See Section V.C.1.

Design and Operational Energy Efficiency Measures

The feasibility of each applicable energy efficiency measure is summarized in below (Table A6) and discussed in more detail below. An estimate of expected control efficiencies is also provided, based on the USEPA's October 2010 guidance entitled "Available and Emerging Technologies for Reducing Greenhouse Gas Emission from Industrial, Commercial, and Institutional Boilers." Only the energy efficiency measures from the all-inclusive list provided in this USEPA guidance for boilers that are transferable or applicable to simple-cycle combustion turbines are listed below and then discussed in more detail below.[49]

Table A6: Energy Efficiency Measures

Energy Efficiency Measure	Estimated CO_2 Emissions Reduction (%)[50]
Equipment Selection	2.4
Inlet Air Cooling	<1
Combustion Tuning and Optimization	3.0
Instrumentation and Controls	4.0

The turbines will be properly set up and tuned, both initially and periodically, in accordance with the manufacturers' recommendations and/or good engineering practices. Invenergy Nelson Expansion will perform maintenance such as combustion inspections, hot-gas-path inspections, and major overhauls, according to the combustion turbine manufacturer's maintenance schedule and/or good engineering practices.

Modern turbines have sophisticated instrumentation and operational controls. The operational control system will control all aspects of the turbine's operation, including the fuel feed and burner operations, to maintain efficient combustion. The operational control system monitors the operation of the turbine and adjusts the fuel flow and other operating parameters to maintain efficient operation and emissions compliance for the load at which a turbine is operating.

The turbines can also utilize evaporative cooling of the inlet air during hot ambient conditions (nominally greater than 60 ^{O}F). This will improve efficiency, as well as power output, during hot weather.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

With the elimination of CCS as a potential control technology, the use of ULSD as a backup only, along with good combustion practices and the implementation of the technically feasible design and operational energy

[49] The following measures from the USEPA's guidance for reducing GHG emissions from boilers are not considered transferable to simple-cycle turbines: Reduction of air leakage; Reduction of fouling of heat transfer surface; and Improved insulation and/insulation jackets. This because simple-cycle turbines do not have heat recovery steam generators.

[50] The efficiency benefit of these measures is difficult to quantify. They generally represent good operating or combustion practices that are routinely observed, and establishing a baseline for comparing where these measures are not used would be challenging. Therefore, the efficiency benefit estimates for the technologies provided in the table above are general guidelines from the USEPA, not site-specific estimates.

efficiency measures discussed above are the only technically feasible control options for minimizing GHG emissions. The combination of these measures is therefore the top-ranked control technology. Implementing energy efficiency measures (both design and operational) results in less fuel firing and lower GHG emissions. If CCS were technically feasible, it would be ranked above the combination of efficient design and operational practices, with the potential for reducing GHG emissions by more than 85 percent.

Even though CCS is not a technically feasible GHG control option, as already discussed, Invenergy Nelson Expansion voluntarily conducted an analysis of the costs impacts of CCS, carrying it forward to Step 4 of the BACT demonstration.

Step 4: Evaluate the Most Effective Controls

The use of ultra-low-sulfur diesel as a back-up fuel, with implementation of the technically feasible design and operational energy efficiency measures as the GHG control technology has no appreciable adverse energy, environmental, or economic impacts and is, therefore, consistent with BACT.

However, as part of Step 4, this analysis evaluates the proposed selected equipment in contrast to what would be considered a more "energy efficient" unit for economic practicability.

Equipment Selection

As already discussed, the proposed GE 7FA.03 turbines meet Invenergy Nelson Expansion's objectives for this project. Their efficiency is similar to those of other available models of turbines. As discussed in the application (Table 9), the small differences in efficiency and emissions with newer models of turbines would not be sufficient to justify requiring another model of turbine be used as BACT for this project.

Invenergy Nelson Expansion currently owns one Model GE 7FA.03 turbine. It is aware of other existing GE 7FA.03 turbines that are available on the secondary equipment market and will purchase one of these units for the second turbine. While it would be feasible to upgrade to slightly more efficient GE 7FA.04 turbines, the cost impacts would be excessive. The analysis indicates that using GE Model 7FA.04 turbines would increase the project costs by approximately 20 percent for an increase in annualized project cost of $1,805,560, for a 2.5 percent increase in energy efficiency. The cost-effectiveness for control of GHG emissions would be $237/ton avoided based on typical operation, which is excessive.[51]

The cost impact of using two new, more efficient GE 7FA.05 model turbines would also be excessive. A GE 7FA.03 turbine cannot be upgraded to a GE 7FA.05, so use of GE 7FA.05 turbines would require purchasing two new

[51] For this analysis, Invenergy Nelson Expansion conservatively assumed that the proposed turbines would typically operate for at most 1,275 hours/year, about half the permitted level of operation. For peaking units, it is very reasonable that the evaluation of BACT address the expected utilization of the turbines rather than the permitted level of operation. In fact, based on experience with existing peaking plants in Illinois, the proposed turbines would typically operate for less than 1,000 hours/year.

turbines. This would increase project costs by more than 50 percent, for an increase in annualized project cost of about $7,750,000, for an improvement in energy efficiency of only about 6.5 percent. The cost-effectiveness for control of GHG emissions would be about $400 per ton of GHG avoided based on typical operation.[52]

Carbon Capture and Storage

Even though CCS is not technically feasible for the project, CCS has been carried through to Step 4 of BACT analysis. This analysis shows that even if CCS were technically feasible, CCS would not be BACT due to its economic impacts.

Invenergy Nelson Expansion evaluated the cost impacts of CCS by estimating the capital equipment cost of a CCS system. The estimate includes the cost for an amine based CO_2 absorption technology and compression system to prepare the CO_2 for transport as a supercritical fluid, as well as the costs of constructing a pipeline to be able to transport the captured CO_2 to the nearest geological formation, 30 miles away, that might potentially serve as a storage site..

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[52] The cost-effectiveness of using GE 7FA.05 turbines for control of NOx would be about $400/ton avoided. The accompanying reduction in GHG emissions would be 19,600 tons/year (608,920 tons/year x 1,275 hours/2,550 hours x 0.065 = 19,790 tons, $7,754,474/year ÷ 19,790 tons/year = $392/ton).

Even considering that the GE Model 7FA.05 would also reduce NOx emissions of the turbines, the cost impacts of requiring GE 7FA.05 turbines would be excessive. The cost-effectiveness for control of NOx would be in excess of $160,000/ton. Assuming that a cost of $100/ton would be acceptable for reducing GHG emissions, $5,775,473/year would remain or be "available" for control of NOx ($7,775,473 – $100/ton x 19,790 tons = $5,775,473 for reduction of NOx). The accompanying reduction in NOx emissions from GE 7FA.05 turbines, considering both the reduction in NOx emissions and improved efficiency, would be 35.5 tons/year (28.5 tons + 108.3 tons x 0.065 = 35.5 tons). The cost-effectiveness of requiring GE 7FA.05 turbines as BACT for NOx would be in excess of $160,000/ton avoided ($5,775,473 ÷ 35.5 = $162,689/ton).

