Prevention of Significant Deterioration Air Construction Permit Application

Pleasants Energy, LLC

Pleasants Energy Facility
Project No. 84344

September 2015

Prevention of Significant Deterioration Air Construction Permit Application

prepared for

Pleasants Energy, LLC
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Waverly, West Virginia

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
AERMAP	AMS/EPA Regulatory Model's terrain pre-processor
AERMOD	AMS/EPA Regulatory Model
AMS	American Meteorological Society
AQAT	Air Quality Assessment Tool
AQRV	Air Quality Related Value
AQS	Air Quality System
BACT	Best Available Control Technology
BPIP-PRIME	Building Profile Input Program – Plume Rise Model Enhancements
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CCS	carbon capture and sequestration
CEM	continuous emission monitor
CFR	Code of Federal Regulations
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent (greenhouse gases)
CRF	capital recovery factor
CSAPR	Cross State Air Pollution Rule
CSR	Code of State Regulations (West Virginia)
DEM	digital elevation model

Abbreviation	**Term/Phrase/Name**
EGUs	electric utility generating units
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
ESPs	electrostatic precipitators
°F	degrees Fahrenheit
FLAG	Federal Land Managers' Air Quality Related Values Work Group
FLM	Federal Land Manager
GE	General Electric
GEP	Good Engineering Practice
GHG	greenhouse gas
g/cm^3	gram per cubic centimeter
GWP	global warming potentials
H_2SO_4	sulfuric acid
HAPs	hazardous air pollutants
HRSG	heat recovery steam generator
lb/hr	pounds per hour
lb/MMBtu	pound per million British thermal units
lb/MW-hr	pound per megawatt-hour
kJ/W-hr	kilojoules per watt hour
kV	kilovolt
LAER	lowest achievable emission rate
MACT	Maximum Achievable Control Technology

Abbreviation	**Term/Phrase/Name**
MMCF	million cubic feet
µg	microgram
$\mu g/m^3$	microgram per cubic meter
MMBtu/hr	million British thermal units per hour
MW	megawatt
MW-hr	megawatt-hour
N/A	not applicable
NAAQS	National Ambient Air Quality Standards
NAD	North American Datum
NAICS	North American Industry Classification System
NED	National Elevation Dataset
NESHAP	National Emission Standard for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
N_2O	nitrous oxide
NSPS	New Source Performance Standards
NSR	New Source Review
OAQPS	Office of Air Quality Planning and Standards
OEPA	Ohio Environmental Protection Agency
OLM	Ozone Limiting Method
O_2	oxygen
PANs	peroxyacetyl nitrates

Abbreviation	**Term/Phrase/Name**
PBL	Planetary Boundary Layer
Pleasants Energy	Pleasants Energy, LLC
PM	particulate matter
$PM_{2.5}$	particulate matter of 2.5 microns in diameter or smaller
PM_{10}	particulate matter of 10 microns in diameter or smaller
ppm	parts per million
ppmvd	parts per million by volume, dry basis
PRIME	Plume Rise Model Enhancements
PSD	Prevention of Significant Deterioration
PVMRM	Plume Volume Molar Ratio Method
RBLC	RACT/BACT/LAER Clearinghouse
ROI	radius of impact
SCR	selective catalytic reduction
SIC	Source Industrial Classification
SIL	Significant Impact Level
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SO_3	sulfur trioxide
SO_4	primary sulfate
TDS	total dissolved solids
tpy	tons per year

Abbreviation	**Term/Phrase/Name**
$\mu g/m^3$	micrograms per cubic meter
USGS	U.S. Geological Survey
UTM	Universal Transverse Mercator
VOC	volatile organic compounds
WVDEP	West Virginia Department of Environmental Protection

1.0 EXECUTIVE SUMMARY

Pursuant to the requirements specified in the West Virginia Code of State Regulations (CSR), Title 45, Series 14 Air Quality provisions, Pleasants Energy, LLC (Pleasants Energy) is submitting this Prevention of Significant Deterioration (PSD) air construction permit application for the proposed modification of the Pleasants Energy facility. Pleasants Energy, located near Waverly, West Virginia within Pleasants County, installed two simple-cycle General Electric (GE) 7FA combustion turbines at the Pleasants Energy facility in 2001, under permit number R13-2373, with an administrative amendment in 2006 (R13-2373A). The permit had operational restrictions to limit the facility's potential to emit to less than 250 tons per year (tpy) of any criteria pollutant so the facility could be minor for PSD. This air construction permit application proposes to increase the operating time of the combustion turbines (hereafter referred to as Project). Since the Project will lift the synthetic minor limitation on the combustion turbines and will increase emissions to over 250 tpy, this Project will be subject to PSD.

As required pursuant to the above-referenced rules, this permit application contains the following analyses/assessments regarding emissions of regulated pollutants associated with the construction and operation of the Project:

- Evaluation of ambient air quality in the area for each regulated pollutant for which the combustion turbine Project will result in a significant net emissions increase
- Demonstration that emissions increases will not cause or contribute to an increase in ambient concentrations of pollutants exceeding the remaining available PSD increment and the National Ambient Air Quality Standards (NAAQS)
- Assessment of any adverse impacts on soils, vegetation, visibility, and growth in the area
- A Best Available Control Technology (BACT) analysis for each regulated pollutant for which the combustion turbine Project will result in a significant net emissions increase

Potential emissions from the Project are given in Table 1-1 which includes start-up and shut-down emissions for the combustion turbines. A full description of equipment associated with the Project is provided in Part 3 of the application.

Table 1-1: Project Maximum Potential Emissions and PSD Significance Levels

Pollutant	Preliminary Maximum Potential Emissions (tpy)[a,b]	PSD Significance Levels (tpy)[b]
NO_x	**464.6**	40
CO	**509.5**	100
$PM/PM_{10}^c/PM_{2.5}^c$	**118.7**	25/15/10
SO_2	39.0	40
VOC	23.8	40
H_2SO_4 Mist	6.0	7
Lead	0.008	0.6
CO_2e	**1,231,633**	75,000

(a) Numbers in bold indicate the PSD significance level is exceeded
(b) tpy = tons per year
(c) Filterable plus condensable

1.2 HAP Emissions

Hazardous air pollutant (HAP) emissions from the Project were calculated in order to determine the total HAP emissions for National Emission Standards for Hazardous Air Pollutants (NESHAP) applicability. The Project will be an area source of HAPs and the entire Pleasants Energy facility will remain an area source of HAPs with the addition of this Project.

1.3 Air Quality Analysis

The existing air quality in the Pleasants County area is designated as attainment or unclassifiable with regard to the NAAQS for all criteria pollutants. An air dispersion modeling analysis was performed for the pollutants subject to PSD to assess potential ambient air quality impacts associated with the Project. The modeling was performed in accordance with approved West Virginia Department of Environmental Protection (WVDEP) and U.S. Environmental Protection Agency (EPA) modeling guidance. The air dispersion modeling protocol for the Project was submitted to the WVDEP in April 2015, with an update submitted in July 2015. In addition, a modeling protocol for the use of the Ozone Limiting Method (OLM) was provided to the WVDEP and the EPA through the WVDEP in March 2015 and was updated in July 2015.

1.4 BACT

A “top-down” BACT analysis was performed for each of the pollutants in Table 1-1 that were above the PSD significance levels: carbon monoxide (CO), nitrous oxides (NO_x), particulate matter (PM)/ particulate matter of 10 microns in diameter or smaller (PM_{10})/ particulate matter of 2.5 microns in diameter or smaller ($PM_{2.5}$), and greenhouse gases (CO_2e).

BACT has been selected to minimize emissions from the Project. Emissions of NO_x from the combustion turbines will be controlled by low NO_x burners. Use of clean fuels and good combustion practices will control emissions of $PM/PM_{10}/PM_{2.5}$ and CO. Emissions of CO_2e will be controlled by the use of natural gas as a primary fuel and efficient turbine design.

Table 1-2 displays the BACT results for the simple-cycle combustion turbines.

Table 1-2: Summary of BACT Results – Simple-Cycle Combustion Turbines

Pollutant	Control	BACT Emissions[a,b,c,d]	Average
NO_x	Low NO_x burners (natural gas)	9 ppm (natural gas)	30-day rolling
	Water injection (fuel oil)	42 ppm (fuel oil)	
CO	Good combustion practices	9 ppm (natural gas) 20 ppm (fuel oil)	30-day rolling
$PM/PM_{10}/PM_{2.5}$	Combustion controls, inlet air filtration, and low ash fuels (natural gas and low sulfur fuel oil)	20.2 lb/hr (natural gas) 39 lb/hr (fuel oil)	3-run stack test
Greenhouse gases	Use of natural gas as a primary fuel and efficient turbine design	1,570 lb CO_2/MW-hr, gross 615,816 tpy CO_2e	Annual

(a) ppm = parts per million; lb/hr = pounds per hour; lb/MW-hr = pound per megawatt hour; tpy = tons per year
(b) BACT emission rates only presented in this table. Maximum lb/hr and tpy are presented in Appendix C for all emission units.
(c) Concentration at 15 percent oxygen while operating at 60 percent load and greater including with TurboPhase under steady state conditions, unless otherwise noted
(d) Emission rate at loads of 60 percent and higher

1.5 Additional Impacts Analysis

The potential impacts of the Project on visibility, soils, vegetation, and growth are discussed in Part 8 of this application. As indicated by the analysis, the addition of the Project will not have a significant impact on visibility, soils, growth, or vegetation in the surrounding area.

2.0 INTRODUCTION

Pursuant to the requirements specified in the West Virginia Code of State Rules, Title 45 Series 14, Pleasants Energy located near Waverly, West Virginia, within Pleasants County is submitting this PSD construction permit application for the proposed modification of the Pleasants Energy simple-cycle combustion turbine plant. Pleasants Energy installed two simple-cycle GE 7FA combustion turbines at the Pleasants Energy facility in 2001 and operates under Title V permit number R30-07300022-2014. The permit had operational restrictions to limit the facility's potential to emit to less than 250 tpy of any criteria pollutant so the facility could be minor for PSD. This Project will increase the hours of operation of the combustion turbines. Since the Project will lift the synthetic minor limitation on the combustion turbines and will increase emissions to over 250 tpy, this Project will be subject to PSD.

Table 2-1 shows potential air emissions associated with the Project including start-up and shut-down emissions for the turbines. The maximum emissions from any operating load and including start-up and shut-down emissions for the combustion turbines were used to demonstrate the maximum potential emissions for each pollutant.

Table 2-1: Project Potential Emissions and PSD Significance Levels

Pollutant	Preliminary Maximum Potential Emissions (tpy)[a,b]	PSD Significance Levels (tpy)[b]
NO_x	**464.6**	40
CO	**509.5**	100
PM/ PM_{10}[c]/ $PM_{2.5}$[c]	**118.7**	25/15/10
SO_2	39.0	40
VOC	23.8	40
H_2SO_4 Mist	6.0	7
Lead	0.008	0.6
CO_2e	**1,231,633**	75,000

(a) Numbers in bold indicate the PSD significance level is exceeded
(b) tpy = tons per year
(c) Filterable plus condensable

As can be seen from Table 2-1, the Project will result in significant emission increases of CO, NO_x, PM/ PM_{10}/$PM_{2.5}$, and CO_2e. These pollutants will be subject to PSD review.

The overall HAP emissions from the Project and the entire Pleasants Energy facility show that the facility will continue to be an area source of HAPs.

This construction permit application is divided into the following sections:

- Part 1 – Executive Summary
- Part 2 – Introduction
- Part 3 – Project Description
- Part 4 – Emissions Estimates (This section provides estimates of emissions associated with the combustion turbine Project.)
- Part 5 – Regulatory Review (This section identifies applicable state and federal air quality regulations.)
- Part 6 – BACT Analysis
- Part 7 – Air Dispersion Modeling (This section provides model descriptions and data requirements for the air quality impact assessment as well as interpretation, analysis, and comparison of the modeling results with applicable air quality regulations.)
- Part 8 – Additional Impact Analysis (This section addresses other potential air quality-related impacts (i.e., growth, soil, vegetation, and visibility).

Construction permit application forms and attachments required by the WVDEP are included in Appendix A of this application.

3.0 PROJECT DESCRIPTION

Pleasants Energy plans to increase the hours of operation of its two simple-cycle GE 7FA combustion turbines at the Pleasants Energy facility located near Waverly, West Virginia. They currently operate under Title V permit number R30-07300022-2014. The facility is located in Pleasants County, which is currently designated as an attainment/unclassified area for all criteria pollutants in 40 Code of Federal Regulations (CFR) Part 81. The location of the Project is shown in Figure B-1 (Appendix B). A plot plan of the Project with the emission point locations is shown in Figures B-2 and B-3 (Appendix B).

3.2 Turbine and Emission Controls

The combustion turbines operate in simple-cycle mode only to generate electricity. The combustion turbines will be permitted with restricted operation. The turbines will have a combined NO_x limit of 464.6 tpy, with compliance shown via continuous emission monitors (CEMs). Additionally, the combustion turbines will be limited to 39.0 tpy of SO_2 emissions on an annual basis. For all other pollutants, the turbines will have an overall fuel usage limit for both combustion turbines combined of 19,084,721,569 standard cubic feet per year (SCF) per year which includes both fuel oil and natural gas. Fuel oil, when combusted will be equal to 889 MMCF per gallon of fuel oil. This fuel limit methodology is consistent with their current minor source permit limitation.

To control emissions of NO_x, each of the combustion turbines will be equipped with low NO_x burners. To minimize the emissions of sulfur dioxide (SO_2), sulfuric acid (H_2SO_4) mist, and $PM/PM_{10}/PM_{2.5}$, the combustion turbines will be controlled through the use of low sulfur fuels and good combustion practices.

4.0 EMISSIONS ESTIMATES

Emission of air contaminants will result from the combustion of natural gas and fuel oil (as a backup fuel) in the proposed simple-cycle combustion turbines.

4.1 Emission Sources

A process flow diagram for the combustion turbines are shown in Figure B-4 (Appendix B). The operating conditions of the combustion turbines are discussed in detail in the sections below, along with the procedures for estimating emissions. Tables showing the emission calculations are included in Appendix C.

4.1.1 Combustion Turbine Emissions Calculation Method

Emissions from the F-Class combustion turbines are dependent on the ambient temperature conditions and the turbine's operating load, which can vary from 60 percent to 100 percent and 100 percent load with TurboPhase operation. To account for representative seasonal climatic variations, potential emissions from the proposed combustion turbines were analyzed at 60 and 100 percent load conditions as well as 100 percent load with TurboPhase for ambient temperatures ranging from negative (-)10 degrees Fahrenheit (°F) to 100 °F. Projected emissions were based on data provided by GE for the 7FA combustion turbine and information from the TurboPhase vendor, as well as AP-42 emission factors. Detailed calculations of the combustion turbine's emissions are provided in Appendix C.

The following conservative assumptions were used to determine potential emissions from the Project:

- A fuel limit of 19,081,721,568.63 standard cubic feet (SCF) of natural gas and fuel per year
- A fuel oil factor of 889 scf/gal of fuel oil combusted
- A NOx annual emissions limit from both combustion turbines combined of 464.6 tons per year
- A SO_2 annual emissions limit from both combustion turbines combined of 39 tons per year.

Natural Gas Operation:

- Start-up and shut-down emissions on natural gas were based on the start-up profile (assumes 120-minutes per start-up and 60 minutes per shut-down) and 365 start-up/shutdown events[1] with up to 20 start-up/shutdown events on fuel oil

[1] One start-up/shut-down event is equal to one start-up plus one shut-down. All start-ups were conservatively assumed to be cold start-ups.

- NO_x emissions were based on the BACT emissions rate 9 parts per million (ppm) and 65 pounds per hour (lb/hr) per turbine without TurboPhase and 75 lb/hr per turbine with TurboPhase for loads of 60 percent and higher with low NO_x burners
- CO emissions were based on the BACT emission rate of 9 ppm and 32 lb/hr without TurboPhase and 36 lb/hr with TurboPhase for loads of 60 percent and greater
- $PM/PM_{10}/PM_{2.5}$ emissions were based on an estimated maximum emission rate of 18 lb/hr without TurboPhase and 20.2 lb/hr with TurboPhase
- SO_2 emissions were based on sulfur content of the natural gas and an estimated maximum emission rate of 2.5 lb/hr without TurboPhase and 2.8 lb/hr with TurboPhase
- Volatile organic carbon (VOC) emissions were based on vendor emission rate of 3.0 lb/hr for without TurboPhase and 3.4 lb/hr with TurboPhase operation for loads of 60 percent and higher
- H_2SO_4 mist emissions were based on mass balance of 10 percent of SO_2 being converted to sulfur trioxide (SO_3) and 100 percent of SO_3 being converted to H_2SO_4 resulting in 0.38 and 0.44 lb/hr for without and with TurboPhase operation
- CO_2e emissions were based on AP-42 emission factors for carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O), and ratioed with their appropriate global warming potentials (GWP) and summed to obtain CO_2e
- Increased lb/hr emissions from TurboPhase were included for 3,250 hours per year per turbine

Fuel Oil Operation:

- NO_x emissions were based on the BACT emissions rate 42 ppm and 470 lb/hr per turbine for loads of 60 percent and higher with low NOx burners
- CO emissions were based on the BACT emission rate of 20 ppm and 72 lb/hr for loads of 60 percent and greater
- $PM/PM_{10}/PM_{2.5}$ emissions were based on an estimated maximum emission rate of 39 lb/hr based on vendor data
- SO_2 emissions were based on sulfur content of the natural gas and an estimated maximum emission rate of 103 lb/hr
- VOC emissions were based on vendor emission rate of 8 lb/hr for loads of 80 percent and higher
- H_2SO_4 mist emissions were based on mass balance of 10 percent of SO_2 being converted to SO_3 and 100 percent of SO_3 being converted to H_2SO_4 resulting in 15.8 lb/hr
- CO_2e emissions were based on AP-42 emission factors for CO_2, CH_4 and N_2O, and ratioed with their appropriate GWP and summed to obtain CO_2e for distillate fuel oil operation

- Start-up and shut-down emissions on fuel oil were based on the start-up profile (assumes 120-minutes per start-up and 60 minutes per shut-down) and 20 start-up/shut-down events on fuel oil[2] per turbine

Based on the above assumptions, Table 4-1 displays the maximum expected hourly emission rates for each combustion turbine stack during natural gas and fuel oil operation. Table 4-2 displays the maximum expected hourly emission rates for each combustion stack during fuel oil operation.

Table 4-1: Maximum Expected Hourly Emission Rates for Each Combustion Turbine, with and without TurboPhase Operation – Natural Gas Operation

Source Description	NO_x	CO	PM/ PM_{10}/ $PM_{2.5}$	VOC	SO_2	H_2SO_4	CO_2e
	pounds per hour (lb/hr)						
GE 7FA combustion turbine without TurboPhase operation	65	32	18	3.0	2.5	0.38	183,961
GE 7FA combustion turbine with TurboPhase operation	75	36	20.2	3.4	2.8	0.44	212,291

Table 4-2: Maximum Expected Hourly Emission Rates for Each Combustion Turbine – Fuel Oil Operation

Source Description	NO_X	CO	PM/ PM_{10}/ $PM_{2.5}$	VOC	SO_2	H_2SO_4	CO_2e
	pounds per hour (lb/hr)						
GE 7FA combustion turbine with fuel oil with and without TurboPhase operation	470	72	39	8	103	15.8	256,873

[2] One start-up/shut-down event is equal to one start-up plus one shut-down. All start-ups were conservatively assumed to be cold start-ups.

4.1.2 Turbine Start-Up and Shut-down Emissions Calculation Method – Natural Gas Operation

Each combustion turbine may start up to 365 times per year which may include up to 20 starts on fuel oil. For natural gas combustion, potential start-up and shut-down emissions were based on a start-up profile and conservatively assumed that there would be up to 365 cold start-ups and 365 shut-down events per turbine per year on natural gas. One start-up and shut-down event is equivalent to one start-up (0 percent load to when the turbine is in "Mode 6", which is approximately 60 percent load or minimum load for steady state operation and emissions compliance) plus one shut-down (60 percent load or minimum load for steady state operation and emissions compliance to 0 percent load). Start-up is assumed to take 120 minutes while shut-down shall take 60 minutes for a total of 180 minutes for one start-up and shut-down event. Potential start-up and shut-down emissions for each combustion turbine are shown in Table 4-3.

Detailed calculations of the potential start-up and shut-down emissions are provided in Appendix C.

Table 4-3: Potential Combustion Turbine Start-up and Shut-down Emissions – Natural Gas Operation

Pollutant	Start-up Emissions (lb/hr)[a,b]	Shut-down Emissions (lb/hr)[a,c]	Maximum Number of Starts Per Turbine[d]	Start-up /Shut-down Emissions (tpy)[a]	Total Start-up /Shut-down Emissions (Both turbines) (tpy)[a]
NOx[a]	121.2	103.3	365	63.1	126.2
CO[a]	384.4	144.4	365	166.7	333.4
$PM/PM_{10}/PM_{2.5}$	18.0	18.0	365	9.9	19.7
VOC[a]	6.8	6.2	365	3.6	7.2
SO_2	2.5	2.5	365	1.4	2.7
H_2SO_4	0.38	0.38	365	0.21	0.42
Lead	--	--	--	--	--
CO_2	183,771	183,771	365	100,615	201,230

(a) lb/hr = pounds per hour; tpy = tons per year
(b) Includes start-up emissions from GE Start-up Summary and actual CEMS start-up data.
(c) Includes shut-down emissions from GE Start-up Summary and actual CEMS shut-down data.
(d) One start-up and shut-down event is equivalent to one start-up plus one shut-down. All emissions based on worst-case cold start data.

4.1.3 Combustion Turbine Start-Up and Shut-down Emissions Calculation Method – Fuel Oil Operation

Potential start-up and shut-down emissions were based on a start-up profile and conservatively assumed that there would be 20 cold start-ups and 20 shut-down events per turbine per year on fuel oil. One start-up and shut-down event is equivalent to one start-up (0 percent load to when the turbine is in "Mode 6", which is approximately 80 percent load or minimum load for steady state operation and emissions compliance) plus one shut-down (80 percent load or minimum load for steady state operation and emissions compliance to 0 percent load). Start-up is assumed to take 120 minutes while shut-down shall take 60 minutes for a total of 180 minutes for one start-up and shut-down event. Potential start-up and shut-down emissions for each combustion turbine while operating on fuel oil are shown in Table 4-4.

Detailed calculations of the potential start-up and shut-down emissions are provided in Appendix C.

Table 4-4: Potential Combustion Turbine Start-up and Shut down Emissions – Fuel Oil Operation

Pollutant	Start-up Emissions (lb/hr)[a,b]	Shut-down Emissions (lb/hr)[a,c]	Maximum Number of Starts on Fuel Oil Per Turbine[d]	Start-up /Shut-down Emissions (tpy)[a]	Total Start-up /Shut-down Emissions (Both turbines) (tpy)[a]
NO_x	561.6	543.1	20	16.7	33.3
CO	230.4	195.7	20	6.6	13.1
$PM/PM_{10}/PM_{2.5}$	39.0	39.0	20	1.2	2.3
VOC	9.1	9.0	20	0.27	0.54
SO_2	103.0	103.0	20	3.1	6.2
H_2SO_4	15.8	15.8	20	0.47	0.95
Lead	0.02	0.02	20	6.6×10^{-4}	1.3×10^{-3}
CO_2	255,995	255,995	20	7,680	15,360

(a) lb/hr = pounds per hour; tpy = tons per year
(b) Includes start-up emissions from GE Start-up Summary and actual CEMS start-up data.
(c) Includes shut-down emissions from GE Start-up Summary and actual CEMS shut-down data.
(d) One start-up and shut-down event is equivalent to one start-up plus one shut-down. All emissions based on worst-case cold start data.

4.1.4 Maximum Start-up and Shut down Emissions

Table 4-5 displays the emissions from 345 start-up/shut down events on natural gas and 20 start-up/shut down events on fuel oil. This represents the worst-case emissions for start-up/shut down emissions.

Table 4-5: Potential Combustion Turbine Start-up and Shut down Emissions – Maximum Emissions

Pollutant	Number of Natural Gas Starts Per Turbine	Start-up/Shutdown Emissions Natural Gas (tpy)	Number of Fuel Oil Starts Per Turbine	Start-up/Shutdown Emissions Fuel Oil (tpy)	Total Start-up/Shutdown Emissions (Both turbines) (tpy)[a]
NOx	345	59.63	20	16.66	152.58
CO	345	157.54	20	6.56	328.22
$PM/PM_{10}/PM_{2.5}$	345	9.32	20	1.17	20.97
VOC	345	3.42	20	0.27	7.39
SO_2	345	1.29	20	3.09	8.77
H_2SO_4	345	0.20	20	0.47	1.34
Lead	345	--	20	0.00	0.00
CO_2e	345	95,200	20	7,706	205,812

(a)Maximum start-up/shutdown emissions based on 345 starts per year on natural gas and 20 starts per year on fuel oil.

4.1.5 Turbine HAP Emissions Calculation Method

The Project will emit HAPs. Detailed HAP emissions calculations from the Project are shown in Appendix C. Emissions of HAPs for this Project will be below 10 tpy of any single HAP and 25 tpy for all aggregate HAPs. HAP emissions from the Project and existing combustion equipment were evaluated for purposes of determining regulatory applicability. The facility will also remain an area source of HAPs with the addition of this Project.

5.0 REGULATORY REVIEW

The Project is subject to various federal and state air regulations. The combustion turbines will combust natural gas and fuel oil as backup. The facility is located approximately ¾ of a mile to the east of Waverly, West Virginia, within Pleasants County. Part 5 contains a discussion of the PSD regulations, applicable Federal regulations, and applicable WVDEP provisions. Where applicable, reference to general limitations is provided when there is no specific requirement that applies to an emission source.

In instances where there are multiple requirements, it is understood that compliance with the most restrictive requirement will demonstrate compliance with all other requirements.

Air quality permitting in West Virginia is under the jurisdiction of the WVDEP. The EPA has given the WVDEP authority to implement and enforce the federal Clean Air Act (CAA) provisions and state air regulations under its approved State Implementation Plan (SIP). The following subsections discuss the applicable federal and state air quality programs, regulations, and standards.

5.2 PSD Regulations and 45CSR14

The existing Pleasants Energy facility was previously permitted as minor source facility for PSD, with a fuel usage limit that kept the facility to less than 250 tons per year of any regulated PSD pollutant. This Project will increase the operation of the combustion turbines over the PSD thresholds as per the PSD regulations, this application and subsequent permit will be as if the facility was never permitted nor constructed.

PSD review is required for all criteria pollutants that will be emitted above significant levels in accordance with 40 CFR 52.21 (incorporated by reference in 45CSR14—2.74). PSD review consists of the following:

- A BACT analysis
- An air quality analysis
- An analysis of additional impacts on visibility, soils, vegetation, and growth

Three criteria were evaluated to determine PSD applicability (EPA 1990):

1. Whether the Project is sufficiently large (in terms of its emissions) to be a “major” stationary source or “major” modification.

2. Whether the source is located in a region designated as “attainment” or “unclassified.”

3. Whether the pollutants emitted from a major stationary source exceed the significant emission levels defined by 40 CFR 51.21.

PSD pollutants include NO_x, SO_2, CO, PM, PM_{10}, $PM_{2.5}$, VOC, CO_2e, hydrogen sulfide, H_2SO_4 mist, fluorides, and lead. The definition of a “major stationary source” is given in 40 CFR 52.21 (b)(1)(i). The Project is not included in the 28 source categories specified in the PSD regulations as being considered a major stationary source if the potential emissions of a PSD pollutant exceed 100 tpy. Therefore the facility would be considered a major stationary source if the potential emissions of a PSD pollutant exceed 250 tpy. Potential emissions from this Project are over 250 tpy threshold for NO_x and CO; thus meeting the first criteria for PSD applicability.

The Project is located in an attainment/unclassified area for all criteria pollutants and will be subject to PSD review rather than a non-attainment NSR.

The maximum potential emissions from the Project are listed in Table 1-1 and include start-up and shut-down emissions from the combustion turbines. The following PSD pollutants exceed the significant emission levels defined by 40 CFR 51.21: NO_x, CO, PM, PM_{10}, $PM_{2.5}$, and CO_2e.

Detailed calculations of potential emissions are contained in Appendix C.

PSD regulations require that the following issues be addressed:

- Determination of BACT on a case-by-case basis, taking into account costs as well as energy, environmental, and economic impacts
- Demonstration that the increase in emissions will not cause or contribute to an exceedance of the NAAQS or PSD increment
- Analysis of the impairment, if any, to visibility, soils, vegetation, and growth

This Project will increase the operation of the combustion turbine above the PSD major source thresholds, as such, this PSD application and subsequent permit will be evaluated as if the site were always PSD back to 2001 when the original minor source permit was issued. Since the original minor source permit (R13-2373) was issued, there have been other air permits issued for this site, however all of them authorized emissions that were less than the PSD significance levels, hence, none of them would have been subject to PSD if the facility was permitted as a PSD major source facility back in 2001. The permits and applications that have been submitted subsequent to the original permit (R13-2373) include the following:

- Permit amendment R13-2373A which was issued only to remedy a typographical error in the original construction permit.
- A G-60 Permit (Approved Registration G60-C067) for the installation of five black-start engines to operate in emergency situations only. Emissions for this Project were less than PSD significance levels for all generators combined at 500 hours each.
- A permit application that is currently being reviewed for the installation of TurboPhase on the combustion turbines to increase output of the combustion turbines. This application also seeks to change the status of the generators to non-emergency, while not increasing the permitted hours of operation (500 hour each) so that they may be operated as needed in high demand periods. The emissions from the two TurboPhase units requested to be permitted in the application are less than the PSD significance levels as well.

5.3 New Source Performance Standards (NSPS) (40 CFR Part 60) and 45CSR16

Standards of Performance for New Stationary Sources are contained in 40 CFR Part 60 and are adopted by reference in 45CSR16. These standards are commonly referred to as new source performance standards (NSPS). The applicable NSPS standards are listed below with a description of how Pleasants Energy plans to meet the standards.

Subpart GG

The combustion turbines are subject to the NSPS for combustion turbines, Subpart GG, which is applicable to combustion turbines constructed prior to 2006. Further, the combustion turbines do not meet the definition of "modified". Per Subpart A definitions, increasing the hours of operation alone does not met the definition of "modified" per 40 CFR Part 60.14 (e)(3) and there is no emissions increase on an hourly basis for any regulated pollutant. Therefore, the combustion turbines are subject to Subpart GG, as they are currently subject to the applicable requirements in this regulation, as outlined below and are not subject to Subpart KKKK as modified units.

Subpart GG of 40 CFR 60 establishes limits for NO_x and SO_2 emissions from stationary gas-fired turbines with a heat input at peak load equal or greater than 10.7 gigajoules per hour or 10 million British thermal units per hour (MMBtu/hr), based on the lower heating value of the fuel fired. Combustion turbines GT1 and GT2 each have a heat input (fuel flow) of approximately 1,571 MMBtu/hr at 59 °F at full load, making each turbine subject to the requirements of Subpart GG as per 40 CFR 60.330.

Subpart GG contains emissions standards (for NO_x and SO_2) in addition to notification, monitoring and testing requirements. The applicable standard limiting the discharge of NO_x into the atmosphere from each turbine is expressed as:

STD = 0.0075 * (14.4/Y) + F

where:

STD = allowable NOx emissions (percent by volume at 15% oxygen (O_2) on a dry basis)

Y = manufacturer's rated heat rate in kilojoules per watt hour (kJ/W-hr), not to exceed 14.4

F = fuel-bound nitrogen allowance

The heat input rate for each of the GE 7FA turbines on natural gas firing is 9.87 kJ/W-hr at 100 percent load and 59 °F. Therefore, the NSPS limitation for NOx is 109 parts per million by volume, dry basis (ppmvd) at 15 percent O_2. The anticipated emission rate for turbines as a result of this project is 9.0 ppmvd at 15 percent O_2 while combusting natural gas and 42 ppmvd while combusting fuel oil. Both of these emission rates are well below the NSPS limit for NO_x. The emissions limit proposed by Pleasants Energy will be more stringent than the limit specified in Subpart GG.

Under the Subpart GG NSPS standards, SO_2 is limited to 0.015 percent SO_2 by volume (150 ppmvd corrected to 15 percent O_2), and fuel oil sulfur content is limited to less than 0.8 percent by weight. The combustion turbines will meet these criteria by using natural gas as the primary fuel source. The facility has a current permit limit of 0.5 grains per 100 standard cubic feet which is approximately 8 ppmvd. Further, the distillate fuel oil that is used at the facility is limited to an annual average sulfur content of 0.05 percent sulfur by weight. Fuel sulfur content for the combustion turbines will therefore be well below the NSPS requirements. The corresponding maximum flue gas SO_2 concentrations will also be well below the NSPS standards, with SO_2 emissions of about 1 ppmvd corrected to 15 percent O_2 during gas firing and 10 ppmvd corrected to 15 percent O_2 during fuel oil firing.

Pleasants Energy will continue to follow permit requirements for fuel monitoring to satisfy the monitoring requirements for sulfur content of the natural gas as required in 40 CFR 60.334.

Subpart KKKK – Not applicable

Subpart KKKK is applicable to all stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005, with a heat input equal to or greater than 10.7

gigajoules per hour (10 MMBtu/hr). Because the combustion turbines were constructed in 2001, this NSPS is not applicable.

Subpart TTTT – Not applicable

Subpart TTTT set Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units (EGUs). This regulation was finalized on August 3, 2015 and applies to new units that commenced construction after January 8, 2014 or reconstruction after June 18, 2015. These combustion turbines commenced construction prior to the applicable date and are not considered “new” source. Further, these combustion turbines do not meet the definition of “reconstructed” or “modified” per the NSPS, so Subpart TTTT is not applicable to the combustion turbines.

5.4 National Emission Standards for Hazardous Air Pollutants (NESHAP) and Maximum Achievable Control Technology (MACT)

NESHAPS are contained in 40 CFR Part 63 and adopted by reference in 45CSR34. These rules contain emissions standards set by the EPA for particular source categories to control HAPs. These categories require the maximum degree of emission reduction of certain HAPs that the EPA determines to be achievable, which is known as the Maximum Achievable Control Technology (MACT). The following MACT standards are applicable to the Project. The entire Pleasants Energy facility, including the Project will be an area source of HAPs.

Subpart YYYY- Not applicable

EPA promulgated MACT standards for new stationary combustion turbines on March 5, 2004. These standards apply to stationary combustion turbines on which construction commenced after January 14, 2003 at major sources of HAPs. On April 7, 2004, however, EPA proposed to remove gas-fired units from the combustion turbine source category regulated by Subpart YYYY. In the interim, the EPA has stayed the applicability of Subpart YYYY requirements for gas-fired combustion turbines.

This regulation is not applicable because the Pleasants Energy facility is not a major source of HAPs.

5.5 Mandatory Reporting of Greenhouse Gases – 40 CFR Part 98

40 CFR Part 98 requires facilities that emit 25,000 metric tons or more per year of greenhouse gases to submit annual reports to EPA. This facility will exceed the reporting threshold and therefore, Pleasants Energy will report greenhouse gas emissions as required.

5.6 Clean Power Plan for Existing Units

The Clean Power Plan is slated to be published in the Federal Register in October 2015. This regulation proposes a 32 percent reduction in greenhouse gas emissions from power plants. Currently, it is unknown how this regulation may affect these simple-cycle combustion turbines, as each state will need to set up a compliance plan in their SIP for final compliance by 2020.

5.7 NAAQS

As stated earlier, Part 7 of this permit application will discuss the ambient air quality analysis and dispersion modeling that will performed for the Project. Modeled impacts will be compared to the NAAQS. The Project is not expected to cause or contribute to a violation of the NAAQS. A full description of the NAAQS modeling analysis will be included in Part 7 of the final permit application.

5.8 Other Ambient Air Quality Standards

Recent Federal Land Manager (FLM) proposed guidance requires, in the course of a PSD application, an assessment of air quality impacts at Class I areas if a proposed major source is located within a certain distance of the Class I area. There are four Class I Areas that are within 300 kilometers of the Project:

- Otter Creek Wilderness (130 kilometers)
- Dolly Sods Wilderness (160 kilometers)
- Shenandoah National Park (200 kilometers)
- James River Face Wilderness (253 kilometers)

In accordance with the Federal Land Managers' Air Quality Related Values Work Group (FLAG) Workshop procedures (June 2010), the use of the Screening Procedure (Q/D) to determine if the Project could opt (screen) out of an Air Quality Related Value (AQRV) assessment for visibility and deposition with CALPUFF is required. If Q/D is less than 10, then no AQRV analysis is required. Based on the ratio of Q/D, the Class I areas do not require further analysis of AQRV. Thus, no CALPUFF analysis was performed for impacts to AQRVs. The analysis is presented in Part 8 of this permit application.

A visibility analysis using VISCREEN was performed on 2 Class II areas and the results are presented in Part 8 of this permit application.

The PSD Class I and Class II Increment analyses are incorporated in Part 7 of this permit application.

5.9 Additional Impact Analysis

The impact of the Project on soils, vegetation, visibility, and growth was considered as part of the PSD process. The construction and operation of the Project is not expected to have a detrimental effect on plants, soils or industrial, commercial, and residential growth. A full analysis of these impacts can be found in Part 8 of this permit application.

5.10 Acid Rain (40 CFR Part 75) and 45CSR33

Title IV of the CAA imposes stringent requirements on electrical utilities and is enforced through the administration of the Title IV Acid Rain Permit Program, which is designed to achieve reductions in emissions of SO_2 and NO_x. The centerpiece of the Title IV program is the establishment of an SO_2 emissions allowance and trading program. The Project will be subject to the 40 CFR Part 75 Acid Rain regulations. Pleasants Energy currently holds an Acid Rain Permit and will be required to update that permit, per the regulations.

In accordance with the Acid Rain regulations, Pleasants energy will submit the application forms to the WVDEP for the revision to their Acid Rain Permit. The contents of the Acid Rain Permit will be incorporated into the modified Title V Operating Permit discussed previously.

5.11 Clean Air Interstate Rule (CAIR) and Cross State Air Pollution Rule (CSAPR)

The facility currently holds allowances per the CSAPR. It is assumed that Pleasants Energy has allowances to use or may obtain more allowances for this project from the new unit set aside.

5.12 Monitoring and Compliance

Monitoring and compliance requirements for operation of the Project come from 40 CFR Part 75 (Acid Rain). The turbines qualify as non-peaking units and are required to install a NO_x CEM.

5.12.1 Initial Compliance Demonstration

Performance testing to demonstrate initial compliance will be conducted on each of the combustion turbines within 180 days of initial start-up or within 60 days after achieving maximum operational capacity, whichever occurs first, unless a greater time is allowed by the construction permit. The following performance tests will be conducted if required in the construction permit:

- PM_{10}-EPA Methods 5 or 5B and Method 201A or 202
- VOC-EPA Method 25A or Method 18 (if necessary)
- Carbon monoxide-EPA Method 10 or 10B

- Visible emissions-EPA Method 9 or Method 22
- Nitrogen oxides-EPA Method 7 or 7E (CEM certification)
- Sulfur dioxide-EPA Method 6, 6A, or 6C

5.12.2 Continuous Emission Monitor (CEM)

The Project is subject to the compliance monitoring requirements under the Acid Rain regulations in 40 CFR Part 75 and NSPS in 40 CFR Part 60. The combustion turbines will continue to employ CEMs in accordance with 40 CFR Part 75 to continuously monitor nitrogen dioxide (NO_2), and volumetric flow rate. The test plan will be contained in the Part 75 monitoring plan and certification application that will be subsequently submitted within the appropriate time periods. CEMs are not required for monitoring SO_2 emissions because natural gas has inherently low sulfur content.

5.13 Title V Operating Permit

40 CFR Part 70, otherwise known as Title V of the CAA, established an air quality operating permit program that provides a central point for tracking all applicable air quality requirements for every source required to obtain a permit. Each state was also required to establish a Title V Operating Permit Program. 45CSR30, Requirements for Operating Permits, establishes such a program. Pleasants Energy will follow the requirements in 45CSR30 in order to update their Title V permit with the changes from the Project.

5.14 West Virginia Air Quality Standards and Regulations

This section describes the WVDEP regulations which apply to the Project.

5.14.1 45CSR10: To Prevent and Control Air Pollution of Sulfur Oxides

Pleasants Energy will meet all applicable requirements of 45CSR10. The combustion turbines are classified as Type ‘b’ units under this rule. Pleasants Energy is located in Pleasants County, West Virginia and is therefore located in Priority Region II. They will meet the following sulfur dioxide weight emission standard as per §45-10-3.1.e:

- Type ‘b’ fuel burning units must not discharge sulfur dioxide from all stacks located at one plant, measured in terms of pounds per hour, in excess of the product of 3.1 and the total design heat inputs for such units in MMBtu/hr.
- Pleasants Energy will meet all testing, monitoring, recordkeeping and reporting requirements as per §45-10-8.

5.14.2 45CSR13: Permits for Construction, Modification, Relocation, and Operation of Stationary Sources of Air Pollutants, Notification Requirements,

Administrative Updates, Temporary Permits, General Permits, Permission to Commence Construction, and Procedures for Evaluation

Pleasants Energy will meet all requirements of 45CSR13 in order to obtain a construction permit for this project.

5.14.3 45CSR20: Good Engineering Practice as Applicable to Stack Heights

Pleasant Energy will construct all stacks in accordance with good engineering practice according to 45CSR20.

5.14.4 45CSR22: Air Quality Management Fee Program

Pleasants Energy will submit all fees required by 45CSR22 in order to obtain a PSD construction permit.

6.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

Federal regulations specify that the owner of a facility subject to a PSD permit must perform a BACT analysis for the control of each PSD regulated pollutant emitted in significant quantities from a new stationary source located in an attainment area. As indicated in Part 5, this Project is subject to PSD review for NO_x, CO, $PM/PM_{10}/PM_{2.5}$, and CO_2e. Therefore, a BACT analysis has been prepared for these pollutants.