[52] As described in the application, the cost-effectiveness of using GE Model 7FA.04 turbines for control of GHG would be about $237/ton avoided. The accompanying reduction in GHG emissions would be 7,541 tons/year (603,310 tons/year x 1,275 hours/2,550 hours x 0.025 = 7,541 tons, $1,805,561/year ÷ 7,541 tons/year = $239/ton).

The GE Model 7FA.04 would not reduce NOx emissions of the turbines, as the 7FA.04 being a dual fuel unit, also carries a 9 ppmvd NOx emissions rating, same as the 7FA.03 model.

[52] The cost-effectiveness of using GE Model LMS100 turbines for control of GHG would be about $441/ton avoided. The accompanying reduction in GHG emissions would be 45,248 tons/year (608,920 tons/year x 1,275 hours/2,550 hours x 0.15 = 45,669 tons, $19,991,215/year ÷ 45,669 tons/year = $438/ton).

Even considering that the GE Model LMS100 turbines would also reduce NOx emissions of the turbines, the cost impacts of requiring Model LMS100 turbines would be excessive. The cost-effectiveness for control of NOx would be in excess of $154,000/ton. Assuming that a cost of $100/ton would be acceptable for reducing GHG emissions, $15,424,326/year would remain or be "available" for control of NOx ($19,991,215 – $100/ton x 45,669 tons = $15,424,326 for reduction of NOx). The accompanying reduction in NOx emissions from GE LMS100 turbines, considering both the reduction in NOx emissions and improved efficiency, would be 99.7 tons/year (93.1 tons + 43.8 tons x 0.15 = 99.7 tons). The cost-effectiveness of requiring GE LMS100 turbines as BACT for NOx would be in excess of $154,000/ton avoided ($15,424,326 ÷ 99.7 = $154,707/ton).

Capital costs for carbon capture were estimated by scaling NETL estimated incremental costs for carbon capture for a large natural gas combined-cycle power plant (Table A7).[53] The pipeline capital cost was estimated assuming a diameter of 6 inches[54] and using the cost calculation formulas provided in a March 2013 NETL paper.[55] The permit application, in includes detailed cost information (BACT Attachment A).

Table A7: Capital Costs for Carbon Capture Implementation	
CCS Component	**Approximate Capital Cost (millions)**
Post-Combustion CO_2 Capture, Compression, and Associated Equipment	\$377.2
CO_2 Pipeline	\$20.3
Total Capital Cost	\$397.5

The above table shows that the capital cost of implementing CCS control technology is just under $400 million. This is much higher than the project's projected capital costs, which are expected to be less than $150 million. This confirms CCS is not a cost-effective control option. While the project's cost estimate is preliminary and subject to change, it does not have the potential to approach the cost of CCS.

In addition to the costs described above, as a qualitative example of the overly prohibitive cost associated with CCS, the additional cost considerations and detailed studies that would be required were CCS to be considered a genuine option for control of GHG from the project.

- The operation of CCS would result in significant reductions of usable plant energy output due to the high energy consumption required for CO_2 capture and compression. The International Energy Agency (IEA) estimates that the energy consumption required for capture and compression on a natural gas-fired unit uses 15 percent of the electrical output from the power generation.[56] This is because natural gas-fired combustion turbine exhaust contains only a dilute amount of CO_2 (specifically, 3 to 4 percent).[57]

- A rigorous analysis would be required to identify appropriate sequestration locations. The above costs analysis assumes, without detailed consideration, that the closest possible location (small coal or shale basins and/or deep saline aquifer) would be a viable option for proposed project CO_2 sequestration needs. The

[53] NETL, "Updated Costs (June 2011 Basis) for Selected Bituminous Baseline Cases." August 2012. DOE/NETL-341/082312. Available at: http://www.netl.doe.gov/research/energy-analysis/search-publications/vuedetails?id=808.
[54] Massachusetts Institute of Technology. "Carbon Management GIS: CO_2 Pipeline Transport Cost Estimate." Updated June 2009. Available at http://www.canadiancleanpowercoalition.com/pdf/CTS12%20-%20Transport.pdf. See Table 1, where a 6-inch diameter pipeline can accommodate annual flows of 190,000 to 540,000 tons/year.
[55] NETL, "Carbon Dioxide Transport and Storage Costs in NETL Studies." March 2013. DOE/NETL-2013/1614. Available at http://www.netl.doe.gov/research/energy-analysis/energy-baseline-studies.
[56] International Energy Agency Cost and Performance of Carbon Dioxide Capture from Power Generation, 2011.
[57] USEPA, Report of the Interagency Task Force on Carbon Capture and Storage, 2010.

identification of a definite long term sequestration location could prove problematic due to uncertainties about the long-term storage of CO_2, its effects on safe drinking water, land ownership, and liability of deploying deep well injection technology.

- CO_2 capture equipment operates at low temperatures, and as a result, capturing CO_2 from a simple-cycle turbine's hotter exhaust would be more costly than from a combined-cycle turbine. The infrequent operation and rapid startups and shutdowns of a simple-cycle peaking facility are also incompatible with carbon capture equipment. Therefore, using cost estimates from a study of carbon capture at a generic combined-cycle power plant is very conservative.

- Additional detailed studies would be required to determine the capital costs associated to construct, design, and license the capture, compression, and delivery systems for eventual storage of CO_2 at a sequestration site.

- Cost considerations for the operation and maintenance of the CO_2 capture, compression, delivery systems, and storage would also need to be evaluated.

Currently, economic impacts are typically analyzed using the procedures found in the USEPA's *Air Pollution Control Cost Manual* - Sixth Edition (EPA 452/B-02-001). Cost effectiveness is evaluated in dollars per ton ($/ton) basis using the annual operating cost ($/yr) divided by the annual emission reduction achieved by the control device (tons/yr). The economic impact of a control technology is considered excessive if the cost on a dollar per ton basis exceeds the amount that other similar or comparable sources have incurred. However, such a comparison is problematic for CO_2e for natural gas turbines; there is no range of costs associated with BACT because CCS is not demonstrated or technically feasible. The USEPA recognized this in its GHG Permitting Guidance, page 42, stating that "it may be appropriate in some cases to assess the cost-effectiveness of a control option in a less detailed quantitative (or even a qualitative) manner," including whether the cost of CCS is "extraordinarily high and by itself would be considered cost prohibitive. Consistent with this guidance, Invenergy Nelson Expansion's quantification of the extraordinarily high capital cost of CCS relative to the cost of the overall project is sufficient to demonstrate that CCS is not cost-effective.

Step 5: Select BACT

Previous BACT determinations for GHG for similar simple-cycle turbines are also listed in Tables A1, above. There are far fewer BACT determinations for GHG than for other pollutants. The BACT limits in these determinations reflect emission factors for GHG based on fuel input to a turbine or limits on the hourly or annual rates of GHG emissions. As such, these determinations generally reflect use of turbines that are designed to comply with regulations for turbines adopted by USEPA. These regulations provide for turbine design for low emissions of NO_x and PM. These regulations also provide for proper operating practices to comply with those emission standards.

Invenergy Nelson Expansion proposes a GHG BACT limit on a 12-month rolling average based on a rate of 1,367 lb CO_2e per MWh gross output for natural gas and 1,934 lb CO_2e per MWh gross output for ULSD. The proposed BACT emission rates reflect operation at full-load during hot summer conditions. As such, they will serve to address all operation, including startup, shutdown and tuning. During these periods, the energy efficiency will be lower than during normal operation, indeed, at the beginning of startup and the end of shutdown, there will be no electrical output. Furthermore, even with proper operation and maintenance, the overall performance and heat rate will degrade over 20 years of operation, resulting in an increase in the CO_2 emission rate. When there is variability in an emission rate, it is appropriate for BACT limits to provide a compliance margin, because BACT is an emissions limit with which the source must comply over its lifetime.[58] Therefore, the proposed BACT limits should be achievable and provide a sufficient compliance margin above expected performance and operating parameters over the life of the unit.

Based on a review of the Clearinghouse and other permit searches, the most comparable units with BACT determinations made on a performance basis are shown below in Table A8.

Compliance with the BACT emission limit will be demonstrated by dividing total CO_2e emissions by the gross energy output by fuel to yield a lb/MWh gross-output emission rate on a 12-month rolling-average basis.[59]

[58] See In re Newmont Nev. Energy Inv., LLC, 12 E.A.D. 429, 442 (EAB 2005).
[59] In order to monitor compliance with the GHG BACT limit, Invenergy Nelson Expansion must comply with 40 CFR Part 98 Subparts A and D. This would include monitoring of fuel usage. It must also involve tracking the number of hours of operation during which both natural gas and ultra-low-sulfur diesel are burned. The monitoring requirement includes continuous fuel flow monitoring. This is consistent with other BACT monitoring requirements for gaseous fuels. Fuel flow multiplied by the emission factors on a heat-input basis (see 40 CFR 98, Tables C-1 and C-2) will yield a consistent quantification of GHG emissions. Invenergy Nelson Expansion will calculate CO_2e emissions (including CO_2, CH_4, and N_2O), on a 12-month rolling-sum basis, following the procedures specified in 40 CFR Part 98, Subparts A and D. This is consistent with methods described in USEPA comment letters as well as other GHG BACT terms previously issued by the USEPA. (For example, USEPA, Comments on Beaver Wood Energy Fair Haven PSD permit application, October 2011, and Comments on Intent-to-Approve for Sevier Power Project. June 2012, available respectively, at www.epa.gov/nsr/ghgdocs/20111017Beaverwood.pdf and www.epa.gov/nsr/ghgdocs/20120607sevier.pdf.)
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Table A8: Recent GHG BACT Determinations for Simple-Cycle Combustion Turbines					
Facility	**Location**	**Equipment Description**	**BACT Control Type***	**BACT Emission Limit**	**Year Issued**
York Plant Holding, LLC	Springettsbury Township, Pennsylvania	-	EE, GDCP	**Gas:** 1,330 lb CO_2e/MWh (net), 30-day rolling average, and 6,000 hours/year when firing gas **Oil:** 1,890 lb CO_2e/MWh (net), a 30-day rolling average, and 1,700 hours/year when firing oil	2012
Pio Pico Energy Center	San Diego, California	300 MW	CF, EE, GDCP, LO	**Gas:** 1,328 lb/MWh (gross) CO_2e, limited to 720 hours/year	2012
Puget Sound Energy	Mt. Vernon, Washington	181 - 207 MW (dependent on turbine choice)	EE, GDCP	**Gas:** 1,299 – 1,310 lb/MWh (net) CO_2e, 365-day rolling average (dependent on turbine choice)	2013
Tampa Electric Company, Polk Station	Mulberry, Florida	165 MW	EE, GDCP, LO	**Gas:** 1,320 CO_2e/MWh, 3-hr rolling average, when firing gas, and 900 hours/year **Oil:** 1,868 CO_2e/MWh, 3-hr rolling average, when firing oil, and 900 hours/year	2013
Florida Power & Light	Lauderdale, Florida	200 MW	EE, GDCP, LO	**Gas:** 1,396 CO_2e/MWh, 720 hour rolling basis when firing gas **Oil:** 1,956 CO_2e/MWh,720 hours rolling basis when firing oil	2014 (proposed)
Shady Hills Power Station	Spring Hill, Florida	GE 7F.05 218 MW	EE, GDCP	**Gas:** 1,377 CO_2e/MWh, 12 month rolling average, when firing gas **Oil:** 1,928 CO_2e/MWh, 12 month rolling average, when firing oil	2014
Indeck Wharton Energy Center	Wharton County, Texas	215 - 225 MW (dependent on turbine choice)	CF, EE, GDCP, LO	**Gas:** 1,276 – 1,337 lb/MWh (gross) CO_2e, 2,500 hour rolling basis (dependent on turbine choice)	2014
Antelope Elk Energy Center	Abernathy, Texas	GE 7F	CF, EE, GDCP, LO	**Gas:** 1,304 lb CO2e/MWh (gross), 4,572-hour rolling average, and 4,572 hours/year	2014
Ector County Energy Center	Goldsmith, Texas	GE 7FA.03 165 MW	CF, EE, GDCP, LO	**Gas:** 1,393 lb CO2e/MWh (gross), 2,500-hr rolling average, and 2,500 hours/year	2014
Southern Company, Nacogdoches Facility	Nacogdoches, Texas	Siemens F5 232 MW	CF, EE, GDCP, LO	**Gas:** 1,316 lb CO2e/MWh (gross), annual basis, and 2,500 hours/year	Applic. Feb. 2014

Table A8: Recent GHG BACT Determinations for Simple-Cycle Combustion Turbines					
Facility	**Location**	**Equipment Description**	**BACT Control Type***	**BACT Emission Limit**	**Year Issued**
Duke Energy Suwannee River Plant	Live Oak, Florida	GE 7FA.03 165 MW	CF, EE, GDCP, LO	**Gas**: 1,416 lb CO2e/MWh (gross), 12-month rolling average, when firing gas **Oil**: 1,982 lb CO2e/MWh (gross), 12-month rolling average, when firing oil	Applic. April 2014

***** Abbreviations for control measures: Clean Fuels – CF; GDCP - Good Design and Combustion Practices; and Limited Operation - LO.

ATTACHMENT B

Best Available Control Technology (BACT) for the Proposed Fuel Heater

INTRODUCTION

This attachment discusses the Illinois EPA's analysis of Best Available Control Technology (BACT) and proposed determinations of BACT for emissions of nitrogen oxides (NOx), particulate (PM, PM_{10} and $PM_{2.5}$) and greenhouse gases (GHGs) from fuel heater that would be constructed in the proposed project.

The fuel heater will only fire natural gas. It will heat water that is then used to heat the natural gas for the turbines. Given function of this heater, when the turbines are not operating or are using ultra-low-sulfur diesel, this heater would be idle or in standby mode. This heater is needed because the natural gas for the turbines will be supplied by an existing high pressure natural gas pipeline and its pressure must be reduced before it is fed to the turbines. The reduction in pressure will cause the temperature of the natural gas to drop below the recommended operating level for natural gas piping and the turbines. This water bath heater will be used to restore the natural gas to the proper temperature. As the fuel heater supports the operation of the proposed turbines, the selection of the supplier for and model of heater will reflect operational considerations, notably reliability and ease of startup so as to not disrupt the operation of the turbines.[60]

PART A: NOx BACT

Proposal

Invenergy Nelson Expansion is proposing that BACT for NOx for the heater be advanced low-NOx combustion technology designed to comply with an emission rate of 0.033 lb/mmBtu.[61]

Step 1: Identify Available Control Technologies

The following NOx control technologies are available for the fuel heater.