Pleasants Energy is permitting two natural gas-fired GE 7FA combustion turbines with fuel oil back-up at the Pleasants Energy facility located near Waverly, West Virginia. The combustion turbines will be operated solely in simple-cycle mode and will be permitted for 19,081,721,569 SCF of natural gas and fuel oil consumption per year combined. Fuel oil, when combusted will be equal to 889 MMCF per gallon of fuel oil. Additionally, the combustion turbines will be limited to 464.6 tons per year combined NOx emissions and 39 tons per year combined SO_2 emissions. Previously permitted, the combustion turbines may operate up to 3,250 hours per year with TurboPhase. This Part describes the BACT analysis for the combustion turbines.

The two combustion turbines will be F-Class combustion turbines with a nominal output of 168 megawatt (MW), each[3] (with a maximum heat input of 1,571 MMBtu/hr, each).

The BACT analysis was performed using the "top-down" approach, which is described in this Part. Along with the potential annual emissions, a summary of the proposed BACT emission limits and the associated control technologies for simple-cycle combustion turbines are shown in Table 6-1. BACT is an emission limitation based on the maximum degree of reduction which the WVDEP determines is achievable, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs.

The EPA has directed by policy that the BACT be determined using a process referred to as the "top-down" approach. The "top-down" process was outlined in a December 1, 1987 memorandum from the EPA Assistant Administrator for Air and Radiation.

[3] Net output at 59 degrees Fahrenheit and 100 percent load

Table 6-1: Summary of BACT Results – Simple-Cycle Combustion Turbines

Pollutant	Control	BACT Emissions[a,b,c,d]	Average
NO_x	Low NO_x burners (natural gas)	9 ppm (natural gas)	30-day rolling
	Water injection (fuel oil)	42 ppm (fuel oil)	
CO	Good combustion practices	9 ppm (natural gas) 20 ppm (fuel oil)	30-day rolling
$PM/PM_{10}/PM_{2.5}$	Combustion controls, inlet air filtration, and low ash fuels (natural gas and low sulfur fuel oil)	20.2 lb/hr (natural gas) 39 lb/hr (fuel oil)	3-run stack test
Greenhouse gases	Use of natural gas as a primary fuel and efficient turbine design	1,570 lb CO_2/MW-hr, gross 615,816 tpy CO_2e	Annual

(a) ppm = parts per million; lb/MW-hr = pound per megawatt hour; tpy = tons per year
(b) BACT emission rates only presented in this table. Maximum lb/hr and tpy are presented in Appendix C for all emission units.
(c) Concentration at 15 percent oxygen while operating at 60 percent load and greater including TurboPhase under steady state conditions, unless otherwise noted
(d) Emission rate at loads of 60 percent and higher

A BACT determination is made for each pollutant for which emissions (as a result of new emission points or a modification to existing emission points) will be greater than the PSD significant emission rate.

An emission limit proposed in a permit application does not automatically mean that the limit has been “achieved in practice” on a similar unit. Many PSD and Lowest Achievable Emission Rate (LAER) permits have been issued over the years for projects that were never constructed and, therefore, never operated. As a result, those emission limits have never been “achieved in practice.” There are also instances in which incorrect limits have been posted to the RBLC, or where the ultimate and final permit limits were subsequently modified prior to permit issuance. In some cases, an applicant may have proposed very stringent limits without a meaningful commercial guarantee, perhaps to avoid a more onerous requirement or an unacceptable air quality impact, and was then unable to continuously achieve the limits in practice. It is also very important to note that an emission rate based on a BACT finding must be continuously met under all normal operating conditions, not just at one optimal design point. Therefore, there must a reasonable assurance that each BACT limit evaluated is truly “demonstrated in practice” on a similar unit and can be continuously achieved under all expected operating condition for the life of the unit.

As identified in EPA’s October 1990 draft of the New Source Review (NSR) Workshop Manual, the basic steps of the “top-down” BACT analysis used in this analysis are listed below:

- Step 1 – Identify all potential control technologies

- Step 2 – Determine technical feasibility (of potential technologies)
- Step 3 – Rank control technologies by control effectiveness
- Step 4 – Evaluate most effective controls and document results
- Step 5 – Select BACT

The EPA has interpreted the statutory and regulatory BACT definitions as containing two core requirements that must be met by any BACT determination. First, the BACT analysis must include consideration of the most effective control options that could be applied. Second, any decision to allow a less stringent emission rate must be justified by an objective analysis of "energy, environmental, and economic impacts" (EPA 1990). This is tempered; however, by the following statement from the NSR Workshop Manual:[4]

> "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."

The first step in the "top-down" BACT process is the identification of potentially available control technologies. One of the ways to identify available control technologies is to review previous BACT determinations for similar sources. EPA's RACT/BACT/LAER Clearinghouse (RBLC) database was reviewed to identify recent BACT determinations for similar projects. This database is maintained on EPA's Technology Transfer Network website at www.epa.gov/ttn/catc. Advanced queries of the database were conducted to identify control technology determinations from January 2000 to July 2013 for sources similar to the proposed combined-cycle combustion turbines and applicable auxiliary equipment. The results of the RBLC query can be found in Appendix D in Tables D-1 to D-8.

To identify previous control technology determinations for comparable sources, a query was run using the "standard search" in which the RBLC database was searched using the following parameters:

- Combustion turbines, Simple-Cycle, 15.220 – Natural gas combustion;
- Combustion turbines, Simple-Cycle, 15.290 – Fuel oil combustion;
- Draft Determinations and RBLC Permits issued during or after January 2000;
- Source Industrial Classification (SIC) code of 4911 for electrical generation plants; and

[4] NSR Workshop Manual, EPA, October 1990, section IV.A.1. Demonstrated and Transferable Technologies. Page B-11

- North American Industry Classification System (NAICS) code for a combustion turbine electrical generation plant 221112 which includes all types of fossil fuel electrical generation plants.

The NAICS and SIC codes are the most appropriate codes to search in the advanced search option of the RBLC. The SIC and NAICS are systems of source classification developed for the purpose of differentiating industrial types. The SIC and the NAICS systems are used in many EPA documents to differentiate types of industries. It is appropriate to use these codes as the match criteria in queries of the RBLC database since other facilities that use similar turbines will likely have similar characteristics. After the NAICS and SIC codes were identified and queries run, combustion turbines that were not similar (e.g., digester gas-fired, cogeneration units, boilers, combined-cycle combustion turbines etc.) were eliminated from the search. Information on turbine emissions was sorted from this listing. A discussion of control options identified in the RBLC database is included in each subsection.

In some cases, the RBLC listings are not clearly categorized and cover both simple- and combined-cycle installations. Also, it should be noted that all RBLC listings in California represent Lowest Achievable Emission Rate (LAER); although they are often listed as BACT, BACT and LAER are essentially the same in California. LAER is a much more stringent requirement than BACT, and involves application of control technology regardless of cost. This is not the case for the proposed combustion turbines for this Project, which are subject only to BACT.

6.2 BACT for Nitrogen Oxides (NO_x) – Combustion Turbines

6.2.1 Step 1. Identify All Potential Control Strategies

NO_x is primarily formed in combustion processes in two ways:

1. The combination of elemental nitrogen with oxygen in the combustion air within the high temperature environment of the combustor (thermal NO_x); and

2. The oxidation of nitrogen contained in the fuel (fuel NO_x).

Natural gas contains negligible amounts of fuel-bound nitrogen, although some molecular nitrogen is present. Therefore, it is assumed that essentially all NO_x emissions from the turbines originate as thermal NO_x. The rate of formation of thermal NO_x is a function of residence time and free oxygen, and is exponential with peak flame temperature.

The combustion turbines will be subject to NO_x limits per NSPS Subpart GG, given their manufacture and installation date of 2001 and thus, emissions must be at least as stringent as the NSPS. Part 5 displays the applicable Subpart GG limits for the combustion turbines.

Control of NO_x emissions from combustion turbines is generally aimed at either the prevention of NO_x formation, or the capture or oxidation of post-combustion NO_x. Since the rate of formation of thermal NO_x is a function of residence time and free oxygen, and is exponential with peak flame temperature, “front-end” control techniques are aimed at controlling one or more of these variables. These controls include the XONON™ system and dry low- NO_x burners. The XONON™ system uses a catalyst to keep the system temperatures lower while dry low- NO_x burners offer a staged combustion process, resulting in a lower peak flame temperature.

Other control methods utilize add-on control equipment to remove NO_x from the exhaust gas stream after its formation. The most common control techniques involve the injection of ammonia into the gas stream to reduce the NO_x to molecular nitrogen and water. Ammonia can either be injected into the system without the use of a catalyst (SNCR) or with the use of a catalyst (SCR). Finally, $SCONO_x$™ relies upon a catalyst similar to SCR to reduce NO_x emissions, but does so without injecting ammonia into the exhaust gas stream.

The output from the RBLC search provided in Appendix D (Table D-1 and Table D-2) shows that a variety of emission limits and control technologies have been applied to combustion turbines. The most stringent limits found during a review of EPA’s database were for facilities located in ozone non-attainment areas. These facilities were required to meet such low emission limits since they were subject to LAER requirements.

Typical BACT determinations for simple-cycle units that are located in attainment areas were in the 2 to 27 ppm range using dry low NO_x combustors, water injection, SCR, or a combination of these technologies. The lower emission rates listed utilize SCR (Table D-1, Appendix D). It is important to note that all reported emission limits that are less than 9 ppm are either combined cycle units, Lowest Achievable Emission Rate (LAER) or are for aeroderivitive combustion turbines. Frame simple cycle combustion turbines similar to the 7FA combustion turbines show that the lowest BACT emission limitation is 9 ppm for natural gas operation. Fuel oil operation shows varied results from 6 ppm (for aeroderivitive, smaller combustion turbines) to 65 ppm (Table D-2, Appendix D).

6.2.2 Step 2. Identify Technically Feasible Control Technologies

6.2.2.1 XONON™ System

The XONON™ system controls NO_x emissions by preventing their formation. The key to the XONON™ system is the utilization of a chemical process versus a flame to combust fuel, thus limiting temperature and NO_x formation. The XONON™ system is an integral part of the combustor. The fuel and air that are supplied to the combustor are thoroughly mixed before entering the catalyst. The catalyst is responsible for combusting the fuel to release its energy. Due to the low catalyst operating temperatures, the nitrogen molecules are not involved in the reaction chemistry; they pass through the catalyst unchanged, thereby eliminating NO_x formation. The XONON™ system does have the same high outlet temperature, and some NO_x is formed in the post-combustion process. However, use of the technology has limited NO_x emissions to less than 2.5 ppm.

Currently, the XONON™ system has not had wide-scale application. It has been demonstrated on a 1.5 MW unit in California, with the unit operating in a base load capacity (24 hours a day, 7 days a week). Tests are underway to apply this technology to other types and sizes of turbines; however, testing data is currently unavailable. As the proposed combustion turbines are expected to experience repeated start-ups and shut-downs, it is unclear how the changing load conditions would affect the XONON™ system. As this is a large combined-cycle project, and the XONON™ system has yet to demonstrate applicability for such units, **the XONON™ system has been deemed technically infeasible for this Project.**

6.2.2.2 $SCONO_x$™ System

The $SCONO_x$™ system is an add-on control device that reduces multiple pollutants. The $SCONO_x$™ system utilizes a single catalyst for the conversion of CO, VOC, and NO_x emissions into carbon dioxide (CO_2), water, and nitrogen gas. The system does not use ammonia and operates most effectively at temperatures ranging from 300 °F to 700 °F. The $SCONO_x$™ system requires natural gas, water, steam, electricity and ambient air to operate, and no special chemicals or processes are necessary. Steam is used periodically to regenerate the catalyst bed and is an integral part of the process.

The exhaust gases of the Project's simple-cycle turbine will be around 1,000 °F. Therefore, the gas stream temperature will be higher than the recommended temperature range for $SCONO_x$ (300 °F to 700 °F) so it would need to be cooled prior to introduction to the catalyst. Additionally, plant steam would need to be diverted to the catalyst bed in order to regenerate it and these combustion turbines are not combined-cycle so no steam is available.

Since a simple-cycle turbine exhaust is greater than 1,000 °F, **$SCONO_x$ is considered to be technically infeasible for the Project.**

6.2.2.3 Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion NO_x control technology in which a reagent (ammonia or urea) is injected into the exhaust gases to react chemically with NO_x, forming nitrogen and water. The success of this process in reducing NO_x emissions is highly dependent on the ability to uniformly mix the reagent into the flue gas at a zone in the exhaust stream at which the flue gas temperature is within a narrow range, typically from 1,700 °F to 2,000 °F. To achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window should be at least 0.5 to 1.0 seconds. The consequences of operating outside the optimum temperature range are severe. Outside the upper end of the temperature range, the reagent will be converted to NO_x. Below the lower end of the temperature range, the reagent will not react with the NO_x and the ammonia slip concentrations (ammonia discharge from the stack) will be very high. The flue gases from the combustion turbine have an exhaust temperature of more than 1,000 °F. Even strategically placing the ammonia injection further upstream would probably result only in peak temperatures of around 1,300 °F. Such a low temperature would require that additional fuel be combusted at some point in order to raise the temperature to the levels that SNCR will operate. Combustion of the additional fuel would not only increase the NO_x emissions, but also all other criteria pollutants, especially CO. In addition, the added fuel used to raise the exhaust gas temperature will increase the annual operating costs for the facility.

SNCR has not been applied to any combustion turbines according to the RBLC database. **Because SNCR has never been applied to combustion turbines, it is considered to be infeasible for the turbines under consideration for this Project.**

6.2.2.4 Selective Catalytic Reduction (SCR)

SCR is a post-combustion technology that employs ammonia in the presence of a catalyst to convert NO_x to nitrogen and water. The function of the catalyst is to lower the activation energy of the NO_x decomposition reaction. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, de-activation due to aging, ammonia slip emissions, and the design of the ammonia injection system.

SCR represents state-of-the-art controls for combined-cycle back end gas turbine NO_x removal; it has seen only limited use on simple-cycle combustion turbines (in areas subject to LAER and small aeroderivative turbines that are probably permitted for more fuel usage than the proposed GE 7FA units for this Project) as determined from the RBLC query. SCR technology is being permitted as LAER and BACT for *combined-cycle* turbines at 2 to 5 ppm NO_x. Conventional SCR uses a metal honeycomb or “foil” catalyst support structure and requires an HRSG to drop flue gas temperatures to less than 600 °F.

Because of the high exhaust temperature of a simple-cycle turbine, a conventional SCR system is not technically feasible. Instead, a high temperature “zeolite”-based SCR system has been introduced for use on certain simple-cycle turbines. Zeolite is a sodium alumina silicate ceramic material with a design operating temperature of approximately 800 to 1,000 °F. Only a few natural gas-fired installations were identified that use these high-temperature systems. Two have had major problems such as catastrophic catalyst failures; the third has not yet acquired a long enough history to sufficiently evaluate its operational effectiveness. Although vendors reported that they have catalysts that they believe will operate under the high temperature conditions, they did not identify many combustion turbines successfully operating with SCR under simple-cycle conditions.

Another option to utilizing an SCR is to dilute the exhaust air to reduce the temperature prior to the SCR catalyst. This requires a lot of extra duct work to allow time for the exhaust to be lowered to the appropriate temperature for a vanadium catalyst.

Since these combustion turbines also combust fuel oil as backup fuel, when fuel oil is used, it has been shown that the catalyst will foul very fast, making the SCR not as efficient and very costly for much more frequent catalyst replacements.

Despite this past experience, SCR is deemed feasible for natural gas-fired units because vendors say that it is available, and it will be discussed further for this combustion turbine.

SCR can be applied to the combustion turbines and is technically feasible for the proposed simple-cycle combustion turbines.

6.2.2.5 Dry Low NO_x Burners

Lean premixed combustors are currently available from most turbine manufacturers for natural gas operatoin. This technology seeks to reduce combustion temperatures, thereby reducing NO_x. In a conventional combustor, the air and fuel are introduced at an approximately stoichiometric ratio and air/fuel mixing occurs at the flame front where diffusion of fuel and air reaches the combustible limit. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing results in a homogenous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower combustion temperatures, which lowers NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Controlled NO_x emission guarantees using dry low NO_x burners range from 9 to 25 ppm for turbines 20 MW or greater, but vary considerably from vendor to vendor. **Low NO_x burners are currently available for these combined-cycle combustion turbines and are a technically feasible control option for the units.**

6.2.2.6 Water or Steam Injection

Water and/or steam injection is a common control used during fuel oil operation. Steam and water injection works to increase the thermal mass by dilution and thereby reduce peak temperatures in the flame zone. With water injection, there is an additional benefit of absorbing the latent heat of vaporization from the flame zone. Water or steam is typically injected at a water-to-fuel ratio of less than one.

Water or steam injection is usually accompanied by an efficiency penalty (typically 2 to 3 percent) but an increase in power output (typically 5 to 6 percent) due to the increased mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Both CO and VOC emissions are increased by water injection depending on the amount of water that is injected. Water injection is generally used for fuel oil combustion because it is difficult to aerosolize the fuel oil for air/fuel mixing, or is used on aeroderivative combustion turbines. Because the combustion turbines will have fuel oil as backup fuel, **water injection is considered a technically feasible option for this Project.**

6.2.2.7 Summary of the Technically Feasible Control Options

The technical feasibility of the NO_x control options for the simple-cycle combustion turbines is summarized in Table 6-2. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the turbines.

Table 6-2: Summary of Technically Feasible NO_x Control Technologies for Simple-Cycle Combustion Turbines

Control System[a]		Expected Performance (ppm)[a]	Technical Feasibility	Comments[a]
Combustion controls	Dry low-NO_x burners	9	Feasible	Standard on combustion turbines for natural gas operation
	Water injection	42	Feasible	Used only during fuel oil operation
Post combustion controls	XONON™	N/A	Not feasible	Testing is still underway. Only used on a 1.5 MW unit not operating continuously.
	$SCONO_x$™	N/A	Not feasible	Effective over a limited temperature range and would require plant steam resulting in additional emissions. There is no steam produced by the plant which is required for the SCONOx.
	Selective non-catalytic reduction	N/A	Not feasible	Exhaust temperature is too low.
	Selective catalytic reduction	2 – 5 (natural gas) 9 – 24 (fuel oil)	Feasible	2 ppm is the lowest achievable emission rate with SCR on natural gas. Catalyst will be fouled on fuel oil.

(a) ppm = parts per million; MW = Megawatts; SCR = selective catalytic reduction

6.2.3 Step 3. Rank the Technically Feasible Control Technologies

Add-on controls may be used for natural gas combustion in the turbines. The GE 7FA combustion turbines under consideration offer 9 ppm NO_x which includes low NO_x burners and 42 ppm NO_x while combusting fuel oil, therefore; low NO_x burners and water injection are used as the baseline for the proposed combustion turbines.

The technically feasible NO_x control technologies for the combustion turbines are ranked by control effectiveness in Table 6-3.

Table 6-3: Ranking of Technically Feasible NO_x Control Technologies for Combustion Turbines

Control Technology[a]	Reduction (%)	Controlled Emission Level (ppm)[a]
SCR	78 – 44	2 – 5 (natural gas)
		9 – 24 (fuel oil)
Low NO_x burners	N/A (baseline for natural gas)	9
Water injection	N/A (baseline for fuel oil)	42

(a) ppm = parts per million; SCR = Selective Catalytic Reduction

6.2.4 Step 4. Evaluate the Most Effective Controls

Recent BACT determinations have indicated a level of 2 to 25 ppm for NO_x emissions from simple-cycle units that are fired with natural gas (Table D-1, Appendix D). The combustion turbines under consideration are able to achieve 9 ppm while combusting natural gas and 42 ppm while combusting fuel oil on a long-term basis.

The simple-cycle units will have low NO_x burners and water injection, which are standard on the combustion turbines.

6.2.4.1.1 Economic Analyses

The simple-cycle turbine BACT analysis contains economic analyses for add-on controls. This section contains information regarding the economic analyses and how they were performed.

For the controls that require an economic analysis, capital costs include the initial cost of components intrinsic to the complete control system. For both oxidation catalyst and SCR systems, these capital costs would include the catalyst modules, transition piece, support frame, piping, provisions for catalyst cleaning and removal, instrumentation, and installation costs. Additionally, the SCR system requires the installation of an ammonia injection system. Annual costs consist of the financial efficiency losses, parasitic loads, and revenue loss from operation of the control system; overhead, maintenance, labor, raw materials, and utilities are included.

Capital and operating costs have been estimated in accordance with EPA guidance. The capital cost estimating technique used in this analysis is based on a factored method of determining direct and indirect installation costs. This technique is a modified version of the “Lang Method,” where installation costs are expressed as a function of known equipment costs. This method is consistent with the latest EPA guidance manual [Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual] on estimating control technology costs (EPA 2002).

Purchased equipment costs represent the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all structural, mechanical, and electrical components required for continuous operation of the device. Depending on the control strategy that is used, these costs may include such items as reagent storage tanks, supply piping, the engine outlet transition piece, a catalyst removal crane, spare parts, and the catalyst and air dilution system. In this BACT evaluation, basic equipment costs were obtained from data provided by vendors and from recent projects with similar units. Instrumentation is usually not included in the basic equipment cost so the OAQPS manual allows that instrumentation may be estimated to be 10 percent of the basic equipment cost.

Direct installation costs consist of the direct expenditures for materials and labor including site preparation, foundations, structural steel, insulation, erection, piping, electrical, painting, and enclosure structures. Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, contingencies, and additional permits and licensing costs.

Direct installation costs are expressed as a function of the purchased equipment cost and are based on the average installation requirements of typical systems. Indirect installation costs are designated as a percentage of the total direct cost (purchased equipment cost plus the direct installation cost) of the system. Other indirect costs include equipment start-up and performance testing, contingency funds, working capital and interest during construction.

Annualized costs are comprised of direct and indirect operation costs. Direct costs include electricity losses, labor, maintenance, replacement parts, raw materials, and utilities. Indirect operating costs include overhead, taxes, insurance, general administration, contingencies, and capital charges. Annualized cost factors used to estimate total annualized costs for the SCR and oxidation catalyst systems are presented in their respective discussions in the sections that follow. These tables are consistent with the EPA guidance on estimating control technology costs (EPA 2002).

Direct operating labor costs vary according to the system operating mode and operating time. Labor supervision is estimated as 15 percent of operating labor. Maintenance costs have been included and are itemized as appropriate. Replacement part costs, such as the cost to replace an aged or failed catalyst, have been included where appropriate. Reagent and utility costs are based upon estimated annual consumption. Based on the experience of other facilities, the catalyst is assumed to require replacement at a minimum of every three years due to failure or aging.

Most indirect operating costs are calculated as a percentage of the total capital cost. The indirect capital costs are based on the capital recovery factor (CRF), defined as:

$$CRF = \frac{i \cdot (1+i)^n}{(1+i)^n - 1}$$

Where:

i = interest rate
n = equipment economic life (years)

A control system's economic life is typically 10 to 20 years. In this analysis, a 20-year equipment economic life (typical length of financing) was used. The average interest rate is assumed to be seven percent. The CRF is calculated to be 0.094.

The cost-effectiveness for each system is calculated by dividing the annualized cost of the available control technology by the annual emissions reduction. The annual emissions reduction is the difference between the baseline emission rate and the controlled emission. All BACT capital and annual cost tables are contained in Appendix E.

6.2.4.1.2 Selective Catalytic Reduction

Energy Impacts

An SCR system results in a loss of energy due to the pressure drop across the SCR catalyst. To compensate for the energy loss in the SCR system, additional natural gas combustion is required to maintain the net energy output, which also results in additional air pollutant emissions.

Environmental Impacts

SCR systems consist of an ammonia injection system and a catalytic reactor. Urea can be decomposed in an external reactor to form ammonia for use in a SCR. Unreacted ammonia may escape through to the exhaust gas. This is commonly called "ammonia slip." It is estimated that ammonia slip from an SCR on a unit this size could be 10 ppm and may be considered to be an environmental impact. The ammonia that is released may also react with other pollutants in the exhaust stream to create fine particulates in the form of ammonium salts. In addition, the storing of the ammonia on-site is another environmental and safety concern. SCR catalysts must also be replaced on a routine basis. In some cases, these catalysts may be classified as a hazardous waste. This typically requires either returning the material to the manufacturer for recycling and reuse or disposal in designated landfills.

Economic Impacts

The costs associated with an SCR system for the combustion turbines operating in simple-cycle mode are shown in Table E-1, Appendix E. The costs used in this analysis is for a brand new combustion turbine and does not take into account the fact that this would be a retrofit to existing combustion turbines. The costs would go up quite a bit if the retrofit costs were included. To be conservative, however the costs only look at the installation as a new facility. The overall total capital investment of installing an SCR system is approximately $19,015,000. The annualized costs associated with an SCR system are shown in Table E-2, Appendix E. On an annual basis, the SCR system would cost $2,912,855, which results in a cost per ton of NO_x removed of $22,992 while removing only 174 tons of NO_x per year, including full permitted operation normal operation on natural gas and fuel oil. Therefore, any control of NO_x by add-on controls would result in costs that would not be economical.

An SCR is not proposed as BACT for the combustion turbine operating in simple-cycle mode because it is not economically feasible.

6.2.4.1.3 Low-NO_x Burners

Energy Impacts

Low NO_x burners are usually accompanied by an efficiency penalty (typically 2 to 3 percent) and an increase in power output (typically 5 to 6 percent). The increase in power output results from the increase in mass flow required to maintain turbine inlet temperature at manufacturer's specifications. Because there is a power increase, no energy impacts are associated with low NO_x burners.

Environmental Impacts

The low NO_x burner system may increase CO and VOC emissions on a lb/hr basis; however, the potential increase in CO and VOC emissions does not outweigh the advantages of decreased NO_x emissions to reduce health effects.

Economic Impacts

The turbine manufacturer currently installs low-NO_x burners as standard equipment on natural gas-fired combustion turbines. With the low-NO_x burners, these turbines may achieve NO_x emission rates of 9 ppm for loads of 60 percent or greater. Since the low-NO_x burners are considered standard equipment on the turbine, there is no annualized cost of the control.

6.2.4.1.4 Water Injection

Energy Impacts

Water injection, used during fuel oil operation only, is also usually accompanied by an efficiency penalty (typically 2 to 3 percent) and an increase in power output (typically 5 to 6 percent). No huge energy impacts are associated with water injection.

Environmental Impacts

Water injection does use water, a natural resource, to control NO_x emissions. However, at the very few operating hours that are requested in this permit (up to 100 hours for each of the two combustion turbines), the water use should be very minimal.

Economic Impacts

The turbine manufacturer currently installs water injection as standard equipment on fuel oil-firing combustion turbines. With water injection, these turbines may achieve NO_x emission rates of 42 ppm for loads of 60 percent or greater when combusting fuel oil. Since the water injection is considered standard equipment on the turbine, there is no annualized cost of the control.

6.2.4.2 Step 5. Proposed NO_x BACT Determination

The BACT recommended for control of NO_x emissions from each of the simple-cycle turbines is low NO_x burners for natural gas combustion and water injection for fuel oil operation. This control will meet a NO_x emission limit of 9 ppm at 15 percent oxygen during steady state conditions on a 30-day rolling average for natural gas operation and 42 ppm at 15 percent oxygen for fuel oil operation.

Low NO_x burners are selected as BACT for NO_x emissions from the simple-cycle combustion turbines while combusting natural gas.

Water injection is selected as BACT for NO_x emissions from the simple-cycle combustion turbines while combusting fuel oil.

6.3 BACT for Carbon Monoxide (CO) – Combustion Turbines

6.3.1 Step 1. Identify Potential Control Strategies

CO is a product resulting from incomplete combustion. Control of CO is typically accomplished by providing adequate fuel residence time and a high temperature in the combustion zone to confirm complete combustion. These control factors, however, also tend to result in increased emissions of NO_x. Conversely, a lower NO_x emission rate achieved through flame temperature control (by water injection or dry lean pre-mix) can result in higher levels of CO emissions. A compromise is usually established where the flame temperature reduction is set to achieve the lowest NO_x emission rate possible while keeping CO emissions to an acceptable level.

CO emissions from combustion turbines are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence. Post-combustion control involves the use of catalytic oxidation; front-end control involves controlling the combustion process to suppress CO formation.

The technologies identified for reducing CO emissions from the proposed turbines are the $SCONO_x$™ system, an oxidation catalyst, and combustion controls. The standard technology for reducing CO emissions is to maintain "good combustion" through proper control and monitoring of the combustion process. A survey of the RBLC database (Table D-3 and Table D-4, Appendix D) indicated that most new simple-cycle combustion turbines in attainment areas do not have add-on controls for CO emissions. CO emissions from simple-cycle turbines from the permitted facilities ranged from 2 to 25 ppm for natural gas operation. It should be noted that the 2 ppm BACT rates were for combustion turbines in nonattainment areas and were likely not F-class machines, but were smaller aeroderivitives that have much lower exhaust temperatures.

6.3.2 Step 2. Identify Technically Feasible Control Technologies

6.3.2.1 $SCONO_x$™ System

The $SCONO_x$™ system was described in the BACT analysis for NO_x in Section 6.2.2.2. Because its operating temperature is much lower than the exhaust of the simple-cycle combustion turbines, as stated in Section 6.2.2.2, $SCONO_x$ is not feasible on the simple-cycle combustion turbines.

The $SCONO_x$™ system is considered to be not technically feasible for the combustion turbines.

6.3.2.2 Oxidation Catalyst

Oxidation catalysts are a post-combustion technology which does not rely on the introduction of additional chemicals, such as ammonia with SCR, for a reaction to occur. The oxidation of CO to CO_2 utilizes excess air present in the turbine exhaust; the activation energy required for the reaction to proceed is lowered in the presence of a catalyst. Products of combustion are introduced into a catalytic bed, with the optimum temperature range for these systems being between 700°F and 1,100°F. At higher temperatures, catalyst sintering may occur, potentially causing permanent damage to the catalyst. The addition of a catalyst bed onto the turbine exhaust will create a pressure drop, resulting in back pressure to the turbine. This has the effect of reducing the efficiency of the turbine and the power generating capabilities.

The use of an oxidation catalyst is considered to be technically feasible for the combustion turbines.

6.3.2.3 Combustion Control

"Good combustion practices" include operational and combustor design elements to control the amount and distribution of excess air in the flue gas to confirm that there is enough oxygen present for complete combustion. Such control practices applied to the proposed turbines can achieve CO emission levels of 9 ppm at for natural gas operation from 60 to 100 percent load and 20 ppm from 60 to 100 percent load for fuel oil operation.

Good combustion practices are a technically feasible method of controlling CO emissions from the proposed combustion turbines.

6.3.2.4 Summary of the Technically Feasible Control Options

The technical feasibility of the CO control options for the proposed combined-cycle combustion turbines is summarized in Table 6-4. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the turbines.

Table 6-4: Summary of Technically Feasible CO Control Technologies for the Combustion Turbines

Control System		Expected Performance (ppm)[a,b]	Feasibility	Comments
Combustion control		9 (natural gas) 20 (fuel oil)	Feasible	Standard on turbines. Not an add-on control
Post combustion controls	$SCONO_x$™	N/A	Not feasible	Effective over a limited temperature range and would require plant steam resulting in additional emissions, produces CO_2 emissions. There is no plant steam at this facility.
	Oxidation catalyst	2 (natural gas) 4.4 (fuel oil)	Feasible	Produces CO_2 emissions

(a) ppm = parts per million
(b) Over all loads of 60% and greater.

6.3.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible CO control technologies for the combustion turbines are ranked by control effectiveness in Table 6-5.

Table 6-5: Ranking of Technically Feasible CO Control Technologies for Combustion Turbines

Control Technology	Reduction (%)[b]	Controlled Emission Level (ppm)[a,b]
Oxidation catalyst	77	2 (natural gas) 4.4 (fuel oil)
Combustion control	N/A (baseline)	9 (natural gas) 20 (fuel oil)

(a) ppm = parts per million
(b) Over all loads of 60% and greater.

6.3.4 Step 4. Evaluate the Most Effective Control Technologies

Operating the combustion turbines with good combustion practices will achieve 9 ppm on a long-term basis for natural gas firing and 20 ppm for fuel oil firing. The next step is to review each of the technically feasible control options for environmental, energy, and economic impacts.

6.3.4.1 Oxidation Catalyst

Energy Impacts

The addition of a catalyst bed onto the turbine exhaust for the oxidation catalyst will create a pressure drop, resulting in back pressure to the turbine. This has the effect of reducing the efficiency of the turbine and the power generating capabilities.

Environmental Impacts

The oxidation catalyst oxidizes CO to CO_2 which is released to the atmosphere. CO_2 is a greenhouse gas (GHG) that may be contributing to global warming and is now a regulated pollutant. Increasing CO_2 emissions could have a negative impact on the atmosphere. The amount of CO_2 produced is minimal, given the magnitude of GHG emissions that trigger permitting (75,000 tpy once another pollutant is subject to PSD) as compared to the amount of CO that triggers permitting (100 tpy), therefore a slight increase in CO_2 is considered negligible compared to the decrease in CO emissions that is attained.

As with all controls that utilize catalysts for removal of pollutants, the catalyst must be disposed of after it is spent. The catalyst may be considered hazardous waste and require special treatment or disposal; even if it is not hazardous, it adds to the already full landfills. Further, the catalyst will be spent and fouled faster when fuel oil is combusted, as it is known that the fuel oil causes fouling of the catalyst.

Economic Impacts

The capital costs associated with an oxidation catalyst for the combustion turbine operating in simple-cycle mode are shown in Table E-3, Appendix E. The total capital investment of installing an oxidation catalyst on the simple-cycle turbine is approximately $8,568,365. The annualized costs associated with an oxidation catalyst are shown in Table E-4, Appendix E. On an annual basis, the oxidation catalyst would cost $1,219,367 which results in a cost per ton of CO removed of $17,805 while removing only 69 tons of CO per year for both natural gas operation and fuel oil operation, based on worst-case normal operation emissions. Therefore, any control of CO by add-on controls would result in costs that would not be economical.

An oxidation catalyst is not proposed as BACT for the combustion turbines because it is not economically feasible.

6.3.5 Step 5. Proposed CO BACT Determination

The BACT recommended for control of CO emissions from each of the combustion turbines is good combustion practices. These practices will meet a CO emission limit of 9 ppm at 15 percent oxygen at loads of 60 percent and greater for natural gas operation and 20 ppm at 15 percent load for loads of 60 percent and greater for fuel oil operation on 30-day rolling averages.

6.4 BACT for Particulate Matter ($PM/PM_{10}/PM_{2.5}$) – Combustion Turbines

6.4.1 Step 1. Identify Potential Control Strategies

Particulate ($PM/PM_{10}/PM_{2.5}$) emissions from natural gas combustion sources consist of inert contaminants in natural gas, of sulfates from fuel sulfur or mercaptans used as odorants, of dust drawn in from the ambient air, and of particulate of carbon and hydrocarbons resulting from incomplete combustion. Therefore, units firing fuels with low ash content and high combustion efficiency exhibit correspondingly low particulate emissions.

Post-combustion controls, such as electrostatic precipitators (ESPs) or baghouses, have never been applied to commercial gas- and oil-fired turbines. Available control strategies include the use of low ash fuel, such as natural gas and low sulfur fuel oil, and combustion controls. BACT emission rates vary in the RBLC database with rates being listed as 0.0045 to 0.017 pounds per million British thermal units (lb/MMBtu) and 2.1 to 34.9 lb/hr for natural gas-fired combustion turbines (Table D-5, Appendix D) and between 13.7 to 19.5 lb/hr for fuel oil operation (Table D-6, Appendix D). As stated previously, these emission rates vary due to many reasons.

6.4.2 Step 2. Identify Technically Feasible Control Technologies

Particulate control devices are not typically installed on gas turbines. Post-combustion controls, such as ESPs or bag houses, have never been applied to commercial gas-fired turbines. For all natural gas-fired combustion units, particulate matter emissions are inherently low and add-on controls are not able to control these already low emissions much further. Therefore, the use of ESPs and bag house filters are both considered technically infeasible, and do not represent an available control technology. Further, to assist with reducing the emissions that are emitted out the stack, the inlet air, which is used during combustion of the fuel, is filtered prior to combustion and ultimately exhausted out the stack. This will further reduce the PM emissions from the outside air that is emitted out the stack.

In the absence of add-on controls, the most effective control method demonstrated for gas turbines is the use of low ash fuel, such as natural gas and low sulfur fuel oil, filtering the inlet air, and combustion controls. This was confirmed by a survey of the RBLC database (Table D-5 and Table D-6, Appendix D) which showed no add-on PM/PM_{10}/$PM_{2.5}$ control technologies for simple-cycle combustion turbines. Proper combustion control and the firing of fuels with negligible or zero ash content (such as natural gas) is the predominant control method listed.

6.4.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible PM/PM_{10}/$PM_{2.5}$ control technologies for the combustion turbines are ranked by control effectiveness in Table 6-6.

Table 6-6: Ranking of Technically Feasible PM/PM_{10}/$PM_{2.5}$ Control Technologies for Combustion Turbines

Control Technology	Reduction (%)	Controlled Emission Level[a]
Low ash and low sulfur fuel, inlet air filtration and combustion control	N/A (baseline)	20.2 lb/hr (natural gas) 39 lb/hr (fuel oil)

(a) For all loads of 60% and greater.
(b) lb/hr = pounds per hour

6.4.4 Step 4. Evaluate the Most Effective Control Technologies

<u>Energy, Environmental, and Economic Impacts</u>

There are no energy, environmental, or economic impacts associated with combustion controls and filtering the inlet air; the use of low ash fuel is not an add-on control device.

6.4.5 Step 5. Proposed $PM/PM_{10}/PM_{2.5}$ BACT Determination

The use of low ash and low sulfur fuels, inlet air filtration, and good combustion control represents BACT for $PM/PM_{10}/PM_{2.5}$ control for the combustion turbines. These operational controls will limit $PM/PM_{10}/PM_{2.5}$ emissions to approximately 20.2 lb/hr and 30 lb/hr for natural gas operation and fuel oil operation, respectively, on a 3-run stack test basis. This limit includes front and back half $PM/PM_{10}/PM_{2.5}$ emissions, and also includes operation of the TurboPhase in the combustion turbines.

6.5 BACT for Greenhouse Gases (GHG) – Combustion Turbines

6.5.1 Step 1. Identify All Potential Control Strategies

For this unit, the CO_2e emissions are due to carbon dioxide (CO_2), methane (CH_4) and nitrous oxides (N_2O) emissions. Global warming potentials (GWP) of methane and nitrous oxide emissions are normalized to the warming potential of carbon dioxide (as CO_2e) by multiplying the methane emissions by 25 and the nitrous oxide emissions by 298. Despite the higher warming potentials of methane and nitrous oxides compared to carbon dioxide, it is expected that carbon dioxide emissions will still account for over 99 percent of the CO_2e GWP for this unit, based on published emission factors for natural gas-fired turbines.

There are two broad strategies for reducing CO_2 emissions from stationary combustion processes such as combustion turbines. The first is to minimize the production of CO_2 through the use of low-carbon fuels and through aggressively energy-efficient design. The use of gaseous fuels, such as natural gas, reduces the production of CO_2 during the combustion process relative to burning solid fuels (e.g., coal or coke) and liquid fuels (e.g., distillate or residual oils). Additionally, a highly efficient operation requires less fuel for process heat, which directly impacts the amount of CO_2 produced. Establishing an aggressive basis for energy recovery and facility efficiency will reduce CO_2 production and the costs to recover it.

The second strategy for CO_2 emission reduction is carbon capture and sequestration (CCS). The inherent design of the combustion turbines produces a dilute CO_2 stream for potential capture.

The CO_2 emissions from the combustion turbines can theoretically be captured through pre-combustion methods or through post-combustion methods. In the pre-combustion approach, oxygen instead of air is used to combust the fuel and a concentrated CO_2 exhaust gas is generated. This approach significantly reduces the capital and energy cost of removing CO_2 from conventional combustion processes using air as an oxygen source, but it incurs significant capital and energy costs associated with separating oxygen from the air.

Post-combustion methods are applied to conventional combustion techniques using air and carbon-containing fuels in order to isolate CO_2 from the combustion exhaust gases. Because the air used for combustion contains nearly 60 percent nitrogen, the CO_2 concentration in the exhaust gases is only 5 to 20 percent depending on the amount of excess air and the carbon content of the fuel.

6.5.2 Step 2. Identify Technically Feasible Control Technologies

6.5.2.1 Fuel Selection

6.5.2.1.1 Low-Carbon Fuels

Numerous fuels are available for use. As Table 6-7 shows, combustion of natural gas yields 40 to 50 percent less CO_2 than does combustion of coal and petroleum coke and approximately 30 percent less CO_2 than does combustion of residual oil. Accordingly, the preferential burning of a low-carbon gaseous fuel in the turbines is an extremely effective CO_2 control technique. This control technique is **technically feasible** for the combustion turbines and is an inherent part of the facility's design.

Table 6-7: CO_2 Emission Factors

Fuel	Pounds CO_2 per MMBtu[a]
Petroleum coke	225
Coal	210
Residual oil	174
Distillate oil	161
Natural gas	117

Source: Energy Information Administration at
http://www.eia.doe.gov/oiaf/1605/coefficients.html
(a) MMBtu = million British thermal units

6.5.2.1.2 Combustion of Biogenic Sources

The combustion turbines have not been designed to accommodate fibrous biomass, such as corn stover, which is the most likely biomass available in sufficient quantities for the unit from the surrounding area. For both regulatory and technical feasibility issues, therefore, **biogenic sources are not a feasible option**.

6.5.2.2 Energy Efficiency

6.5.2.2.1 Selection of Efficient Turbine Design

This option reduces carbon dioxide emissions by ensuring that the plant is as efficient as possible, thereby reducing the amount of fuel burned per megawatt-hr produced.