1. Selective Catalytic Reduction (SCR); and

2. Selective Non-Catalytic Reduction (SNCR).

Step 2: Eliminate Technically Infeasible Options

1. Selective Catalytic Reduction (SCR)

[60] The potential emissions of the fuel heater are based on this heater having a maximum heat input capacity of 15 mmBtu/hour.

[61] For large natural gas-fired combustion units, advanced low-NOx combustion technology usually involves a NOx emission rate of no more than 0.02 lb/mmBtu. However, because the fuel heater is relatively small and will operate intermittently, advanced low-NOx combustion technology will be less effective and a higher limit is appropriate.

SCR is not technically feasible for the heater. This is because the technical prerequisites for SCR to be effective will not be present. The heater will operates with varying duty cycles and not operate consistently at stable loads. This is necessary for SCR so that reagent is injected into the flue gas at an appropriate rate while the temperature of the flue gas and the catalyst bed is in the range for the catalytic NOx reduction reaction to occur.

2. **Selective Non-Catalytic Reduction (SNCR)**

SNCR is not technically feasible for the heater. This is because the technical prerequisites for SNCR to be effective would not be present. Most significantly, as a process heater, the heater would not include a zone in its ductwork where the flue gas would be in the temperature range for the NOx reduction reaction to take place. In addition, as is also a concern for SCR, this unit would be operated with varying duty cycles and not operate consistently at a stable load.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

There is not a feasible alternative to advanced low-NOx combustion technology.

Step 4: Evaluate the Most Effective Controls

As there is not a feasible alternative to advanced low-NOx combustion technology, a further evaluation is not needed.

Step 5: Select BACT

Previous BACT determinations for NOx for units similar to the fuel heater are listed in Table B. These determinations confirm that SCR and SNCR are not used on units like the heater. NOx emissions are typically controlled by low-NOx combustion technology and good operating practices. A wide-range of NOx emission rates are specified, from as high as 0.18 lb/mmBtu to as low as 0.033 lb/mmBtu. BACT is proposed to be set at the lowest limit, 0.033 lb/mmBtu, since Invenergy Nelson Expansion has not attempted to demonstrate that this limit will not be achievable.

Table B: Previous BACT Determinations for NOx, PM and GHGs from Natural Gas-Fired Heaters

RBLC ID/ Permit No.	Facility	Issue Date	Process Description	Capacity (mmBtu/hr)	Pollutant	BACT Limit(s)	Control Measure(s)
PA-0296 (Draft)	Berks Hollow	12/17/13	Fuel Preheater	8.5	NOx	0.035 lb/mmBtu	
					$PM/PM_{2.5}$	0.007 lb/mmBtu	
					GHG, as CO_2e	4996.3 tons/yr	
MI-410	Thetford Generating	07/25/13	NG Fuel Heaters	12 each	NOx	0.06 lb/mmBtu, GCP	
					PM/	0.007 lb/mmBtu,	
					$PM_{10}/PM_{2.5}$	0.02 lb/mmBtu	
					GHG, as CO_2e	6156.0 tons/yr, 12-mo rolling	
PA-0288	Sunbury Generation	04/1/13	Dewpoint Heater	15	NOx	0.085 lb/mmBtu	
					$PM/PM_{10}/PM_{2.5}$	0.008 lb/mmBtu	
LA-0262	Cornerstone Chemical Co.	05/03/12	Stack Heater	61	NOx	10.15 lb/hr, hourly (0.17 lb/mmBtu)	GOP
CA-1212	City of Palmdale	10/18/11	Auxiliary Heater	40	NOx	9 ppmvd @3% O_2	
					$PM/PM_{10}/PM_{2.5}$	0.3 lb/hr	
					GHG, as CO_2e	No Limit	
LA-0244	Sasol N.A. Inc.	11/29/10	NG Charge Heater	87.3	NOx	7.15 lb/hr (0.08 lb/mmBtu)	LNB
CA-1191	City of Victorville	2/11/10	Auxiliary Heater	40/35	NOx	0.033 lb/mmBtu	
					$PM/PM_{10}/PM_{2.5}$	0.2 gr/100scf	
					GHG, as CO_2e		
LA-0231	Lake Charles Cogen.	06/22/09	Methanation Startup Heater	56.9	NOx	5.58 lb/hr	Good Design, GOP
					CO	4.69 lb/hr	
					PM	0.42 lb/hr	
SC-0115	GP Clarendon LP	02/10/09	Backup Oil Heater	75	NOx	3.57 lb/hr	LNB
					CO	6 lb/hr	GMPP, Tune-ups Inspections
					VOM	0.39 lb/hr (0.0054 lb/mmBtu)	GCP
					PM_{10}	0.54 lb/hr	
FL-0303	FPL West County	7/30/08	NG Process Heaters	10	NOx	0.095 lb/mmBtu	
					$PM/PM_{10}/PM_{2.5}$	2.0 gr/100scf	
					GHG, as CO_2e		
NV-0035	Tracy Substation Expansion	8/16/05	Fuel Preheaters	4	NOx	0.014 lb/mmBtu	
					$PM/PM_{10}/PM_{2.5}$	0.02 lb/mmBtu	

PART B: BACT FOR PARTICULATE (PM, PM_{10} and $PM_{2.5}$)

Introduction

Natural gas is the cleanest commercially available fuel. Particulate emissions from heater burning natural gas are inherently very low. Emissions are appropriately addressed using the emission factor for total particulate matter (i.e., filterable and condensable particulate) from USEPA's *Compilation of Air Pollutant Emission Factors*, AP-42, and Table 1.4-2.

Proposal

Invenergy Nelson Expansion is proposing that BACT for particulate for the fuel heater be equipment design and use of good combustion practices to comply with the following emission rates for total particulate (filterable and condensable particulate): 0.0075 lb/mmBtu and 0.113 lb/hr.

Step 1: Identify Available Control Technologies

The available technologies for particulate control include the following:

1. Cyclones;

2. Wet Scrubbers;

3. Electrostatic Precipitators (ESP);

4. Fabric Filters; and

5. Design and Good Combustion Practices.

Step 2: Eliminate Technically Infeasible Options

1. **Cyclones**

Cyclones have not been demonstrated as a control technology for particulate from natural gas-fired units like the fuel heater. Cyclones are not a technically feasible control option for the heater.

2. **Wet Scrubbers**

Wet scrubber technology has not been demonstrated as a control for particulate from natural gas-fired units like the fuel heater. Wet scrubbing is not a technically feasible control option for the heater.

3. **Electrostatic Precipitators (ESP)**

Electrostatic precipitators (ESPs) have not been demonstrated as a control for particulate from natural gas-fired units like the fuel heater. As such, an ESP is not a technically feasible control option for the heater.