- Combustion control optimization and energy efficient equipment – The combustion turbines and their design is highly efficient. This is technically and economically feasible. Potential options that may increase efficiency include the following:
  - Fast ramp-up/ramp-down
  - High starting reliability
  - TurboPhase
  - 18-stage high-efficiency, axial flow compressor with variable inlet guide vanes
  - Fuel gas heating (to a maximum of 75 °F) to improve turbine efficiency
  - Dry low-NO_x burners
  - Inlet air filtration utilizing high efficiency cartridge filters to clean combustion air and remove contaminants
  - On and off-line compressor water wash system to remove deposits and other contaminants from compressor blades to maintain efficient operation

- Combined heat and power plant –There are no adjacent industries which could use process steam from the plant, so this is not technically feasible. In addition, these combustion turbines are not combined cycle and steam is not part of the Project design.

6.5.2.3 Add-on Control Devices

6.5.2.3.1 Catalytic Oxidation

Nitrous oxide emissions are reduced by passing the combustion gases over a catalyst, converting to nitrogen plus oxygen. Similarly, VOC emissions, such as methane, may be converted from CH_4 to CO_2 plus water. For the same reasons given above in the discussion for CO BACT controls, **catalytic oxidation is technically feasible for this unit.**

6.5.2.3.2 Thermal Oxidation

There are several types of thermal oxidation technology. All of these technologies oxidize methane (CH_4) to carbon dioxide and water, by raising the temperature of the gas stream being treated to approximately

1,600ºF for approximately one to two seconds. Given sufficient mixing, this residence time and temperature is capable of achieving at least a 98 percent reduction in methane emissions for these processes. Secondary pollutants are produced by thermal oxidation. These include NO_x and CO from the combustion of natural gas used to heat the process stream. Thermal oxidation technologies also may employ some form of heat recovery, either recuperative or regenerative, to reduce economic, environmental and energy costs. In the case of a turbine, it is expected that approximately 3.5 lb/hr of methane will be produced at full load (with an exhaust flow rate of approximately 2.2 million actual cubic feet per minute). The exhaust gas stream is thus both high volume and low in methane concentration, so would need to be concentrated to the point that the methane would be capable of combustion. Also, additional CO_2 would be produced due to the need for combusting natural gas to heat the methane to the oxidation point, so the overall effectiveness in reducing CO_2e emissions due to methane by oxidizing them to carbon dioxide would be much less due to the additional carbon dioxide produced in order to combust the methane in the first place. **Therefore, thermal oxidation is technically infeasible for this unit.**

6.5.2.4 Carbon Dioxide Capture and Sequestration (CCS)

This is a general term which is used for approaches that capture and separate CO_2 from an exhaust stream, and then store it in a place which will keep it from the atmosphere for a long time. The three general categories of carbon dioxide capture are pre-combustion CO_2 capture, oxygen-combustion, and post-combustion CO_2 capture.

6.5.2.4.1 Pre-combustion CO_2 Capture

Pre-combustion CO_2 capture is used in gasification plants, where the CO_2 is captured from the syngas prior to combustion in the turbine, where it is relatively concentrated in the gas stream. This facility is not a gasification plant; therefore **pre-combustion capture is not technically feasible**.

6.5.2.4.2 Post-combustion CO_2 Capture

Post-combustion CO_2 capture is used for units such as pulverized coal plants. In these units, the flue gas concentration of CO_2 runs between 10-15 percent by volume, and is released at atmospheric pressure. This results in a high actual volume of gas to be treated, while trace impurities in the airflow tend to reduce the effectiveness of the CO_2 adsorbing process, and compressing the captured CO_2 from atmospheric pressure to pipeline pressure represents a large parasitic load. The currently available process is costly and energy intensive, so research is being done on ways to increase the solvent capture efficiency and reduce the cost. These approaches include investigating the use of alternative solvents, solid sorbents or membranes. Of these potentially more efficient approaches, most are currently at laboratory/bench scale, so are not technically feasible. Pilot scale processes are starting to be placed in service, such as a 48 MW slipstream project at Brindisi, Italy, started in March 2011, which is limited to capturing less than 10,000 tons of CO_2 per year. Another pilot program was completed at Mountaineer Power Plant near New Haven, West Virginia. Actual large scale CCS project phases were planned for this site, however the projects were cancelled. In addition, the DOE-supported FutureGen project was also cancelled. No commercially available post-combustion CO_2 capture systems are known to have been installed at a large power plant as other than pilot-scale demonstration projects. Even though there have been no projects of this size that have successfully employed this technology, the EPA has stated in their document “PSD and Title V Permitting Guidance for Greenhouse Gases” (March 2011) that “for the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is “available” for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams.” Because these combustion turbines will be used for peaking purposes, and will ramp up and down to follow the load, they are not considered to have a pure, constant CO_2 stream. For the purposes of this BACT analysis, **post-combustion capture is considered not technically feasible for the simple-cycle combustion turbines.**

6.5.2.4.3 CO_2 Sequestration

CO_2 sequestration involves transporting CO_2 to a suitable geologic location where it can be injected as a supercritical fluid into deep, underground rock formations for permanent storage. Identifying a suitable site within an economically-viable distance will require site-specific quantitative risk assessment. Four trapping methods are known: mineral trapping, physical adsorption, hydrodynamic trapping, and solubility trapping.

1. Mineral Trapping

In this method, the CO_2 is trapped by undergoing a chemical reaction with various minerals, resulting in the formation of a carbonate mineral. This process can be rapid or very slow, depending on the chemistry of the rock and water at the site. Mineral trapping is expected to result in the most stable, permanent form of geological CO_2 sequestration. Experiments have shown that basalt formations can rapidly transform injected CO_2 into carbonate minerals, beginning precipitation in a few months’ time and projected complete conversion within 100 years or less, depending on depth of injection. Sandstone formations low in carbonates may also be suitable candidates, depending on the mineral contents of the formations. These methods have been demonstrated only on a laboratory scale, so are **not technically feasible**.

2. Physical Adsorption

In this case, CO_2 molecules are trapped in micropore wall surfaces of coal organic matter or organic rich shales. The hydrostatic pressure in the formation controls the adsorption process. The injection of CO_2 can also result in driving off methane for collection by other wells, helping the economics. West Virginia has multiple coal beds throughout the State. Coal beds have historically not produced much methane. Some coal beds in the US are being tested for CO_2 storage/methane recovery, but this is currently at a pilot phase. Use of coal beds in West Virginia would require much further study to locate a suitable site for sequestration and are currently **not technically feasible.**

3. Hydrodynamic Trapping

In the case of Hydrodynamic Trapping, the pore space of an aquifer takes the injected carbon dioxide, and the aquifer is capped by an impermeable rock layer to trap the CO_2 well below the near-surface environment. For storage purposes, the aquifer should be saline enough to be non-potable, and deep enough (over 2,700 feet) to confirm that the pressure is sufficient to keep the compressed CO_2 in a supercritical or liquid phase. As the state of West Virginia is unlikely to apply for primacy for the Class VI regulations (governing injection wells), EPA rules for a minimum of 10,000 milligrams per liter total dissolved solids (TDS) to qualify as saline enough to be suitable for injection will probably apply. Discovering locations which exceed 10,000 milligrams per liter would require more exploration and test wells to characterize the site and determine the aquifer suitability. A pilot scale injection study took place near Shadyside, Ohio but due the geologic complexities within the western Appalachian Basin, the injection rates were reported to be much lower than expected and required higher injection pressures. Due to the cost of exploration and the difficulty in finding a suitable injection site, hydrodynamic trapping is **not technically feasible** at this time.

4. Solubility Trapping

In this case, the CO_2 dissolves in the water or forms carbonic acid, becoming slightly heavier and sinking to the bottom of the aquifer. Solubility trapping also occurs during CO_2 flooding for enhanced oil recovery (EOR). In this case, the CO_2 dissolves into the oil, and is trapped by the immobile, non-recoverable oil. CO_2 flooding has been used for years for EOR, resulting in some existing injection infrastructure at oilfields, although the sequestration effects were not originally monitored. However, oil fields have stored crude oil and natural gas for millions of years, and the geologic conditions that trap oil and gas are also the conditions suitable for CO_2 storage. If the CO_2 is used for EOR, the cost of transporting it to the oilfield may be partially offset. The nearest oilfield using EOR appears to be the Appalachian Basin, located very close to the site, within 50 miles, although the existing infrastructure is at capacity as far as ability to inject CO_2. Therefore, solubility trapping is **not technically feasible** at this time.

6.5.2.4.4 Summary of CO_2 Sequestration

To summarize, existing CO_2 capture technologies have not been applied at large power plants, as the energetic costs are prohibitive, and while more efficient approaches are being investigated, none have currently been developed past the pilot-stage. Even though post-combustion technology for CO_2 capture has not been demonstrated on a simple-cycle combustion turbine, the EPA has stated that it is considered technologically feasible, however this Project will not have a pure CO_2 stream as it is a peaking plant and will ramp up and down and start-up and shut-down daily when it operates. However, a published cost estimate for a 235 MW slipstream pilot project in West Virginia is $668 million, so scaling that linearly to a size capable of handling the approximate 300 net MW capacity of this Project would be over $852 million. Potential carbon sequestration sites in West Virginia may exist, but the technologies to use them are mostly still in the pilot-scale phase of development, and Pleasants Energy would need to do much more investigation in order to discover where the sites are, if any, and characterize them enough to demonstrate the long-term viability of the locations. When looking at cost to construct a pipeline that may not need to be more than 50 miles, as determined from another power project (IPL Ottumwa Generating Station –in Iowa) using an average cost of approximately $1.4 million/mile of pipeline this cost is over $70 million. The capital costs would also need to include costs for gas compression, additional injection and monitoring wells necessary to handle the volume of CO_2 produced, pipeline right-of-way, operation and maintenance costs, etc.

The facts are that the qualitative cost estimate of capture and sequestration is quite high, the technological effectiveness for the capture equipment for a unit of this size has not been demonstrated in practice yet, and there is uncertainty as to whether locations capable of storing the large amounts of CO_2 that would be produced per year exist within a closer radius of the plant, and the fact that the Pleasants Energy facility does not have a pure CO_2 stream **are sufficient to eliminate this option without requiring a more detailed site-specific technological or economic analysis.**

6.5.2.5 Summary of Technically Feasible Control Technologies

The technical feasibility of the GHG control options for the combustion turbines is summarized in Table 6-8. The expected performance has been determined considering the performance of existing systems, vendor guarantees, permitted emission limits, and the design requirements for the combustion turbines.

Table 6-8: Summary of Technically Feasible GHG Control Technologies for Combustion Turbines

Control System		Technical Feasibility	Comments
Fuel selection	Low carbon fuels	Feasible	Natural gas has been selected as the fuel for this Project
	Combustion of biogenic sources	Not feasible	--
Energy efficiency	Efficient turbine design	Feasible	Standard for the turbines under consideration
Post combustion controls	Catalytic oxidation	Not feasible	Will reduce methane emissions but create more carbon dioxide
	Thermal oxidation	Not feasible	--
Carbon capture	Pre-combustion CO_2 capture	Not feasible	--
	Post-combustion CO_2 capture	Not feasible	Never demonstrated on combustion turbines and costs for a coal plant are not economically feasible
Carbon sequestration	Mineral trapping	Not feasible	--
	Physical adsorption	Not feasible	--
	Hydrodynamic trapping	Not feasible	--
	Solubility trapping	Not feasible	--

6.5.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible control technologies are natural gas with distillate fuel oil as backup fuel, and efficient turbine design. The use of low-carbon fuels and aggressively energy-efficient design to reduce CO_2 emissions is inherent in the design of the Project combustion turbines and is considered the baseline condition.

Table 6-9 presents the ranking of the GHG technologies deemed feasible for the Project. While these two technologies are “ranked” in order of their presentation, they are more appropriately considered as a suite of measures that will be implemented to confirm that the Project generates and consumes power in the most efficient manner and thereby achieves BACT for GHGs.

Table 6-9: GHG Technology Ranking for the Project

Technology	Ranking	Applied to Project
Simple – cycle combustion turbines (employing efficient, state-of-the-art design)	1	Yes
Clean fuel – natural gas	2	Yes

6.5.4 Step 4. Evaluate the Most Effective Control Technologies

6.5.4.1 Environmental, Energy, and Economic Feasibility of Control Options

Because Pleasants Energy is proposing to utilize both of the feasible technologies for reducing GHGs from the generation of power, no detailed analysis is provided to compare the available control technologies' relative environmental, energy and economic impacts.

6.5.5 Step 5. Proposed Greenhouse Gas BACT Determination

BACT for greenhouse gas emissions from the combustion turbines is determined to be the use of natural gas as a fuel and efficient turbine design. These design options will allow the simple-cycle combustion turbines to not exceed 1,570 lb CO_2/MW-hr (gross) on an annual basis, and each turbine will not exceed 615,816 tpy CO_2e of all greenhouse gases combined.

6.6 BACT for Start-Up and Shut-down Emissions - Combustion Turbines

6.6.1 Step 1. Identify Potential Control Strategies

Criteria pollutants will be emitted during start-up and shut-down of the combustion turbines. Start-up emissions are generally higher for CO and NO_x emissions because of incomplete combustion that occurs during the transient states.

Pleasants Energy estimates not more than 365 start-up/shut-down events per turbine per year will occur on natural gas and not more than 20 start-up/shut-down events per year. One start-up/shut-down event is equivalent to one start-up (initiating the start to Mode 6 emissions compliance is achieved (approximately 60 percent load) plus one shut-down (generally 60 to 0 percent load).

6.6.2 Step 2. Identify Technically Feasible Control Technologies

There are no technically feasible control technologies for start-up and shut-down emissions from the combustion turbines, except to minimize emissions during these periods using good combustion practices.

6.6.3 Step 3. Rank the Technically Feasible Control Technologies

Since there are no technically feasible control technologies for start-up and shut-down emissions, there is nothing to rank.

6.6.4 Step 4. Evaluate the Most Effective Control Technologies

There are no technically feasible control options for start-up and shut-down emissions; therefore there are no environmental, energy or economic impacts to discuss.

6.6.5 Step 5. Proposed Start-up and Shut down BACT Determination

Table 6-10 displays the BACT levels for start-up and shut-down emissions for natural gas operation.

Table 6-10: Start-up and Shut down Emissions for the Combustion Turbines on Natural Gas

Pollutant	Start-up Emissions (lb/hr)[a,b]	Shut-down Emissions (lb/hr)[a,c]	Number of Starts Per Turbine[d]	Start-up /Shut-down Emissions (tpy)[a]	Total Start-up /Shut-down Emissions (Both turbines) (tpy)[a]
NOx[a]	121.2	103.3	365	63.1	126.2
CO[a]	384.4	144.4	365	166.7	333.4
$PM/PM_{10}/PM_{2.5}$	18.0	18.0	365	9.9	19.7
VOC[a]	6.8	6.2	365	3.6	7.2
SO_2	2.5	2.5	365	1.4	2.7
H_2SO_4	0.38	0.38	365	0.21	0.42
Lead	--	--	--	--	--

(a) lb/hr = pounds per hour; tpy = tons per year
(b) Includes start-up emissions from GE Start-up Summary and actual CEMS start-up data.
(d) Includes shut-down emissions from GE Start-up Summary and actual CEMS shut-down data.
(a) One start-up and shut-down event is equivalent to one start-up plus one shut-down. All emissions based on worst-case cold start data.

Table 6-11: Start-up and Shut down Emissions for the Combustion Turbines on Fuel Oil

Pollutant	Start-up Emissions (lb/hr)[a,b]	Shut-down Emissions (lb/hr)[a,c]	Number of Starts Per Turbine[d]	Start-up /Shut-down Emissions (tpy)[a]	Total Start-up /Shut-down Emissions (Both turbines) (tpy)[a]
NO_x	561.6	543.1	20	16.7	33.3
CO	230.4	195.7	20	6.6	13.1
$PM/PM_{10}/PM_{2.5}$	39.0	39.0	20	1.2	2.3
VOC	9.1	9.0	20	0.27	0.54
SO_2	103.0	103.0	20	3.1	6.2
H_2SO_4	15.8	15.8	20	0.47	0.95
Lead	0.02	0.02	20	6.6×10^{-4}	1.3×10^{-3}

(a) lb/hr = pounds per hour; tpy = tons per year
(b) Includes start-up emissions from GE Start-up Summary and actual CEMS start-up data.
(c) Includes shut-down emissions from GE Start-up Summary and actual CEMS shut-down data.
(d) One start-up and shut-down event is equivalent to one start-up plus one shut-down. All emissions based on worst-case cold start data.

BACT work practice standards consisting of Good Combustion Practices are applicable to the combustion turbines and will be used at all times during start-up and shut-down. Pleasants Energy will create and maintain work practice standards for start-up and shut-down prior to commercial operation and will keep the plans on-site.

7.0 AIR DISPERSION MODELING

Since the Project is subject to PSD review, an air dispersion modeling analysis is required for each regulated NSR pollutant that exceeds its PSD significance level. According to the emission calculations for this Project, $NO_{x,}$ CO, PM/PM_{10}/$PM_{2.5}$, and CO_2e are subject to PSD review; as a result, an air quality analysis was performed for NOx, CO, and PM_{10}/$PM_{2.5}$ using the EPA-approved American Meteorological Society (AMS)/EPA Regulatory Model (AERMOD). Consistent with WVDEP guidance, modeling of PM and CO_2e will not be conducted, since there are no modeling thresholds for these pollutants.

A pre-project meeting was held with the WVDEP to discuss the modeling protocol that would be used for this Project. The latest version (Revision 2) of the air dispersion modeling and OLM modeling protocol that incorporates WVDEP's comments (August 2015) is presented in Appendix F of this application.

A summary of the models, the modeling techniques, and modeling results for the Project are discussed in the following sections.

7.1 Air Dispersion Model

Air dispersion modeling was performed using the latest version of the AERMOD model (Version 15181). The AERMOD model is an EPA-approved, steady-state Gaussian air dispersion model that is designed to estimate downwind ground-level concentrations from single or multiple sources using detailed meteorological data. AERMOD is a model currently approved for industrial sources and PSD permits. The WVDEP requested that Pleasants Energy demonstrate regulatory compliance through its use.

Major features of the AERMOD model are as follows:

- Plume rise, in stable conditions, is calculated using Briggs equations that consider wind and temperature gradients at stack top and half the distance to plume rise; in unstable conditions, plume rise is superimposed on the displacements by random convective velocities, accounting for updrafts and downdrafts due to momentum and buoyancy as a function of downwind distance for stack emissions.
- Plume dispersion receives Gaussian treatment in horizontal and vertical directions for stable conditions and non-Gaussian probability density function in vertical direction for unstable conditions.
- AERMOD creates profiles of wind, temperature, and turbulence, using all available measurement levels and accounts for meteorological data throughout the plume depth.

- Surface characteristics, such as Bowen ratio, albedo, and surface roughness length, may be specified to better simulate the modeling domain.
- Planetary Boundary Layers (PBL) such as friction velocity, Monin-Obukhov length, convective velocity scale, mechanical and convective height, and sensible heat flux may be specified.
- AERMOD uses a convective (based upon hourly accumulation of sensible heat flux) and a mechanical mixed layer height.
- AERMOD’s terrain pre-processor (AERMAP) provides information for the advanced critical dividing streamline height algorithms and uses National Elevation Dataset (NED) to obtain elevations.
- AERMOD uses vertical and horizontal turbulence-based plume growth (from measurements and/or PBL theory) that varies with height and uses continuous growth functions.
- AERMOD uses convective updrafts and downdrafts in a probability density function to predict plume interaction with the mixing lid in convective conditions while using a mechanically mixed layer near the ground.
- Plume reflection above the lid is considered.
- AERMOD models impacts that occur within the cavity regions of building downwash via the use of the plume rise model enhancements (PRIME) algorithm, and then uses the standard AERMOD algorithms for areas without downwash.

Details of the modeling algorithms contained in the AERMOD model may be found in the User's Guide for AERMOD. The regulatory default option was selected for this analysis since it met the EPA guideline requirements and WVDEP modeling guidance requirements, with the exception of the 1-hour NO_2 modeling. The 1-hour NO_2 modeling options selected are detailed in the OLM modeling protocol in Appendix F of this application.

The following default model options, which were discussed in the air dispersion modeling protocol, were used:

- Gradual Plume Rise
- Stack-tip Downwash
- Buoyancy-induced Dispersion
- Calms and Missing Data Processing Routine
- Calculate Wind Profiles
- Calculate Vertical Potential Temperature Gradient

- Rural Dispersion

7.2 Model Parameters

Modeling runs were conducted at full load and partial loads of the combustion turbines to confirm that operation of the Project will not result in impacts greater than the NAAQS and PSD Class II Increments. The expected hourly emission rates and modeling parameters for one combustion turbine operating on natural gas and fuel oil are shown in Table 7-1 and Table 7-2, respectively. These emission rates represent projected worst-case ambient conditions under various operating loads and include start-up and shut-down emissions. The annual emissions are based on worst-case annual emissions.

Table 7-1: Combustion Turbine Emissions and Modeling Parameters – Natural Gas Operation (per Turbine)

Pollutant	100% Load with TurboPhase[a]	100% Load	80% Load	Start-up/ Shut down
	pounds per hour (lb/hr)			
NO_x	75 (53[c])	65 (53[c])	54 (53[c])	121.2[b] (53[c])
CO	36	32	26	384.4[b]
$PM_{10}/PM_{2.5}$	20.2 (11.54[c])	18 (11.54[c])	18 (11.54[c])	18 (11.54[c])
Stack Parameters[d]				
Stack temperature (ºF)[d]	1,131	1,131	1,097	1,097
Exit velocity (ft/s)[d]	166.6	148.2	139.6	139.6
Stack height (feet)	114.5	114.5	114.5	114.5
Stack diameter (feet)	18	18	18	18

(a) Worst-case emissions with TurboPhase operation
(b) Maximum 1-hour start-up emissions (worst-case combustion turbine emissions during start-up)
(c) Maximum annual emissions, annualized based on 8,760 hours per year to obtain lb/hr rates, including start-up and shutdown emissions on gas and oil and 19,081,721,569 SCF/year fuel combusted for both turbines combined which includes fuel oil at 889 SCF/gal.
(d) ºF = degrees Fahrenheit, ft/s = feet per second

Table 7-2: Combustion Turbine Emissions and Modeling Parameters – Fuel Oil Operation (per Turbine)

Pollutant	100% Load[a]	80% Load	Start-up/ Shut down
	pounds per hour (lb/hr)		
NO_x[b]	53[d]	53[d]	53[d]
CO	72	53	230.4[c]
$PM_{10}/PM_{2.5}$	39 (11.54[d])	39 (11.54[d])	39 (11.54[d])
Stack Parameters[d]			
Stack temperature (ºF)[e]	1,131	1,158	1,158
Exit velocity (ft/s)[e]	148.2	141.7	141.7
Stack height (feet)	114.5	114.5	114.5
Stack diameter (feet)	18	18	18

(a) Worst-case emissions with TurboPhase operation
(b) The combustion turbine back-up fuel oil operation and start-up emissions are intermittent and will not be included in the NO_2 1-hour modeling analysis
(c) Maximum 1-hour start-up emissions (worst-case combustion turbine emissions during start-up)
(d)Maximum annual emissions, annualized based on 8,760 hours per year to obtain lb/hr rates, including start-up and shutdown emissions on gas and oil and 19,081,721,569 SCF/year fuel combusted for both turbines combined which includes fuel oil at 889 SCF/gal.
(e) ºF = degrees Fahrenheit, ft/s = feet per second

7.3 Modeling Methodology

The modeling methodology used for this analysis is summarized in the sections below. Further specifications, detailed in the air dispersion modeling protocol and OLM modeling protocol submitted as part of this application can be found in Appendix F of this application.

7.3.1 Good Engineering Practice

Sources included in a PSD permit application are subject to Good Engineering Practice (GEP) stack height requirements outlined in 40 CFR Part 51, Sections 51.100 and 51.118. As defined by the regulations, GEP height is calculated as the greater of 65 meters (measured from the ground level elevation at the base of the stack) or the height resulting from the following formula:

$$GEP = H + 1.5L$$

Where

H = the height of nearby structure(s) measured from the ground level elevation at the base of the stack; and

L = the lesser dimension (height or projected width) of nearby structure(s) (i.e., building height or the greatest crosswind distance of the building - also known as maximum projected width).

To meet stack height requirements, the point sources were evaluated in terms of their proximity to nearby structures. The purpose of this evaluation was to determine if the discharge from the stack will become caught in the turbulent wake of a building or other structure, resulting in downwash of the plume. Downwash of the plume can result in elevated ground-level concentrations. In *Guideline for Determination of Good Engineering Practice Stack Height* (EPA, 1985), EPA provides guidance for determining whether building downwash will occur. The downwash analysis was performed consistent with the methods prescribed in this guidance document.

Calculations for determining the direction-specific downwash parameters were performed using the most current version of the EPA's Building Profile Input Program – Plume Rise Model Enhancements (Version 04274), otherwise referred to as the BPIP-PRIME downwash algorithm. The BPIP-PRIME model provides direction-specific building dimensions to evaluate downwash conditions. The Project is located in a rural area and the only buildings that could potentially affect emissions from the Project are the on-site structures.

After running the BPIP-PRIME model, it was determined that the GEP stack height for this Project will not exceed 65 meters. The combustion turbine stacks are 114.5 feet (34.9 meters)

7.3.2 Receptor Grid

The overall purpose of the modeling analysis is to quantify the ground-level concentrations from the operation of the Project to determine if the Project will result in, or contribute to, concentrations above the NAAQS and/or PSD Class II Increments. The modeling runs were conducted using the AERMOD model in simple and complex terrain mode within a 20- by 20-kilometer Cartesian grid to determine the significant impact area (SIA) for each pollutant. The grid incorporates the following spacing between receptors based on guidance from WVDEP: 50-meter out to 1 kilometer, 100-meter from 1 to 3 kilometers, 250-meter from 3 to 10 kilometers, and 500-meter from 10 to 20 kilometers (Figure G-1, Appendix G). Receptors were also placed along the fence line boundary at a spacing of 50 meters. The significant impact area exceeded 20 kilometers for the 1-hour NO_2 averaging period; therefore, the grid was extended to a 50-by-50 kilometer grid for the 1-hour NO_2 modeling (Figure G-2, Appendix G). The significant impact area did not exceed 20 kilometers for all other pollutants and averaging periods and the receptor grid was not extended.

The appropriate U.S. Geological Survey (USGS) Digital Elevation Model (DEM) terrain files (1/3 arc second) were used to obtain the necessary receptor elevations. North American Datum of 1983 (NAD 83) was used to develop the Universal Transverse Mercator (UTM) coordinates for this Project.

AERMOD has a terrain preprocessor (AERMAP) which uses gridded terrain data for the modeling domain to calculate not only a XYZ coordinate, but a representative terrain-influence height associated with each receptor location selected. This terrain-influenced height is called the height scale and is separate for each individual receptor. AERMAP (Version 11103) utilized the electronic digital elevation model (DEM) terrain data to populate the model with receptor elevations.

7.3.3 Meteorological Data

Surface air meteorological data from Parkersburg Wood County Airport, West Virginia (Station ID 03804) and upper air data from Wilmington Airborne Park, Ohio (Station ID 13841) were used for years 2010 to 2014. A profile base elevation value of 253.3 meters was used. The dominant wind direction is shown in Figure G-3 in Appendix G. Based on guidance from WVDEP, a surface sensitivity analysis was performed. AERSURFACE inputs for both the Project site and the Parkersburg Wood County Airport were used to generate meteorological data for both sets of AERSURFACE inputs. The results of the modeling analysis demonstrated that the AERSURFACE inputs for the Project site produce the worst-case results for all pollutants and averaging periods modeled for the Project. Therefore, the Project site AERSURFACE analysis was used to generate the meteorological data for the air dispersion modeling analysis. The modeling protocol in Appendix F discusses the analysis.

7.3.4 Land Use Parameters

Based on the Auer scheme, the existing land use for a 3-kilometer area surrounding the Project is more than 50 percent rural. Also, the population density is fewer than 750 people per square kilometer for the same area. Therefore, rural dispersion coefficients were used in the AERMOD models. The modeling protocol in Appendix F discusses the Auer scheme analysis.

7.3.5 Significant Impact Area Determination

The AERMOD model was run for the Project using the worst-case impact scenario for the combustion turbines. If any modeled pollutant resulted in impacts below the significance levels for each averaging period, no further modeling for that pollutant and averaging period was required to determine compliance with the NAAQS or PSD Class II Increments. However, if the modeling predicted impacts at or above the modeling significance level for any pollutant, a cumulative analysis including all point sources within the radius of impact (ROI) was required for that pollutant and averaging period.

7.3.6 Background Air Quality

As stated previously, if any pollutant exceeds its respective PSD significance level, a refined analysis (cumulative analysis) will be performed for that pollutant and averaging period. This analysis will be used to determine compliance with the PSD Class II Increments and the NAAQS. The NAAQS are set up to protect the air quality for all sensitive populations and attainment is determined by the comparison to the NAAQS thresholds. As such, there is an existing concentration of each criteria pollutant that is present in ambient air that must be included in an analysis to account for items such as mobile source emissions that are not accounted for in the model. Monitored ambient concentrations will be added to the modeled ground level impacts to account for these sources.

The EPA and state agencies collect ambient air quality pollutant concentrations from monitors that are placed throughout each state. The data that is collected by the monitors is available on the EPA website (http://www.epa.gov/airdata/). For the Project, background values for each pollutant were identified from the representative monitors in the area. Each pollutant has been reviewed for applicable monitors and the background values were identified based on this analysis. The monitored background levels will be added to the modeled NAAQS impacts, as previously discussed.

In accordance with EPA documentation[5], there are three criteria that should be considered when selecting a representative existing ambient air monitor to represent ambient air concentrations for a project. These three criteria include the following:

- Monitor Location,
- Data Quality; and
- Currentness of Data.

Further discussion on these three criteria is detailed in the modeling protocol in Appendix F.

The regional background concentrations for the modeled pollutants and averaging periods for the cumulative modeling analysis are listed in Table 7-3.

[5] U.S EPA. Ambient Air Monitoring Guidelines for Prevention of Significant Deterioration (PSD). EPA-450/4-87-007. May 1987.

Table 7-3: Background Concentration for the NO_2 1-hour Averaging Period

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)[a]	Form of the Standard	Air Quality System Monitor ID
NO_2	1-hour	68.3	98th percentile averaged over years 2012 to 2014	Charleroi, Pennsylvania (Monitor 42-125-0005)
$PM_{2.5}$	24-hour	19.4	98th percentile averaged over years 2012 to 2014	Vienna, West Virginia (Monitor 54-107-1002)

(a) $\mu g/m^3$ = micrograms per cubic meter

7.3.7 NAAQS and PSD Class II Increment Analysis

Per discussions with WVDEP, all major stationary sources that emit pollutants subject to this analysis within 20 kilometers of the Project site were addressed for the NAAQS and PSD Class II Increment analysis for pollutants that exceed their respective significant impact level. Sources located 20 to 25 kilometers from the site were analyzed on a case-by-case basis. The inventories of sources were developed in accordance with applicable EPA guidance, input from the WVDEP, and the Ohio Environmental Protection Agency (OEPA). The emissions and stack parameters have been determined for the inventory sources from permits, emission inventories and other information. A list of the inventory sources provided by the WVDEP and OEPA is located in Appendix F and on DVD in Appendix H. The submitted cumulative modeling includes all stationary sources that emit pollutants subject to this analysis and that are located within 20 kilometers. Sources within 20-25 kilometers were included on a case-by-case basis.

7.3.8 Ambient Monitoring

The modeling analysis that was conducted for the Project addresses the pre-construction monitoring provision of the PSD regulations. The regulations specify significant monitoring levels for each PSD pollutant that triggers the requirement to perform one year of pre-construction ambient air monitoring. For any impacts predicted to be below the monitoring *de minimis* levels, Pleasants Energy requests pre-construction ambient air monitoring not be required. For any predicted concentrations reaching or exceeding the monitoring *de minimis* levels, Pleasants Energy plans to meet all pre-construction monitoring requirements stated in the "Ambient Monitoring Guidelines for Prevention of Significant Deterioration" (EPA). The NAAQS, modeling/monitoring significance levels, and PSD Class II Increment thresholds for the modeled pollutants are shown in Table 7-4.

Table 7-4: NAAQS, Significance, and Monitoring Levels and PSD Class II Increment (μg/m^3)

Pollutant	Averaging Period	NAAQS	Modeling Significance Level	Monitoring Significance Level	PSD Class II Increment
			micrograms per cubic meter (μg/m^3)		
NO_2	Annual	100	1	14	25
	1-hour	188.7	7.5[c]	NA	NA
CO	8-hour	10,000[d]	500	575	NA
	1-hour	40,000[d]	2,000	NA	NA
PM_{10}	Annual	NA	1	NA	17
	24-hour	150[d]	5	10	30[d]
$PM_{2.5}$	Annual	12	0.3[a]	NA	4
	24-hour	35	1.2[a]	4[b]	9[d]

(a)United States Court of Appeals for the District of Columbia Circuit on January 22, 2013, vacated and remanded portions of the EPA rule establishing significant impact levels and vacated the rule establishing the significant monitoring concentration for $PM_{2.5}$ however, the $PM_{2.5}$ significant impact levels may still be used for Class II modeling analyses.
(b) The $PM_{2.5}$ 24-hour Significant Monitoring Concentration vacated by the United States Court of Appeals for the District of Columbia Circuit on January 22, 2013, is not considered valid in West Virginia. However, representative local monitoring data is available for use.
(c) The 1-hour NO_2 significance value is an interim value that the West Virginia Department of Environmental Protection (WVDEP) has adopted and the WVDEP is in agreement with the EPA that this is the de minimis value.
(d) The pollutants that are allowed one NAAQS exceedance per year and one PSD Class II Increment exceedance per year.

7.3.9 NO_2 Modeling – Multi-Tiered Screening Approach

The AERMOD model predicts ground-level concentrations of any generic pollutant without chemical transformations. Thus, the modeled NO_x emission rate will give ground-level modeled concentrations of NO_x. NAAQS values are presented as NO_2.

The EPA has a three-tier approach to modeling NO_2 concentrations.

- Tier I – total conversion, or all $NO_x = NO_2$
- Tier II – use a default NO_2/NO_x ratio
- Tier III – case-by-case detailed screening methods, such as OLM and Plume Volume Molar Ratio Method (PVMRM)

Initial modeling for the Project was performed using both Tier I and Tier II methodologies. It was determined from these modeling iterations that less conservative methods for determining 1-hour NO_2 compliance would be needed for this Project. Therefore, the ambient impact of the 1-hour NO_x predicted by the models was screened using the Tier III – OLM. The OLM modeling protocol, which discussed the proposed model to be used and the OLM methodology is shown in Appendix F of this application for reference.

Per WVDEP guidance and EPA's March 2011 memo[6] the applicant modeled only continuous operation for the 1-hour standard. The combustion turbine back-up fuel oil operation was not included in the 1-hour modeling analysis as the combustion turbines will operate on fuel oil only in emergency situations when natural gas is curtailed and for testing purposes at periods which cannot be predicted with reasonable certainty. In addition, start-up emissions from the combustion turbines on fuel oil were not modeled for the 1-hour NO_2 standard, either, as it is expected that there will be at most 20 starts per turbine per year which will be only in emergency situations and for testing purposes at unknown time periods. These operations will not contribute significantly to the annual distribution of the daily maximum 1-hour concentrations.

The Tier III OLM was not applied to the NO_x annual averaging period modeled impacts. All NO_x was assumed to be NO_2 for the annual averaging period; so Tier I was used for this averaging period.

7.3.9.1 In-Stack NO_2/NO_x Ratios

The amount of NO_2 present in the stack gases was determined for each piece of equipment being modeled and was determined from published data. A default in-stack NO_2/NO_x ratio of 0.5 was used for the natural gas-fired turbines per EPA's March 2011 Memo[7], as an appropriate equipment-specific in-stack ratio was not identified. For the cumulative modeling analysis, a default in-stack ratio NO_2/NO_x[8] ratio of 0.5 was used for inventory sources less than 1 kilometer from the Project site (this includes the existing sources at Pleasants Energy facility). Based on guidance from WVDEP, an in-stack NO_2/NO_x ratio of 0.2 was used for inventory sources greater than 1 kilometer away from the Project site.

Additionally, an equilibrium NO_2/NO_x ratio of 0.90 was used per EPA's March 2011 Memo.

7.3.9.2 Hourly Ozone Data

The selected monitor to be used for the 1-hour hourly ozone background is the West Virginia Air Pollution Control Commission monitoring station located in Vienna, Wood County, West Virginia (Air Quality System [AQS] ID: 54-107-1002). The applicant was advised by WVDEP to use this monitor for ozone season data as it is representative of the Project site. Additionally, the Vienna monitor is located in

[6] March 1, 2011 EPA Memo from Tyler Fox. Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard

[7] March 1, 2011 EPA Memo from Tyler Fox. Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard

a similar land-use area as the land-use near the Project; therefore, the monitor will provide data that is representative of the ozone concentrations in the Project area.

Because the Vienna monitor only has ozone season data available, two other monitors were selected for the non-ozone season data: the Lawrenceville monitoring station located in Pittsburg, Pennsylvania (AQS ID: 43-003-0008), and the Quaker City monitoring station located in Quaker City, Ohio (AQS ID: 39-121-9991). The Quaker City monitoring station is located closer to the Project site (approximately 70 kilometers from the Project site) than the Lawrenceville Station (approximately 170 kilometers from the Project site). The Quaker City station was deemed the most representative for the non-ozone season data due to its close proximity to the Project site. However, 2010 non-ozone season data is not available at the Quaker City station so data from the Lawrenceville station was used for this time period. Ozone data from the Lawrenceville station should be conservative due to its location in an urban area. Data from the Quaker City station was used for the non-ozone season hourly data for years 2011-2014.

Hourly background ozone concentrations were obtained from the EPA Technology Transfer Network Air Quality System for the Vienna monitoring station located in Wood County, West Virginia (AQS ID: 54-107-1002), the Lawrenceville monitoring station located in Pittsburg, Pennsylvania (AQS ID: 43-003-0008), and the Quaker City monitoring station located in Ohio (AQS ID: 39-121-9991). Data from each monitoring station was used for the time periods previously discussed. The background data was formatted for use in the AERMOD model and processed for years 2010 to 2014 to match the meteorological data years used in the modeling. The following steps and assumptions were used to create the hourly ozone data:

- One to six missing values: The average of the previous and following value was used.
- More than six missing values: Data was substituted based the maximum of the ozone concentrations measured during that hour in the month of the missing values.

7.4 Significance Model Results

Significance modeling was performed for NO_x, CO, and $PM_{10}/PM_{2.5}$ for the operation of the combustion turbines.

7.4.1 NO_2 Results

After examining the modeling results at all load levels, it was determined that no exceedances of the annual NO_2 modeling significance level occurred, and that no further modeling was required. The annual predicted impacts were lower than the ambient air monitoring *de minimis* level and therefore no pre-construction ambient monitoring is proposed for NO_2.

The model predicted that impacts greater than the 1-hour NO_2 modeling significance level occurred, and refined modeling would be required. The maximum modeled concentrations for the NO_2 1-hour and annual average periods are given in Table 7-5.

7.4.2 CO Results

After examining the modeling results at all load levels, it was determined that no exceedances of the 1-hour and 8-hour CO modeling significance levels occurred, and that no further modeling was required. Also the 8-hour predicted impacts were less than the ambient air monitoring *de minimis* level. The maximum modeled concentrations for CO are given in Table 7-5.

7.4.3 PM_{10} Results

After examining the modeling results at all load levels, it was determined that no exceedances of the annual and 24-hour PM_{10} modeling thresholds occurred; therefore, no further modeling was required for this pollutant. Additionally, the 24-hour predicted impacts for PM_{10} were lower than the ambient air monitoring *de minimis* levels and no pre-construction monitoring will be required. The maximum modeled results from the PM_{10} annual and 24-hour averaging periods are shown in Table 7-5.

7.4.4 $PM_{2.5}$ Results

After examining the modeling results at all load levels, it was determined that no exceedances of the annual $PM_{2.5}$ modeling thresholds occurred; therefore, no further modeling was required for this averaging period. The model predicted that impacts greater than the 24-hour $PM_{2.5}$ modeling significance level occurred, and refined modeling would be required. The maximum modeled concentrations for the $PM_{2.5}$ 24-hour and annual average periods is given in Table 7-5. The high first high is shown for 24-hour and annual PM_{10} and for the 24-hour and annual $PM_{2.5}$ the highest average first high over 5 years is shown.

Additionally, the 24-hour predicted impacts for $PM_{2.5}$ were lower than the ambient air monitoring *de minimis* levels and no pre-construction monitoring will be required.

7.4.5 Significance Modeling Summary

The maximum impacts from the Project are listed in Table 7-5. The results of the significance modeling indicate that the impacts of the CO 1-hour and 8-hour, NO_2 annual, PM_{10} annual and 24-hour, and $PM_{2.5}$ annual averaging periods from the Project will not result in a significant impact at any location. No further modeling is required for a PSD pollutant if the modeled impacts are below the significance levels.

Table 7-5: Maximum Modeled Concentrations

Pollutant	Averaging Period	UTM Coordinates[a]		Year	Predicted Concentration	Modeling Significance Level	Monitoring De Minimis Level
		Easting (meters)	Northing (meters)		micrograms per cubic meter ($\mu g/m^3$)		
NO_2	Annual	468,100	4,356,200	2012	0.1	1	14
	1-hour	467,700	4,356,200	5 years	45.7	7.5	--
CO	1-hour	467,700	4,356,200	2012	174.3	2000	--
	8-hour	468,100	4,356,200	2013	80.0	500	575
PM_{10}	Annual	468,100	4,356,200	2012	0.03	1	--
	24-hour	468,950	4,353,500	2014	2.8	5	10
$PM_{2.5}$	Annual	468,100	4,356,200	5 years	0.02	0.3	--
	24-hour	468,100	4,356,200	5 years	2.1	1.2	4

(a) UTM = Universal Transverse Mercator: NAD83

The modeling analyses indicate that the Project's emissions will exceed the PSD modeling significance thresholds for the NO_2 1-hour and the $PM_{2.5}$ 24-hour averaging periods. Refined modeling analyses were conducted to demonstrate compliance with the NAAQS and PSD Class II Increments.

Model input and output files for each pollutant are provided in Appendix H on DVD. In addition, area plots with concentration contour plots of each pollutant are shown in Figures G-4 to G-11 in Appendix G.

7.5 PSD Class II Increment Modeling

There are no PSD Class II Increment thresholds for 1-hour NO_2; therefore, no PSD Class II Increment analysis was performed for NO_2. A refined modeling analysis was conducted for the $PM_{2.5}$ 24-hour averaging period to demonstrate compliance with the PSD Class II Increment.

An inventory of sources within the expected ROI was used in the refined analysis. This inventory of sources and modeled parameters can be seen in the DVD in Appendix H of this application. An area plot with a concentration contour plot of the 24-hour $PM_{2.5}$ increment is shown in Figure G-12 in Appendix G

There were modeled PSD Increment exceedances for the $PM_{2.5}$ 24-hour averaging period. Further analysis demonstrated that the proposed Project is not significant at the receptors that exceed the Increment. As such, it was determined that there is enough available $PM_{2.5}$ PSD Class II Increment to construct and operate the proposed Project.

The results of the PSD Class II Increment analysis are shown below in Table 7-6. The second highest high was used for the 24-hour averaging periods.

Table 7-6. $PM_{2.5}$ Class II Increment Modeling Results

Pollutant	Averaging Period	UTM Coordinates[a] Easting (meters)	UTM Coordinates[a] Northing (meters)	Year	Predicted Concentration ($\mu g/m^3$)	PSD Class II Increment ($\mu g/m^3$)
$PM_{2.5}$	24-hour	451,500	4,353,000	2013	882.8[b,c]	9

(a) UTM = Universal Transverse Mercator: NAD83
(b) Value is 2nd highest high
(c) The Project is not significant at any modeled exceedance

7.6 NAAQS Modeling

A refined modeling analysis was conducted for the 1-hour NO_2 and 24-hour $PM_{2.5}$ averaging periods to demonstrate compliance with the NAAQS.

The existing Pleasants Energy sources were included in the cumulative modeling (TurboPhase engines and diesel generators). To accurately reflect the operation of the existing diesel generators only two of the five generators were included in the cumulative modeling. A maximum of two diesel generators will operate simultaneously at any given time.

The modeling results showed that the Project is not contributing to any NAAQS exceedance. Although there were modeled NAAQS exceedances for the 1-hour NO_2 averaging period and 24-hour $PM_{2.5}$ averaging period, further analysis (as found in Appendix H) demonstrates that the Project is not significant (does not exceed the significant impact level [SIL]) at the receptors that exceed the NAAQS. Therefore, the Project will be in compliance with the NAAQS. The NAAQS analysis modeling results are shown in Table 7-7.

Table 7-7: NAAQS Modeling Results

Pollutant and Averaging Period		UTM Coordinates[a] Easting (meters)	UTM Coordinates[a] Northing (meters)	Year	Predicted Concentration	Background Concentration	Total Concentration	NAAQS
					micrograms per cubic meter ($\mu g/m^3$)			
NO_2	1-hour	475,250	4,358,750	5 years	141.4	68.3	209.7[b]	188
$PM_{2.5}$	24-hour	451,500	4,353,000	5 years	582.8	19.4	602.2[b]	35

(a) UTM = Universal Transverse Mercator: NAD83
(b) The Project is not significant at any modeled exceedances

The NAAQS thresholds were compared to the following highs shown in Table 7-8 for each averaging period.

Table 7-8. Modeled Highs

Pollutant	Averaging Period	Modeled High
NO_2	1-hour	98th Percentile
$PM_{2.5}$	24-hour	98th Percentile

The model input and output files (including the additional analysis) are provided on DVD in Appendix H. In addition, an area plot with a concentration contour plot is provided in Figure G-13 and G-14 in Appendix G.

7.7 PSD Class I Increment Analysis

Recent Federal Land Manager (FLM) guidance requires that a proposed major source, in the course of a PSD application, perform an assessment of air quality impacts at Class I areas if these areas are located within approximately 300 kilometers of the Project. There are four Class I Areas that are within 300 kilometers of the Project:

- Otter Creek Wilderness (130 kilometers)
- Dolly Sods Wilderness (160 kilometers)
- Shenandoah National Park (200 kilometers)
- James River Face Wilderness (253 kilometers)

The locations of the Project site and the Class I Areas are shown in Appendix F of this application (Figure A-6, Appendix A to the modeling protocol).

To determine if further analysis is required for the Class I Increment analysis, modeled impacts at receptors placed 50 kilometers in the direction of each Class I area were compared to the Class I significance thresholds. The receptor elevations were adjusted accordingly to resemble the elevation at the respective Class I areas is shown in Table 7-9. The Class II modeled impacts in comparison to the Class I significance threshold is shown in Table 7-10. Based on the analysis, it was determined that the impacts from the Project will not significantly impact the four Class I areas that are within 300 kilometers of the Project and does not require further analysis.

Table 7-9: Class I Receptor Coordinates and Elevations

Class I Area	UTM Coordinates[a]		Elevation (meters)	Hill Height (meters)
	Easting (meters)	Northing (meters)		
Otter Creek Wilderness	518,049.4	4,342,002	1,148	1,148
Dolly Sods Wilderness	518,049.4	4,342,002	1,219	1,219
Shenandoah National Park	513,993.2	4,331,840	1,123	1,123
James River Face Wilderness	501,712.5	4,316,433	792	792

(a) UTM = Universal Transverse Mercator: NAD 83

Table 7-10: Class II Modeled Impacts and Class I Significant Impact Level

Pollutant	Averaging Time	Maximum Modeled value at 50 kilometer Receptor (μg/m^3)				Class I Significant Impact Level (μg/m^3)
		Otter Creek Wilderness	Dolly Sods Wilderness	Shenandoah National Park	James River Face Wilderness	
PM_{10}	24-hour	0.0276	0.0256	0.0320	0.0650	0.3
	Annual	0.0012	0.0011	0.0011	0.0020	0.2
$PM_{2.5}$	24-hour	0.0276	0.0256	0.0320	0.0650	0.07
	Annual	0.0012	0.0011	0.0011	0.0020	0.06
NO_2[a]	Annual	0.0045	0.0043	0.0042	0.0077	0.1

(a) Modeled as NO_x

7.8 Analysis of Secondary $PM_{2.5}$ Formation

An analysis of secondary $PM_{2.5}$ formation as a result of the Project was performed and is detailed in the modeling protocol in Appendix F. Secondary $PM_{2.5}$ formation should have insignificant impacts on the overall $PM_{2.5}$ emissions from the Project.

7.9 Conclusion

The modeling results shown in Table 7-5, demonstrate that no exceedances of the annual NO_2, 8-hour and 1-hour CO, annual and 24-hour PM_{10}, and annual $PM_{2.5}$ modeling significance levels are predicted; consequently, no further modeling is required. A refined modeling analysis was conducted to demonstrate compliance with the PSD Class II Increment for 24-hour $PM_{2.5}$ and NAAQS for 1-hour NO_2 and 24-hour $PM_{2.5}$. The Project will not cause or contribute to any modeled Class II PSD Increment or NAAQS exceedances.

The operation of the Project will not cause or contribute to a significant degradation of ambient air quality. After examining the results of the model, it has been determined that the modeling requirements for CO, NO_2, and PM_{10}/$PM_{2.5}$ have been fulfilled, and no further modeling is required.

8.0 ADDITIONAL IMPACT ANALYSIS

The additional impacts analysis requirement under PSD includes the ambient air quality impact analysis, soils and vegetation impacts, visibility impairment, and growth analysis for the Project.

8.2 Construction Impacts

There will be no construction associated with this Project; therefore, the potential for short-term adverse effects on air quality in the immediate area around the site will not occur.

8.1 Vegetation Impacts

The following sections briefly describe the potential effects of CO, CO_2, NO_2, $PM/PM_{10}/PM_{2.5}$, and synergistic effects of pollutants produced by the installation of the Project on the nearby vegetation. The potential effects of the air emissions to vegetation within the immediate vicinity of the Project will be compared to scientific research examining the effects of pollution on vegetation. Damage to vegetation often results from acute exposure to pollution, but may also occur after prolonged or chronic exposures. Acute exposures are typically manifested by internal physical damage to leaf tissues, while chronic exposures are more associated with the inhibition of physiological processes such as photosynthesis, carbon allocation, and stomatal functioning.[8]

8.1.1 Carbon Monoxide

CO is not known to injure plants nor has it been shown to be taken up by plants. Consequently, no adverse impacts to vegetation at or near the Project are expected from CO stack emissions from the Project.

8.1.2 Carbon Dioxide

CO_2 is not known to injure plants. Long-term exposure to elevated CO_2 levels has shown to improve the efficiency of nutrient, water, and photosynthesis in some plants.[9] However, the improved efficiencies that result from elevated CO_2 levels may not necessarily result in greater yields for crop plants.[10] No adverse impacts to vegetation at or near the facility are expected from CO_2 stack emissions from the Project.

[8] Hallgren, 1984; Hill and Littlefield, 1969; Mansfield and Freer-Smith, 1984.
[9] Drake, Gonzalez-Meler, and Long 1997; Leakey, Ainsworth, Bernacchi, Rogers, Long, and Ort 2009
[10] Morgan, Bollero, Nelson, Dohleman, and Long 2005

8.1.3 Nitrogen Oxides

During fuel combustion, atmospheric and fuel-bound nitrogen is oxidized to nitrogen oxide (NO) and small amounts of NO_2.[11] The NO is photochemically oxidized to NO_2, which is then subsequently consumed during the production of ozone and peroxyacetyl nitrates (PANs). NO_2 has been shown to deleteriously impact vegetation.[12] Different plant species exhibit different levels of sensitivity to nitrogen oxides; however, sensitivities to nitrogen oxides generally decrease as water becomes less available in the soil. Typical leaf injury responses include interveinal necrotic blotches for angiosperms and red-brown distal necrosis in gymnosperms.[13] The blotches on the leaves and along the leaf margins are the result of cell damage and dehydration of leaf tissues. Injury threshold concentrations vary by species and dose. In general, short-term, high concentrations of NO_2 are required for deleterious impacts on plants.[14] A 1-hour NO_2 concentration of 7,520 micrograms per cubic meter ($\mu g/m^3$) will result in a 5 percent foliar injury for the most susceptible plant species.[15] For the most NO_2 sensitive plant species, the minimum concentrations at which adverse growth effects or tissue injury occurred have been reported at 1,200 $\mu g/m^3$ (1 hour) [16], 3,760 $\mu g/m^3$ (4 hour averaging time) [17], 500 $\mu g/m^3$ (24 hour)[18], 564 $\mu g/m^3$ (1 month averaging time) [19], and 94 $\mu g/m^3$ (1 year averaging time) [20]. The injury threshold concentration for plants that are grown in West Virginia is 7,380 $\mu g/m^3$ for tomato (*Lycopersicon esculentum*) and annual sunflower (*Helianthus annuus*). Lamb's quarters (*Chenopodium album*) a common, weedy plant found in disturbed areas in West Virginia was not injured for two hours at concentrations of 1.9 $\mu g/m^3$ NO_2. Furthermore, short-term fumigations of approximately 1-hour, 20-hours, and 48-hours at NO_2 concentrations of 940 to 38,000 $\mu g/m^3$, 470 $\mu g/m^3$, and 3,000 to 5,000 $\mu g/m^3$, respectively, have been shown to impair photosynthesis in a number of herbaceous [tomato, oats (*Avena sativa*), alfalfa and woody plants.[21] Moreover, Taylor and McLean (1970),[22] in their review of NO_2 effects on vegetation, noted that long-term exposures of phytotoxic doses of NO_2 ranged from 280 to 560 $\mu g/m^3$.

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[11] Chang 1981
[12] Taylor et al. 1975; Kozlowski and Constantinidou 1986; Darrall 1989
[13] Kozlowski and Constantinidou 1986
[14] Prinz and Brandt 1985
[15] U.S. Environmental Protection Agency. 1993. *Air Quality Criteria for Oxides of Nitrogen (Final, 1993)*. EPA/600/8-91/049aF-cF, 1993. U.S. Environmental Protection Agency.
[16] Dvorak, A.J., et al. 1978 . *Impacts of coal-fired power plants on fish, wildlife, and their habitats*. U.S. Fish and Wildlife Service, Ann Arbor, MI. 261 pp.
[17] U.S. Environmental Protection Agency. 1993. *Air Quality Criteria for Oxides of Nitrogen (Final, 1993)*. EPA/600/8-91/049aF-cF, 1993. U.S. Environmental Protection Agency.
[18] Dvorak, A.J., et al. 1978 . *Impacts of coal-fired power plants on fish, wildlife, and their habitats*. U.S. Fish and Wildlife Service, Ann Arbor, MI. 261 pp.
[19] U.S. Environmental Protection Agency. 1993. *Air Quality Criteria for Oxides of Nitrogen (Final, 1993)*. EPA/600/8-91/049aF-cF, 1993. U.S. Environmental Protection Agency.
[20] U.S. Environmental Protection Agency. 1993. *Air Quality Criteria for Oxides of Nitrogen (Final, 1993)*. EPA/600/8-91/049aF-cF, 1993. U.S. Environmental Protection Agency.
[21] Hill and Bennett 1970; Capron and Mansfield 1976; Smith 1981
[22] Taylor and McLean, 1970.

The maximum annual modeled value for the Project is 0.1 μg/m^3 and the maximum 1-hour NO_2 modeled value for the Project is 27.9 μg/m^3. These levels are low, so it is highly unlikely that NO_2 emissions will impact vegetation adjacent to or surrounding the Project.

8.1.4 Particulate Matter

Particulates have been typically shown to be detrimental to vegetation within the immediate vicinity of the source. The phytotoxic response of a given plant species to particulate deposition on leaves varies depending on the concentration and composition of the airborne particulates. The effects of particle deposition are on a plant or plant community is difficult to measure. Experimental evidence indicates that the deposition of most common particulate materials on leaf surfaces result in less direct harm to plants than phytotoxic gases, which are absorbed and assimilated more rapidly and cause greater direct injury to plant tissues.[23] The most obvious effect of particle deposition on vegetation is a physical smothering of the leaf surface. This will reduce light transmission to the plant and cause a decrease in photosynthesis. Other phytotoxic effects of particulate deposition on leaves that could result in plant injury include the pH and chemical make-up of the particulates (salts and trace metals) that could affect leaf chemistry.

The maximum PM_{10} 24-hour and $PM_{2.5}$ 24-hour modeled values for the Project are 1.4 μg/m^3 and 1.0 μg/m^3, respectively. These levels are low, so it is highly unlikely that PM_{10} and $PM_{2.5}$ emissions will impact vegetation adjacent to the Pleasants Energy facility.

8.1.5 Synergistic Effects of Pollutants

Air pollutants are known to act in concert to cause injury to or decrease the functioning of plants.[24] Synergistic refers to the combined effects of pollutants when they are greater than is expected from the additive effect of the compounds. The inhibitory effects of NO_2 and NO[25] have been reported in various short-term studies for crop plants (e.g., soybean, broad bean (*Vicia faba*), annual sunflower, and tomato). The concentrations of pollutants (80 to 981 μg/m^3) in this study are higher than the concentrations predicted to occur near the Project. Consequently, no synergistic effects of the air pollutants are expected to inhibit vegetation at or near the Pleasants Energy facility.

8.2 Soil Impacts

A soil inventory was completed by obtaining a soil survey within the 3-kilometer radius study area surrounding the facility. The soil survey was obtained from the Natural Resource Conservation Service.

[23] Guderian R. 1986. Terrestrial Ecosystems: Particulate Deposition. In: *Air Pollutants and Their Effects on the Terrestrial Ecosystem* (Legge AH, Krupa SV, eds). Advances in Environmental Science and Technology (Vol. 18). 339-363, Wiley, New York, USA

[24] *See* reviews of Reinert et al. 1975; Omrod 1982

[25] Capron and Mansfield 1976

The different soil types that were found to be in excess of one percent of the total land area of the 3-kilometer study area are listed in Table 8-1. The most abundant soil type in the vicinity of the Project was Upshur-Gilpin complex, at 20.38 percent.

Table 8-1. Soils Within 3 kilometers of the Project

Ashton silt loam	Lindside silt loam	Sensbaugh loam
Duncannon silt loam	Melvin silt loam	Upshur association
Gilpin-Sumritville-Upshur complex	Mentor silt loam	Upshur-Gilpin complex
Gilpin-Upshur complex	Monongahela and Tilsit silt loams	Vandalia silty clay loam
Hackers silt loam	Peabody-Gilpin complex	Water
Lakin loamy fine sand	Senecaville silt loam	--

According to the U.S. Department of Agriculture Soil Conservation Service, the Upshur series consists of well drained soils formed in red clayey shale or mudstone residuum. Upshur soils are on hills and hillslopes on summits, shoulders, and backslopes. The full range of slope is from 0 to 70 percent. Surface runoff potential is medium to very rapid. Major uses of Upshur soils are for cultivation or woodland. Where Upshur soils are hayland, pasture, and cropland, they are cultivated with the principal crops being grass-legume hay, corn soybeans, wheat, or oats. Where Upshur soils are wooded, they are dominated by oaks (*Quercus* spp.), hickory (*Carya* spp.), and yellow-poplar (*Liriodendrom tulipifera*).

Nitrates caused by NO_x deposition onto the soil can be either beneficial or detrimental to soil depending on its composition. However, the proposed NO_x emission rates and consequently the impacts generated by the Project are not expected to have an adverse impact upon soils in the immediate vicinity since they are below the NAAQS.

8.3 Industrial, Residential, and Commercial Growth Impacts

The purpose of the growth impact analysis is to quantify growth resulting from the increase in time of operation of the Project and assess air quality impacts that would result from that growth.

The facility employs six full-time employees. This Project will not significantly affect growth in the area. The increase in natural gas demand due to the operation of the Project will have no major impact on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected at this time.

8.4 Visibility and Deposition Analysis

8.4.1 Class I Area Analysis

Recent Federal Land Manager (FLM) guidance requires that a proposed major source, in the course of a PSD application, perform an assessment of air quality impacts at Class I areas if these areas are located within approximately 300 kilometers of the Project. There are four Class I Areas that are within 300 kilometers of the Project:

- Otter Creek Wilderness (130 kilometers)
- Dolly Sods Wilderness (160 kilometers)
- Shenandoah National Park (200 kilometers)
- James River Face Wilderness (253 kilometers)

The locations of the Project site and the Class I Areas are shown in Appendix F of this application (Figure A-6, Appendix A to the modeling protocol).

Following the most recent FLAG Workshop procedures (June 2010), the use of the Screening Procedure (Q/D) to determine if the Project could opt (screen) out of an AQRV assessment for visibility and deposition with CALPUFF was made. Following the screening procedures in FLAG, the emissions of NO_x, SO_2, PM_{10}/$PM_{2.5}$, and H_2SO_4 mist were summed. An adjustment was made to the combustion turbine emissions to reflect full time operation because the combustion turbines have an annual fuel limit. A conservative hourly operation of 5,100 hours per year was used to ratio the emissions for full-year operation. The screening analysis is summarized below for the four Class I areas located within 300 kilometers of the Project:

Table 8-2: Class I Screening Analysis

Class I Area	Q[a] (tpy)[b]	D (Kilometers)	Q/D
Otter Creek Wilderness	1,079	130	8.3
Dolly Sods Wilderness	1,079	160	6.7
Shenandoah National Park	1,079	200	5.4
James River Face Wilderness	1,079	253	4.3

(a) Q=sum(NO_x+$PM_{10/2.5}$+SOx+H_2SO_4)*(8,760/5,100)
(b) tpy = tons per year

In accordance with the FLAG Guidance, if Q/D is less than 10, then no AQRV analysis is required. Based on the ratio of Q/D, the Class I areas do not require further analysis of AQRV. Thus, no CALPUFF analysis was performed for impacts to AQRVs.

8.4.2 Class II Area Analysis

The Project will be located in a Class II area. With respect to visibility conditions around the facility, there are no known Class II screening visibility criteria that have been recommended at this time. A visibility analysis was performed on the two sites listed below:

- North Bend State Park, a state park located approximately 25 kilometers east-southeast of the Project location
- Blennerhassett Island State Historical Park, located approximately 24 kilometers west-southwest of the Project location

The visibility analysis was performed in accordance with the guidelines set forth in EPA-450/4-88-015, Workbook for Plume Visual Impact Screening and Analysis. Within the document, the model VISCREEN is recommended for plume visibility analysis. Several refinement levels of VISCREEN are described. The first-level VISCREEN analysis uses worst-case meteorological conditions (F-class stability, one meter per second wind speed). This level of screening results in the most conservative (worst-case) visibility results. If the plume visibility against the sky and terrain is below a level perceivable to the human eye, the visibility modeling is complete. If the plume is above this level, a second-level VISCREEN analysis that uses actual meteorological data and refined particle characteristics can be performed. The second-level model will result in a more realistic visibility analysis. If this plume visibility still does not meet sky and terrain contrast levels, a third-level model may be performed which can add more statistical analysis.

<u>First-Level VISCREEN</u>

The first-level VISCREEN model was performed for the Project. The inputs into the model included particulate matter, NO_x, primary NO_2, soot, and primary sulfate (SO_4). The maximum annual particulate and NO_x emission rates of 118.7 and 464.6 tpy respectively, were used in the VISCREEN analysis.

According to the workbook, primary NO_2, soot, and primary SO_4 can be assumed to be zero except for very specific sources. Since the facility is not one of the specified sources, the emissions for the last three pollutants (primary NO_2, soot, and primary SO_4) are assumed to be zero. The next set of inputs into the first-level VISCREEN model considers the distance between the source, observer and area, and the background visual range. Background visibility was determined from the VISCREEN manual to be 40 kilometers.

The last inputs into the model are particle sizes, background ozone, plume-source-observer angle, stability, and wind speed. All of these inputs are automatically set if the default option is chosen. For the first-level analysis, the workbook tells the analyst to choose the default option, which sets the following particle sizes:

- background fine = 0.3 micrometer (μm) diameter, 1.5 gram per cubic centimeter (g/cm^3) density,
- background course = 6 μm diameter, 2.5 g/cm^3 density,
- plume particulate = 2 μm diameter, 2.5 g/cm^3 density,
- plume soot = 0.1 μm diameter, 2 g/cm^3 density, and
- plume primary sulfate = 0.5 μm diameter, 1.5 g/cm^3.

The background ozone is 0.04 ppm, the plume-source-observer angle is 11.25 degrees, the worst case atmospheric stability is an F stability class, and the worst case wind speed is 1 meter per second.

The VISCREEN model output compares the calculated Delta E and contrast from the plume to present default comparison values. Delta E is the color difference parameter used to characterize the perceptibility of the plume on a color difference between the plume and a viewing background such as the sky, a cloud, or a terrain feature. Color differences are due to differences in three dimensions: brightness (L*), color hue (a*), and saturation (b*). Delta E is calculated for several lines of sight. A green contrast analysis is also performed for various lines of sight using a green wavelength and contrasting the plume with the terrain and sky backgrounds. The critical E value is 2.0 and the green contrast value is 0.05 for Class I areas; however, there are currently no Class II screening visibility criteria for the state of West Virginia.

The results of the first-level VISCREEN model are provided in Appendix I. The visual analyses show that the emissions from the Project exceed the Class I sky and terrain perceptibility threshold at each of the two sites; therefore, a second-level VISCREEN analysis was performed.

<u>Second-Level VISCREEN</u>

While the Level 1 screening uses the worst-case meteorological conditions, Level 2 uses observed meteorological data to provide a better, site specific analysis of the visual impacts. The site-specific average wind speed and stability class were determined for the Level 2 analysis. Under most circumstances, the one percent worst atmospheric dispersion day (i.e., the fourth worst day of any year) is typically the worst dispersion conditions for a plume.

The workbook provides guidance on how to determine the one percent worst day. A second-level screening analysis allows the following parameters to be adjusted to representative data if available:

- Particle size distribution
- Background visual range
- Complex terrain
- One percent worst meteorological days

Since measurements of particle size are not known, and the background visual range has not been measured in the Project area, these parameters were left at their workbook suggested values. The terrain surrounding the proposed Project is assumed to be flat; therefore, no adjustments were made for terrain. The workbook suggests ranking the plume dispersion by the product of the vertical and horizontal diffusion coefficients ($\sigma_z\sigma_y$) and the wind speed (U)**.** If the plume takes more than 12 hours to reach a receptor, this dispersion condition was not factored into the one percent worst day.

The analysis of the five-years of meteorological data used to determine the one percent worst day is shown in Appendix I for each of the two sites. Pre-ASOS meteorological data is required to determine the joint frequency distribution. The Parkersburg Wood County Airport, West Virginia (Station ID 03804) station does not have pre-ASOS data. Therefore, a wind rose plot for Huntington/Tri-State Airport (Station ID 03860) for years 1986 to 1990 and Parkersburg Wood County Airport for years 2009 to 2014 were generated to confirm that the data was similar. The wind rose plots are shown in Appendix I and were determined to be comparable. Integrated surface hourly meteorological data and upper air from the Huntington/Tri-State Airport (Station ID 03860) was used for years 1986 to 1990 to determine the wind speed and stability class for this analysis. Appendix I contains the joint frequency distribution results.

The visual results of the second-level screening analysis show that the emissions from the Project pass the Class I sky and terrain perceptibility thresholds at North Bend State Park located 25 kilometers away and Blennerhassett Island State Historical Park located 24 kilometers away, using the stability class and wind speed determined from joint frequency distribution. The results of the second-level VISCREEN are shown in Appendix I.

8.5 Conclusion

As shown by the results presented in this section of the application and additional supplemental information, the Project will not have a significant adverse impact on the air quality, soils, vegetation, visibility and or growth in the surrounding area.

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APPENDIX A – WVDEP FORMS

APPENDIX A

TABLE OF CONTENTS

WEST VIRGINIA DEPARTMENT OF ENVIRONMENTAL PROTECTION **DIVISION OF AIR QUALITY** 601 57th Street, SE Charleston, WV 25304 (304) 926-0475 www.dep.wv.gov/daq	***APPLICATION FOR NSR PERMIT*** ***AND*** ***TITLE V PERMIT REVISION*** ***(OPTIONAL)***
PLEASE CHECK ALL THAT APPLY TO **NSR (45CSR13)** (IF KNOWN): ☒ **CONSTRUCTION** ☐ **MODIFICATION** ☐ **RELOCATION** ☐ **CLASS I ADMINISTRATIVE UPDATE** ☐ **TEMPORARY** ☐ **CLASS II ADMINISTRATIVE UPDATE** ☐ **AFTER-THE-FACT**	PLEASE CHECK TYPE OF **45CSR30 (TITLE V)** REVISION (IF ANY): ☐ **ADMINISTRATIVE AMENDMENT** ☐ **MINOR MODIFICATION** ☐ **SIGNIFICANT MODIFICATION** IF ANY BOX ABOVE IS CHECKED, INCLUDE TITLE V REVISION INFORMATION AS **ATTACHMENT S** TO THIS APPLICATION

FOR TITLE V FACILITIES ONLY: Please refer to "Title V Revision Guidance" in order to determine your Title V Revision options (Appendix A, "Title V Permit Revision Flowchart") and ability to operate with the changes requested in this Permit Application.

Section I. General

1. Name of applicant *(as registered with the WV Secretary of State's Office):* Pleasants Energy, LLC	2. Federal Employer ID No. ***(FEIN):*** 26-3603167
3. Name of facility *(if different from above):*	4. The applicant is the: ☐ **OWNER** ☐ **OPERATOR** ☒ **BOTH**
5A. Applicant's mailing address: 10319 South Pleasants Highway, St. Mary's, WV 26170	5B. Facility's present physical address: 10319 South Pleasants Highway, St. Mary's, WV 26170

6. **West Virginia Business Registration.** Is the applicant a resident of the State of West Virginia? ☐ **YES** ☒ **NO**

- If **YES,** provide a copy of the **Certificate of Incorporation/Organization/Limited Partnership** (one page) including any name change amendments or other Business Registration Certificate as **Attachment A.**
- If **NO,** provide a copy of the **Certificate of Authority/Authority of L.L.C./Registration** (one page) including any name change amendments or other Business Certificate as **Attachment A.**

7. If applicant is a subsidiary corporation, please provide the name of parent corporation: GDF Suez Energy North America, Inc.

8. Does the applicant own, lease, have an option to buy or otherwise have control of the *proposed site?* ☒ **YES** ☐ **NO**

- If **YES,** please explain: Applicant owns site
- If **NO,** you are not eligible for a permit for this source.

9. Type of plant or facility (stationary source) to be **constructed, modified, relocated, administratively updated** or **temporarily permitted** (e.g., coal preparation plant, primary crusher, etc.): Electric generating peaking station	10. North American Industry Classification System **(NAICS)** code for the facility: 221112
11A. DAQ Plant ID No. (for existing facilities only): 073 – 00022	11B. List all current 45CSR13 and 45CSR30 (Title V) permit numbers associated with this process (for existing facilities only): R30-07300022-2014 (Title V), R13-2373, R13-2373A, G60-C067

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

12A.

– For **Modifications, Administrative Updates** or **Temporary permits** at an existing facility, please provide directions to the *present location* of the facility from the nearest state road;
– For **Construction** or **Relocation permits,** please provide directions to the *proposed new site location* from the nearest state road. Include a **MAP** as **Attachment B**.

From 1st Street in Waverly, head east on Highway 2 approximately 1 mile. The Pleasants Energy facility entrance is on the south side of the highway.

12.B. New site address (if applicable):	12C. Nearest city or town: Waverly	12D. County: Pleasants
12.E. UTM Northing (KM): 4353.573	12F. UTM Easting (KM): 468.629	12G. UTM Zone: 17

13. Briefly describe the proposed change(s) at the facility:
The Project consists of increasing the capacity of the two combustion turbines at the Pleasants Energy.

14A. Provide the date of anticipated installation or change: 10/01/2015 – If this is an **After-The-Fact** permit application, provide the date upon which the proposed change did happen: / /	14B. Date of anticipated Start-Up if a permit is granted: 04/01/2016

14C. Provide a **Schedule** of the planned **Installation** of/**Change** to and **Start-Up** of each of the units proposed in this permit application as **Attachment C** (if more than one unit is involved).

15. Provide maximum projected **Operating Schedule** of activity/activities outlined in this application:
Hours Per Day Days Per Week Approximately 5,000 hours per year per combustion turbine

16. Is demolition or physical renovation at an existing facility involved? ☐ **YES** ☒ **NO**

17**. Risk Management Plans.** If this facility is subject to 112(r) of the 1990 CAAA, or will become subject due to proposed changes (for applicability help see www.epa.gov/ceppo), submit your **Risk Management Plan (RMP)** to U. S. EPA Region III.

18**. Regulatory Discussion.** List all Federal and State air pollution control regulations that you believe are applicable to the proposed process *(if known).* A list of possible applicable requirements is also included in Attachment S of this application (Title V Permit Revision Information). Discuss applicability and proposed demonstration(s) of compliance *(if known).* Provide this information as **Attachment D.**

Section II. Additional attachments and supporting documents.

19. Include a check payable to WVDEP – Division of Air Quality with the appropriate **application fee** (per 45CSR22 and 45CSR13).

20. Include a **Table of Contents** as the first page of your application package.

21. Provide a **Plot Plan,** e.g. scaled map(s) and/or sketch(es) showing the location of the property on which the stationary source(s) is or is to be located as **Attachment E** (Refer to ***Plot Plan Guidance***) **.**
– Indicate the location of the nearest occupied structure (e.g. church, school, business, residence).

22. Provide a **Detailed Process Flow Diagram(s)** showing each proposed or modified emissions unit, emission point and control device as **Attachment F.**

23. Provide a **Process Description** as **Attachment G.**
– Also describe and quantify to the extent possible all changes made to the facility since the last permit review (if applicable).

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

24. Provide **Material Safety Data Sheets (MSDS)** for all materials processed, used or produced as **Attachment H.**
– For chemical processes, provide a MSDS for each compound emitted to the air.

25. Fill out the **Emission Units Table** and provide it as **Attachment I.**

26. Fill out the **Emission Points Data Summary Sheet (Table 1 and Table 2)** and provide it as **Attachment J.**

27. Fill out the **Fugitive Emissions Data Summary Sheet** and provide it as **Attachment K.**

28. Check all applicable **Emissions Unit Data Sheets** listed below:

☐ Bulk Liquid Transfer Operations
☐ Haul Road Emissions
☐ Quarry
☐ Chemical Processes
☐ Hot Mix Asphalt Plant
☐ Solid Materials Sizing, Handling and Storage Facilities
☐ Concrete Batch Plant
☐ Incinerator
☐ Grey Iron and Steel Foundry
☐ Indirect Heat Exchanger
☐ Storage Tanks
☒ General Emission Unit, specify Combustion Turbines

Fill out and provide the **Emissions Unit Data Sheet(s)** as **Attachment L.**

29. Check all applicable **Air Pollution Control Device Sheets** listed below:

☐ Absorption Systems
☐ Baghouse
☐ Flare
☐ Adsorption Systems
☐ Condenser
☐ Mechanical Collector
☐ Afterburner
☐ Electrostatic Precipitator
☐ Wet Collecting System
☐ Other Collectors

Fill out and provide the **Air Pollution Control Device Sheet(s)** as **Attachment M.**

30. Provide all **Supporting Emissions Calculations** as **Attachment N,** or attach the calculations directly to the forms listed in Items 28 through 31.

31. **Monitoring, Recordkeeping, Reporting and Testing Plans.** Attach proposed monitoring, recordkeeping, reporting and testing plans in order to demonstrate compliance with the proposed emissions limits and operating parameters in this permit application. Provide this information as **Attachment O.**

➢ Please be aware that all permits must be practically enforceable whether or not the applicant chooses to propose such measures. Additionally, the DAQ may not be able to accept all measures proposed by the applicant. If none of these plans are proposed by the applicant, DAQ will develop such plans and include them in the permit.

32. **Public Notice.** At the time that the application is submitted, place a **Class I Legal Advertisement** in a newspaper of general circulation in the area where the source is or will be located (See 45CSR§13-8.3 through 45CSR§13-8.5 and ***Example Legal Advertisement*** for details). Please submit the **Affidavit of Publication** as **Attachment P** immediately upon receipt.

33**. Business Confidentiality Claims.** Does this application include confidential information (per 45CSR31)?

☐ **YES** ☒ **NO**

➢ If **YES,** identify each segment of information on each page that is submitted as confidential and provide justification for each segment claimed confidential, including the criteria under 45CSR§31-4.1, and in accordance with the DAQ's ***"Precautionary Notice – Claims of Confidentiality"*** guidance found in the ***General Instructions*** as **Attachment Q.**

Section III. Certification of Information

34. **Authority/Delegation of Authority.** Only required when someone other than the responsible official signs the application. Check applicable **Authority Form** below:

☐ Authority of Corporation or Other Business Entity
☐ Authority of Partnership
☐ Authority of Governmental Agency
☐ Authority of Limited Partnership

Submit completed and signed **Authority Form** as **Attachment R.**

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

35A. **Certification of Information.** To certify this permit application, a Responsible Official (per 45CSR§13-2.22 and 45CSR§30-2.28) or Authorized Representative shall check the appropriate box and sign below.

Certification of Truth, Accuracy, and Completeness

I, the undersigned ☒ **Responsible Official** / ☐ **Authorized Representative,** hereby certify that all information contained in this application and any supporting documents appended hereto, is true, accurate, and complete based on information and belief after reasonable inquiry I further agree to assume responsibility for the construction, modification and/or relocation and operation of the stationary source described herein in accordance with this application and any amendments thereto, as well as the Department of Environmental Protection, Division of Air Quality permit issued in accordance with this application, along with all applicable rules and regulations of the West Virginia Division of Air Quality and W.Va. Code § 22-5-1 et seq. (State Air Pollution Control Act). If the business or agency changes its Responsible Official or Authorized Representative, the Director of the Division of Air Quality will be notified in writing within 30 days of the official change.

Compliance Certification

Except for requirements identified in the Title V Application for which compliance is not achieved, I, the undersigned hereby certify that, based on information and belief formed after reasonable inquiry, all air contaminant sources identified in this application are in compliance with all applicable requirements.

SIGNATURE ____ DATE: ____________________

(Please use blue ink) *(Please use blue ink)*

35B. Printed name of signee: Gerald Gatti		35C. Title: Plant Manager
35D. E-mail: Gerald.Gatti@gdfsuezna.com	36E. Phone: 304-665-4201	36F. FAX: 304-665-4218
36A. Printed name of contact person (if different from above):		36B. Title:
36C. E-mail:	36D. Phone:	36E. FAX:

PLEASE CHECK ALL APPLICABLE ATTACHMENTS INCLUDED WITH THIS PERMIT APPLICATION:

- ☒ **Attachment A: Business Certificate**
- ☒ **Attachment B: Map(s)**
- ☒ **Attachment C: Installation and Start Up Schedule**
- ☒ **Attachment D: Regulatory Discussion**
- ☒ **Attachment E: Plot Plan**
- ☒ **Attachment F: Detailed Process Flow Diagram(s)**
- ☒ **Attachment G: Process Description**
- ☐ **Attachment H: Material Safety Data Sheets (MSDS)**
- ☒ **Attachment I: Emission Units Table**
- ☒ **Attachment J: Emission Points Data Summary Sheet**
- ☐ **Attachment K: Fugitive Emissions Data Summary Sheet**
- ☒ **Attachment L: Emissions Unit Data Sheet(s)**
- ☐ **Attachment M: Air Pollution Control Device Sheet(s)**
- ☒ **Attachment N: Supporting Emissions Calculations**
- ☒ **Attachment O: Monitoring/Recordkeeping/Reporting/Testing Plans**
- ☒ **Attachment P: Public Notice**
- ☐ **Attachment Q: Business Confidential Claims**
- ☐ **Attachment R: Authority Forms**
- ☐ **Attachment S: Title V Permit Revision Information**
- ☒ **Application Fee**

Please mail an original and three (3) copies of the complete permit application with the signature(s) to the DAQ, Permitting Section, at the address listed on the first page of this application. Please DO NOT fax permit applications.

FOR AGENCY USE ONLY – IF THIS IS A TITLE V SOURCE:

- ☐ ***Forward 1 copy of the application to the Title V Permitting Group and:***
- ☐ ***For Title V Administrative Amendments:***
  - ☐ ***NSR permit writer should notify Title V permit writer of draft permit,***
- ☐ ***For Title V Minor Modifications:***
  - ☐ ***Title V permit writer should send appropriate notification to EPA and affected states within 5 days of receipt,***
  - ☐ ***NSR permit writer should notify Title V permit writer of draft permit.***
- ☐ ***For Title V Significant Modifications processed in parallel with NSR Permit revision:***
  - ☐ ***NSR permit writer should notify a Title V permit writer of draft permit,***
  - ☐ ***Public notice should reference both 45CSR13 and Title V permits,***
  - ☐ ***EPA has 45 day review period of a draft permit.***

All of the required forms and additional information can be found under the Permitting Section of DAQ's website, or requested by phone.

ATTACHMENT A –
CURRENT BUSINESS CERTIFICATE

State of West Virginia

Certificate

I, Natalie E. Tennant, Secretary of State of the State of West Virginia, hereby certify that

PLEASANTS ENERGY, LLC

was duly authorized under the laws of this state to transact business in West Virginia as a foreign limited liability company on December 17, 1999.

The company is filed as an at-will company, for an indefinite period.

I further certify that the LLC (PLLC) has not been revoked by the State of West Virginia nor has a Certificate of Cancellation been issued.

Therefore, I hereby issue this

CERTIFICATE OF AUTHORIZATION

Validation ID:0WV1X_44545

Given under my hand and the Great Seal of the State of West Virginia on this day of June 22, 2015

Secretary of State

Notice: A certificate issued electronically from the West Virginia Secretary of State's Web site is fully and immediately valid and effective. However, as an option, the issuance and validity of a certificate obtained electronically may be established by visiting the Certificate Validation Page of the Secretary of State's Web site, https://apps.wv.gov/sos/businessentitysearch/validate.aspx entering the validation ID displayed on the certificate, and following the instructions displayed. Confirming the issuance of a certificate is merely optional and is not necessary to the valid and effective issuance of a certificate.

ATTACHMENT B –
MAP
(SEE FIGURE B-1 IN APPENDIX B TO PSD REPORT)

ATTACHMENT C –
INSTALLATION AND STARTUP SCHEDULE

Attachment C – Installation and Startup Schedule

Pleasants Energy plans to make the change to their operations detailed in the permit application in June 2016 or as soon as the permit is granted.

ATTACHMENT D –
REGULATORY DISCUSSION
(SEE SECTION 5.0 IN PSD REPORT)

ATTACHMENT E –
PLOT PLAN
(SEE FIGURES B-2 AND B-3 IN APPENDIX B TO PSD REPORT)

ATTACHMENT F –
PROCESS FLOW DIAGRAMS
(SEE FIGURE B-4 IN APPENDIX B TO PSD REPORT)

ATTACHMENT G –
PROCESS DESCRIPTION
(SEE SECTION 3.0 IN PSD REPORT)

ATTACHMENT I –
EMISSION UNITS TABLE

Attachment I

Emission Units Table

(includes all emission units and air pollution control devices that will be part of this permit application review, regardless of permitting status)

Emission Unit ID[1]	Emission Point ID[2]	Emission Unit Description	Year Installed/ Modified	Design Capacity	Type[3] and Date of Change	Control Device[4]
GT01	EP1	General Electric Model 7FA Turbine	2001	1,571 MMBtu/hr	Modification, date TBD	None
GT02	EP2	General Electric Model 7FA Turbine	2001	1,571 MMBtu/hr	Modification, date TBD	None

[1] For Emission Units (or Sources) use the following numbering system:1S, 2S, 3S,... or other appropriate designation.
[2] For Emission Points use the following numbering system:1E, 2E, 3E, ... or other appropriate designation.
[3] New, modification, removal
[4] For Control Devices use the following numbering system: 1C, 2C, 3C,... or other appropriate designation.