4. **Filters (Baghouse)**

Filters have not been demonstrated as a control for particulate from natural gas-fired units like the fuel heater. As such, filtration is not a technically feasible control option for the heater.

5. **Design and Good Combustion Practices**

Equipment design would address the burners in the fuel heater. As discussed, emission testing will not be possible for this unit to verify compliance with applicable emission limits. However, burners that are designed to meet specified emission rates can be required. Good combustion practices, which focus on combustion efficiency, will also act to reduce particulate emissions as these emissions are products of incomplete combustion. Equipment design and good combustion practices are technically feasible for the heater.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The only control technology that is technically feasible for the fuel heater is a combination of equipment design and good combustion practices. A ranking is not needed.

Step 4: Evaluate the Most Effective Controls

Because only one technology, equipment design and good combustion practices, is feasible and is selected, further evaluation is not needed

Step 5: Select BACT

Previous BACT determinations for particulate for heaters are listed in Table B, above. These determinations confirm that equipment design and good combustion practices are required as BACT for particulate for heaters. The BACT determinations for heaters in Indiana, Louisiana and South Carolina all set limits for particulate that reflect the emission factors for particulate in the USEPA's *Compilation of Air Pollutant Factors*, i.e., 0.0075 lb/mmBtu for total PM, including both filterable and condensable particulate. In these circumstances, until and unless the USEPA formally establishes lower factor(s) for particulate emissions from natural gas-fired combustion units, including units like the heater, the specified emission rates should be based on USEPA's current emission factors. The USEPA's published emission factors, notwithstanding their weaknesses, are an authoritative determination of the particulate emissions of natural gas-fired combustion units. In addition, they are emission levels with which the manufacturers of the fuel heater should be able to provide reliable performance guarantees.

Accordingly, the Illinois EPA is proposing the following as BACT for the heater for particulate equipment design and use of good combustion practices to comply with the following emission rates for total particulate: 0.0075 lb/mmBtu and 0.113 lb/hr.

PART C: BACT FOR GHG

Introduction

GHG emissions, primarily CO_2, will be generated by the combustion of natural gas in the fuel heater. For the fuel heater for GHGs, the emissions are based on emission factor for GHGs for firing of natural gas from USEPA's *Compilation of Air Pollutant Emission Factors*, Table 1.4-2.

For the fuel heater, Invenergy Nelson Expansion proposed proper design and good combustion practices as BACT for GHG. The Illinois EPA is also proposing that BACT for GHG be design and the use of good combustion practices. In addition, to quantitatively address GHG emissions as part of BACT, the Illinois EPA is proposing that the permit limit that would be set for the annual GHG emissions of the fuel heater also be part of the BACT determination. This is because the fuel heater would be a relatively small source of GHGs and emissions would be minimized by good combustion practices.

Step 1: Identify Available Control Technologies

The following GHG control technologies are available for the fuel heater:

1. Carbon Capture and Sequestration (CCS); and

2. Design and Operational Energy Efficiency Measures[62]

Step 2: Eliminate Technically Infeasible Options

The technical feasibility of potential control technology options for GHG emissions from the proposed heater are summarized below. Additional explanation follows.

Technical Feasibility of GHG Technologies for the Fuel Heater		
Technology Option	**Demonstrated in Practice?**	**Technically Feasible?**
Carbon Capture and Storage	No	No
Design and Operational Energy Efficiency Measures	No	Yes

1. Carbon Capture and Sequestration (CCS)

For the fuel heater, CCS would be used to capture CO_2 from the exhaust, purify, compress, and transport CO_2 to a location for sequestration or use for Enhanced Oil Recovery. The concentration of CO_2 in the exhaust stream from the heater will be dilute, similar to the concentration of CO_2 from natural gas-fired boilers and heaters. For dilute flue gas streams, CCS is a "significant and challenging technical issue that may not be readily suitable for CCS."[63] The intermittent nature of the operation of this heater would add another challenging, if not intractable issue, for use of CCS. CCS is not a feasible

[62] Energy efficiency measures include energy efficient equipment design, reducing heat loss, and good operating and maintenance practices. These measures reduce GHG emissions by reducing consumption of fuel.
[63] Report of the Interagency Task Force on Carbon Capture and Storage, *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010.

technology for the heater.

2. Design and Good Combustion Practices

Design and good combustion practices will act to lower GHG emissions. Energy efficiency focuses on reducing the amount of energy/fuel used in the process and is considered a key approach for reducing GHG emissions. Energy efficiency measures may include efficient design, proper operation and tuning and/or installing process-monitoring and process-control systems (e.g., management of the fuel-air mixture in the combustion zone) depending on the unit specifications and use.

Step 3: Rank the Remaining Control Technologies by Control Effectiveness

The implementation of design and operational energy efficiency measures is the only technically feasible control option for GHG emissions from this heater. The combination of these measures is therefore the top-ranked control technology. Implementing energy efficient design and operating practices results in less fuel firing and lower GHG emissions, and is consistent with a survey of recent GHG BACT limitations listed in the Clearinghouse.

Step 4: Evaluate the Most Effective Controls

The implementation of design and operational energy efficiency measures would not have appreciable adverse economic impacts. It is therefore consistent with BACT.

Step 5: Select BACT

For the heater, Invenergy Nelson Expansion has proposed good combustion practices as BACT for GHG emissions. The unit will also be designed and operated in an energy efficient manner. This determination is consistent with previous BACT determinations, as demonstrated by the list of determinations in the Clearinghouse for GHG BACT control methods for similar units listed below.

Previous BACT determinations for GHG for similar emission units are listed in Table B. They confirm that good operating practices and good combustion practices are required as BACT. The limits set as BACT restrict units to their potential emissions of GHG, most commonly in pounds per mmBtu. As discussed, given the nature of the fuel heater and its GHG emissions, it is considered appropriate as BACT to address the annual GHG emissions of the fuel heater. Accordingly, the Illinois EPA is proposing that GHG BACT for the fuel heater be:

1. Good combustion practices; and

2. GHG emissions, as CO_2e, not to exceed 1,836 tons/year after commissioning of the turbines is complete.

ATTACHMENT C

Detailed Discussion of Air Quality Analysis for NO_2, PM_{10} and $PM_{2.5}$

An ambient air quality analysis was conducted by Invenergy to assess the impact of the emissions of the proposed project, considering normal operations, tuning operations and startup/shutdown for both fuels. These analyses determined that the proposed project will not cause or contribute to a violation of any applicable air quality standard. For purposes of these analyses, the two proposed turbines are referred to as CT3 and CT4 and the two existing turbines at the plant are referred to as CT1 and CT2.

Modeling Procedure

Significance Analysis (Step 1): The starting point for determining the extent of the modeling necessary for any proposed project is evaluating whether the project would have a "significant impact." The PSD rules identify Significant Impact Levels (SIL), which represent thresholds triggering a need for more detailed modeling.[64] These thresholds are specified for all criteria pollutants except ozone and lead.