ATTACHMENT J –
EMISSION POINTS DATA SUMMARY SHEET

Attachment J
EMISSION POINTS DATA SUMMARY SHEET

Table 1: Emissions Data

Emission Point ID No. *(Must match Emission Units Table & Plot Plan)*	Emission Point Type[1]	Emission Unit Vented Through This Point *(Must match Emission Units Table & Plot Plan)*		Air Pollution Control Device *(Must match Emission Units Table & Plot Plan)*		Vent Time for Emission Unit *(chemical processes only)*		All Regulated Pollutants - Chemical Name/CAS[3] *(Speciate VOCs & HAPS)*	Maximum Potential Uncontrolled Emissions [4]		Maximum Potential Controlled Emissions [5]		Emission Form or Phase *(At exit conditions, Solid, Liquid or Gas/Vapor)*	Est. Method Used [6]	Emission Concentration[7] (ppmv or mg/m[4])
		ID No.	Source	ID No.	Device Type	Short Term[2]	Max (hr/yr)		lb/hr	ton/yr	lb/hr	ton/yr			
EP1	Vertical stack	GT1						NOx, CO, $PM/PM_{10}/PM_{2.5}$, VOC, SO_2, H_2SO_4, CO_2, N_2O, CH_4, CO_2e, HAPs	See Appendix C – Emissions Calculations						
EP2	Vertical stack	GT2						NOx, CO, $PM/PM_{10}/PM_{2.5}$, VOC, SO_2, H_2SO_4, CO_2, N_2O, CH_4, CO_2e, HAPs	See Appendix C – Emissions Calculations						

The EMISSION POINTS DATA SUMMARY SHEET provides a summation of emissions by emission unit. Note that uncaptured process emission unit emissions are not typically considered to be fugitive and must be accounted for on the appropriate EMISSIONS UNIT DATA SHEET and on the EMISSION POINTS DATA SUMMARY SHEET. Please note that total emissions from the source are equal to all vented emissions, all fugitive emissions, plus all other emissions (e.g. uncaptured emissions). Please complete the FUGITIVE EMISSIONS DATA SUMMARY SHEET for fugitive emission activities.

1 Please add descriptors such as upward vertical stack, downward vertical stack, horizontal stack, relief vent, rain cap, etc.

2 Indicate by "C" if venting is continuous. Otherwise, specify the average short-term venting rate with units, for intermittent venting (ie., 15 min/hr). Indicate as many rates as needed to clarify frequency of venting (e.g., 5 min/day, 2 days/wk).

3 List all regulated air pollutants. Speciate VOCs, including all HAPs. Follow chemical name with Chemical Abstracts Service (CAS) number. **LIST** Acids, CO, CS_2, VOCs, H_2S, Inorganics, Lead, Organics, O_3, NO, NO_2, SO_2, SO_3, all applicable Greenhouse Gases (including CO_2 and methane), etc. **DO NOT LIST** H_2, H_2O, N_2, O_2, and Noble Gases.

4 Give maximum potential emission rate with no control equipment operating. If emissions occur for less than 1 hr, then record emissions per batch in minutes (e.g. 5 lb VOC/20 minute batch).

5 Give maximum potential emission rate with proposed control equipment operating. If emissions occur for less than 1 hr, then record emissions per batch in minutes (e.g. 5 lb VOC/20 minute batch).

6 Indicate method used to determine emission rate as follows: MB = material balance; ST = stack test (give date of test); EE = engineering estimate; O = other (specify).

7 Provide for all pollutant emissions. Typically, the units of parts per million by volume (ppmv) are used. If the emission is a mineral acid (sulfuric, nitric, hydrochloric or phosphoric) use units of milligram per dry cubic meter (mg/m^3) at standard conditions (68 °F and 29.92 inches Hg) (see 45CSR7). If the pollutant is SO_2, use units of ppmv (See 45CSR10).

Attachment J
EMISSION POINTS DATA SUMMARY SHEET

Table 2: Release Parameter Data								
Emission Point ID No. *(Must match Emission Units Table)*	Inner Diameter (ft.)	Exit Gas			Emission Point Elevation (ft)		UTM Coordinates (km)	
		Temp. (^{o}F)	Volumetric Flow [1] (acfm) *at operating conditions*	Velocity (fps)	Ground Level *(Height above mean sea level)*	Stack Height [2] *(Release height of emissions above ground level)*	Northing	Easting
EP1[3]	18	1,131	2,540,552	166.6	650	114.5	4,353.8100	468.6270
EP2[3]	18	1,131	2,540,552	166.6	650	114.5	4,353.8142	468.6810
EP1[4]	18	1,131	2,260,000	148.2	650	114.5	4,353.8100	468.6270
EP2[4]	18	1,131	2,260,000	148.2	650	114.5	4,353.8142	468.6810

[1] Give at operating conditions. Include inerts.
[2] Release height of emissions above ground level.
[3] 100% load operation, with TurboPhase operation
[4] 100% load operation, without TurboPhase operation

ATTACHMENT L –
EMISSION UNIT DATA SHEETS

Attachment L
EMISSIONS UNIT DATA SHEET
GENERAL

To be used for affected sources other than asphalt plants, foundries, incinerators, indirect heat exchangers, and quarries.

Identification Number (as assigned on *Equipment List Form*):

1. Name or type and model of proposed affected source: General Electric Model 7FA Turbines (GT1 and GT2) - Natural gas combustion. Pleasants Energy plans to increase the hours of operation of GT1 and GT2.
2. On a separate sheet(s), furnish a sketch(es) of this affected source. If a modification is to be made to this source, clearly indicated the change(s). Provide a narrative description of all features of the affected source which may affect the production of air pollutants. See Process Flow Diagram (Figure B-4) in Appendix B of the PSD Air Construction Permit Application report.
3. Name(s) and maximum amount of proposed process material(s) charged per hour: N/A
4. Name(s) and maximum amount of proposed material(s) produced per hour: N/A
5. Give chemical reactions, if applicable, that will be involved in the generation of air pollutants: Combustion of natural gas

* The identification number which appears here must correspond to the air pollution control device identification number appearing on the *List Form*.

6. Combustion Data (if applicable):

(a) Type and amount in appropriate units of fuel(s) to be burned:

Natural gas, maximum of 19,081,721,569 SCF per year for both turbines combined. This includes fuel oil combustion as well

(b) Chemical analysis of proposed fuel(s), excluding coal, including maximum percent sulfur and ash:

Annual average sulfur content of the natural gas shall not exceed 0.5 grains per 100 scf

(c) Theoretical combustion air requirement (ACF/unit of fuel):

@ °F and psia.

(d) Percent excess air:

(e) Type and BTU/hr of burners and all other firing equipment planned to be used:

N/A

(f) If coal is proposed as a source of fuel, identify supplier and seams and give sizing of the coal as it will be fired:

N/A

(g) Proposed maximum design heat input: 1,571 $\times 10^6$ BTU/hr.

7. Projected operating schedule:

Hours/Day	Days/Week	Weeks/Year

8. Projected amount of pollutants that would be emitted from this affected source if no control devices were used: **Emissions are per combustion turbine.*

@ 1,131 °F and psia

a.	NO_X	75 lb/hr	grains/ACF
b.	SO_2	2.8 lb/hr	grains/ACF
c.	CO	36 lb/hr	grains/ACF
d.	PM_{10}	20.2 lb/hr	grains/ACF
e.	Hydrocarbons	lb/hr	grains/ACF
f.	VOCs	3.4 lb/hr	grains/ACF
g.	Pb	lb/hr	grains/ACF
h.	Specify other(s)		
	H_2SO_4	0.43 lb/hr	grains/ACF
	CO_2e	212,296 lb/hr	grains/ACF
		lb/hr	grains/ACF
		lb/hr	grains/ACF
		lb/hr	grains/ACF

NOTE: (1) An Air Pollution Control Device Sheet must be completed for any air pollution device(s) used to control emissions from this affected source.

(2) Complete the Emission Points Data Sheet.

9. Proposed Monitoring, Recordkeeping, Reporting, and Testing
Please propose monitoring, recordkeeping, and reporting in order to demonstrate compliance with the proposed operating parameters. Please propose testing in order to demonstrate compliance with the proposed emissions limits.

MONITORING	RECORDKEEPING
CEMS for NOx emissions. Fuel monitors for natural gas and fuel oil. Calculating SO2 emissions.	Records of fuel usage (natural gas and fuel oil) as well as tons per year NOx emissions and SO2 emissions.
REPORTING	TESTING

MONITORING. PLEASE LIST AND DESCRIBE THE PROCESS PARAMETERS AND RANGES THAT ARE PROPOSED TO BE MONITORED IN ORDER TO DEMONSTRATE COMPLIANCE WITH THE OPERATION OF THIS PROCESS EQUIPMENT OPERATION/AIR POLLUTION CONTROL DEVICE.

RECORDKEEPING. PLEASE DESCRIBE THE PROPOSED RECORDKEEPING THAT WILL ACCOMPANY THE MONITORING.

REPORTING. PLEASE DESCRIBE THE PROPOSED FREQUENCY OF REPORTING OF THE RECORDKEEPING.

TESTING. PLEASE DESCRIBE ANY PROPOSED EMISSIONS TESTING FOR THIS PROCESS EQUIPMENT/AIR POLLUTION CONTROL DEVICE.

10. Describe all operating ranges and maintenance procedures required by Manufacturer to maintain warranty

Attachment L
EMISSIONS UNIT DATA SHEET
GENERAL

To be used for affected sources other than asphalt plants, foundries, incinerators, indirect heat exchangers, and quarries.

Identification Number (as assigned on *Equipment List Form*):

1. Name or type and model of proposed affected source: General Electric Model 7FA Turbines (GT1 and GT2) – Fuel oil combustion. Pleasants Energy plans to increase the annual operation of GT1 and GT2.
2. On a separate sheet(s), furnish a sketch(es) of this affected source. If a modification is to be made to this source, clearly indicated the change(s). Provide a narrative description of all features of the affected source which may affect the production of air pollutants. See Process Flow Diagram (Figure B-4) in Appendix B of the PSD Air Construction Permit
3. Name(s) and maximum amount of proposed process material(s) charged per hour: N/A
4. Name(s) and maximum amount of proposed material(s) produced per hour: N/A
5. Give chemical reactions, if applicable, that will be involved in the generation of air pollutants: Combustion of fuel oil

* The identification number which appears here must correspond to the air pollution control device identification number appearing on the *List Form*.

6. Combustion Data (if applicable):

(a) Type and amount in appropriate units of fuel(s) to be burned:

Ultra-low sulfur distillate fuel oil which is limited to a maximum of 19,081,721,569 SCF for both turbines combined for fuel oil and natural gas combustion combined. Fuel oil equal 889 SCF for every gallon of fuel oil combusted.

(b) Chemical analysis of proposed fuel(s), excluding coal, including maximum percent sulfur and ash:

Annual average sulfur content of the low sulfur distillate fuel shall not exceed 0.05 percent Only ultra-low sulfur diesel fuel will be combusted in the combustion turbines (15 parts per million or less sulfur)

(c) Theoretical combustion air requirement (ACF/unit of fuel):

@ °F and psia.

(d) Percent excess air:

(e) Type and BTU/hr of burners and all other firing equipment planned to be used:

N/A

(f) If coal is proposed as a source of fuel, identify supplier and seams and give sizing of the coal as it will be fired:

N/A

(g) Proposed maximum design heat input: 1,571 $\times 10^6$ BTU/hr.

7. Projected operating schedule:

Hours/Day	Days/Week	Weeks/Year

8. Projected amount of pollutants that would be emitted from this affected source if no control devices were used:			
@ 1,131 °F and			psia
a. NO_X	470	lb/hr	grains/ACF
b. SO_2	103	lb/hr	grains/ACF
c. CO	72	lb/hr	grains/ACF
d. PM_{10}	39	lb/hr	grains/ACF
e. Hydrocarbons		lb/hr	grains/ACF
f. VOCs	8	lb/hr	grains/ACF
g. Pb		lb/hr	grains/ACF
h. Specify other(s)			
H_2SO_4	15.8	lb/hr	grains/ACF
CO_2e	256,873	lb/hr	grains/ACF
		lb/hr	grains/ACF
		lb/hr	grains/ACF
		lb/hr	grains/ACF

NOTE: (1) An Air Pollution Control Device Sheet must be completed for any air pollution device(s) used to control emissions from this affected source.

(2) Complete the Emission Points Data Sheet.

9. Proposed Monitoring, Recordkeeping, Reporting, and Testing
Please propose monitoring, recordkeeping, and reporting in order to demonstrate compliance with the proposed operating parameters. Please propose testing in order to demonstrate compliance with the proposed emissions limits.

MONITORING	RECORDKEEPING
CEMS for NOx emissions. Fuel monitors for natural gas and fuel oil. Calculation of SO2 emissions.	Records of fuel usage (natural gas and fuel oil) as well as tons per year NOx emissions. Records of SO2 emissions.
REPORTING	TESTING

MONITORING. PLEASE LIST AND DESCRIBE THE PROCESS PARAMETERS AND RANGES THAT ARE PROPOSED TO BE MONITORED IN ORDER TO DEMONSTRATE COMPLIANCE WITH THE OPERATION OF THIS PROCESS EQUIPMENT OPERATION/AIR POLLUTION CONTROL DEVICE.

RECORDKEEPING. PLEASE DESCRIBE THE PROPOSED RECORDKEEPING THAT WILL ACCOMPANY THE MONITORING.

REPORTING. PLEASE DESCRIBE THE PROPOSED FREQUENCY OF REPORTING OF THE RECORDKEEPING.

TESTING. PLEASE DESCRIBE ANY PROPOSED EMISSIONS TESTING FOR THIS PROCESS EQUIPMENT/AIR POLLUTION CONTROL DEVICE.

10. Describe all operating ranges and maintenance procedures required by Manufacturer to maintain warranty

ATTACHMENT O –
MONITORING – RECORDKEEPING – REPORTING – TESTING
(SEE SECTION 5.1 IN PSD REPORT)

ATTACHMENT P –
PUBLIC NOTICE

AIR QUALITY PERMIT NOTICE
Notice of Application

Notice is given that **Pleasants Energy, LLC** has applied to the West Virginia Department of Environmental Protection, Division of Air Quality, for a **45CSR13 Construction Permit** for the increase in operation of the existing simple combustion turbines. The facility is located on **Latitude, Longitude: 39.333, -81.365**, **10319 South Pleasants Highway**, **St. Marys**, in **Pleasants** County, West Virginia.

The applicant estimates the potential to discharge the following Regulated Air Pollutants will be: **NO_X: 464.62 tpy, CO: 509.5 tpy, VOC: 23.8 tpy, SO_2: 39.0 tpy, PM_{10}: 118.7 tpy, Total HAPs: 6.2 tpy**

Startup of operation is planned to begin on or about the **First** day of **June**, **2016**. Written comments will be received by the West Virginia Department of Environmental Protection, Division of Air Quality, 601 57th Street, SE, Charleston, WV 25304, for at least 30 calendar days from the date of publication of this notice.

Any questions regarding this permit application should be directed to the DAQ at (304) 926-0499, extension 1227, during normal business hours.

Dated this the **15** day of **September**, **2015**.

By: **Pleasants Energy, LLC**
Gerald Gatti
Plant Manager
10319 South Pleasants Highway
St. Marys, WV 26170

ATTACHMENT R –
AUTHORITY FORM

AUTHORITY OF LIMITED LIABILITY COMPANY (LLC)

TO: The West Virginia Department of Environmental Protection, Division of Air Quality

DATE: June 22, 2015

ATTN: Director

LLC's Federal Employer I.D. Number 26-3603167

The undersigned hereby files with the West Virginia Department of Environmental Protection, Division of Air Quality, a permit application and hereby certifies that the said name is a trade name which we are using in the conduct of an unincorporated business.

Further, we have agreed or certified as follows:

(1) The undersigned is a member and in that capacity may represent the interests of the LLC and may obligate and legally bind all current or future members and the LLC.

(2) The LLC is authorized to do business in the State of West Virginia.

(3) The name and business address of each member:

Member: Herman Schopman
Address: 1990 Post Oak Blvd, Suite 1900
Houston, TX 77056
Telephone No.: 713-636-0000

Member: Stefaan Sercu
Address: 1990 Post Oak Blvd, Suite 1900
Houston, TX 77056
Telephone No.: 713-636-0000

Member: Patrick Gaussent
Address: 1990 Post Oak Blvd, Suite 1900
Houston, TX 77056
Telephone No.: 713-636-0000

(4) If any other persons become members of the undersigned or our relations as such be altered in any way or if the business should become incorporated, the undersigned will notify you promptly.

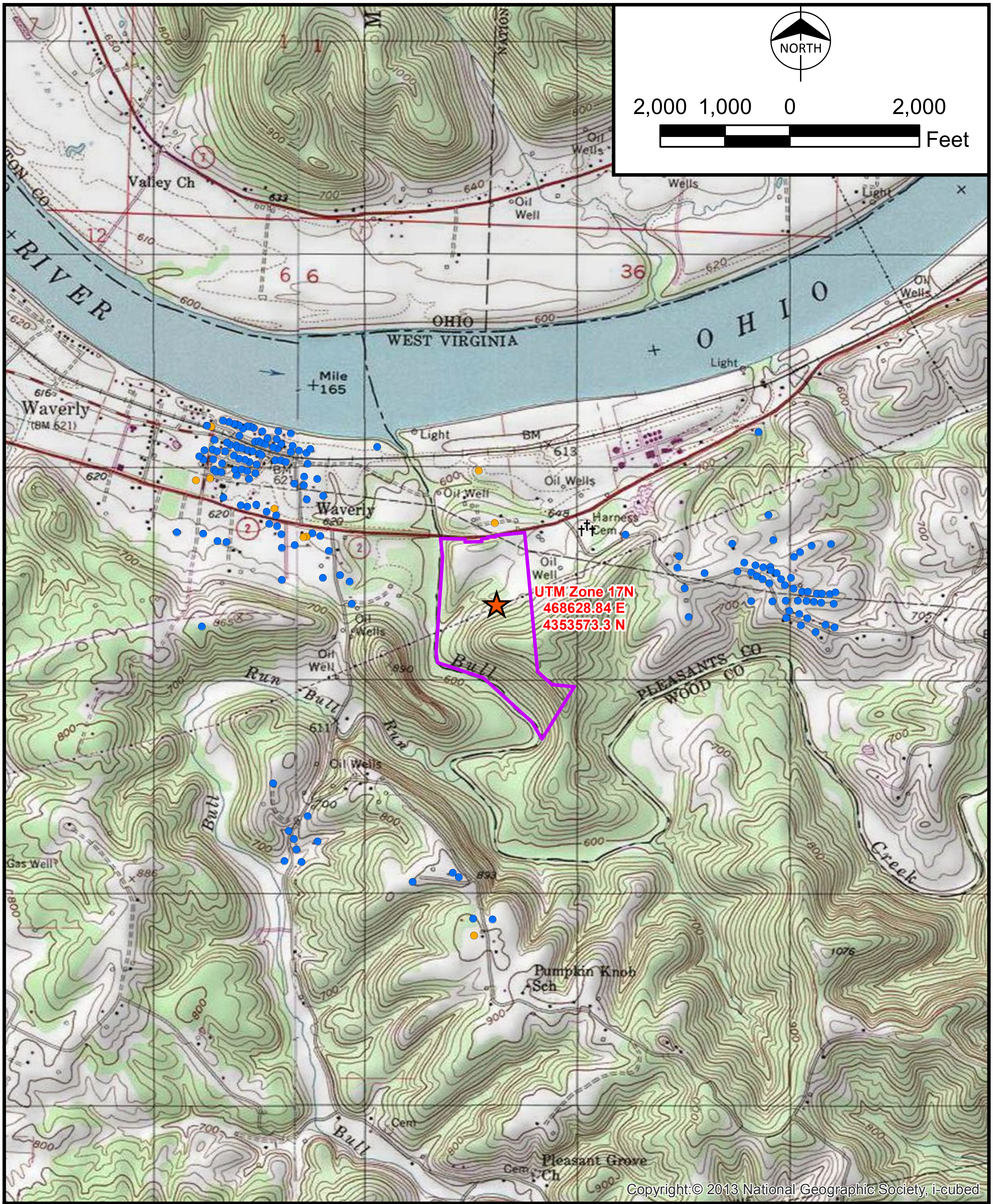
MEMBER OF LLC (Signature)

Herman Schopman
MEMBER OF LLC (Typed)

Address:
1990 Post Oak Blvd, Suite 1900
Houston, TX 77056
Telephone No.: 713-636-0000

Pleasants Energy, LLC

APPENDIX B – FIGURES



Legend

- Business
- House
- Cemetery
- Project Location
- Property Boundary

BURNS McDONNELL

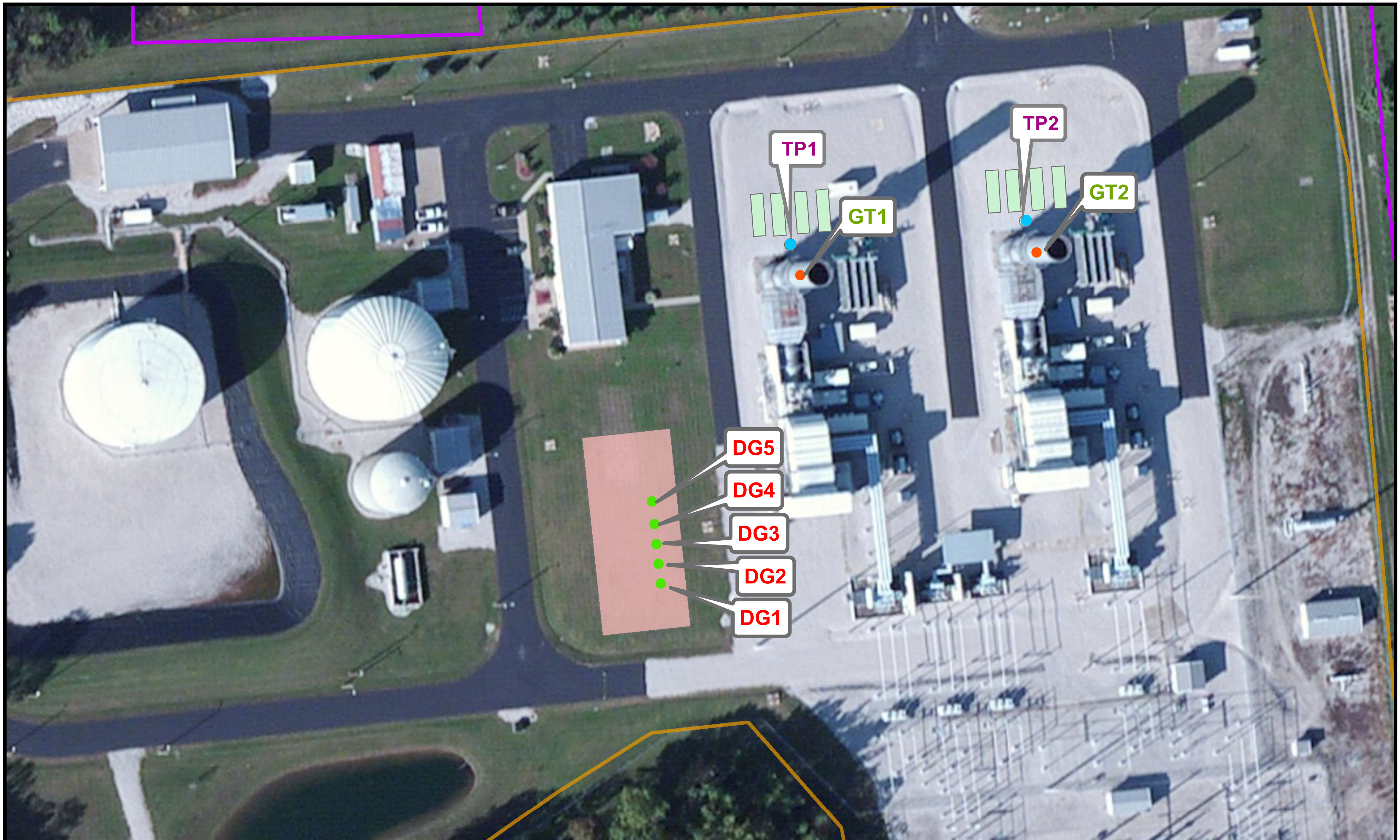
Figure B-1
Area Map
Pleasants Energy, LLC

Source: 2013 National Geographic Society, i-cubed, Burns & McDonnell

Issued: 7/28/2015

Path: R:\GDF_Suez\79835_Pleasants_Engn\GIS\DataFiles\ArcDocs\PSD Report\Figure B-1 Area Map.mxd ecrobbins 7/28/2015

Path: R:\GDF_Suez\79835_Pleasants_Engn\GIS\DataFiles\ArcDocs\PSD Report\Figure B-2 - PlotPlan.mxd ecrobbins 7/28/2015



Legend

- Turbophase System
- Fence Line
- Generator Building
- Property Boundary
- Combustion Turbine
- Emergency Generator
- TurboPhase Stack

NORTH

100 50 0 100

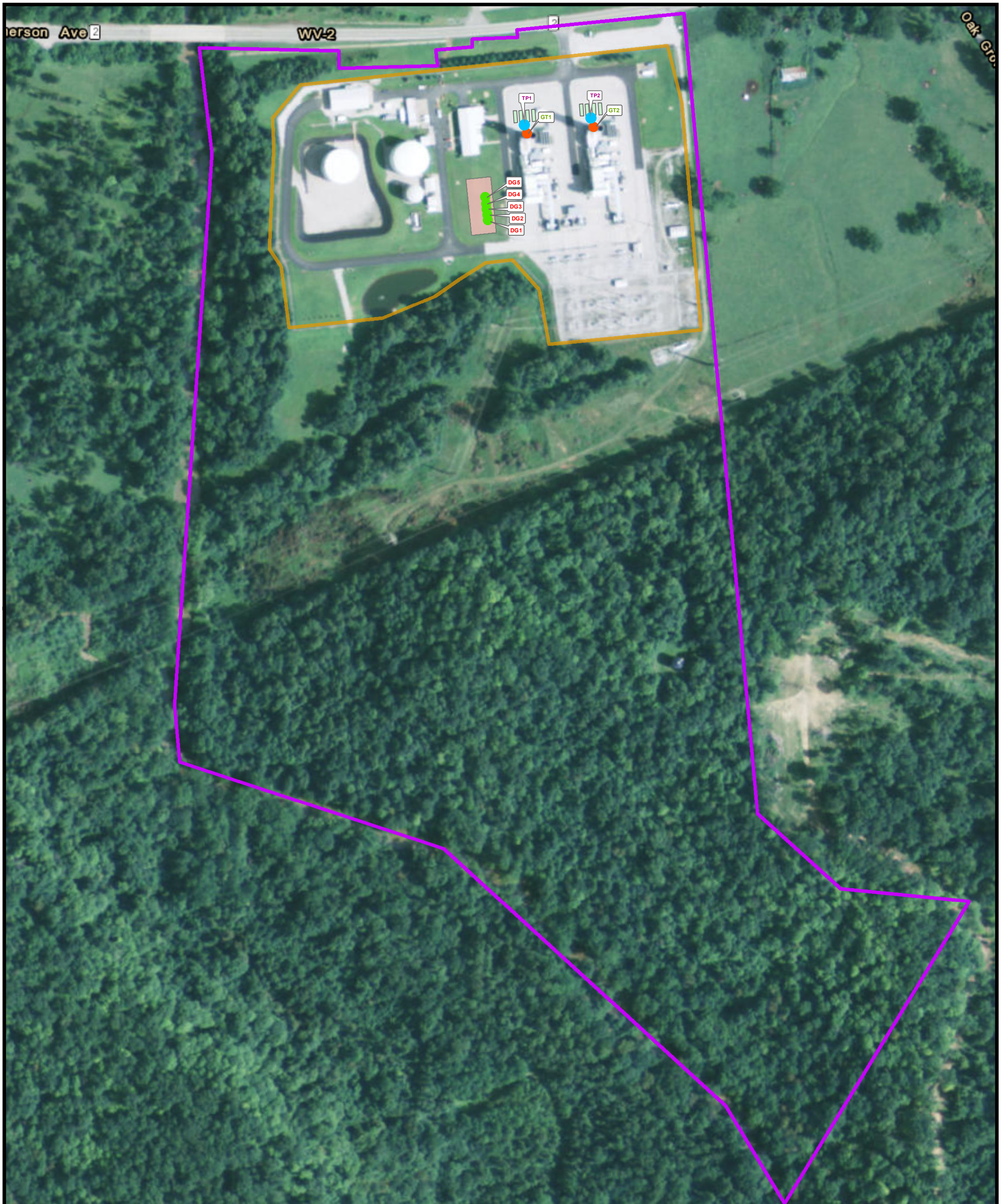
Scale in Feet

BURNS McDONNELL

Figure B-2
Facility Plot Plan
Pleasants Energy, LLC

Issued: 7/28/2015

Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community
Esri, HERE, DeLorme, MapmyIndia, © OpenStreetMap contributors and Burns & McDonnell



Path: R:\GDF_Suez\79835_Pleasants_Engn\GIS\DataFiles\ArcDocs\PSD Report\Figure B-3 Property Boundary.mxd ecrobbins 7/28/2015

Legend

Property Boundary

NORTH

350 175 0 350

Scale in Feet

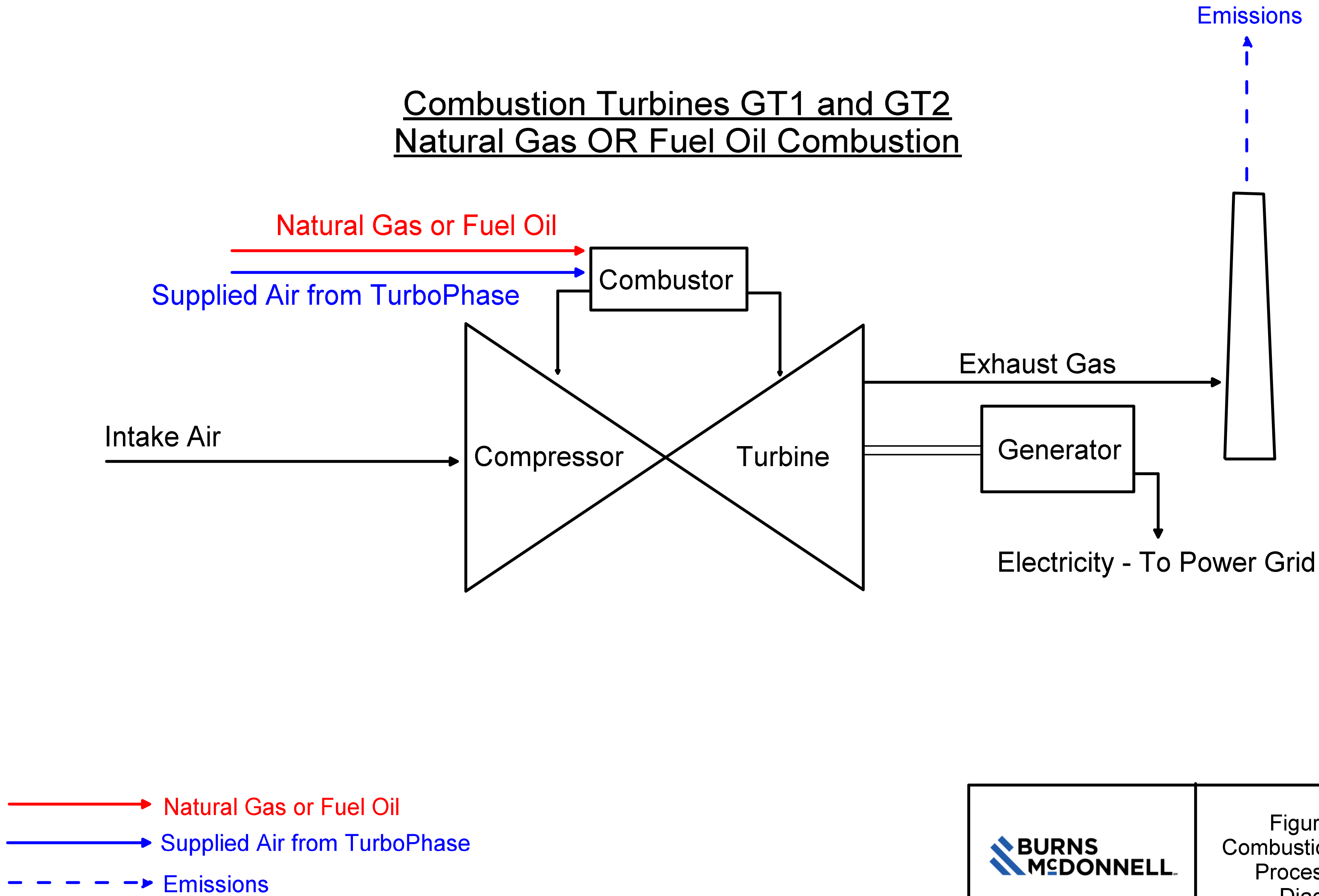
BURNS McDONNELL

Figure B-3
Property Boundary
Pleasants Energy, LLC

Source: Source: Esri, DigitalGlobe, GeoEye, Earthstar Geographics, CNES/Airbus DS, USDA, USGS, AEX, Getmapping, Aerogrid, IGN, IGP, swisstopo, and the GIS User Community
Esri, HERE, DeLorme, MapmyIndia, © OpenStreetMap contributors and Burns & McDonnell

Issued: 7/28/2015

Pleasants Energy, LLC
Combustion Turbine Process Flow Diagram



BURNS McDONNELL

Figure B-4
Combustion Turbine
Process Flow
Diagram

APPENDIX C – EMISSION CALCULATIONS

Pleasants Energy, LLC - PSD Project

Overall Project Emissions Increase and Post-Project Facility Total Emissions

Project Emissions Estimates (Maximum Potential to Emit)

Pollutant	Emissions Each Combustion Turbine (tpy)	Total Project Emissions (tpy)	PSD Significant Emission Rates
NOx	232.3	464.6	40
CO	254.8	509.5	100
PM	59.3	118.7	25
PM_{10}	59.3	118.7	15
$PM_{2.5}$	59.3	118.7	10
VOC	11.9	23.8	40
SO2	19.5	39.0	40
Lead	0.0	0.008	0.6
H_2SO_4	3.0	6.0	7
CO2e	615,816	1,231,633	75,000
Total HAPs	2.39	4.8	--

(a) Emissions are based on worst-case emissions from any operating scenario. Based on fuel limit of 19,081,721,568 SCF of gas plus fuel oil for both turbines combined. Includes startup and shutdown emissions (365 per year per turbine.)

(c) Bolded values exceed their PSD significant emission rates and are subject to PSD review.

Total Facility Emissions After Project (Existing and Project Sources)

Pollutant	Existing Emissions			Project Emissions	Facility Total After Project
	Emissions from Turbophase Systems (8 Engines Total)[a] (tpy)	Diesel Generators (Five Generators)[b] (tpy)	Diesel Storage Tank (tpy)	Total Project Emissions (Combustion Turbines) (tpy)	Total Emissions (tpy)
NOx	39.4	6.0	--	464.6	**510.0**
CO	8.7	31.5	--	509.5	**549.7**
PM/PM10	2.6	0.90	--	118.7	**122.2**
PM_{10}	2.6	0.90	--	118.7	**122.2**
$PM_{2.5}$	2.6	0.90	--	118.7	**122.2**
VOC	2.4	3.6	6.9E-04	23.8	**29.8**
SO2	0.13	6.6E-02	--	39.0	**39.2**
Lead	--	--	--	8.2E-03	**8.2E-03**
H_2SO_4	2.0E-02	1.0E-02	--	6.0	**6.0**
CO2e	25,879	5,850	--	1,231,633	**1,263,362**
Total HAPs	7.9	0.16	--	4.8	**12.9**

(a) Emissions based on 2 TurboPhase systems with 4 engines each, limited to 3,250 hours per year per engine.
(b) Emissions based on 5 diesel generators limited to 500 hours each.