The $PM_{2.5}$ air quality analysis conducted for the project follows the USEPA Guidance Memorandum dated May 20, 2014. This memorandum addresses an action on January 22, 2013, by a federal court that vacated and remanded to the USEPA two portions of the provisions of PSD for $PM_{2.5}$, the $PM_{2.5}$ SILs and the $PM_{2.5}$ significant monitoring concentration (SMC), as established by USEPA in earlier rulemaking. This guidance provides that:

1. The adopted $PM_{2.5}$ SILs (1.2 µg/m^3, 24-hour, and 0.3 µg/m^3, annual) can be used if the differences between the $PM_{2.5}$ NAAQS (24-hour, 35 µg/m^3, and annual, 12 µg/m^3) and the most recent monitored values at a nearby representative $PM_{2.5}$ monitor, are greater than the values of SILs adopted by USEPA. As shown in Table C1, monitored ambient air concentrations are more than one SIL below the applicable NAAQS. Thus, consistent with USEPA guidance, use of the $PM_{2.5}$ SIL is permissible for the primary $PM_{2.5}$ air quality analysis for the project.

2. Since the use of the SILs is justified, a SIL analysis was conducted for the project to address whether the impacts are less than the SIL.

3. Since the 24-hour $PM_{2.5}$ impacts of the project were determined to be less than the SIL of 1.2 µg/m^3, analysis of consumption of PSD increment is not needed for the project.

[64] The significant impact levels do not correlate with health or welfare thresholds for humans, nor do they correspond to a threshold for effects on flora or fauna.

Table C1: Background Monitoring Data for Ambient Air Quality

Pollutant / Averaging Period	Monitoring Location	Units	Highest Values per Averaging Period			Average or Highest 2011-2013	Standard
			2011	2012	2013		
NO_2 1-hour (1)	Northbrook (1)	ppb	45	44	48	45.7	100
NO_2 Annual		ppb	11	12	12	11.7	53
$PM_{2.5}$ 24-hour	Adams Elementary School, Davenport, IA (2)	μg/m³	23.4	19.5	17.3	20.1	35
$PM_{2.5}$ Annual (primary)		μg/m³	11.5	9.96	9.83	10.4	12
$PM_{2.5}$ Annual (secondary)		μg/m³	11.5	9.96	9.83	10.4	15
PM_{10} 24-hour	Northbrook (3)	μg/m³	36	41	29	41.0	150

Note 1: the primary NO_2 1-hour standard was established in January 22, 2010. The 1-hour standard is based on a 3-year average of the 8th highest daily maximum concentrations in a year [a 3-year average of the 98th percentile of the annual distribution of daily maximum 1-hour average concentrations]. The Northbrook monitoring site was selected to be the most representative to the mostly rural conditions of the Nelson location.

Note 2: $PM_{2.5}$ 24-hour standard is in the form as a 98th percentile (8th high), averaged over 3 years. The Adams elementary School, Davenport , IA monitoring sites was selected to be the most representative per guidance from IEPA since the IEPA PM2.5 monitoring data did not meet the quality requirements.

Note 3: PM_{10} 24-hour standard is not to be exceeded more than once per year therefore the 2nd high value is reported. The Northbrook monitoring sites was selected to be the most representative to the mostly rural conditions of the Nelson location.

Refined (Full Impact) Analysis (Step 2): For pollutants and averaging times for which impacts are above the SIL, more detailed modeling is performed by incorporating proposed new emissions units at the plant, stationary sources in the surrounding area (from a regional inventory), and a background concentration.

Refined Culpability Analysis (Step 3): For pollutants for which the refined (full impact) modeling continues to indicate modeled exceedance(s) of a NAAQS, a culpability (cause and contribute) analysis is performed incorporating additional specific procedures consistent with USEPA guidance.

In Step 1, the air quality impacts of the project's emissions of NOx, PM_{10} and $PM_{2.5}$ were evaluated. Only the impacts of NOx on a 1-hour average were significant. Therefore, a further, more comprehensive evaluation was conducted for 1-hour impacts of this project on NO_2 air quality to identify operating scenarios that would have significant impacts.

Table C2: Results of the Significance Analysis (μg/m³)

Pollutant	Averaging Period	Maximum Predicted Impact	Significant Impact Level
NO_2	1-hour	20.6 (Table C4)	7.5*
NO_2	Annual	0.48	1
PM_{10}	24-hour	0.78	5
$PM_{2.5}$	24-hour	0.75	1.2**
$PM_{2.5}$	Annual	0.04	0.3**

* Interim Significant Impact Level

** While the SILs for $PM_{2.5}$ were vacated in early 2013, reliance on the SILs is permissible in appropriate circumstances.[65] In this case, the differences between the $PM_{2.5}$ NAAQS (24-hour, 35 μg/m^3, and annual, 12 μg/m^3) and recent design values monitored at a nearby representative $PM_{2.5}$ monitor, the Davenport, Iowa monitor (24-hr, 23.4 μg/m^3, and annual, 11.5 μg/m^3, considering the period 2011-2013) are much greater than the SILs adopted by USEPA.[66] Thus, consistent with USEPA guidance, use of the $PM_{2.5}$ SILs is permissible in this case.

Table C3 presents the results of this further analysis, which included all operating scenarios. Based on the results, certain partial load ULSD-fired scenarios required further evaluation along with the base-load scenario.

Table C3: Screening 1ST-HIGHEST MAX DAILY 1-HR NO_2 (single year analysis)

Group ID	**Maximum Concentration (μg/m^3)**
CT4 SU/SD ULSD, CT3 50% Load ULSD	32.0
CT3 & CT4 @ 50% Load ULSD	32.0
CT3 SU/SD ULSD, CT4 Base Load ULSD	27.3
CT3 & CT4 SU/SD ULSD	27.3
CT3 SU/SD ULSD, CT4 75% Load ULSD	27.3
CT3 SU/SD ULSD, CT4 50% Load ULSD	27.3
CT3 & CT4 Base Load ULSD	27.7
CT4 SU/SD ULSD, CT3 Base Load ULSD	26.5
CT4 SU/SD ULSD, CT3 75% Load ULSD	26.3
CT3 & CT4 75% Load ULSD	26.2
CT3 & CT4 50% Load Natural Gas	13.3
CT4 SU/SD NG, CT3 50% Load NG	13.3
CT3 & CT4 50% Load NG Evaporative Cooling	13.0
CT3 & CT4 75% Load Natural Gas	9.66
CT4 SU/SD NG, CT3 75% Load Natural Gas	9.62
CT3 & CT4 Base Load NG Evaporative Cooling	9.08
CT3 & CT4 75% Load NG Evaporative Cooling	8.97
CT3 & CT4 Base Load Natural Gas	9.00
CT4 SU/SD NG, CT3 Base Load Natural Gas	8.34
CT3 SU/SD NG, CT4 Base Load Natural Gas	7.54
CT3 SU/SD NG, CT4 75% Load Natural Gas	7.38
CT3 SU/SD NG, CT4 50% Load Natural Gas	7.37

CT = Combustion Turbine, SU/SD = Startup/Shutdown

As the results demonstrate the NO_2 1-hour impacts may be significant for several operating scenarios. For this reason, a SIL analysis was conducted for each of the operating scenarios listed above. This analysis indicated that the impacts were significant for the SIL. Accordingly, an additional

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[65] USEPA, Office of Air Quality Planning and Standards, *Circuit Court Decision on $PM_{2.5}$ Significant Impact Levels and Significant Monitoring Concentration: Questions and Answers*, March 4, 2013. p 3:

> The EPA does not interpret the Court's decision to preclude the use of SILs for $PM_{2.5}$ entirely but additional care should be taken by permitting authorities in how they apply those SILs so that the permitting record supports a conclusion that the source will not cause or contribute to a violation of the $PM_{2.5}$ NAAQS.