Pleasants Energy, LLC - PSD Project
Operating Scenarios Emissions

Number of Combustion Turbines (GT1 & GT2)	2	
Fuel Limit	19,081,721,569	scf/year
Fuel Oil factor	889	scf/gal fuel oil combusted
GT1 & GT2 Combustion Turbine Size	1,571	MMBtu/hr
Natural gas heating value	1,020	MMBtu/MMcf
#2 Fuel Oil heating value	0.14	MMBtu/gal
Fuel Oil Consumption Rate	11,214	gal/hr
Natural gas operation with TurboPhase per turbine	3,250	hours
Total Number of Starts (Natural Gas + Fuel Oil)	365	
Number of Natural Gas Starts Per Turbine	345	
Number of Fuel Oil Starts Per Turbine	20	

Pollutant	100% Load Natural Gas Emission Rate (lb/hr)	Natural Gas 100% Load With TurboPhase Emission Rate (lb/hr)	Natural Gas Startup Emission Rate (lb/hr)	Natural Gas Shutdown Emission Rate (lb/hr)	Fuel Oil 100% Load With TurboPhase Emission Rate (lb/hr)	Fuel Oil Startup Emission Rate (lb/hr)	Fuel Oil Shutdown Emission Rate (lb/hr)
NOx	65.00	75.00	121.17	103.32	470.00	561.64	543.09
CO	32.00	36.00	384.43	144.43	72.00	230.37	195.68
$PM/PM_{10}/PM_{2.5}$	18.00	20.20	18.00	18.00	39.00	39.00	39.00
VOC	3.00	3.40	6.83	6.19	8.00	9.14	8.95
SO_2	2.50	2.80	2.50	2.50	103.00	103.00	103.00
H_2SO_4	0.38	0.44	0.38	0.38	15.77	15.77	15.77
Lead	-	-	--	--	0.02	0.02	0.02
CO_2	183,771	212,072	183,771	183,771	255,995	255,995	255,995
N_2O	0.35	0	0	0	2	2	2
CH_4	3.46	4	3	3	10	10	10
CO_2e	183,961	212,291	183,961	183,961	256,873	256,873	256,873

Pleasants Energy, LLC - PSD Project
Operating Scenarios Emissions

Natural Gas Only Option

Pollutant	Fuel Limit on Natural Gas Only per Turbine[a,b] (tpy)	Fuel Limit on Natural Gas Only Both Turbines[a,b] (tpy)
NOx	232.30	464.60
CO	254.77	509.54
$PM/PM_{10}/PM_{2.5}$	59.33	118.65
VOC	11.92	23.84
SO_2	8.23	16.46
H_2SO_4	1.28	2.56
Lead	-	-
CO_2	615181.47	1,230,363
N_2O	1.16	2.32
CH_4	11.57	23.14
CO_2e	615816.26	1,231,633

Fuel Oil		Natural Gas	
0	hours/year	6,195	Approximate hours/year
-	gal/yr	9,731,678	MMBtu/yr
-	SCF/yr equivalent	9,541	MMCF/yr
-	MMCF/yr	9,540,860,784.3	SCF/yr

9,540,860,784 SCF/yr per turbine
19,081,721,568.6 SCF/yr both turbines combined

(a) Emissions include 365 start-up/shut-down events on natural gas per turbine
(b) NOx emissions are capped at 232.3 tpy per turbine

Max Fuel Oil Option

Pollutant	4,205,357 gal/yr on Fuel Oil Only, per Turbine[a] (tpy)	4,205,357 gal/yr on Fuel Oil Only, Both Turbines[a] (tpy)
NOx	90.69	181.38
CO	17.90	35.81
$PM/PM_{10}/PM_{2.5}$	7.31	14.63
VOC	1.53	3.06
SO_2	19.31	38.63
H_2SO_4	2.96	5.91
Lead	0.00	0.01
CO_2	47,999	95,998
N_2O	0.39	0.78
CH_4	1.95	3.89
CO_2e	48,164	96,327

Fuel Oil		Natural Gas	
375	hours/year	-	hours/year
4,205,357	gal/yr	-	MMBtu/yr
3,738,562,500	SCF/yr equivalent	-	MMCF/yr
3,738.56	MMCF/yr	-	SCF/yr

3,738,562,500 SCF/yr per turbine
7,477,125,000.00 SCF/yr both turbines combined

(a) Emissions include 20 start-up/shut-down events on fuel oil and 4,205,357 gal/yr each turbine

Realistic Operating Scenario Option 1

Pollutant	Annual Emissions Per Turbine[a,b] (tpy)	Annual Emissions Both Turbines Combined[a,b] (tpy)
NOx	232.30	464.60
CO	237.49	474.98
$PM/PM_{10}/PM_{2.5}$	51.58	103.15
VOC	10.70	21.40
SO_2	16.91	33.83
H_2SO_4	2.61	5.22
Lead	2.20E-03	4.40E-03
CO_2	521828.01	1,043,656
N_2O	1.14	2.29
CH_4	10.37	20.74
CO_2e	522427.79	1,044,856

Fuel Oil		Natural Gas	
200	hours/year	4900	hours/year
2,242,857	gal/yr	7,697,900	MMBtu/yr
1,993,900,000	SCF/yr equivalent	7,547	MMCF/yr
1,993.90	MMCF/yr	7,546,960,784.31	SCF/yr

9,540,860,784 SCF/yr per turbine
19,081,721,568.63 SCF/yr both turbines combined

(a) Emissions include 345 start-up/shut-down events on natural gas and 20 start-up/shut-down events on fuel oil per turbine
(b) NOx emissions are capped at 232.3 tpy per turbine

Pleasants Energy, LLC - PSD Project
Operating Scenarios Emissions

Realistic Operating Scenario Option 2

Pollutant	Annual Emissions Per Turbine[a,b,c] (tpy)	Annual Emissions Both Turbines Combined (tpy)[a,b,c]
NOx	232.30	464.60
CO	233.43	466.87
$PM/PM_{10}/PM_{2.5}$	49.25	98.50
VOC	10.36	20.72
SO_2	19.52	39.03
H_2SO_4	3.01	6.02
Lead	0.00	0.00E+00
CO_2	493821.97	987,644
N_2O	1.14	2.28
CH_4	10.01	20.01
CO_2e	494411.25	988,823

(a) Emissions include 345 start-up/shut-down events on natural gas and 20 start-up/shut-down events on fuel oil per turbine
(b) Emissions based on 2,592.1 MMCF of fuel oil and 6,948.8 MMCF of natural gas per turbine
(c) NOx emissions are capped at 232.3 tpy per turbine

Fuel Oil		Natural Gas	
260	Approximate hours/year	4512	Approximate hours/year
2,915,714	gal/yr	7,087,767	MMBtu/yr
2,592,070,000	SCF/yr equivalent	6,948,790,784	SCF/yr
2,592.07	MMCF/yr	6,948.79	MMCF/yr

9,540,860,784 SCF/yr per turbine
19,081,721,568.63 SCF/yr both turbines combined

Maximum emissions from all three scenarios

Pollutant	Maximum Emissions per Turbine[a] (tpy)	Maximum Emissions Both Turbines (tpy)[a]
NOx	232.30	464.60
CO	254.77	509.54
$PM/PM_{10}/PM_{2.5}$	59.33	118.65
VOC	11.92	23.84
SO_2	19.52	39.03
H_2SO_4	3.01	6.02
Lead	0.00	0.01
CO_2	615181.47	1230362.93
N_2O	1.16	2.32
CH_4	11.57	23.14
CO_2e	615816.26	1231632.52

(a) NOx emissions are capped at 232.3 tpy per turbine

Pleasants Energy, LLC - PSD Project
HAPs Emissions - Existing and Project Emissions for Natural Gas Only Operation

Hours of Operation

Combustion Turbine Natural Gas Operation (2) =	6,195	hours per year per combustion turbine
Combustion Turbine Fuel Oil Operation (2) =	0	hours per year per combustion turbine
Tier IV Diesel Generator (5) =	500	hours per year per generator
Turbophase Natural Gas Engine (8) =	3,250	hours per year per engine

Project HAPs (Natural Gas Only)		
HAP	Maximum Potential Emissions tpy	
Formaldehyde	1.97	Largest HAP
Toluene	1.27	2nd Largest
Xylene	0.62	3rd Largest
TOTAL Project HAPs	**4.77**	

*Natural Gas Only is Worst Case Scenario

Total Facility HAPs (Existing + Project)		
HAP	Maximum Potential Emissions tpy	
Formaldehyde	7.80	Largest HAP
Toluene	1.32	2nd Largest
Acetaldehyde	1.31	3rd Largest
TOTAL Facility HAPs	**12.91**	

Fuel Usage

Generators - Diesel	hp	mmBtu/hr		
Tier IV Diesel Generator =	4,376	28.6		
Number of diesel generators =	5			
TurboPhase Module (Each Engine	hp	mmBtu/hr		
Gas engine (Each) =	2,750	17.0		
Oxidation Catalyst =	50%	% Control		
Number of gas engines=	8	Engines (4 per Turbophase Module)		
Combustion Turbines	mmBtu/hr	mmCF/hr	1,020	MMBtu/MMcf
			Gas heat content value from AP-42 Section 1.4, updated 7/98	
Natural Gas Operation (Each) =	1,571	1.540		
Fuel Oil Operation (each) =	1,571			
Number of Combustion Turbines =	2			

			Existing HAPS									Project Emissions								Totals	
			Natural Gas - TurboPhase				Fuel Oil - Diesel Generators					Natural Gas- Internal Combustion				Fuel Oil - Internal Combustion					
Chemical	CAS	POM?	Emission Factors[a] lb/MMBTU	Gas Engine (Each) (lb/hr)	Gas Engine (Each) (tpy)	Total (8 Gas Engines) (tpy)	Emission Factor[b] (lb/MMBtu)	One Generator (lb/hr)	One Generator (tpy)	Combined Generator Emissions (5 Generators) (tpy)	Total Existing HAPS (tpy)	Emission Factor[c] (lb/MMBtu)	One Combustion Turbine Emissions (lb/hr)	One Combustion Turbine Emissions (tpy)	Combined Combustion Turbine Emissions(2) (tpy)	Emission Factor[c] (lb/MMBtu)	One Combustion Turbine Emissions (lb/hr)	One Combustion Turbine Emissions (tpy)	Combined Combustion Turbine Emissions (2) (tpy)	Total Project HAPS (tpy)	Total Facility HAPs (Existing + Project) (tpy)
2-Methylnaphthalene	97-57-6	POM	3.32E-05	2.82E-04	4.59E-04	3.67E-03					3.7E-03										3.67E-03
1,1,2,2-Tetrachloroethane	79-34-5		4.00E-05	3.40E-04	5.53E-04	4.42E-03					4.4E-03										4.42E-03
1,1,2-Trichloroethane	79-00-5		3.18E-05	2.70E-04	4.39E-04	3.51E-03					3.5E-03										3.51E-03
2,2,4-Trimethylpentane	540-84-1		2.50E-04	2.13E-03	3.45E-03	2.76E-02					2.8E-02										2.76E-02
Acenaphthene	83-32-9	POM	1.25E-06	1.06E-05	1.73E-05	1.38E-04	4.68E-06	1.34E-04	3.35E-05	1.67E-04	3.1E-04										3.05E-04
Acenaphthylene	203-96-8	POM	5.53E-06	4.70E-05	7.64E-05	6.11E-04	9.23E-06	2.64E-04	6.60E-05	3.30E-04	9.4E-04										9.41E-04
Acetaldehyde	75-07-0		8.36E-03	7.11E-02	1.15E-01	9.24E-01	2.52E-05	7.21E-04	1.80E-04	9.01E-04	9.2E-01	4.0E-05	6.3E-02	1.9E-01	3.9E-01					3.89E-01	1.31
Acrolein	107-02-8		5.14E-03	4.37E-02	7.10E-02	5.68E-01	7.88E-05	2.25E-03	5.64E-04	2.82E-03	5.7E-01	6.4E-06	1.0E-02	3.1E-02	6.2E-02					6.23E-02	6.33E-01
Anthracene	120-12-7	POM					1.23E-06	3.52E-05	8.80E-06	4.40E-05	4.4E-05										4.40E-05
Arsenic																1.10E-05	1.7E-02	0.0E+00	0.0E+00	0.00E+00	0.00E+00
Benz(a)anthracene	56-55-3	POM					6.22E-07	1.78E-05	4.45E-06	2.22E-05	2.2E-05										2.22E-05
Benzene	71-43-2		4.40E-04	3.74E-03	6.08E-03	4.86E-02	7.76E-04	2.22E-02	5.55E-03	2.77E-02	7.6E-02	1.2E-05	1.9E-02	5.8E-02	1.2E-01	5.5E-05	8.6E-02	0.0E+00	0.0E+00	1.17E-01	1.93E-01
Benzo(a)pyrene	50-32-8	POM	4.15E-07	3.53E-06	5.73E-06	4.59E-05	2.57E-07	7.35E-06	1.84E-06	9.19E-06	5.5E-05										5.50E-05
Benzo(b)fluoranthene	205-99-2	POM	1.66E-07	1.41E-06	2.29E-06	1.83E-05	1.10E-06	3.15E-05	7.87E-06	3.93E-05	5.8E-05										5.77E-05
Benzo(g,h,l)perylene	191-24-2	POM	4.14E-07	3.52E-06	5.72E-06	4.57E-05	5.56E-07	1.59E-05	3.98E-06	1.99E-05	6.6E-05										6.56E-05
Benzo(k)fluoranthene	205-82-3	POM					2.18E-07	6.24E-06	1.56E-06	7.80E-06	7.8E-06										7.80E-06
Beryllium																3.10E-07	4.9E-04	0.0E+00	0.0E+00	0.00E+00	0.00E+00
Biphenyl	92-51-3		2.12E-04	1.80E-03	2.93E-03	2.34E-02					2.3E-02										2.34E-02
1,3-Butadiene	106-99-0		2.67E-04	2.27E-03	3.69E-03	2.95E-02					3.0E-02	4.3E-07	6.8E-04	2.1E-03	4.2E-03	1.6E-05	2.5E-02	0.0E+00	0.0E+00	4.18E-03	3.37E-02
Cadmium																4.80E-06	7.5E-03	0.0E+00	0.0E+00	0.00E+00	0.00E+00
Carbon Tetrachloride	56-23-5		3.67E-05	3.12E-04	5.07E-04	4.06E-03					4.1E-03										4.06E-03
Chlorobenzene	108-90-7		3.04E-05	2.58E-04	4.20E-04	3.36E-03					3.4E-03										3.36E-03
Chloroethane			1.87E-06	1.59E-05	2.58E-05	2.07E-04					2.1E-04										2.07E-04
Chloroform	67-66-3		2.85E-05	2.42E-04	3.94E-04	3.15E-03					3.1E-03										3.15E-03
Chromium																1.10E-05	1.7E-02	0.0E+00	0.0E+00	0.00E+00	0.00E+00
Chrysene	218-01-9	POM	6.93E-07	5.89E-06	9.57E-06	7.66E-05	1.53E-06	4.38E-05	1.09E-05	5.47E-05	1.3E-04										1.31E-04
Dibenzo(a,h)anthracene	53-70-3	POM					3.46E-07	9.90E-06	2.47E-06	1.24E-05	1.2E-05										1.24E-05
Dichlorobenzene	25321-22-6																				0.00E+00
1,3-Dichloropropene	542-75-6		2.64E-05	2.24E-04	3.65E-04	2.92E-03					2.9E-03										2.92E-03
Ethyl benzene	100-41-4		3.97E-05	3.37E-04	5.48E-04	4.39E-03					4.4E-03	3.2E-05	5.0E-02	1.6E-01	3.1E-01					3.11E-01	3.16E-01
Ethylene Dibromide	106-93-4		4.43E-05	3.77E-04	6.12E-04	4.90E-03					4.9E-03										4.90E-03
Fluoranthene	206-44-0	POM	1.11E-06	9.44E-06	1.53E-05	1.23E-04	4.03E-06	1.15E-04	2.88E-05	1.44E-04	2.7E-04										2.67E-04
Fluorene	86-73-7	POM	5.67E-06	4.82E-05	7.83E-05	6.27E-04	1.28E-05	3.66E-04	9.15E-05	4.58E-04	1.1E-03										1.08E-03
Formaldehyde	500-00-0		5.28E-02	4.49E-01	7.29E-01	5.83	7.89E-05	2.26E-03	5.64E-04	2.82E-03	5.8E+00	2.0E-04	3.2E-01	9.8E-01	2.0E+00	2.8E-04	4.4E-01	0.0E+00	0.0E+00	1.97E+00	7.80
Hexane	110-54-3		1.11E-03	9.44E-03	1.53E-02	1.23E-01					1.2E-01										1.23E-01
Indeno(1,2,3-cd)pyrene	193-39-5	POM					4.14E-07	1.18E-05	2.96E-06	1.48E-05	1.5E-05										1.48E-05
Manganese																7.9E-04	1.2E+00	0.0E+00	0.0E+00	0.00E+00	0.00E+00
Mercury																1.20E-06	1.9E-03	0.0E+00	0.0E+00	0.00E+00	0.00E+00
Methanol	67-56-1		2.50E-03	2.13E-02	3.45E-02	2.76E-01					2.8E-01										2.76E-01
Methylene Chloride	75-09-2		2.00E-05	1.70E-04	2.76E-04	2.21E-03					2.2E-03										2.21E-03
Naphthalene	91-20-3		7.44E-05	6.32E-04	1.03E-03	8.22E-03	1.30E-04	3.72E-03	9.30E-04	4.65E-03	1.3E-02	1.3E-06	2.0E-03	6.3E-03	1.3E-02	3.5E-05	5.5E-02	0.0E+00	0.0E+00	1.27E-02	2.55E-02
Nickel																4.60E-06	7.2E-03	0.0E+00	0.0E+00	0.00E+00	0.00E+00
PAH			2.69E-05	2.29E-04	3.72E-04	2.97E-03					3.0E-03	2.2E-06	3.5E-03	1.1E-02	2.1E-02	4.0E-05	6.3E-02	0.0E+00	0.0E+00	2.14E-02	2.44E-02
Phenanathrene	85-01-8	POM	1.04E-05	8.84E-05	1.44E-04	1.15E-03	4.08E-05	1.17E-03	2.92E-04	1.46E-03	2.6E-03										2.61E-03
Phenol	108-95-2		2.40E-05	2.04E-04	3.32E-04	2.65E-03					2.7E-03										2.65E-03
Propylene							2.79E-03	7.98E-02	2.00E-02	9.98E-02	1.0E-01										9.98E-02
Pyrene	129-00-0	POM	1.36E-06	1.16E-05	1.88E-05	1.50E-04	3.71E-06	1.06E-04	2.65E-05	1.33E-04	2.8E-04										2.83E-04
Selenium																2.50E-05	3.9E-02	0.0E+00	0.0E+00	0.00E+00	0.00E+00
Styrene	100-42-5		2.36E-05	2.01E-04	3.26E-04	2.61E-03					2.6E-03										2.61E-03
Tetrachloroethane	25322-20-7		2.48E-06	2.11E-05	3.43E-05	2.74E-04					2.7E-04										2.74E-04
Toluene	108-88-3		4.08E-04	3.47E-03	5.64E-03	4.51E-02	2.81E-04	8.04E-03	2.01E-03	1.00E-02	5.5E-02	1.3E-04	2.0E-01	6.3E-01	1.3E+00					1.27E+00	1.32
Vinyl Chloride	75-01-4		1.49E-05	1.27E-04	2.06E-04	1.65E-03					1.6E-03										1.65E-03
Xylene	1330-20-7		1.84E-04	1.56E-03	2.54E-03	2.03E-02	1.93E-04	5.52E-03	1.38E-03	6.90E-03	2.7E-02	6.4E-05	1.0E-01	3.1E-01	6.2E-01					6.23E-01	6.50E-01
TOTAL				6.14E-01	9.97E-01	**7.94**		**0.13**	**0.03**	**0.16**	**8.14**		0.77	2.39	4.77		2.00	0.00	0.00	4.77	12.91

(a) Emission Factors from AP-42 Section 3.2, Updated 7/2000. Emissions per engine (4 engines per Turbophase Module)
(b) Emission factors from AP-42, Section 3.4, 6/1996, except where noted
(c) Emission factors for combustion turbines from AP-42 Section 3.1, Updated 2/2000. Natural gas formaldehyde emission factor from Sims Roy EPA Memo "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines" 8/21/2001.

Pleasants Energy, LLC - PSD Project
HAPs Emissions - Existing and Project Emissions for Natural Gas and Fuel Oil Operation

Hours of Operation

Combustion Turbine Natural Gas Operation (2) =	4,512	hours per year per combustion turbine
Combustion Turbine Fuel Oil Operation (2) =	260	hours per year per combustion turbine
Tier IV Diesel Generator (5) =	500	hours per year per generator
Turbophase Natural Gas Engine (8) =	3,250	hours per year per engine

Project HAPs (Natural Gas and Fuel Oil)		
HAP	Maximum Potential Emissions tpy	
Formaldehyde	1.55	Largest HAP
Toluene	0.92	2nd Largest
Xylene	0.45	3rd Largest
TOTAL Project HAPs	**4.00**	

**Natural Gas Only is Worst Case Scenario*

Total Facility HAPs (Existing + Project)		
HAP	Maximum Potential Emissions tpy	
Formaldehyde	7.38	Largest HAP
Acetaldehyde	1.21	2nd Largest
Toluene	0.98	3rd Largest
TOTAL Facility HAPs	**12.13**	

Fuel Usage

Generators - Diesel	hp	mmBtu/hr		
Tier IV Diesel Generator =	4,376	28.6		
Number of diesel generators =	5			
TurboPhase Module (Each Engine	hp	mmBtu/hr		
Gas engine (Each) =	2,750	17.0		
Oxidation Catalyst =	50%	% Control		
Number of gas engines=	8	Engines (4 per Turbophase Module)		
Combustion Turbines	mmBtu/hr	mmCF/hr	1,020	MMBtu/MMcf
			Gas heat content value from AP-42	
Natural Gas Operation (Each) =	1,571	1.540	Section 1.4, updated 7/98	
Fuel Oil Operation (each) =	1,571			
Number of Combustion Turbines =	2			

Existing HAPS

Chemical	CAS	POM?	Natural Gas - TurboPhase: Emission Factors[a] lb/MMBTU	Gas Engine (Each) (lb/hr)	Gas Engine (Each) (tpy)	Total (8 Gas Engines) (tpy)	Fuel Oil - Diesel Generators: Emission Factor[b] (lb/MMBtu)	One Generator (lb/hr)	One Generator (tpy)	Combined Generator Emissions (5 Generators) (tpy)	Total Existing HAPS (tpy)
2-Methylnaphthalene	97-57-6	POM	3.32E-05	2.82E-04	4.59E-04	3.67E-03					3.7E-03
1,1,2,2-Tetrachloroethane	79-34-5		4.00E-05	3.40E-04	5.53E-04	4.42E-03					4.4E-03
1,1,2-Trichloroethane	79-00-5		3.18E-05	2.70E-04	4.39E-04	3.51E-03					3.5E-03
2,2,4-Trimethylpentane	540-84-1		2.50E-04	2.13E-03	3.45E-03	2.76E-02					2.8E-02
Acenaphthene	83-32-9	POM	1.25E-06	1.06E-05	1.73E-05	1.38E-04	4.68E-06	1.34E-04	3.35E-05	1.67E-04	3.1E-04
Acenaphthylene	203-96-8	POM	5.53E-06	4.70E-05	7.64E-05	6.11E-04	9.23E-06	2.64E-04	6.60E-05	3.30E-04	9.4E-04
Acetaldehyde	75-07-0		8.36E-03	7.11E-02	1.15E-01	9.24E-01	2.52E-05	7.21E-04	1.80E-04	9.01E-04	9.2E-01
Acrolein	107-02-8		5.14E-03	4.37E-02	7.10E-02	5.68E-01	7.88E-05	2.25E-03	5.64E-04	2.82E-03	5.7E-01
Anthracene	120-12-7	POM					1.23E-06	3.52E-05	8.80E-06	4.40E-05	4.4E-05
Arsenic											
Benz(a)anthracene	56-55-3	POM					6.22E-07	1.78E-05	4.45E-06	2.22E-05	2.2E-05
Benzene	71-43-2		4.40E-04	3.74E-03	6.08E-03	4.86E-02	7.76E-04	2.22E-02	5.55E-03	2.77E-02	7.6E-02
Benzo(a)pyrene	50-32-8	POM	4.15E-07	3.53E-06	5.73E-06	4.59E-05	2.57E-07	7.35E-06	1.84E-06	9.19E-06	5.5E-05
Benzo(b)fluoranthene	205-99-2	POM	1.66E-07	1.41E-06	2.29E-06	1.83E-05	1.10E-06	3.15E-05	7.87E-06	3.93E-05	5.8E-05
Benzo(g,h,I)perylene	191-24-2	POM	4.14E-07	3.52E-06	5.72E-06	4.57E-05	5.56E-07	1.59E-05	3.98E-06	1.99E-05	6.6E-05
Benzo(k)fluoranthene	205-82-3	POM					2.18E-07	6.24E-06	1.56E-06	7.80E-06	7.8E-06
Beryllium											
Biphenyl	92-51-3		2.12E-04	1.80E-03	2.93E-03	2.34E-02					2.3E-02
1,3-Butadiene	106-99-0		2.67E-04	2.27E-03	3.69E-03	2.95E-02					3.0E-02
Cadmium											
Carbon Tetrachloride	56-23-5		3.67E-05	3.12E-04	5.07E-04	4.06E-03					4.1E-03
Chlorobenzene	108-90-7		3.04E-05	2.58E-04	4.20E-04	3.36E-03					3.4E-03
Chloroethane			1.87E-06	1.59E-05	2.58E-05	2.07E-04					2.1E-04
Chloroform	67-66-3		2.85E-05	2.42E-04	3.94E-04	3.15E-03					3.1E-03
Chromium											
Chrysene	218-01-9	POM	6.93E-07	5.89E-06	9.57E-06	7.66E-05	1.53E-06	4.38E-05	1.09E-05	5.47E-05	1.3E-04
Dibenzo(a,h)anthracene	53-70-3	POM					3.46E-07	9.90E-06	2.47E-06	1.24E-05	1.2E-05
Dichlorobenzene	25321-22-6										
1,3-Dichloropropene	542-75-6		2.64E-05	2.24E-04	3.65E-04	2.92E-03					2.9E-03
Ethyl benzene	100-41-4		3.97E-05	3.37E-04	5.48E-04	4.39E-03					4.4E-03
Ethylene Dibromide	106-93-4		4.43E-05	3.77E-04	6.12E-04	4.90E-03					4.9E-03
Fluoranthene	206-44-0	POM	1.11E-06	9.44E-06	1.53E-05	1.23E-04	4.03E-06	1.15E-04	2.88E-05	1.44E-04	2.7E-04
Fluorene	86-73-7	POM	5.67E-06	4.82E-05	7.83E-05	6.27E-04	1.28E-05	3.66E-04	9.15E-05	4.58E-04	1.1E-03
Formaldehyde	500-00-0		5.28E-02	4.49E-01	7.29E-01	5.83	7.89E-05	2.26E-03	5.64E-04	2.82E-03	5.8E+00
Hexane	110-54-3		1.11E-03	9.44E-03	1.53E-02	1.23E-01					1.2E-01
Indeno(1,2,3-cd)pyrene	193-39-5	POM					4.14E-07	1.18E-05	2.96E-06	1.48E-05	1.5E-05
Manganese											
Mercury											
Methanol	67-56-1		2.50E-03	2.13E-02	3.45E-02	2.76E-01					2.8E-01
Methylene Chloride	75-09-2		2.00E-05	1.70E-04	2.76E-04	2.21E-03					2.2E-03
Naphthalene	91-20-3		7.44E-05	6.32E-04	1.03E-03	8.22E-03	1.30E-04	3.72E-03	9.30E-04	4.65E-03	1.3E-02
Nickel											
PAH			2.69E-05	2.29E-04	3.72E-04	2.97E-03					3.0E-03
Phenanathrene	85-01-8	POM	1.04E-05	8.84E-05	1.44E-04	1.15E-03	4.08E-05	1.17E-03	2.92E-04	1.46E-03	2.6E-03
Phenol	108-95-2		2.40E-05	2.04E-04	3.32E-04	2.65E-03					2.7E-03
Propylene							2.79E-03	7.98E-02	2.00E-02	9.98E-02	1.0E-01
Pyrene	129-00-0	POM	1.36E-06	1.16E-05	1.88E-05	1.50E-04	3.71E-06	1.06E-04	2.65E-05	1.33E-04	2.8E-04
Selenium											
Styrene	100-42-5		2.36E-05	2.01E-04	3.26E-04	2.61E-03					2.6E-03
Tetrachloroethane	25322-20-7		2.48E-06	2.11E-05	3.43E-05	2.74E-04					2.7E-04
Toluene	108-88-3		4.08E-04	3.47E-03	5.64E-03	4.51E-02	2.81E-04	8.04E-03	2.01E-03	1.00E-02	5.5E-02
Vinyl Chloride	75-01-4		1.49E-05	1.27E-04	2.06E-04	1.65E-03					1.6E-03
Xylene	1330-20-7		1.84E-04	1.56E-03	2.54E-03	2.03E-02	1.93E-04	5.52E-03	1.38E-03	6.90E-03	2.7E-02
TOTAL				6.14E-01	9.97E-01	**7.94**		**0.13**	**0.03**	**0.16**	**8.14**

Project Emissions / Totals

Chemical	Natural Gas- Internal Combustion: Emission Factor[c] (lb/MMBtu)	One Combustion Turbine Emissions (lb/hr)	One Combustion Turbine Emissions (tpy)	Combined Combustion Turbine Emissions(2) (tpy)	Fuel Oil - Internal Combustion: Emission Factor[c] (lb/MMBtu)	One Combustion Turbine Emissions (lb/hr)	One Combustion Turbine Emissions (tpy)	Combined Combustion Turbine Emissions (2) (tpy)	Totals: Total Project HAPS (tpy)	Total Facility HAPs (Existing + Project) (tpy)
2-Methylnaphthalene										3.67E-03
1,1,2,2-Tetrachloroethane										4.42E-03
1,1,2-Trichloroethane										3.51E-03
2,2,4-Trimethylpentane										2.76E-02
Acenaphthene										3.05E-04
Acenaphthylene										9.41E-04
Acetaldehyde	4.0E-05	6.3E-02	1.4E-01	2.8E-01					2.84E-01	1.21
Acrolein	6.4E-06	1.0E-02	2.3E-02	4.5E-02					4.54E-02	6.16E-01
Anthracene										4.40E-05
Arsenic					1.10E-05	1.7E-02	2.2E-03	4.5E-03	4.49E-03	4.49E-03
Benz(a)anthracene										2.22E-05
Benzene	1.2E-05	1.9E-02	4.3E-02	8.5E-02	5.5E-05	8.6E-02	1.1E-02	2.2E-02	1.08E-01	1.84E-01
Benzo(a)pyrene										5.50E-05
Benzo(b)fluoranthene										5.77E-05
Benzo(g,h,I)perylene										6.56E-05
Benzo(k)fluoranthene										7.80E-06
Beryllium					3.10E-07	4.9E-04	6.3E-05	1.3E-04	1.27E-04	1.27E-04
Biphenyl										2.34E-02
1,3-Butadiene	4.3E-07	6.8E-04	1.5E-03	3.0E-03	1.6E-05	2.5E-02	3.3E-03	6.5E-03	9.58E-03	3.91E-02
Cadmium					4.80E-06	7.5E-03	9.8E-04	2.0E-03	1.96E-03	1.96E-03
Carbon Tetrachloride										4.06E-03
Chlorobenzene										3.36E-03
Chloroethane										2.07E-04
Chloroform										3.15E-03
Chromium					1.10E-05	1.7E-02	2.2E-03	4.5E-03	4.49E-03	4.49E-03
Chrysene										1.31E-04
Dibenzo(a,h)anthracene										1.24E-05
Dichlorobenzene										0.00E+00
1,3-Dichloropropene										2.92E-03
Ethyl benzene	3.2E-05	5.0E-02	1.1E-01	2.3E-01					2.27E-01	2.31E-01
Ethylene Dibromide										4.90E-03
Fluoranthene										2.67E-04
Fluorene										1.08E-03
Formaldehyde	2.0E-04	3.2E-01	7.2E-01	1.4E+00	2.8E-04	4.4E-01	5.7E-02	1.1E-01	1.55E+00	7.38
Hexane										1.23E-01
Indeno(1,2,3-cd)pyrene										1.48E-05
Manganese					7.9E-04	1.2E+00	1.6E-01	3.2E-01	3.23E-01	3.23E-01
Mercury					1.20E-06	1.9E-03	2.5E-04	4.9E-04	4.90E-04	4.90E-04
Methanol										2.76E-01
Methylene Chloride										2.21E-03
Naphthalene	1.3E-06	2.0E-03	4.6E-03	9.2E-03	3.5E-05	5.5E-02	7.1E-03	1.4E-02	2.35E-02	3.64E-02
Nickel					4.60E-06	7.2E-03	9.4E-04	1.9E-03	1.88E-03	1.88E-03
PAH	2.2E-06	3.5E-03	7.8E-03	1.6E-02	4.0E-05	6.3E-02	8.2E-03	1.6E-02	3.19E-02	3.49E-02
Phenanathrene										2.61E-03
Phenol										2.65E-03
Propylene										9.98E-02
Pyrene										2.83E-04
Selenium					2.50E-05	3.9E-02	5.1E-03	1.0E-02	1.02E-02	1.02E-02
Styrene										2.61E-03
Tetrachloroethane										2.74E-04
Toluene	1.3E-04	2.0E-01	4.6E-01	9.2E-01					9.21E-01	0.98
Vinyl Chloride										1.65E-03
Xylene	6.4E-05	1.0E-01	2.3E-01	4.5E-01					4.54E-01	4.81E-01
TOTAL		0.77	1.74	3.48		2.00	0.26	0.52	4.00	12.13

(a) Emission Factors from AP-42 Section 3.2, Updated 7/2000. Emissions per engine (4 engines per Turbophase Module)
(b) Emission factors from AP-42, Section 3.4, 6/1996, except where noted
(c) Emission factors for combustion turbines from AP-42 Section 3.1, Updated 2/2000. Natural gas formaldehyde emission factor from Sims Roy EPA Memo "Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines" 8/21/2001.

Pleasants Energy, LLC - PSD Project
Natural Gas Potential Emissions for Turbines 1 & 2

GT1 & GT2 Combustion Turbine Size	1,571	MMBtu/hr
Number of Combustion Turbines (GT1 & GT2)	2	
Natural Gas Operation With Turbophase	3,250	Hours per turbine
Number of Natural Gas Starts Per Turbine	365	May include up to 20 starts on fuel oil.
Natural gas heating value	1,020	MMBtu/MMcf

Natural Gas Operation Emissions (lb/hr)

Pollutant	100% Load Natural Gas Emission Rate (lb/MMBtu)	100% Load Natural Gas Emission Rate (lb/hr)	100% Load With TurboPhase Emission Rate (lb/hr)	80% Load Natural Gas Emission Rate[a] (lb/hr)	60% Load Natural Gas Emission Rate[a] (lb/hr)	Natural Gas Start-up Emissions[b] (lb/hr)	Natural Gas Shutdown Emissions[c] (lb/hr)
NOx	--	65	75	54	44	121.2	103.3
CO	--	32	36	26	22	384.4	144.4
$PM/PM_{10}/PM_{2.5}$	--	18	20.2	18	18	18.0	18.0
VOC	--	3	3.4	2.4	3	6.8	6.2
SO_2	--	2.5	2.8	--	--	2.5	2.5
H_2SO_4	--	0.38	0.44	--	--	0.38	0.38
Lead	--	-	-	--	--	--	--
CO_2	117.0	183,771	212,072	--	--	183,771	183,771
N_2O	2.20E-04	0.35	0.40	--	--	0.35	0.35
CH_4	2.20E-03	3.46	3.98	--	--	3.5	3.5
CO_2e	--	183,961	212,291	--	--	183,961	183,961

(a) For modeling purposes only
(b) Assumes start-up is 120 minutes.
(c) Assumes shut-down is 60 minutes.

Pleasants Energy, LLC - PSD Project
Natural Gas Potential Emissions for Turbines 1 & 2

Natural Gas Only Startup/Shutdown Emissions

Pollutant	Start-up Emissions (lb/hr)	Shutdown Emissions (lb/hr)	Number of Starts Per Turbine	Start-up/Shutdown Emissions (tpy)	Total Start-up/Shutdown Emissions (Both turbines) (tpy)
NOx[a]	121.17	103.32	365	63.08	126.17
CO[a]	384.43	144.43	365	166.68	333.35
$PM/PM_{10}/PM_{2.5}$	18	18	365	9.86	19.71
VOC[a]	6.83	6.19	365	3.62	7.24
SO_2	2.5	2.5	365	1.37	2.74
H_2SO_4	0.38	0.38	365	0.21	0.42
Lead	--	--	--	--	--
CO_2	183,771	183,771.33	365	100,614.80	201,229.61
N_2O	0.35	0.35	365	0.19	0.38
CH_4	3.46	3.46	365	1.90	3.79
CO_2e	183,961	183,961.13	365	100,718.72	201,437.44

(a) Startup emissions based on CEMS data, and vendor load and startup profiles
(b) Includes shutdown emissions from "startup summary" plus an additional hour of normal emissions.

Natural Gas Plus Fuel Oil Startup/Shutdown Emissions

Pollutant	Number of Natural Gas Starts Per Turbine	Start-up/Shutdown Emissions Natural Gas (tpy)	Number of Fuel Oil Starts Per Turbine	Start-up/Shut down Emissions Fuel Oil (tpy)	Total Start-up/Shutdown Emissions (Both turbines) (tpy)[a]
Nox	345	59.63	20	16.66	152.58
CO	345	157.54	20	6.56	328.22
$PM/PM_{10}/PM_{2.5}$	345	9.32	20	1.17	20.97
VOC	345	3.42	20	0.27	7.39
SO_2	345	1.29	20	3.09	8.77
H_2SO_4	345	0.20	20	0.47	1.34
Lead	345	--	20	0.00	0.00
CO_2	345	95101.66	20	7679.84	205563.01
N_2O	345	0.18	20	0.06	0.48
CH_4	345	1.79	20	0.31	4.21
CO_2e	345	95199.88	20	7706.19	205812.16

(a) Includes 345 start-up/shut down on natural gas and 20 start-up/shut down on fuel oil to meet total of 365 starts per year.

Stack Parameters for Combustion Turbines on Natural Gas

Scenario	Height (ft)	Temp. (F)	Velocity (ft/sec)	Diameter (ft)	ACFM	Stack Discharge Type	Fuel
100% Load Natural Gas Operation	114.5	1131	148.2	18.00	2,260,000	Vertical	Natural Gas
100% Load Natural Gas with TurboPhase Operation	114.5	1131	166.6	18.00	2,540,552	Vertical	Natural Gas
80% Load Natural Gas Operation[a]	114.5	1097	139.58	18		Vertical	Natural Gas
60% Load Natural Gas Operation[b]	114.5	1143	130.96	18		Vertical	Natural Gas

(a) 80% Load stack parameters are also used for Start-up stack parameters. 80% load stack parameters from original permit application
(b) 60% Load velocity is a 60% ratio of the 100% load velocity

Pleasants Energy, LLC - PSD Project
Fuel Oil Potential Emissions for Turbines 1 & 2

GT1 & GT2 Combustion Turbine Size	1,570	MMBtu/hr
Number of Combustion Turbines (GT1 & GT2)	2	
Number of Fuel Oil Starts Per Turbine	20	
#2 Fuel Oil heating value	0.14	MMBtu/gal
Fuel Consumption Rate	11,214	gal/hr

Fuel Oil Operation Emissions (lb/hr)

Pollutant	100% Load Fuel Oil Emission Rate (lb/MMBtu)	100% Load Fuel Oil Emission Rate (lb/hr)	80% Load Fuel Oil Emission Rate[a] (lb/hr)	60% Load Fuel Oil Emission Rate[a] (lb/hr)	Start-up Emissions (lb/hr)[b]	Shutdown Emissions (lb/hr)[c]
NO_x	--	470	391	240	561.6	543.1
CO	--	72	53	49	230.4	195.7
$PM/PM_{10}/PM_{2.5}$	--	39	39	39	39.0	39.0
VOC	--	8	6	8	9.1	9.0
SO_2	--	103	87	--	103.0	103.0
H_2SO_4	--	15.8	--	--	15.8	15.8
Lead	1.4E-05	0.02	--	--	0.02	0.02
CO_2	163.1	255,995	--	--	255,995	255,995
N_2O	1.32E-03	2.1	--	--	2.1	2.1
CH_4	6.61E-03	10.4	--	--	10.4	10.4
CO_2e	-	256,873	--	--	256,873	256,873

(a) For modeling purposes only
(b) Assumes start-up is 120 minutes.
(c) Assumes shut-down is 60 minutes
(d) Emissions are based on 20 start-ups and 20 shut-downs, and the remainder of the 200 hours per turbine is 100% load operation

Pleasants Energy, LLC - PSD Project
Fuel Oil Potential Emissions for Turbines 1 & 2

Fuel Oil Startup Emissions

Pollutant	Start-up Emissions (lb/hr)[a]	Shutdown Emissions (lb/hr)[b]	Number of Starts Per Turbine	Start-up/Shutdown Emissions (tpy)	Total Start-up/Shutdown Emissions (Both turbines) (tpy)
NOx	561.64	543.09	20	16.66	33.33
CO	230.37	195.68	20	6.56	13.13
PM/PM10/PM2.5	39	39	20	1.17	2.34
VOC	9.14	8.95	20	0.27	0.54
SO2	103	103	20	3.09	6.18
H2SO4	15.77	15.77	20	0.47	0.95
Lead	0.02	0.02	20	6.59E-04	1.32E-03
CO2	255,994.65	255,994.65	20	7,679.84	15,359.68
N2O	2.1	2.1	20	0.06	0.12
CH4	10.4	10.4	20	0.31	0.62
CO2e	256873.1	256873.1	20	7706.19	15,412.39

(a) Startup emissions based on CEMS data, and vendor load and startup profiles

(b) Includes shutdown emissions from "startup summary" for 30 minutes and one hour of full load emissions.

Stack Parameters

Scenario	Height (ft)	Temp. (F)	Velocity (ft/sec)	Diameter (ft)	ACFM	Stack Discharge Type	Fuel
100% Load Natural Gas Operation	114.5	1131	148.2	18.00	2,260,000	Vertical	Fuel Oil
80% Load Natural Gas Operation[a]	114.5	1158	141.66	18.00		Vertical	Fuel Oil
60% Load Natural Gas Operation[b]	114.5	1145	135.1	18.00		Vertical	Fuel Oil

(a) 80% Load stack parameters are also used for Start-up stack parameters. 80% load stack parameters from original permit application

Pleasants Energy, LLC - Facility Expansion
H_2SO_4 Emissions

Sulfuric Acid Mist Emissions

Assume 10% of SO2 is converted to SO3
Assume 100% of SO3 is converted to H2SO4

	Conversion Percent
Assume 10% of SO2 is converted to SO3	10
Assume 100% of SO3 is converted to H2SO4	100

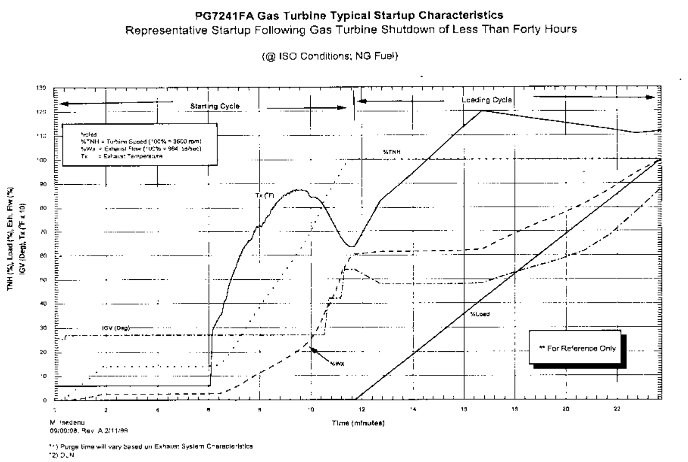
SO2 + 1/2 O2 = SO3
SO3 + H2O = H2SO4

	One unit				
	lb/hr SO2	lb/hr SO2 converted to SO3	lb/hr SO3 created	lb/hr H2SO4 created	tons / year H2SO4
Tier IV Diesel Generator (one unit)	0.053	0.0053	0.0066	0.0081	0.00203
Combustion Turbine (one unit, natural gas)	2.500	0.2500	0.3124	0.3827	0.93771
Turbophase Engine (one unit, natural gas)	0.010	0.0010	0.0012	0.0015	0.00249
Combustion Turbines (one unit, fuel oil)	103.0	10.30	12.8723	15.7688	1.57688
Combustion Turbine (one unit, natural gas with TurboPhase Operation)	2.800	0.2800	0.3499	0.4287	1.87756
				Total H2SO4	**4.40**

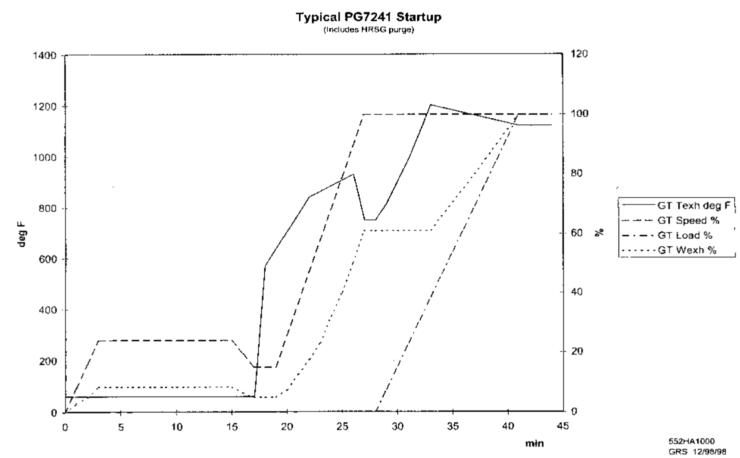
Molecular Weights	
SO2	64.0638
SO3	80.0632
H2SO4	98.07848

Pleasants Energy, LLC - PSD Project
Load Information

Warm start info



Cold start info



Pleasants Energy, LLC - PSD Project
Natural Gas Startup Summary

Scenario One
Cold Start

Flame to Full Start No Load (FSNL)

CO	250	lbs
NOX	10	lbs

Emissions During Startup

VOC	3.83	lb
NOX	35.16	lb
CO	102.43	lb

Total Emissions

VOC	3.83	lb per start
CO	352.4	lb per start
NOX	45.16	lb per start

Scenario Two
Warm Start

Flame to Full Start No Load (FSNL)

CO	250
NOX	10

Emissions During Startup

VOC	3.19	lb
NOX	29.32	lb
CO	85.43	lb

Total Emissions

VOC	3.19	lb per start
CO	335.43	lb per start
NOX	39.32	lb per start

Shutdown
Assume Warm Start for Shutdown scenario

Full Start No Load (FSNL) to Flameout

CO	27	lbs
NOX	9	lbs

Emissions During Shutdown

VOC	3.19	lb
NOX	29.32	lb
CO	85.43	lb

Total Emissions

VOC	3.19	lb per shutdown
NOX	38.32	lb per shutdown
CO	112.43	lb per shutdown

From Data Sheets:

Flame to Full Start No Load (FSNL)

CO	250	lbs
NOX	10	lbs

Full Start No Load (FSNL) to Flameout

CO	27	lbs
NOX	9	lbs

VOC

Percent Lo	Emissions (	Rate of Change
0	18.5	-1.466666667
9	5.3	95.5
10	100.8	-7.61
23	1.87	60.13
24	62	-8.375
28	28.5	-2.7
29	25.8	-1
39	15.8	0.144444444
48	17.1	0
50	17.1	
50	1.84	0.0198
100	2.83	

CO

Percent Lo	Emissions	Rate of Change
0	187.2	-0.133333
9	186	1814
10	2000	-151.3462
23	32.5	1487.8
24	1520.3	-102.45
28	1110.5	-46.5
29	1064	-13.56667
32	1023.3	-9.441667
44	910	-10
46	890	-3.75
50	875	
50	19.6	0.4
51	20	0.1666667
63	22	0.1428571
70	23	0.2
100	29	

NOX

Percent Lo	Emissions	Rate of Change
0	97.5	-2.5
1	95	7.1625
9	152.3	-49.4
10	102.9	10.46923
23	239	-46.3
24	192.7	12.1
27	229	10.25
31	270	7.866667
40	340.8	11.02857
47	418	12.9
48	430.9	2.75
50	436.4	
50	37	0.9
51	37.9	0.390323
82	50	0.444444
91	54	0.555556
100	59	

Scenario One: Cold Start

Load = 0	28.055556	
Load = 10(	42.472222	
Startup Ra	0.1441667	minutes per load %

Scenario 2: Warm Start

Load = 0	11.729412	
Load = 10(	23.752941	
Startup Ra	0.1202353	minutes per load %

Pleasants Energy, LLC - PSD Project
Fuel Oil Startup Summary

Scenario One			Scenario Two			Shutdown		
Cold Start			**Warm Start**			**Assume Warm Start for Shutdown scenario**		
Flame to Full Start No Load (FSNL)			Flame to Full Start No Load (FSNL)			Full Start No Load (FSNL) to Flameout		
CO	100	lbs	CO	75		CO	75	lbs
NOX	10	lbs	NOX	5		NOX	5	lbs
Emissions During Startup			Emissions During Startup			Emissions During Shutdown		
VOC	1.14	lb	VOC	0.95	lb	VOC	0.95	lb
NOX	81.64	lb	NOX	68.09	lb	NOX	68.09	lb
CO	58.37	lb	CO	48.68	lb	CO	48.68	lb
Total Emissions			**Total Emissions**			**Total Emissions**		
VOC	1.14	lb per start	VOC	0.95	lb per start	VOC	0.95	lb per shutdown
NOX	91.64	lb per start	NOX	73.09	lb per start	NOX	73.09	lb per shutdown
CO	158.4	lb per start	CO	123.68	lb per start	CO	123.68	lb per shutdown

From Data Sheets:

Flame to Full Start No Load (FSNL)			Full Start No Load (FSNL) to Flameout		
CO	100	lbs	CO	75	lbs
NOX	10	lbs	NOX	5	lbs

VOC			CO			NOX		
Percent Lo	Emissions (	Rate of Change	Percent Lo	Emissions	Rate of Change	Percent Lo	Emissions	Rate of Change
0	25	-1.52	0	1040	-33.88889	0	108	1
10	9.8	-0.62	18	430	-45	2	110	10
20	3.6	-0.1	22	250	-5	10	190	18.5
26	3	0	26	230	-2.5	20	375	20
49	3	-1	30	220	-3	22	415	16.25
50	2	0	40	190	-1	26	480	15
60	2	0.025	45	185	-1.25	30	540	17.5
100	3	0.03	49	180	-110	40	715	15.8
			50	70	-0.04	46	810	13.3
			100	68		49	850	

Scenario One: Cold Start

Load = 0	28.055556	
Load = 10(	42.472222	
Startup Ra	0.1441667	minutes per load %

Scenario 2: Warm Start

Load = 0	11.729412	
Load = 10(	23.752941	
Startup Ra	0.1202353	minutes per load %

Pleasants Energy, LLC - TurboPhase Project / Existing Emissions Calculations
TurboPhase Engines Emissions Estimate

Natural Gas Engines for TurboPhase

Heat Input per TurboPhase Module (TPM) (Each Engine)	17.00	MMBtu/hr
Engine Size	2,750	hp
Engine Size	2,000	kW
Displacement	<10	L/cylinder
Annual Operation (per Engine)	3,250	hours/year

TPM Engine Stack Running Beside CT Stack- Stack Parameters

Number of Stacks	Height (ft)	Exhaust Temp. (F)	Exit Velocity (ft/sec)	Stack Diameter (ft)	ACFM	Stack Discharge Type	Fuel
2 (4 TPM Modules per Stack)	114.5	482	150.00	2.50	41,902	Vertical	Natural Gas

Pollutant	Emission Factors (Controlled, no SCR)			Emissions (per engine or TPM))		One TurboPhase System Emissions (4 engines, one stack)		Two TurboPhase Systems Emissions (8 TPM, two stacks)
	g/hp-hr	lb/MMBtu	Source	lb/hr	tpy	lb/hr	tpy	tpy
NOx	0.50	--	Vendor	3.03	4.93	12.13	19.70	39.41
CO	0.11	--	Vendor	0.67	1.08	2.67	4.33	8.67
$PM/PM_{10}/PM_{2.5}$	--		Vendor	0.20	0.33	0.80	1.30	2.60
VOC	0.03	--	Vendor	0.18	0.30	0.73	1.18	2.36
SO_2	--	5.88E-04	AP-42[A]	0.01	1.62E-02	0.04	0.06	0.13
H_2SO_4	--	--	Mass Balance	1.53E-03	2.49E-03	0.01	9.95E-03	1.99E-02
CO_2e	--	--	40 CFR Part 98[B]	1,990.67	3,234.84	7962.67	12,939.34	25,878.68

[A] AP-42 Section 3.4 (7/00) Table 3.2-1

[B] Greenhouse Gas Reporting Rule- Subpart C of Part 98

NSPS Limits: 40 CFR Part 60, Subapart JJJJ, (40 CFR 60.4233(e) and Table 1)

NOx g/hp-hr	CO g/hp-hr	VOC g/hp-hr
1.00	2.00	0.70

Pleasants Energy, LLC - TurboPhase Project / Existing Emissions Calculations
Blackstart Generators Emissions Estimate

Tier IV Diesel Generators (5)

Fuel Consumption, Each Generator (100% load)	208.8	Gal/hr
Heat Input, Each Generator	28.61	MMBtu/hr
Power Output, hp	4,376	hp
Power Output, kW	3000	kW
Sulfur Content of Fuel	0.0015	%
Displacement	5.29	L/cylinder
Annual Operation (per Engine)	500	hours/year (per engine)

Stack Parameters

Height (ft)	Temp. (F)	Velocity (ft/sec)	Diameter (ft)	ACFM	Stack Discharge Type	Fuel
45	882.2	124.98	2.00	23557.40	Vertical	Diesel

Pollutant	Emission Factors				Emissions (One Engine)		Emissions (Five Engines)	
	lb/hp hr	g/hp-hr	lb/MMBtu	Source	lb/hr	tpy	lb/hr	tpy
NOx	1.10E-03	0.50	--	NSPS[C]	4.82	1.21	24.10	6.03
CO	5.75E-03	2.61	--	NSPS[C]	25.18	6.29	125.90	31.47
$PM/PM_{10}/PM_{2.5}$	1.6E-04	0.07		NSPS[C]	0.72	0.18	3.60	0.90
VOC	6.58E-04	0.30	--	NSPS[C]	2.88	0.72	14.39	3.60
SO_2	1.21E-05	0.01	--	AP-42[A]	0.05	1.33E-02	0.27	0.07
H_2SO_4	--	--	--	Mass Balance	8.13E-03	2.03E-03	0.04	0.01
CO_2	--	--	163.05	Part 98[B]	4,664.26	1,166.06	23,321.28	5,830.32
N_2O	--	--	1.32E-03	Part 98[B]	0.04	0.01	0.19	0.05
CH_4	--	--	6.61E-03	Part 98[B]	0.19	0.05	0.95	0.24
CO_2e	--	--	--		4,680.26	1,170.07	23,401.30	5850.33

[A] AP-42 Section 3.4 (10/96) Table 3.4-1

[B] Greenhouse Gas Reporting Rule- Subpart C of Part 98

[C] NSPS Subpart IIII Limits

NSPS Limits - 40 CFR Part 60, Subpart IIII, (40 CFR 60.4201(c) and 40 CFR 1039.102 - Table 7)

	NOx	CO	PM	NMHC
g/kW-hr	0.67	3.5	0.10	0.40
g/hp-hr	0.50	2.61	0.07	0.30

Pleasants Energy, LLC - Facility Expansion / Existing Emissions Calculations
Diesel Storage Tanks

Description:
Horizontal Fixed Roof Tanks

Assumptions for All tanks:
Weather - Columbus, Ohio data
Type - Horizontal Fixed Roof Tank
Color/Shade - White/White (Default)
Fuel - Distillate #2 Fuel Oil
Monthly Calculation - Throughput distributed evenly over the entire year

Generator Fuel Oil Tanks (1)
Size: 2500 gallons

VOC Emissions[1]	
lb/yr	tpy
1.37	**6.9E-04**

[1] *EPA TANKS program was run for VOC emissions from the fuel tank*

APPENDIX D – RBLC TABLES

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
MD-0040	11/12/2008	CPV ST CHARLES	COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC	MD			DRY LOW NOX BURNER AND SCR	2	PPMVD @ 15% O2	BACT-PSD
MD-0040	11/12/2008	CPV ST CHARLES	COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC	MD			DRY LOW NOX BURNER AND SCR	2	PPMVD @ 15% O2	BACT-PSD
TX-0540	2/27/2009	BOSQUE COUNTY POWER PLANT	BOSQUE POWER COMPANY LLC	TX	170	MW	BACT IS 9 PPMVD AT 15% O2 THROUGH THE USE OF DRY LOW-NOX (DLN) COMBUSTERS WHEN THE COMBUSTION TURBINE IS OPERATING IN THE SIMPLE CYCLE MODE.	2	PPMVD	BACT-PSD
*OR-0050	3/5/2014	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	OR	2988	MMBtu/hr	Utilize dry low-NOx burners when combusting natural gas; Utilize water injection when combusting ULSD; Utilize selective catalytic reduction (SCR) with aqueous ammonia injection at all times except during startup and shutdown; Limit the time in startup or shutdown.	2	PPMDV AT 15% O2	BACT-PSD
CA-1174	12/11/2009	EL CAJON ENERGY LLC	EL CAJON ENERGY LLC	CA	49.95	MW	Water injection and SCR	2.5	PPMV	BACT-PSD
CA-1175	7/2/2008	ESCONDIDO ENERGY CENTER LLC		CA	46.5	MW	SCR water injection	2.5	PPMV@15% OXYGE	BACT-PSD
CA-1176	12/4/2008	ORANGE GROVE PROJECT		CA	49.8	MW	SCR water injection	2.5	PPM	BACT-PSD
NJ-0075	9/24/2009	BAYONNE ENERGY CENTER	BAYONNE ENERGY CENTER, LLC	NJ	603	MMBTU/H	SELECTIVE CATALYTIC REDUCTION SYSTEM (SCR) AND WET LOW-EMISSION (WLE) COMBUSTORS SUBJECT TO LAER	2.5	PPMVD@15%O2	LAER
NJ-0076	10/27/2010	PSEG FOSSIL LLC KEARNY GENERATING STATION	PSEG FOSSIL LLC	NJ	8940000	MMBtu/year (HHV)	SCR and Use of Clean Burning Fuel: Natural gas	2.5	PPMVD@15%O2	OTHER CASE-BY-CASE
NJ-0077	9/16/2010	HOWARD DOWN STATION	VINELAND MUNICIPAL ELECTRIC UTILITY (VMEU)	NJ	5000	MMFT3/YR	THE TURBINE WILL UTILIZE WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION (SCR) TO CONTROL NOX EMISSION AND USE CLEAN FUELS NATURAL GAS AND ULTRA LOW SULFUR DISTILLATE OIL TO MINIMIZE NOX EMISSIONS	2.5	PPMVD@15%O2	OTHER CASE-BY-CASE
*OR-0050	3/5/2014	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	OR	1690	MMBtu/hr	Utilize water injection when combusting natural gas or ULSD; Utilize selective catalytic reduction (SCR) with aqueous ammonia injection at all times except during startup and shutdown; Limit the time in startup or shutdown.	2.5	PPMDV AT 15% O2	BACT-PSD
OK-0072	5/6/2002	REDBUD POWER PLT	REDBUD ENERGY LP	OK	1832	MMBTU/H	SELECTIVE CATALYTIC REDUCTION (SCR)	3.5	PPM @ 15% O2	BACT-PSD
FL-0261	10/26/2004	ARVAH B. HOPKINS GENERATING STATION	CITY OF TALLAHASSEE	FL	50	mw	WATER INJECTION SYSTEM, SCR	5	PPMVD @15% O2	BACT-PSD
WA-0312	7/18/2003	FREDONIA ENERGY STATION	PUGET SOUND ENERGY	WA	108	MW	SCR	5	PPMVD	BACT-PSD
TX-0388	2/12/2002	SAND HILL ENERGY CENTER	AUSTIN ELECTRIC UTILITY	TX	48	MW (EACH)	DRY, LOW NOX BURNERS	5	PPM @ 15% O2	BACT-PSD
CA-0953	10/18/2001	ALLIANCE COLTON--CENTURY	ALLIANCE COLTON--CENTURY	CA	40	MW	SCR OR XONON	5	PPMVD	LAER
AZ-0045	7/25/2001	PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	PPL SUNDANCE ENERGY, LLC	AZ	450	MW	SCR	5	PPM @ 15% O2	BACT-PSD
CA-0951	7/13/2001	INDIGO ENERGY FACILITY	INDIGO ENERGY FACILITY	CA	45	MW	SCR	5	PPMVD	LAER
CA-0952	5/18/2001	LA DEPT OF WATER & POWER	LA DEPT OF WATER & POWER	CA	47.4	MW	SCR	5	PPMVD	LAER
*WY-0070	8/28/2012	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	WY	40	MW	SCR	5	PPMV AT 15% O2	BACT-PSD
*WY-0070	8/28/2012	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	WY	40	MW	SCR	5	PPMV AT 15% O2	BACT-PSD
*WY-0070	8/28/2012	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	WY	40	MW	SCR	5	PPMV AT 15% O2	BACT-PSD
*ND-0029	5/14/2013	PIONEER GENERATING STATION	BASIN ELECTRIC POWER COOPERATIVE	ND	451	MMBtu/hr	Water injection plus SCR	5	PPPMVD	BACT-PSD
*ND-0030	9/16/2013	LONESOME CREEK GENERATING STATION	BASIN ELECTRIC POWER COOP.	ND	412	MMBtu/hr	SCR	5	PPMVD	BACT-PSD
*MN-0075	7/1/2008	GREAT RIVER ENERGY - ELK RIVER STATION	GREAT RIVER ENERGY	MN	2169	MMBTU/H	DRY LOW-NOX COMBUSTION WHEN COMBUSTING NATURAL GAS	9	PPM	BACT-PSD

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
OK-0120	3/22/2007	PSO RIVERSIDE JENKS POWER STA	PUBLIC SERVICE CO OF OKLAHOMA	OK			DRY-LOW NOX BURNERS	9	PPMVD	BACT-PSD
FL-0287	11/17/2006	OLEANDER POWER PROJECT	OLEANDER POWER PROJECT, L.P	FL	190	MW	DLN COMBUSTORS WATER INJECTION	9	PPM @15% O2	BACT-PSD
*FL-0279	4/28/2006	TEC/POLK POWER ENERGY STATION	TAMPA ELECTRIC COMPANY (TEC)	FL	1834	MMBtu/hr	DRY LOW NOX	9	PPMVD @ 15% O2	BACT-PSD
FL-0279	4/28/2006	TEC/POLK POWER ENERGY STATION	TAMPA ELECTRIC COMPANY (TEC)	FL	1834	MMBTU/H	DRY LOW NOX	9	PPMVD @ 15% O2	BACT-PSD
MS-0074	12/10/2004	MOSELLE PLANT	SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION	MS	1143.3	MMBTU/H	DRY, LOW-NOX BURNER WITH INLET GAS COOLING.	9	PPM VD @ 15% O2	BACT-PSD
MN-0052	9/10/2003	GREAT RIVER ENERGY LAKEFIELD JUNCTION STATION	GREAT RIVER ENERGY	MN	109	MW	DRY LOW NOX, GOOD COMBUSTION PRACTICE	9	PPM @ 15% O2	BACT-PSD
MS-0057	5/29/2003	SMEPA - SILVER CREEK GENERATING	SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MS	1109.3	MMBTU/H	DRY LOW NOX BURNERS	9	PPM @ 15% O2	BACT-PSD
FL-0244	4/16/2003	FPL MARTIN PLANT	FLORIDA POWER & LIGHT	FL	170	MW	DRY LOW NOX COMBUSTORS	9	PPMVD @ 15% O2	BACT-PSD
FL-0245	4/15/2003	FPL MANATEE PLANT - UNIT 3	FLORIDA POWER & LIGHT	FL	170	MW	DRY LOW NOX COMBUSTORS	9	PPMVD @ 15% O2	BACT-PSD
VA-0262	12/6/2002	MIRANT AIRSIDE INDUSTRIAL PARK	MIRANT DANVILLE, LLC	VA	84	MW	LEAN PRE-MIX LOW NOX BURNERS AND GOOD COMBUSTION PRACTICES. SELECTIVE CATALYTIC REDUCTION SYSTEM AND A CONTINUOUS EMISSION MONITORING DEVICE.	9	PPMVD @ 15% O2	BACT-PSD
IL-0086	11/27/2002	KENDALL NEW CENTURY DEVELOPMENT, LLC	KENDALL NEW CENTURY DEVELOPMENT, LLC	IL	1000.5	MMBTU/H	ADVANCED LOW NOX COMBUSTORS	9	PPMDV @ 15% O2	BACT-PSD
IN-0114	7/24/2002	MIRANT SUGAR CREEK LLC	MIRANT SUGAR CREEK LLC	IN	1490.5	MMBTU/H	DRY LOW NOX COMBUSTORS, GOOD COMBUSTION PRACTICES, CLEAN FUEL -- NATURAL GAS	9	PPMVD @ 15% O2	BACT-PSD
MI-0345	7/1/2002	EL PASO MERCHANT ENERGY CO.	EL PASO MERCHANT ENERGY CO.	MI	170	MW	DRY LOW-NOX BURNERS. CEM FOR NOX. REQUIRED TESTING PER NSPS-GG, 60-180 DAYS	9	PPMVD @ 15% O2	BACT-PSD
NC-0086	1/10/2002	FAYETTEVILLE GENERATION, LLC	FAYETTEVILLE GENERATION, LLC	NC	1702	MMBTU/H	DLN COMBUSTORS AND SCR	9	PPMVD	BACT-PSD
IN-0096	11/16/2001	SOUTHERN INDIANA- AB BROWN GENERATING STATION	SOUTHERN INDIANA GAS & ELECTRIC COMPANY	IN	1145.8	MMBTU/H	USE DRY LOW NOX COMBUSTOR WITH NATURAL GAS AS SOLE FUEL.	9	PPM@15% O2	BACT-PSD
SC-0069	11/8/2001	DUKE ENERGY MILL CREEK COMBUSTION TURBINE STATION	DUKE ENERGY COMPANY	SC	81.7	MW	DRY LOW NOX COMBUSTOR	9	PPM @ 15% O2	BACT-PSD
MI-0296	9/18/2001	FIRST ENERGY CORPORATION - SUMPTER PLANT	FIRST ENERGY CORPORATION - SUMPTER PLANT	MI	83	MW	DRY LOW-NOX BURNERS	9	PPMDV @ 15% O2	N/A
FL-0226	9/11/2001	EL PASO MANATEE ENERGY CENTER	EL PASO MERCHANT ENERGY CENTER	FL	1.79	MMCF/H	GE 2.6 DRY LOW NOX SYSTEM.	9	PPMVD @ 15% O2	BACT-PSD
FL-0227	9/7/2001	EL PASO BELLE GLADE ENERGY CENTER	EL PASO MERCHANT ENERGY CENTER	FL	1.79	MMCF/H	GE 2.6 DRY LOW NOX SYSTEM	9	PPMVD @ 15% O2	BACT-PSD
FL-0225	8/17/2001	EL PASO BROWARD ENERGY CENTER	EL PASO MERCHANT ENERGY COMPANY	FL	1.79	MMCF/H	GE 2.6 DRY LOW NOX. PIPELINE NATURAL GAS	9	PPMVD @ 15% O2	BACT-PSD
FL-0229	8/15/2001	POMPANO BEACH ENERGY CENTER	POMPANO BEACH ENERGY. LLC	FL	1.91	MMCF/H	GE 2.6 DRY LOW NOX SYSTEM AND WATER INJECTION SYSTEM.	9	PPMVD @ 15%O2	BACT-PSD
MI-0319	7/23/2001	DETROIT EDISON- GREENWOOD ENERGY CENTER	DETROIT EDISON- GREENWOOD ENERGY CENTER	MI	82.4	MW	DRY LOW-NOX BURNERS. NATURAL GAS USAGE NOT TO EXCEED 27300 MILLION CUBIC FEET PER YEAR (TOTAL 4)	9	PPMDV @ 15% O2	BACT-PSD
MI-0321	7/23/2001	DETROIT EDISON- BELLE RIVER PLANT	DETROIT EDISON- BELLE RIVER PLANT	MI	82.4	MW	DRY LOW NOX BURNERS. SEE POLLUTANT NOTES.	9	PPMDV @15%O2	BACT-PSD
FL-0228	7/15/2001	DEERFIELD BEACH ENERGY CENTER	DEERFIELD BEACH ENERGY CENTER, L.L.C.	FL	1.91	MMCF/H	GE DRY LOW NOX SYSTEM, WET INJECTION AND LIMITED FUEL USAGE.	9	PPMVD @ 15% O2	BACT-PSD
CO-0053	5/31/2001	PLATTE RIVER POWER AUTHORITY- RAWHIDE STATION	PLATTE RIVER POWER AUTHORITY	CO	82	MW	DRY LOW NOX SYSTEM	9	PPMVD @ 15% O2	BACT-PSD
IN-0088	5/29/2001	DUKE ENERGY KNOX LLC	DUKE ENERGY KNOX LLC	IN	1158	MMBTU/H	DRY LOW NOX BURNERS. LB/H LIMIT FOR EACH CT.	9	PPMDV @15% O2	BACT-PSD
IN-0086	5/9/2001	MIRANT SUGAR CREEK, LLC	MIRANT SUGAR CREEK, LLC	IN	170	MW	GOOD COMBUSTION. LB/H LIMIT IS FOR EACH CT.	9	PPMVD @ 15% 02	BACT-PSD
OK-0074	5/1/2001	KIAMICHI ENERGY FACILITY	KIOWA POWER PARTNERS LLC	OK	181.6	MW EACH	DRY LOW NOX PROCESS	9	PPM @ 15% O2	BACT-PSD
FL-0218	2/14/2001	MIDWAY ENERGY CENTER	ENRON/MIDWAY DEVELOPMENT COMPANY, L.L.C.	FL	1700	MMBTU/H	DRY LOW NOX TECHNOLOGY, WATER INJECTION. PRIMARY LIMIT = GAS; ALTERNATE = OIL.	9	PPMVD @ 15% O2	BACT-PSD
IN-0117	1/29/2001	SIGECO A.B. BROWN STATION	SIGECO A.B. BROWN STATION	IN	1110.9	MMBTU/H	DRY LOW NOX COMBUSTORS, STEAM INJECTION WHILE FIRING FUEL OIL.	9	PPMVD @ 15% O2	BACT-PSD

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
FL-0310	1/12/2009	SHADY HILLS GENERATING STATION	SHADY HILLS POWER COMPANY	FL	170	MW	FIRING NATURAL GAS AND USING DLN 2.6 COMBUSTORS TO MINIMIZE NOX EMISSSIONS.	9	PPMVD @ 15% O2	BACT-PSD
FL-0319	3/10/2009	GREENLAND ENERGY CENTER	JACKSONVILLE ELECTRIC AUTHORITY (JEA)	FL	30213	GAL/YR	DLN Combustion System when firing natural gas and water injection system when firing fuel oil.	9	PPMVD @15% O2 ((	BACT-PSD
GA-0139	5/14/2010	DAHLBERG COMBUSDTION TURBINE ELECTRIC GENERATING FACILITY (P	SOUTHERN POWER COMPANY	GA	1530	MW	DRY LOW NOX BURNERS (FIRING NATURAL GAS). WATER INJECTION (FIRING FUEL OIL).	9	PPM@15%02	BACT-PSD
MN-0075	7/1/2008	GREAT RIVER ENERGY - ELK RIVER STATION	GREAT RIVER ENERGY	MN	2169	MMBTU/H	DRY LOW-NOX COMBUSTION WHEN COMBUSTING NATURAL GAS	9	PPM	BACT-PSD
*FL-0346	4/22/2014	LAUDERDALE PLANT	FLORIDA POWER & LIGHT	FL	2000	MMBtu/hr (approx)	Required to employ dry low-NOx technology and wet injection. Water injection must be used when firing ULSD.	9	PPMVD @ 15% 02	BACT-PSD
*ND-0028	2/22/2013	R.M. HESKETT STATION	MONTANA-DAKOTA UTILITIES CO.	ND	986	MMBTU/H	Dry low-NOx combustion (DLN)	9	PPMVD @15% OYY(	BACT-PSD
*TX-0686	4/22/2014	ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	TX	202	MW	DLN	9	PPM	BACT-PSD
*TX-0688	12/19/2014	SR BERTRON ELECTRIC GENERATION STATION	NRG TEXAS POWER	TX	225	MW	DLN	9	PPM	BACT-PSD
*TX-0694	2/2/2015	INDECK WHARTON ENERGY CENTER	INDECK WHARTON, L.L.C.	TX	220	MW	DLN combustors	9	PPMVD	BACT-PSD
*TX-0695	8/1/2014	ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	TX	180	MW	DLN combustors	9	PPMVD	BACT-PSD
*TX-0696	9/22/2014	ROANâ€™S PRAIRIE GENERATING STATION	TENASKA ROANâ€™S PRAIRIE PARTNERS (TRPP), LLC	TX	600	MW	DLN combustors	9	PPMVD	BACT-PSD
*TX-0701	5/13/2013	ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	TX	180	MW	Dry low NOx combustor	9	PPMVD	BACT-PSD
*TX-0733	5/12/2015	ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	TX	202	MW	Dry Low NOx burners	9	PPMVD AT 15% O2	BACT-PSD
*TX-0734	5/8/2015	CLEAR SPRINGS ENERGY CENTER (CSEC)	NAVASOTA SOUTH PEAKERS OPERATING COMPANY II, LLC.	TX	183	MW	dry low-NOx (DLN) burners	9	PPMVD @ 15% O2	BACT-PSD
GA-0094	12/27/2001	EFFINGHAM COUNTY POWER, LLC	EFFINGHAM COUNTY POWER, LLC	GA	185	MW	LOW NOX BURNERS	10	PPMVD @ 15% O2	BACT-PSD
GA-0099	11/9/2001	SANDERSVILLE GENERATING STATION	DUKE ENERGY SANDERSVILLE LLC	GA	80	MW	LOW NOX COMBUSTORS	10	PPM @ 15% O2	BACT-PSD
GA-0108	11/9/2001	SANDERSVILLE GENERATING STATION	DUKE ENERGY SANDERSVILLE LLC	GA	80	MW	LOW NOX BURNERS	10	PPM @ 15% O2	BACT-PSD
VA-0263	3/11/2003	ODEC - LOUISA FACILITY	OLD DOMINION ELECTRIC COOPERATIVE	VA	1624	MMBTU/H	GOOD COMBUSTION PRACTICES AND A CONTINUOUS EMISSION MONITORING SYSTEM.	10.5	PPMVD @ 15% O2	N/A
VA-0263	3/11/2003	ODEC - LOUISA FACILITY	OLD DOMINION ELECTRIC COOPERATIVE	VA	901	MMBTU/H	GOOD COMBUSTION PRACTICES AND A CONTINUOUS EMISSION MONITORING SYSTEM.	10.5	PPMVD @ 15% O2	N/A
VA-0282	3/11/2003	ODEC - LOUISA	Old Dominion Electric Coop - Louisa	VA	1624	MMBTU/H	DRY LOW NOX COMBUSTOR	10.5	PPMVD @ 15% O2	BACT-PSD
VA-0282	3/11/2003	ODEC - LOUISA	Old Dominion Electric Coop - Louisa	VA	901	MMBTU/H	DRY LOW NOX COMBUSTORS	10.5	PPMVD @ 15% O2	BACT-PSD
VA-0280	2/14/2003	ODEC -MARSH	Old Dominion Electric Cooperative	VA	1624	MMBTU/H	DRY LOW NOX COMBUSTORS WHEN FIRING NATURAL GAS, WATER INJECTION WHEN FIRING FUEL OIL.	10.5	PPMVD	BACT-PSD
NC-0084	1/25/2002	ROWAN GENERATING CO., LLC, ROWAN GENERATING FACILI	ROWAN GENERATING CO., LLC	NC	155	MW	DRY LOW NOX COMBUSTORS	10.5	PPMVD	BACT-PSD
FL-0249	6/15/2001	DUKE ENERGY/FORT PIERCE	DUKE ENERGY FORT PIERCE LLC	FL	80	MW	DRY LOW NOX COMBUSTION TECHNOLOGY WHEN FIRING NATURAL GAS, WET INJECTION WHEN FIRING FUEL OIL	10.5	PPMVD @ 15% O2	BACT-PSD
MS-0072	12/10/2004	TVA - KEMPER COMBUSTION TURBINE PLANT		MS				12	PPM @ 15% 02	BACT-PSD
GA-0107	6/9/2003	TALBOT ENERGY FACILITY	OGLETHORPE POWER CORPORATION	GA	108	MW	DLN COMBUSTORS	12	PPM @ 15% O2	BACT-PSD
KY-0093	6/6/2003	LOUISVILLE GAS AND ELECTRIC COMPANY	LOUISVILLE GAS AND ELECTRIC COMPANY	KY	160	MW	DRY LOW NOX COMBUSTORS	12	PPM @ 15% O2	BACT-PSD
KY-0082	7/27/2001	EAST KENTUCKY POWER COOP, INC. - JK SMITH GENERATI	EAST KENTUCKY POWER COOP, INC.	KY	1039	MMBTU/H	GOOD COMBUSTION	12	PPM @ 15% O2	BACT-PSD
FL-0250	7/18/2001	DUKE ENERGY/LAKE	DUKE LAKE ENERGY LLC	FL	80	MW	DRY LOW NOX COMBUSTION TECHNOLOGY	12	PPMVD @ 15% 02	BACT-PSD
KY-0083	6/22/2001	LOUISVILLE GAS & ELECTIC CO. - TRIMBLE CO GENERATI	LOUISVILLE GAS & ELECTIC CO.	KY	160	MW	DRY LOW NOX BURNERS	12	PPM @ 15% O2	BACT-PSD
MS-0063	5/30/2001	WARREN PEAKING POWER FACILITY	WARREN POWER, LLC	MS	959.8	MMBTU/H	DRY LOW NOX COMBUSTORS	12	PPM	BACT-PSD

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
FL-0285	1/26/2007	PROGRESS BARTOW POWER PLANT	PROGRESS ENERGY FLORIDA (PEF)	FL	1972	MMBTU/H	WATER INJECTION DRY LOW NOX	15	PPMVD	BACT-PSD
FL-0300	12/22/2006	JACKSONVILLE ELECTRIC AUTHORITY/JEA	JACKSONVILLE ELECTRIC AUTHORITY	FL	1804	MMBTU/H	NATURAL GAS AS PRIMARY FUEL WITH 0.05% SULFUR DISTILLATE AS BACKUP. USES WATER INJECTION WHEN FIRING OIL.	15	PPM @ 15% 02 (GAS	Other Case-by-Case
MO-0067	12/29/2004	SOUTH HARPER PEAKING FACILITY	AQUILA, INC.	MO	1455	mmBtu/h	DRY-LOW NOX BURNERS	15	PPM	
IN-0111	3/13/2003	DUKE ENERGY VERMILLION STATION	DUKE ENERGY VERMILLION STATION	IN	80	MW	DRY LOW NOX COMBUSTORS	15	PPMVD @ 15% O2	BACT-PSD
MI-0267	6/7/2001	RENAISSANCE POWER LLC	RENAISSANCE POWER LLC	MI	170	MW	DRY LOW NOX BURNERS. LIMITS DO NOT APPLY DURING STARTUP SHUTDOWN OR MALFUNCTION. THESE EPISODES ARE LIMITED TO 200 H/YR TOTAL FOR 4 TURBINES	15	PPMDV @15% O2	BACT-PSD
*TX-0691	5/20/2014	PH ROBINSON ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	TX	65	MW	DLN combustors	15	PPMVD	BACT-PSD
*IN-0173	6/4/2014	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	283	MMBTU/H, EACH	DRY LOW NOX COMBUSTORS	22.65	PPMVD AT 15% OXY	BACT-PSD
*IN-0180	6/4/2014	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	283	MMBTU/H, EACH	DRY LOW NOX COMBUSTORS	22.65	PPMVD AT 15% OXY	BACT-PSD
*NV-0046	5/16/2006	GOODSPRINGS COMPRESSOR STATION	KERN RIVER GAS TRANSMISSION COMPANY	NV	97.81	MMBTU/H	THE SOLONOX BURNER IN EACH TURBINE UTILIZES THE DRY LOW-NOX TECHNOLOGY TO CONTROL NOX EMISSIONS.	25	PPMVD	BACT-PSD
WI-0240	1/26/2006	WE ENERGIES CONCORD	WISCONSIN ELECTRIC POWER	WI	100	mw	WATER INJECTION	25	PPMDV @ 15% O2	BACT-PSD
AL-0208	2/1/2005	EXXON MOBILE BAY -- NORTHWEST GULF FIELD	EXXON MOBIL PRODUCTION CO.	AL	6000	bhp	SOLONOX COMBUSTOR	25	PPM @ 15%O2	BACT-PSD
AL-0209	2/1/2005	EXXON MOBILE -- MOBILE BAY - BON SECURE BAY FIELD	EXXON MOBIL PRODUCTION CO.	AL	3600	bhp	SOLONOX COMBUSTION	25	PPM @ 15% O2	BACT-PSD
FL-0232	4/25/2002	CALPINE/AUBURNDALE COGENERATION FACILITY	CALPINE EASTERN	FL	1591	MMBTU/H	WATER INJECTION	25	PPMVD	Other Case-by-Case
IN-0095	12/7/2001	ALLEGHENY ENERGY SUPPLY CO. LLC	ALLEGHENY ENERGY SUPPLY CO. LLC (ACADIA BAY ENERGY	IN	469	MMBTU/H	WATER INJECTION	25	PPM@15% O2 (24HR	BACT-PSD
PA-0171	7/10/2001	ALLEGHENY ENERGY SUPPLY COMPANY,	ALLEGHENY ENERGY SUPPLY COMPANY, LLC	PA	44	MW	WATER INJECTION SYSTEM AND SCR	25	PPM @ 15% O2	Other Case-by-Case
OK-0127	6/13/2008	WESTERN FARMERS ELECTRIC ANADARKO	WESTERN FARMERS ELECTRIC COOPERATIVE	OK	462.7	MMBTU/H	WATER INJECTION	25	PPM	BACT-PSD
*MN-0075	7/1/2008	GREAT RIVER ENERGY - ELK RIVER STATION	GREAT RIVER ENERGY	MN	2169	MMBTU/H	WATER INJECTION WHEN COMBUSTING FUEL OIL	42	PPM	BACT-PSD
MS-0072	12/10/2004	TVA - KEMPER COMBUSTION TURBINE PLANT		MS				42	PPM @ 15% 02	BACT-PSD
FL-0244	4/16/2003	FPL MARTIN PLANT	FLORIDA POWER & LIGHT	FL	170	MW	WATER INJECTION	42	PPMVD @ 15% O2	BACT-PSD
MN-0075	7/1/2008	GREAT RIVER ENERGY - ELK RIVER STATION	GREAT RIVER ENERGY	MN	2169	MMBTU/H	WATER INJECTION WHEN COMBUSTING FUEL OIL	42	PPM	BACT-PSD
AL-0187	1/29/2001	TENASKA ALABAMA III GENERATING STATION	TENASKA ALABAMA III PARTNERS LP	AL	170	MW	DRY LOW NOX COMBUSTORS	0.033	LB/MMBTU	BACT-PSD
PA-0187	3/21/2001	GRAYS FERRY COGEN PARTNERSHIP	GRAYS FERRY COGEN PARTNERSHIP	PA	135	MW	SELECTIVE CATALYTIC REDUCTION CC (No SCR on Simple cycle)	0.0344	LB/MMBTU	BACT-PSD
IA-0063	2/5/2003	WISDOM GENERATION STATION	CORN BELT POWER COOPERATIVE	IA	80	MW	DLN (NATURAL GAS), WATER INJECTION (FUEL OIL)	0.037	LB/MMBTU	Other Case-by-Case
NC-0087	11/20/2001	DUKE ENERGY - BUCK COMBUSTION TURBINE FACILITY	DUKE ENERGY CORPORATION	NC	80	MW	DRY-LOW NOX	0.042	LB/MMBTU	BACT-PSD
AR-0043	2/27/2001	PINE BLUFF ENERGY LLC	PINE BLUFF ENERGY LLC	AR	170	MW	DRY LOW NOX DESIGN.	0.0467	LB/MMBTU	BACT-PSD
IA-0064	1/31/2003	ROQUETTE AMERICA	ROQUETTE AMERICA	IA	495	MMBTU/H	DRY LOW NOX BURNERS	0.06	LB/MMBTU	BACT-PSD
IA-0058	4/10/2002	GREATER DES MOINES ENERGY CENTER	MIDAMERICAN ENERGY	IA	350	MW		0.09	LB/MMBTU	BACT-PSD
NJ-0048	8/29/2001	PRIME ENERGY	PRIME ENERGY L.P.	NJ	670	MMBTU/H	WATER INJECTION	0.15	LB/MMBTU	Other Case-by-Case
NJ-0048	8/29/2001	PRIME ENERGY	PRIME ENERGY L.P.	NJ	670	MMBTU/H	N/A	0.15	LB/MMBTU	Other Case-by-Case
AL-0187	1/29/2001	TENASKA ALABAMA III GENERATING STATION	TENASKA ALABAMA III PARTNERS LP	AL	170	MW	WATER INJECTION	0.167	LB/MMBTU	BACT-PSD
NJ-0056	9/10/2001	CONSOLIDATED EDISON DEVELOPMENT (CED)	CONSOLIDATED EDISON DVPMT.-LAKEWOOD GEN. FACILITY	NJ	1959	MMBTU/H, 174.2 MW	DRY LOW NOX	0.34	LB/MW-H	BACT-PSD
FL-0310	1/12/2009	SHADY HILLS GENERATING STATION	SHADY HILLS POWER COMPANY	FL	2.5	MW	PURCHASE MODEL IS AT LEAST AS STRINGENT AS THE BACT VALUES, UNDER EPA CERTIFICATION.	6.9	G/HP-H	BACT-PSD
*TX-0457	6/26/2003	CITY PUBLIC SERVICE LEON CREEK PLANT	CITY PUBLIC SERVICE	TX			NOX EMISSIONS WILL BE LIMITED TO 5 PPMVD BY ADDING SELECTIVE CATALYTIC REDUCTION (SCR) TECHNOLOGY TO THE EXHAUST STACK.	8.4	LB/H	BACT-PSD

Table D-1 - RBLC Results for NOx Emissions for Simple Cycle Combustion Turbine (Natural Gas)

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
CT-0143	6/10/2001	PPL WALLINGFORD ENERGY, LLC	PPL WALLINGFORD ENERGY, LLC	CT	461.2	MMBTU/H	SELECTIVE CATALYST REDUCTION; LOW NOX BURNER	4.3	LB/H	BACT-PSD
OH-0262	8/15/2002	ANR	ANR PIPELINE COMPANY	OH	122	MMBTU/H	DRY LOW NOX (DLN) BURNERS NATURAL GAS ONLY FUEL	17.1	LB/H	BACT-PSD
*CO-0076	12/11/2014	PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	CO	799.7	mmbtu/hr each	SCR and dry low NOx burners	23	LB/H	BACT-PSD
*TX-0468	1/23/2003	UNION CARBIDE TEXAS CITY OPERATIONS	UNION CARBIDE CORPORATION - A SUBSIDIARY OF DOW CC	TX	12000	lb/hr		24	LB/HR	BACT-PSD
LA-0257	12/6/2011	SABINE PASS LNG TERMINAL	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	LA	286	MMBTU/H	water injection	28.68	LB/H	BACT-PSD
LA-0219	8/15/2007	CREOLE TRAIL LNG IMPORT TERMINAL	CREOLE TRAIL LNG, LP	LA	30	MW EA.	DRY LOW EMISSIONS (DLE) COMBUSTION TECHNOLOGY WITH LEAN PREMIX OF AIR AND FUEL	29	LB/H	BACT-PSD
VA-0279	1/8/2003	CINCAP - MARTINSVILLE	Cinergy Capital & Trading	VA	82	MW	DRY LOW NOX COMBUSTOR TECHNOLOGY EMPLOYING LEAN PREMIX COMBUSTION CONTROLS	30.6	LB/H	BACT-PSD
TX-0351	3/11/2002	WEATHERFORD ELECTRIC GENERATION FACILITY	SEI TEXAS LLC	TX	1079	MMBTU/H	NONE INDICATED	35	LB/H	N/A
MS-0079	1/30/2003	WARREN PEAKING POWER FACILITY (WARREN POWER, LLC)	WARREN PEAKING POWER FACILITY (WARREN POWER, LLC)	MS	959.8	mmbtu/h	LOW NOX BURNERS	46.7	LB/H	BACT-PSD
LA-0157	3/8/2002	PERRYVILLE POWER STATION	PERRYVILLE ENERGY PARTNERS, LLC	LA	170	MW	USE OF NATURAL GAS AS FUEL AND GOOD OPERATING PRACTICES. LOW NOX BURNERS	58	LB/H	BACT-PSD
OH-0274	10/1/2002	DPLE TAIT PEAKING STATION	DAYTON POWER AND LIGHT ENERGY	OH	80	mw	WATER INJECTION AND DLN COMBUSTORS	62	LB/H	BACT-PSD
OH-0253	6/4/2002	DAYTON POWER AND LIGHT COMPANY	DAYTON POWER AND LIGHT COMPANY	OH	1115	MMBTU/H	WATER INJECTION AND DRY LOW NOX COMBUSTORS	62	LB/H	BACT-PSD
TX-0351	3/11/2002	WEATHERFORD ELECTRIC GENERATION FACILITY	SEI TEXAS LLC	TX	1910	MMBTU/H	NONE INDICATED	63	LB/H	N/A
OK-0044	8/16/2001	SMITH POCOLA ENERGY PROJECT	SMITH COGENERATION OK INC	OK	171.5	MW	LOW NOX BURNERS	63	LB/H	BACT-PSD
OH-0255	3/29/2001	PSEG WATERFORD ENERGY LLC	PSEG WATERFORD ENERGY LLC	OH	170	MW	DRY LOW NOX BURNERS (DLN), STAGE I	64	LB/H	BACT-PSD
OH-0259	9/11/2001	JACKSON COUNTY GENERATING, LLC	ENTERGY CORPORATION	OH	160	MW	LOW NOX BURNERS.	66	LB/H	BACT-PSD
VA-0281	1/10/2003	CHICKAHOMINY POWER	DYNEGY MARKETING AND TRADE COMMERCIAL POWER	VA	182.6	MW	DRY LOW NOX COMBUSTORS	107	LB/H	BACT-PSD