[66] Consistent with USEPA's guidance (March 4, 2013, "Draft Guidance for $PM_{2.5}$ Permit Modeling")

> …if the preconstruction monitoring data shows that the difference between the $PM_{2.5}$ NAAQS and the measured $PM_{2.5}$ background concentrations in the area is greater than the applicable vacated SIL value, then the EPA believes it would be sufficient in most cases for permitting authorities to conclude that a source with an impact below that SIL value will not cause or contribute to a violation of the NAAQS…

analysis was conducted for the 1st high, 1-hour NO_2 impact averaged over a 5 year period. The results of this analysis as performed for this pollutant and averaging period are shown in Table C4.

Table C4: NO_2 Significance Analysis (1st-Highest Max, Daily 1-Hour, 5 Year Average)	
Group ID	**Max of Concentration (µg/m³)**
CT4 SU/SD ULSD, CT3 50% Load ULSD	20.6
CT3 & CT4 @ 50% Load ULSD	20.2
CT4 SU/SD ULSD, CT3 Base Load ULSD	19.5
CT3 & CT4 Base Load ULSD	19.5
CT3 & CT4 75% Load ULSD	18.8
CT4 SU/SD ULSD, CT3 75% Load ULSD	18.8
CT3 SU/SD ULSD, CT4 75% Load ULSD	18.7
CT3 SU/SD ULSD, CT4 Base Load ULSD	18.6
CT3 & CT4 SU/SD ULSD	18.6
CT3 SU/SD ULSD, CT4 50% Load ULSD	18.4
CT4 SU/SD NG, CT3 75% Load Natural Gas	10.4
CT4 SU/SD NG, CT3 Base Load Natural Gas	10.4
CT3 SU/SD NG, CT4 Base Load Natural Gas	10.3
CT4 SU/SD NG, CT3 50% Load NG	10.2
CT3 SU/SD NG, CT4 75% Load Natural Gas	10.2
CT3 SU/SD NG, CT4 50% Load Natural Gas	9.94
CT3 & CT4 50% Load Natural Gas	8.57
CT3 & CT4 50% Load NG Evap. Cooling	8.07
CT3 & CT4 75% Load Natural Gas	6.93
CT3 & CT4 Base Load NG Evap. Cooling	6.89
CT3 & CT4 Base Load Natural Gas	6.89
CT3 & CT4 75% Load NG Evap. Cooling	6.88

CT = Combustion Turbine, SU/SD = Startup/Shutdown

To evaluate the worst case operating cases for $PM_{2.5}$, a 24-hour NAAQS screening approach was conducted. The 1st High Screening Analysis included all of the operating scenarios. Table C5 presents the results of the $PM_{2.5}$ analysis.

Table C5 -- SIL 1st-HIGHEST 24-HR $PM_{2.5}$ 5 Year Average	
Group ID	**Max. Concentration (µg/m³)**
CT3 & CT4 SU/SD ULSD	0.75
CT3 SU/SD ULSD, CT4 Base Load ULSD	0.70
CT3 SU/SD ULSD, CT4 75% Load ULSD	0.70
CT4 SU/SD ULSD, CT3 75% Load ULSD	0.69
CT4 SU/SD ULSD, CT3 50% Load ULSD	0.67
CT3 SU/SD ULSD, CT4 50% Load ULSD	0.67
CT4 SU/SD ULSD, CT3 Base Load ULSD	0.65
CT3 & CT4 75% Load ULSD	0.64
CT3 & CT4 Base Load ULSD	0.60
CT3 & CT4 @ 50% Load ULSD	0.60
CT3 & CT4 75% Load Natural Gas	0.54
CT3 & CT4 Base Load Natural Gas	0.54
CT3 & CT4 75% Load NG Evap. Cooling	0.54
CT3 & CT4 50% Load Natural Gas	0.54
CT3 & CT4 Base Load NG Evap. Cooling	0.54
CT3 & CT4 50% Load NG Evap. Cooling	0.54
CT4 SU/SD NG, CT3 75% Load Natural Gas	0.54
CT4 SU/SD NG, CT3 Base Load Natural Gas	0.53
CT3 SU/SD NG, CT4 75% Load Natural Gas	0.53
CT4 SU/SD NG, CT3 50% Load NG	0.53
CT3 SU/SD NG, CT4 Base Load Natural Gas	0.53

Table C5 -- SIL 1st-HIGHEST 24-HR $PM_{2.5}$ 5 Year Average	
Group ID	**Max. Concentration (µg/m³)**
CT3 SU/SD NG, CT4 50% Load Natural Gas	0.53

The significance screening analysis (Step 1) results demonstrate that all impacts over all averaging periods for PM_{10} are insignificant and no refined (full impact) analysis is required for this pollutant. Likewise, the annual NO_2 impact is not significant and a refined analysis is not required for annual NO_2.[67]

As the SIL Analysis results demonstrate, the impacts from the 24-hour $PM_{2.5}$ 1st highs averaged over 5 years are not significant. Table C6 shows the NAAQS analysis for the same averaging period.

Table C6: NAAQS 8th-HIGHEST 24-HR $PM_{2.5}$	
Group ID	**Max. Concentration (µg/m³)**
CT3 & CT4 SU/SD ULSD	0.38
CT3 SU/SD ULSD, CT4 75% Load ULSD	0.35
CT3 SU/SD ULSD, CT4 Base Load ULSD	0.35
CT4 SU/SD ULSD, CT3 75% Load ULSD	0.35
CT3 SU/SD ULSD, CT4 50% Load ULSD	0.34
CT4 SU/SD ULSD, CT3 Base Load ULSD	0.34
CT4 SU/SD ULSD, CT3 50% Load ULSD	0.34
CT3 & CT4 75% Load ULSD	0.32
CT3 & CT4 Base Load ULSD	0.32
CT3 & CT4 Base Load Natural Gas	0.31
CT3 & CT4 Base Load NG Evap. Cooling	0.31
CT3 & CT4 75% Load NG Evap. Cooling	0.31
CT3 SU/SD NG, CT4 75% Load Natural Gas	0.31
CT4 SU/SD NG, CT3 75% Load Natural Gas	0.31
CT3 & CT4 75% Load Natural Gas	0.31
CT4 SU/SD NG, CT3 Base Load Natural Gas	0.31
CT3 SU/SD NG, CT4 Base Load Natural Gas	0.31
CT3 SU/SD NG, CT4 50% Load Natural Gas	0.31
CT4 SU/SD NG, CT3 50% Load NG	0.31
CT3 & CT4 50% Load Natural Gas	0.31
CT3 & CT4 50% Load NG Evap. Cooling	0.31
CT3 & CT4 @ 50% Load ULSD	0.30
CT3 & CT4 SU/SD NG	0.10

The results of the Significance Analysis for all pollutants are shown below... Results are also included for SO_2 and CO, which are not subject to PSD. (Table C7)

Table C7: Results of the Significance Analysis (µg/m³)			
Pollutant	Averaging Period	Maximum Predicted Impact	Significant Impact Level

[67] The significance analysis may also be relevant to the approach to pre-application air quality monitoring. In this case, the need for $PM_{2.5}$ ambient monitoring data has been fulfilled by representative data. $PM_{2.5}$ data collected at the monitoring station in Davenport, Iowa has been deemed representative of ambient air quality at the Nelson Energy Center. Based on the proximity of the Davenport monitoring station to the project site and the representativeness of the primary topographical feature between the two sites, flat agricultural land, it is appropriate to rely upon the Davenport monitor to fulfill PSD requirements for $PM_{2.5}$ preconstruction monitoring data for the proposed project (40 CFR 52.21(m)(1)(iv)).

Table C7: Results of the Significance Analysis ($\mu g/m^3$)			
Pollutant	Averaging Period	Maximum Predicted Impact	Significant Impact Level
NO_2	1-hour	20.6	7.5*
NO_2	Annual	0.48	1
PM_{10}	24-hour	0.78	5
$PM_{2.5}$	24-hour	0.75	1.2**
$PM_{2.5}$	Annual	0.04	0.3**
SO_2	1-Hour	0.10	7.8
SO_2	3-Hour	0.16	25
CO	1-Hour	10.7	40.000
CO	8-Hour	6.8	10,000

* Interim Significant Impact Level

** As discussed, while the SIL for $PM_{2.5}$ was vacated, use of the $PM_{2.5}$ SIL is permissible in the air quality analysis for this project.

Full Impact Analysis for NO_2 (1-hour)

The refined (full impact) Step 2 analysis indicates that, during operation at maximum capacity, the proposed new emission units at the plant, stationary sources in the surrounding area (using a regional inventory), and the background concentration, would result in modeled impacts exceeding the NO_2 1-hour NAAQS.[68] For the full impact NAAQS evaluation, for peaking turbines under ULSD -fired operation and including regional inventory sources, maximum modeled 1-hour NO_2 impacts, plus the background concentration, resulted in a maximum concentration of 328 $\mu g/m^3$, compared to the NAAQS of 188 $\mu g/m^3$. The maximum modeled concentration was dominated by impacts from an existing source in the regional inventory, with the maximum modeled concentration located 8600 meters west of the plant, near the steel mill in Sterling.

However, a culpability analysis demonstrates that the project does not significantly cause or contribute to this modeled exceedance. ULSD fired maximum load and startup NO_2 1-hour scenarios (representing turbines at maximum load and under startup) for the project show impacts of 6.25 and 5.97 $\mu g/m^3$ in this location, which are below the significance threshold of 7.5 $\mu g/m^3$.

Pursuant to guidance from the Illinois EPA and consistent with USEPA Office of Air Quality Planning and Standards (OAQPS) Guidance Memorandum, “Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard,” by Tyler Fox, Air Quality Modeling Group, C439-01, dated March 1, 2011, an additional analysis was conducted using the MAXDCONT option in AERMOD (which is used to determine contributions from other nearby sources in combination with the proposed future emissions from the Invenergy Nelson Expansion project) to further demonstrate that no significant contributions from the Invenergy Nelson Expansion project would occur. This analysis continued through the ranked distribution until the cumulative impact was below the NAAQS for the 1-hour NO_2 standard. The analysis was conducted at the single maximum receptor as discussed above and ran ranked daily values over the 5-year averaging period. The 132nd ranked distribution shows the impacts meeting the hourly NAAQS of 188 $\mu g/m^3$ (including the impact of the background sources, the impacts from the project and the monitoring data).

68 USEPA has not established PSD increments for 1-hour NO_2.

As discussed above and shown in Table C8 the contributions from Invenergy Nelson Expansion along with background concentrations of NO_2 are below the NAAQS, while showing an exceedance of the NAAQS by existing source ID 195818AAI (NAAQS Max 8th High Concentration).

Table C8 Contributing Source Analysis with Peaker Natural Gas and ULSD SU/SD				
Group	Source IEPA ID Number	**NAAQS** Max 8th High Concentration (µg/m^3)	8th High Concentration w/ Background[1] (µg/m^3)	Status - Compare Standard to Predicted Impact
ALLPNORM	NA	283	369	Exceeds Standard
ALLPSUOL	NA	283	369	Exceeds Standard
H83EPA67	195818AAI	213	299	Exceeds Standard
H83EPA39	195818AAI	79.6	165	Compliant with Standard
H83EPA63	195818AAI	42.6	129	Compliant with Standard
H83EPA26	195818AAI	17.6	103	Compliant with Standard
H83EPA7	195818AAI	8.98	94.9	Compliant with Standard
H83EPA64	195818AAI	7.98	93.9	Compliant with Standard
H75EPA3	195050ABN	6.81	92.7	Compliant with Standard
H83EPA33	195818AAI	6.64	92.5	Compliant with Standard
PEAKEROL	NA	**6.25**	**92.1**	Compliant with Standard
PSU_OL	NA	**5.97**	**91.9**	Compliant with Standard
H83EPA50	195818AAI	4.68	90.6	Compliant with Standard
H80EPA1	195813AAH	3.35	89.3	Compliant with Standard
P419O20	NA	**3.14**	**89.0**	Compliant with Standard
P319O20	NA	**3.12**	**89.0**	Compliant with Standard
H85EPA1	195818AAW	3.42	89.3	Compliant with Standard
P3_OSU	NA	**2.98**	**88.9**	Compliant with Standard
P4_OSU	NA	**2.99**	**88.9**	Compliant with Standard
H82EPA14	195818AAH	2.69	88.6	Compliant with Standard
H77EPA1	195809AAO	2.51	88.4	Compliant with Standard
H34EPA1	103815AAD	2.50	88.4	Compliant with Standard
H79EPA2	195813AAG	1.44	87.3	Compliant with Standard
H72EPA1	195045ABA	1.30	87.2	Compliant with Standard
H84EPA5	195818AAU	1.07	87.0	Compliant with Standard
H76EPA1	195050ABW	0.94	86.8	Compliant with Standard
H28EPA4	103020ACN	0.88	86.8	Compliant with Standard
P3_NSU[2]	NA	**0.80**	**86.7**	Compliant with Standard
P4_NSU[2]	NA	**0.80**	**86.7**	Compliant with Standard

Notes:
1. This column conservatively includes background along with the source contributions, likely over estimating actual contributions.
2. Individual units, CT3 and CT4 NG SU/SD are at a nominal rate of 73.1 lb NOX per SU/SD cycle.

As shown in Appendix B-2 in the application – "AERMOD MAXDCONT Refined Modeling Cause or Contribute Summary Table", the project's contributions are not significant relative to the NAAQS. The Cause or Contribute Summary Table shows the ranked distribution of the cause and contribution analysis until the cumulative impact was below the NAAQS. It is important to note that other existing nearby sources are causing the potential exceedances to the NAAQS for 1-hour NO_2 Standard. The proposed project will not jeopardize local air quality.