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
NV-0036	5/5/2005	TS POWER PLANT	NEWMONT NEVADA ENERGY INVESTMENT, LLC	NV	373.3	MMBTU/H	SCR & WATER INJECTION	6	PPMVD	BACT-PSD
WI-0240	1/26/2006	WE ENERGIES CONCORD	WISCONSIN ELECTRIC POWER	WI	100	mw	WATER INJECTION	65	PPMDV @ 15% O2	BACT-PSD
OH-0253	3/7/2006	DAYTON POWER AND LIGHT COMPANY	DAYTON POWER AND LIGHT COMPANY	OH	1115	MMBTU/H	WATER INJECTION	195	LB/H	BACT-PSD
OH-0253	3/7/2006	DAYTON POWER AND LIGHT COMPANY	DAYTON POWER AND LIGHT COMPANY	OH	1115	MMBTU/H	WATER INJECTION	195	LB/H	BACT-PSD
OH-0333	12/3/2009	DAYTON POWER & LIGHT ENERGY LLC	DAYTON POWER & LIGHT COMPANY	OH	4216	H/YR	Water injection	269	LB/H	BACT-PSD

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
VA-0261	9/6/2002	CPV CUNNINGHAM CREEK	COMPETITIVE POWER VENTURE	VA	2132	MMBTU/H	GOOD COMBUSTION PRACTICES.	2	PPM @ 15% O2	BACT-PSD
MD-0040	11/12/2008	CPV ST CHARLES	COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC	MD			OXIDATION CATALYST	2	PPMVD @ 15% O2	BACT-PSD
MD-0040	11/12/2008	CPV ST CHARLES	COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC	MD			OXIDATION CATALYST	2	PPMVD @ 15% O2	BACT-PSD
*OR-0050	3/5/2014	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	OR	2988	MMBtu/hr	Oxidation catalyst; Limit the time in startup or shutdown.	3.3	PPMDV AT 15% O2	BACT-PSD
*MN-0075	7/1/2008	GREAT RIVER ENERGY - ELK RIVER STATION	GREAT RIVER ENERGY	MN	2169	MMBTU/H	GOOD COMBUSTION PRACTICES	4	PPM	BACT-PSD
MN-0075	7/1/2008	GREAT RIVER ENERGY - ELK RIVER STATION	GREAT RIVER ENERGY	MN	2169	MMBTU/H	GOOD COMBUSTION PRACTICES	4	PPM	BACT-PSD
*FL-0346	4/22/2014	LAUDERDALE PLANT	FLORIDA POWER & LIGHT	FL	2000	MMBtu/hr (approx)	Good combustion practices	4	PPMVD @ 15% O2	BACT-PSD
*TX-0694	2/2/2015	INDECK WHARTON ENERGY CENTER	INDECK WHARTON, L.L.C.	TX	220	MW	DLN combustors	4	PPMVD	BACT-PSD
FL-0319	3/10/2009	GREENLAND ENERGY CENTER	JACKSONVILLE ELECTRIC AUTHORITY (JEA)	FL	30213	GAL/YR	Good Combustion	4.1	PPMVD @ 15% O2 (GAS)	BACT-PSD
NJ-0075	9/24/2009	BAYONNE ENERGY CENTER	BAYONNE ENERGY CENTER, LLC	NJ	603	MMBTU/H	CO OXIDATION CATALYST AND CLEAN BURNING FUELS	5	PPMVD@15%O2	OTHER CASE-BY-CASE
NJ-0076	10/27/2010	PSEG FOSSIL LLC KEARNY GENERATING STATION	PSEG FOSSIL LLC	NJ	8940000	MMBtu/year (HHV)	Oxidation Catalyst, Good combustion practices	5	PPMVD@15% O2	OTHER CASE-BY-CASE
NJ-0077	9/16/2010	HOWARD DOWN STATION	VINELAND MUNICIPAL ELECTRIC UTILITY (VMEU)	NJ	5000	MMFT3/YR	THE TURBINE WILL UTILIZE A CATALYTIC OXIDIZER TO CONTROL CO EMISSION, IN ADDITION TO USING CLEAN BURNING FUELS, NATURAL GAS AND ULTRA LOW SULFUR	5	PPMVD@15%O2	OTHER CASE-BY-CASE
CA-0952	5/18/2001	LA DEPT OF WATER & POWER	LA DEPT OF WATER & POWER	CA	47.4	MW	OXIDATION CATALYST	6	PPMVD	LAER
CA-0951	7/13/2001	INDIGO ENERGY FACILITY	INDIGO ENERGY FACILITY	CA	45	MW	OXIDATION CATALYST	6	PPMVD	LAER
WA-0306	9/11/2001	CLIFFS ENERGY PROJECT	GNA ENERGY, INC.	WA	45	MW, EA	OXIDATION CATALYST	6	PPM @ 15% O2	BACT-PSD
CA-0953	10/18/2001	ALLIANCE COLTON--CENTURY	ALLIANCE COLTON--CENTURY	CA	40	MW	OXIDATION CATALYST	6	PPMVD	LAER
FL-0261	10/26/2004	ARVAH B. HOPKINS GENERATING STATION	CITY OF TALLAHASSEE	FL	50	mw	OXIDATION CATALYST	6	PPMDV @ 15% O2	Other Case-by-Case
*WY-0070	8/28/2012	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	WY	40	MW	Oxidiation Catalyst	6	PPMV AT 15% O2	BACT-PSD
*WY-0070	8/28/2012	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	WY	40	MW	Oxidation Catalyst	6	PPMV AT 15% O2	BACT-PSD
*WY-0070	8/28/2012	CHEYENNE PRAIRIE GENERATING STATION	BLACK HILLS POWER, INC.	WY	40	MW	Oxidation Catalyst	6	PPMV AT 15% O2	BACT-PSD
*ND-0029	5/14/2013	PIONEER GENERATING STATION	BASIN ELECTRIC POWER COOPERATIVE	ND	451	MMBtu/hr	Catalytic oxidation system	6	PPMVD	BACT-PSD
*ND-0030	9/16/2013	LONESOME CREEK GENERATING STATION	BASIN ELECTRIC POWER COOP.	ND	412	MMBtu/hr	Oxidation Catalyst	6	PPMVD	BACT-PSD
*OR-0050	3/5/2014	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	OR	1690	MMBtu/hr	Oxidation catalyst; Limit the time in startup or shutdown.	6	PPMDV AT 15% O2	BACT-PSD
FL-0310	1/12/2009	SHADY HILLS GENERATING STATION	SHADY HILLS POWER COMPANY	FL	170	MW		6.5	PPMVD @ 15% O2 NG	BACT-PSD
FL-0225	8/17/2001	EL PASO BROWARD ENERGY CENTER	EL PASO MERCHANT ENERGY COMPANY	FL	1.79	MMCF/H	GOOD COMBUSTION PRACTICES. PRIMARY LIMIT: FULL LOAD	7.4	PPMVD @ 15% O2	BACT-PSD
FL-0227	9/7/2001	EL PASO BELLE GLADE ENERGY CENTER	EL PASO MERCHANT ENERGY CENTER	FL	1.79	MMCF/H	COMBUSTION CONTROLS. PRIMARY LIMIT IS FOR FULL LOAD	7.4	PPMVD @ 15% O2	BACT-PSD
FL-0226	9/11/2001	EL PASO MANATEE ENERGY CENTER	EL PASO MERCHANT ENERGY CENTER	FL	1.79	MMCF/H	COMBUSTION CONTROLS. PRIMARY LIMIT: FULL LOAD	7.4	PPMVD @ 15% O2	BACT-PSD
FL-0245	4/15/2003	FPL MANATEE PLANT - UNIT 3	FLORIDA POWER & LIGHT	FL	170	MW	GOOD COMBUSTION DESIGN AND PRACTICES	7.4	PPMVD @ 15% O2	BACT-PSD
AZ-0045	7/25/2001	PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	PPL SUNDANCE ENERGY, LLC	AZ	45	MW	OXIDATION CATALYST	7.5	PPM @ 15% O2	BACT-PSD

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
MI-0303	7/26/2001	MIDLAND COGENERATION	MIDLAND COGENERATION VENTURE	MI	1914.6	MMBTU/H	CONCENTRATION LIMIT IS MORE STRICT WITH DUCT BURNER OFF.	7.9	PPMDV @ 15% 02	BACT-PSD
MI-0345	7/1/2002	EL PASO MERCHANT ENERGY CO.	EL PASO MERCHANT ENERGY CO.	MI	170	MW	GOOD COMBUSTION	7.9	PPMVD @ 15% O2	BACT-PSD
MS-0055	6/24/2002	EL PASO MERCHANT ENERGY CO.	EL PASO MERCHANT ENERGY CO.	MS	1737	MMBTU/H	GOOD COMBUSTION PRACTICE	8	PPMV @ 15% O2	BACT-PSD
VA-0258	8/29/2002	WHITE OAK POWER	WHITE OAK POWER COMPANY, LLC	VA	1731	MMBTU/H	GOOD COMBUSTION PRACTICE	8	PPMVD @ 15% O2	BACT-PSD
FL-0244	4/16/2003	FPL MARTIN PLANT	FLORIDA POWER & LIGHT	FL	170	MW	GOOD COMBUSTION DESIGN AND PRACTICES	8	PPMVD @ 15% O2	BACT-PSD
FL-0285	1/26/2007	PROGRESS BARTOW POWER PLANT	PROGRESS ENERGY FLORIDA (PEF)	FL	1972	MMBTU/H	GOOD COMBUSTION	8	PPMVD	BACT-PSD
NM-0043	1/8/2001	ENERGY SOUTHWEST	ENERGY SOUTHWEST	NM	1500	MMBTU/H	GOOD COMBUSTION PRACTICES PERMIT LIMIT IS 9 PPM FOR BOTH THE SIMPLE AND COMBINED CYCLE.	9	PPM	Other Case-by-Case
FL-0218	2/14/2001	MIDWAY ENERGY CENTER	ENRON/MIDWAY DEVELOPMENT COMPANY, L.L.C.	FL	1700	MMBTU/H	PIPELINE NATURAL GAS, COMBUSTION CONTROLS. PRIMARY LIMIT = GAS; ALTERNATE = OIL.	9	PPMVD @ 15 % O2	BACT-PSD
IN-0086	5/9/2001	MIRANT SUGAR CREEK, LLC	MIRANT SUGAR CREEK, LLC	IN	170	MW	GOOD COMBUSTION. LB/H LIMIT IS FOR EACH CT.	9	PPMVD @ 15% 02	BACT-PSD
KY-0083	6/22/2001	LOUISVILLE GAS & ELECTIC CO. - TRIMBLE CO GENERATI	LOUISVILLE GAS & ELECTIC CO.	KY	160	MW	GOOD COMBUSTION PRACTICE	9	PPM @ 15% O2	BACT-PSD
FL-0228	7/15/2001	DEERFIELD BEACH ENERGY CENTER	DEERFIELD BEACH ENERGY CENTER, L.L.C.	FL	1.91	MMCF/H	GOOD COMBUSTION.	9	PPMVD @ 15% O2	BACT-PSD
FL-0229	8/15/2001	POMPANO BEACH ENERGY CENTER	POMPANO BEACH ENERGY. LLC	FL	1.91	MMCF/H	COMBUSTION CONTROLS.	9	PPMVD @ 15% O2	BACT-PSD
GA-0094	12/27/2001	EFFINGHAM COUNTY POWER, LLC	EFFINGHAM COUNTY POWER, LLC	GA	185	MW	GOOD COMBUSTION PRACTICES	9	PPMVD @ 15% O2	BACT-PSD
NC-0084	1/25/2002	ROWAN GENERATING CO., LLC, ROWAN GENERATING FACILI	ROWAN GENERATING CO., LLC	NC	155	MW	COMBUSTION CONTROL	9	PPMVD	BACT-PSD
IA-0060	7/23/2002	HAWKEYE GENERATING, LLC	ENTERGY	IA	33.77	BILLION CF/YR	GCP - SIMPLE CYCLE	9	PPMVD (EQUIVALENT)	BACT-PSD
IA-0060	7/23/2002	HAWKEYE GENERATING, LLC	ENTERGY	IA	33.77	BILLION CF/YR	GCP SIMPLE CYCLE	9	PPMVD (EQUIVALENT)	BACT-PSD
IN-0114	7/24/2002	MIRANT SUGAR CREEK LLC	MIRANT SUGAR CREEK LLC	IN	1490.5	MMBTU/H	GOOD COMBUSTION PRACTICES, CLEAN FUEL -- NATURAL GAS.	9	PPMVD @ 15% O2	BACT-PSD
VA-0266	2/14/2003	ODEC - MARSH RUN FACILITY	Old Dominion Electric Cooperative	VA	1624	MMBTU/H	GOOD COMBUSTION PRACTICES AND CLEAN BURNING FUEL.	9	PPMVD	N/A
VA-0280	2/14/2003	ODEC -MARSH	Old Dominion Electric Cooperative	VA	1624	MMBTU/H	GOOD COMBUSTION PRACTICE	9	PPMVD	BACT-PSD
VA-0282	3/11/2003	ODEC - LOUISA	Old Dominion Electric Coop - Louisa	VA	1624	MMBTU/H	GOOD COMBUSTION PRACTICES	9	PPMVD	BACT-PSD
VA-0263	3/11/2003	ODEC - LOUISA FACILITY	OLD DOMINION ELECTRIC COOPERATIVE	VA	1624	MMBTU/H	GOOD COMBUSTION PRACTICES AND CONTINUOUS EMISSION MONITORING SYSTEM.	9	PPMVD @ 15% O2	N/A
KY-0093	6/6/2003	LOUISVILLE GAS AND ELECTRIC COMPANY	LOUISVILLE GAS AND ELECTRIC COMPANY	KY	160	MW	GOOD COMBUSTION PRACTICE	9	PPM @ 15% O2	BACT-PSD
GA-0139	5/14/2010	DAHLBERG COMBUSDTION TURBINE ELECTRIC GENERATING FACILITY (P	SOUTHERN POWER COMPANY	GA	1530	MW	GOOD COMBUSTION PRACTICES	9	PPM@15%02	BACT-PSD
TX-0540	2/27/2009	BOSQUE COUNTY POWER PLANT	BOSQUE POWER COMPANY LLC	TX	170	MW	BACT IS THE USE OF GOOD COMBUSTION PRACTICES TO MINIMIZE THE PRODUCTS OF INCOMPLETE COMBUSTION AND ACHIEVE 9 PPMVD AT 15% O2 IN THE TURBINE EXHAUST	9	PPMVD	BACT-PSD
*TX-0686	4/22/2014	ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	TX	202	MW	Good combustion practices; limited hours	9	PPMVD	BACT-PSD
*TX-0688	12/19/2014	SR BERTRON ELECTRIC GENERATION STATION	NRG TEXAS POWER	TX	225	MW	Good Combustion Practices	9	PPM	BACT-PSD
*TX-0695	8/1/2014	ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	TX	180	MW	DLN combustors	9	PPMVD	BACT-PSD
*TX-0696	9/22/2014	ROANâ€™S PRAIRIE GENERATING STATION	TENASKA ROANâ€™S PRAIRIE PARTNERS (TRPP), LLC	TX	600	MW	DLN combustors	9	PPMVD	BACT-PSD
*TX-0701	5/13/2013	ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	TX	180	MW	Good combustion practices	9	PPMVD	BACT-PSD

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*TX-0733	5/12/2015	ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	TX	202	MW	Good combustion practices; limited operating hours	9	PPMVD @ 15% O2	BACT-PSD
*TX-0734	5/8/2015	CLEAR SPRINGS ENERGY CENTER (CSEC)	NAVASOTA SOUTH PEAKERS OPERATING COMPANY II, LLC.	TX	183	MW	DLN burners and good combustion practices	9	PPMVD @ 15% O2	BACT-PSD
FL-0232	4/25/2002	CALPINE/AUBURNDALE COGENERATION FACILITY	CALPINE EASTERN	FL	1591	MMBTU/H	GOOD COMBUSTION	10	PPM	Other Case-by-Case
MN-0053	7/15/2004	FAIRBAULT ENERGY PARK	MN MUNICIPAL POWER AGENCY	MN	1663	MMBTU/H	GOOD COMBUSTION PRACTICES.	10	PPMVD @ 15% 02	BACT-PSD
SC-0058	7/2/2001	GENPOWER ANDERSON, LLC	GENPOWER ANDERSON, LLC	SC	640	MW	GOOD COMBUSTION PRACTICES & CLEAN BURNING FUELS	11.7	PPMVD	BACT-PSD
SC-0064	5/23/2002	SCE&G - JASPER COUNTY GENERATING FACILITY	SCE&G	SC	170	MW (EACH)	GOOD COMBUSTION PRACTICES	14	PPMVW	BACT-PSD
FL-0244	4/16/2003	FPL MARTIN PLANT	FLORIDA POWER & LIGHT	FL	170	MW	GOOD COMBUSTION DESIGN AND PRACTICES	15	PPMVD @ 15% O2	BACT-PSD
MI-0267	6/7/2001	RENAISSANCE POWER LLC	RENAISSANCE POWER LLC	MI	170	MW	GOOD COMBUSTION PRACTICES. EMISSION RATE 0.0336 LB/MMBTU	15.1	PPMDV @ 15% O2	BACT-PSD
*NV-0046	5/16/2006	GOODSPRINGS COMPRESSOR STATION	KERN RIVER GAS TRANSMISSION COMPANY	NV	97.81	MMBTU/H	GOOD COMBUSTION PRACTICE	16	PPMVD	BACT-PSD
OK-0072	5/6/2002	REDBUD POWER PLT	REDBUD ENERGY LP	OK	1832	MMBTU/H	GOOD COMBUSTION PRACTICES AND DESIGN	17.2	PPM @ 15% O2	BACT-PSD
FL-0249	6/15/2001	DUKE ENERGY/FORT PIERCE	DUKE ENERGY FORT PIERCE LLC	FL	80	MW	GOOD COMBUSTION DESIGN AND OPERATING PRACTICES	20	PPMVD @ 15% O2	BACT-PSD
FL-0250	7/18/2001	DUKE ENERGY/LAKE	DUKE LAKE ENERGY LLC	FL	80	MW	GOOD COMBUSTION DESIGN AND OPERATING PRACTICES	20	PPMVD @ 15% 02	BACT-PSD
MS-0072	12/10/2004	TVA - KEMPER COMBUSTION TURBINE PLANT		MS				20	PPM @ 15% 02	BACT-PSD
MS-0074	12/10/2004	MOSELLE PLANT	SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION	MS	1143.3	MMBTU/H		20	PPM VD @ 15% O2	BACT-PSD
IN-0117	1/29/2001	SIGECO A.B. BROWN STATION	SIGECO A.B. BROWN STATION	IN	1110.9	MMBTU/H	GOOD COMBUSTION PRACTICE	25	PPMVD @ 15% O2	BACT-PSD
IN-0088	5/29/2001	DUKE ENERGY KNOX LLC	DUKE ENERGY KNOX LLC	IN	1158	MMBTU/H	GOOD COMBUSTION. LB/H LIMIT FOR EACH CT.	25	PPMDV @15% O2	BACT-PSD
PA-0171	7/10/2001	ALLEGHENY ENERGY SUPPLY COMPANY, LLC/HARRISON CITY	ALLEGHENY ENERGY SUPPLY COMPANY, LLC	PA	44	MW	CO CATALYST	25	PPM @ 15% O2	Other Case-by-Case
MI-0319	7/23/2001	DETROIT EDISON- GREENWOOD ENERGY CENTER	DETROIT EDISON- GREENWOOD ENERGY CENTER	MI	82.4	MW	CATOX AT $4522 PER TON OF CO AND VOC, NOT REQUIRED.	25	PPMDV @ 15% O2	BACT-PSD
MI-0321	7/23/2001	DETROIT EDISON- BELLE RIVER PLANT	DETROIT EDISON- BELLE RIVER PLANT	MI	82.4	MW	GOOD COMBUSTION. SEE POLLUTANT NOTES.	25	PPMDV @15% O2	BACT-PSD
KY-0082	7/27/2001	EAST KENTUCKY POWER COOP, INC. - JK SMITH GENERATI	EAST KENTUCKY POWER COOP, INC.	KY	1039	MMBTU/H	GOOD COMBUSTION	25	PPM @ 15% O2	Other Case-by-Case
MI-0296	9/18/2001	FIRST ENERGY CORPORATION - SUMPTER PLANT	FIRST ENERGY CORPORATION - SUMPTER PLANT	MI	83	MW	HAS CEMS FOR CO MONITORING OF PERFORMANCE.	25	PPMDV @ 15% O2	BACT-PSD
SC-0069	11/8/2001	DUKE ENERGY MILL CREEK COMBUSTION TURBINE STATION	DUKE ENERGY COMPANY	SC	81.7	MW	COMBUSTION CONTROLS	25	PPM @ 15% O2	BACT-PSD
IN-0096	11/16/2001	SOUTHERN INDIANA- AB BROWN GENERATING STATION	SOUTHERN INDIANA GAS & ELECTRIC COMPANY	IN	1145.8	MMBTU/H	GOOD COMBUSTION PRACTICES	25	PPM@ 15% O2	BACT-PSD
IN-0095	12/7/2001	ALLEGHENY ENERGY SUPPLY CO. LLC	ALLEGHENY ENERGY SUPPLY CO. LLC (ACADIA BAY ENERGY	IN	469	MMBTU/H	GOOD COMBUSTION PRACTICES	25	PPM@15% OX (24HR AV)	BACT-PSD
IL-0086	11/27/2002	KENDALL NEW CENTURY DEVELOPMENT, LLC	KENDALL NEW CENTURY DEVELOPMENT, LLC	IL	1000.5	MMBTU/H	GOOD COMBUSTION PRACTICES	25	PPMVD @ 15% O2	BACT-PSD
VA-0282	3/11/2003	ODEC - LOUISA	Old Dominion Electric Coop - Louisa	VA	901	MMBTU/H	GOOD OPERATING PRACTICES	25	PPMVD	BACT-PSD
VA-0263	3/11/2003	ODEC - LOUISA FACILITY	OLD DOMINION ELECTRIC COOPERATIVE	VA	901	MMBTU/H	GOOD COMBUSTION PRACTICES AND A CONTINUOUS EMISSION MONITORING SYSTEM.	25	PPMVD @ 15% O2	N/A
IN-0111	3/13/2003	DUKE ENERGY VERMILLION STATION	DUKE ENERGY VERMILLION STATION	IN	80	MW	GOOD COMBUSTION PRACTICE	25	PPMVD @ 15% O2	BACT-PSD
MS-0057	5/29/2003	SMEPA - SILVER CREEK GENERATING	SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MS	1109.3	MMBTU/H	GOOD OPERATING PRACTICES	25	PPMVD @ 15% O2	BACT-PSD

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MN-0052	9/10/2003	GREAT RIVER ENERGY LAKEFIELD JUNCTION STATION	GREAT RIVER ENERGY	MN	109	MW	GOOD COMBUSTION PRACTICES - OPTIMIZED OPERATION OF GAS TURBINE	25	PPM @ 15% O2	BACT-PSD
MS-0072	12/10/2004	TVA - KEMPER COMBUSTION TURBINE PLANT		MS				25	PPM @ 15 02	BACT-PSD
MS-0072	12/10/2004	TVA - KEMPER COMBUSTION TURBINE PLANT		MS				25	PPM @ 15% 02	BACT-PSD
MO-0067	12/29/2004	SOUTH HARPER PEAKING FACILITY	AQUILA, INC.	MO	1455	mmBtu/h	GOOD COMBUSTION PRACTICES	25	PPMVD	BACT-PSD
*ND-0028	2/22/2013	R.M. HESKETT STATION	MONTANA-DAKOTA UTILITIES CO.	ND	986	MMBTU/H	Good Combustion	25	PPMVD @ 15% OXYGEN	BACT-PSD
*TX-0691	5/20/2014	PH ROBINSON ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	TX	65	MW	DLN combustors	25	PPMVD	BACT-PSD
MS-0063	5/30/2001	WARREN PEAKING POWER FACILITY	WARREN POWER, LLC	MS	959.8	MMBTU/H	EFFICIENT COMBUSTION PRACTICES	25	PPM	BACT-PSD
OK-0070	6/13/2002	GENOVA OK I POWER PROJECT	GENOVA OKLAHOMA LLC	OK	1872	MMBTU/H	COMBUSTION CONTROL	30	PPM @ 15% O2	BACT-PSD
TX-0388	2/12/2002	SAND HILL ENERGY CENTER	AUSTIN ELECTRIC UTILITY	TX	48	MW (EACH)	LIMITED TO 2,750 HOURS PER YEAR. SEE NOTE	43	PPM @ 15% O2	BACT-PSD
NM-0047	12/24/2002	EL PASO NATURAL GAS - LORDSBURG COMPRESSOR STATION	EL PASO NATURAL GAS	NM	13994	hp/h	GOOD COMBUSTION PRACTICES AND PIPELINE QUALITY FUEL.	50	PPM @ 15% O2	BACT-PSD
AL-0208	2/1/2005	EXXON MOBILE BAY -- NORTHWEST GULF FIELD	EXXON MOBIL PRODUCTION CO.	AL	6000	bhp		50	PPM @ 15% O2	BACT-PSD
AL-0209	2/1/2005	EXXON MOBILE -- MOBILE BAY - BON SECURE BAY FIELD	EXXON MOBIL PRODUCTION CO.	AL	3600	bhp		50	PPM @ 15% O2	BACT-PSD
VA-0262	12/6/2002	MIRANT AIRSIDE INDUSTRIAL PARK	MIRANT DANVILLE, LLC	VA	84	MW	GOOD COMBUSTION PRACTICES.	51	PPMVD @ 15% O2	BACT-PSD
OK-0104	11/23/2004	HORSEHOE LAKE GENERATING STATION	OG & E	OK	45	mw	GOOD COMBUSTION PRACTICES	62.5	PPMVD @15% O2	BACT-PSD
OK-0127	6/13/2008	WESTERN FARMERS ELECTRIC ANADARKO	WESTERN FARMERS ELECTRIC COOPERATIVE	OK	462.7	MMBTU/H	NO CONTROLS FEASIBLE.	63	PPM	BACT-PSD
*MN-0075	7/1/2008	GREAT RIVER ENERGY - ELK RIVER STATION	GREAT RIVER ENERGY	MN	2169	MMBTU/H	GOOD COMBUSTION CONTROL	150	PPM	
MN-0075	7/1/2008	GREAT RIVER ENERGY - ELK RIVER STATION	GREAT RIVER ENERGY	MN	2169	MMBTU/H	GOOD COMBUSTION CONTROL	150	PPM	
NM-0048	8/19/2002	CAMBRAY ENERGY CENTER	DEMING ENERGY, LLC	NM	80	MW	GOOD COMBUSTION PRACTICES, NG AS PRIMARY FUEL	203	PPM @ 15% O2	BACT-PSD
*MN-0075	7/1/2008	GREAT RIVER ENERGY - ELK RIVER STATION	GREAT RIVER ENERGY	MN	2169	MMBTU/H	GOOD COMBUSTION CONTROL	250	PPM	BACT-PSD
MN-0075	7/1/2008	GREAT RIVER ENERGY - ELK RIVER STATION	GREAT RIVER ENERGY	MN	2169	MMBTU/H	GOOD COMBUSTION CONTROL	250	PPM	BACT-PSD
GA-0107	6/9/2003	TALBOT ENERGY FACILITY	OGLETHORPE POWER CORPORATION	GA	108	MW	GOOD COMBUSTION PRACTICE	0.019	LB/MMBTU	BACT-PSD
AL-0166	1/18/2001	HILLABEE ENERGY CENTER	CALPINE CONSTRUCTION FINANCE CORPORATION LC	AL	229	MW	GOOD COMBUSTION PRACTICES. ALTERNATE LIMIT: TURBINE WITH DUCT FIRING.	0.023	LB/MMBTU	BACT-PSD
IA-0058	4/10/2002	GREATER DES MOINES ENERGY CENTER	MIDAMERICAN ENERGY	IA	350	MW		0.023	LB/MMBTU	BACT-PSD
AL-0187	1/29/2001	TENASKA ALABAMA III GENERATING STATION	TENASKA ALABAMA III PARTNERS LP	AL	170	MW	EFFICIENT COMBUSTION	0.0284	LB/MMBTU	BACT-PSD
*IN-0173	6/4/2014	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	283	MMBTU/H, EACH	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	0.03	LB/MMBTU	BACT-PSD
*IN-0180	6/4/2014	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	283	MMBTU/H, EACH	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	0.03	LB/MMBTU	BACT-PSD
AL-0187	1/29/2001	TENASKA ALABAMA III GENERATING STATION	TENASKA ALABAMA III PARTNERS LP	AL	170	MW	EFFICIENT COMBUSTION	0.0368	LB/MMBTU	BACT-PSD
GA-0099	11/9/2001	SANDERSVILLE GENERATING STATION	DUKE ENERGY SANDERSVILLE LLC	GA	80	MW		0.0592	LB/MMBTU	BACT-PSD
GA-0108	11/9/2001	SANDERSVILLE GENERATING STATION	DUKE ENERGY SANDERSVILLE LLC	GA	80	MW	GOOD COMBUSTION PRACTICE	0.0592	LB/MMBTU	BACT-PSD

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NC-0087	11/20/2001	DUKE ENERGY - BUCK COMBUSTION TURBINE FACILITY	DUKE ENERGY CORPORATION	NC	80	MW	COMBUSTION CONTROL	0.0613	LB/MMBTU	BACT-PSD
CO-0053	5/31/2001	PLATTE RIVER POWER AUTHORITY-RAWHIDE STATION	PLATTE RIVER POWER AUTHORITY	CO	82	MW	GOOD COMBUSTION CONTROL PRACTICES	0.064	LB/MMBTU	BACT-PSD
AR-0043	2/27/2001	PINE BLUFF ENERGY LLC	PINE BLUFF ENERGY LLC	AR	170	MW	GOOD COMBUSTION PRACTICES	0.0168	LB/MMBTU	BACT-PSD
VA-0265	1/10/2003	CHICKAHOMINY POWER	DYNEGY	VA	1862	MMBTU/H	CLEAN BURNING FUELS AND GOOD COMBUSTION PRACTICES.	3.7	LB/H	BACT-PSD
OR-0030	6/22/2001	KLAMATH FALLS FACILITY	PACIFICORP POWER MARKETING, INC.	OR	26.3	MW, EA	OXIDATION CATALYST, ENGLEHARDT/CAMET OR EQUIVALENT	10.7	LB/H	BACT-PSD
*TX-0457	6/26/2003	CITY PUBLIC SERVICE LEON CREEK PLANT	CITY PUBLIC SERVICE	TX			OXIDATION CATALYST	12.2	LB/H	BACT-PSD
CT-0143	6/10/2001	PPL WALLINGFORD ENERGY, LLC	PPL WALLINGFORD ENERGY, LLC	CT	461.2	MMBTU/H	CO OXIDATION CATALYST.	16.8	LB/H	BACT-PSD
LA-0257	12/6/2011	SABINE PASS LNG TERMINAL	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	LA	286	MMBTU/H	Good combustion practices and fueled by natural gas	17.46	LB/H	BACT-PSD
LA-0219	8/15/2007	CREOLE TRAIL LNG IMPORT TERMINAL	CREOLE TRAIL LNG, LP	LA	30	MW EA.	DRY LOW EMISSIONS (DLE) COMBUSTION TECHNOLOGY WITH LEAN PREMIX OF AIR AND FUEL	17.8	LB/H	BACT-PSD
WI-0240	1/26/2006	WE ENERGIES CONCORD	WISCONSIN ELECTRIC POWER	WI	100	mw		20	LB/H	BACT-PSD
OH-0262	8/15/2002	ANR	ANR PIPELINE COMPANY	OH	122	MMBTU/H	NATURAL GAS ONLY FUEL, GOOD COMBUSTION	22.6	LB/H	BACT-PSD
LA-0157	3/8/2002	PERRYVILLE POWER STATION	PERRYVILLE ENERGY PARTNERS, LLC	LA	170	MW	GOOD OPERATING PRACTICES AND USE OF NATURAL GAS AS FUEL. BACT FOR NOX, LOW NOX BURNERS AND/OR SELECTIVE CATALYTIC REDUCTION, IS ALSO BACT FOR CO.	28	LB/H	BACT-PSD
OK-0044	8/16/2001	SMITH POCOLA ENERGY PROJECT	SMITH COGENERATION OK INC	OK	171.5	MW	GOOD OPERATING PRACTICE	31	LB/H	BACT-PSD
TX-0351	3/11/2002	WEATHERFORD ELECTRIC GENERATION FACILITY	SEI TEXAS LLC	TX	1910	MMBTU/H	NONE INDICATED	31	LB/H	Other Case-by-Case
*TX-0456	6/13/2003	EXXON MOBIL CHEMICAL BAYTOWN OLEFINS PLANT	EXXON MOBIL CORPORATION	TX				32.34	LB/H	BACT-PSD
NJ-0056	9/10/2001	CONSOLIDATED EDISON DEVELOPMENT (CED)	CONSOLIDATED EDISON DVPMT.-LAKEWOOD GEN. FACILITY	NJ	1959	MMBTU/H, 174.2 MW	N/A	32.6	LB/H	BACT-PSD
OH-0255	3/29/2001	PSEG WATERFORD ENERGY LLC	PSEG WATERFORD ENERGY LLC	OH	170	MW		33	LB/H	BACT-PSD
NE-0022	6/22/2004	C. W. BURDICK GENERATING STATION	Grand Island Utilities	NE	1	MILLION SCF/H	GOOD COMBUSTION PRACTICES	34.7	LB/H	Other Case-by-Case
OH-0259	9/11/2001	JACKSON COUNTY GENERATING, LLC	ENTERGY CORPORATION	OH	160	MW		34.9	LB/H	BACT-PSD
VA-0269	1/8/2003	CINCAP MARTINSVILLE	Cinergy Capital & Trading	VA	82	MW	GOOD COMBUSTION PRACTICES AND CONTINUOUS EMISSION MONITORING SYSTEM.	51.7	LB/H	Other Case-by-Case
VA-0279	1/8/2003	CINCAP - MARTINSVILLE	Cinergy Capital & Trading	VA	82	MW	GOOD COMBUSTION PRACTICE	51.7	LB/H	BACT-PSD
*CO-0076	12/11/2014	PUEBLO AIRPORT GENERATING STATION	BLACK HILLS ELECTRIC GENERATION, LLC	CO	799.7	mmbtu/hr each	Catalytic Oxidation.	55	LB/H	BACT-PSD
TX-0351	3/11/2002	WEATHERFORD ELECTRIC GENERATION FACILITY	SEI TEXAS LLC	TX	1079	MMBTU/H	NONE INDICATED	58	LB/H	Other Case-by-Case
MS-0079	1/30/2003	WARREN PEAKING POWER FACILITY (WARREN POWER, LLC)	WARREN PEAKING POWER FACILITY (WARREN POWER, LLC)	MS	959.8	mmbtu/h	GOOD COMBUSTION PRACTICES	58	LB/H	BACT-PSD
OK-0120	3/22/2007	PSO RIVERSIDE JENKS POWER STA	PUBLIC SERVICE CO OF OKLAHOMA	OK			GOOD COMBUSTION PRACTICES & DESIGN	59	LB/H	BACT-PSD
NE-0021	6/22/2004	CASS COUNTY POWER PLANT	Omaha Public Power	NE	173	MW	GOOD COMBUSTION PRACTICES	63	LB/H	Other Case-by-Case
NJ-0048	8/29/2001	PRIME ENERGY	PRIME ENERGY L.P.	NJ	670	MMBTU/H	WATER INJECTION	65	LB/H	Other Case-by-Case
*TX-0468	1/23/2003	UNION CARBIDE TEXAS CITY OPERATIONS	UNION CARBIDE CORPORATION - A SUBSIDIARY OF DOW CC	TX	12000	lb/hr		78	LB/HR	BACT-PSD
VA-0281	1/10/2003	CHICKAHOMINY POWER	DYNEGY MARKETING AND TRADE COMMERCIAL POWER	VA	182.6	MW	CLEAN FUEL, GOOD COMBUSTION CONTROL	81	LB/H	BACT-PSD

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OH-0291	11/17/2004	OHIO EDISON CO.-WEST LORAIN PLANT	FIRST ENERGY	OH	85	MW		83	LB/H	BACT-PSD
TX-0390	8/21/2002	EAST REFINERY	FLINT HILLS RESOURCES, LP	TX	87	MW EACH	GOOD COMBUSTION PRACTICES.	112	LB/H	Other Case-by-Case
OH-0304	1/17/2006	ROLLING HILLS GENERATING PLANT	ROLLING HILLS GENERATING, LLC	OH	209	MW	GOOD ENGINEERING PRACTICES	119	LB/H	BACT-PSD
NJ-0048	8/29/2001	PRIME ENERGY	PRIME ENERGY L.P.	NJ	670	MMBTU/H	N/A	200	LB/H	Other Case-by-Case
OH-0253	6/4/2002	DAYTON POWER AND LIGHT COMPANY	DAYTON POWER AND LIGHT COMPANY	OH	1115	MMBTU/H		301	LB/H	BACT-PSD
OH-0274	10/1/2002	DPLE TAIT PEAKING STATION	DAYTON POWER AND LIGHT ENERGY	OH	80	mw		301	LB/H	BACT-PSD
OH-0333	12/3/2009	DAYTON POWER & LIGHT ENERGY LLC	DAYTON POWER & LIGHT COMPANY	OH	15020	H/YR	efficient combution technology	301	LB/H	BACT-PSD
OH-0253	6/4/2002	DAYTON POWER AND LIGHT COMPANY	DAYTON POWER AND LIGHT COMPANY	OH	1115	MMBTU/H		350	LB/H	BACT-PSD
*TX-0456	6/13/2003	EXXON MOBIL CHEMICAL BAYTOWN OLEFINS PLANT	EXXON MOBIL CORPORATION	TX				553	LB/HR	BACT-PSD
*TX-0456	6/13/2003	EXXON MOBIL CHEMICAL BAYTOWN OLEFINS PLANT	EXXON MOBIL CORPORATION	TX				576.5	LB/H	BACT-PSD
LA-0258	12/21/2011	CALCASIEU PLANT	ENTERGY GULF STATES LA LLC	LA	1900	MM BTU/H EACH	DRY LOW NOX COMBUSTORS	781	LB/H	BACT-PSD
OH-0253	6/4/2002	DAYTON POWER AND LIGHT COMPANY	DAYTON POWER AND LIGHT COMPANY	OH	1115	MMBTU/H		800	LB/H	BACT-PSD
OH-0333	12/3/2009	DAYTON POWER & LIGHT ENERGY LLC	DAYTON POWER & LIGHT COMPANY	OH	4216	H/YR	efficient combustion technology	800	LB/H	BACT-PSD
LA-0224	3/20/2008	ARSENAL HILL POWER PLANT	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	LA	2110	MMBTU/H	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTURE'S RECOMMENDED PROCEDURES.	964.57	LB/H	BACT-PSD
*TX-0456	6/13/2003	EXXON MOBIL CHEMICAL BAYTOWN OLEFINS PLANT	EXXON MOBIL CORPORATION	TX				1492	LB/H	BACT-PSD
LA-0224	3/20/2008	ARSENAL HILL POWER PLANT	SOUTHWEST ELECTRIC POWER COMPANY (SWEPCO)	LA	2110	MMBTU/H	COMPLETE EVENTS AS QUICKLY AS POSSIBLE ACCORDING TO MANUFACTURE'S RECOMMENDED PROCEDURES.	1508.15	LB/H	BACT-PSD
*TX-0456	6/13/2003	EXXON MOBIL CHEMICAL BAYTOWN OLEFINS PLANT	EXXON MOBIL CORPORATION	TX				1523	LB/H	BACT-PSD
OH-0253	6/4/2002	DAYTON POWER AND LIGHT COMPANY	DAYTON POWER AND LIGHT COMPANY	OH	1115	MMBTU/H		1700	LB/H	BACT-PSD
OH-0274	10/1/2002	DPLE TAIT PEAKING STATION	DAYTON POWER AND LIGHT ENERGY	OH	80	mw		1700	LB/H	BACT-PSD
*TX-0456	6/13/2003	EXXON MOBIL CHEMICAL BAYTOWN OLEFINS PLANT	EXXON MOBIL CORPORATION	TX				2191.0801	LB/H	BACT-PSD
PA-0205	9/17/2002	DUKE YUKON ENERGY, LLC	DUKE ENERGY	PA	84	MW	GOOD COMBUSTION PRACTICE	71	T/YR	BACT-PSD
MI-0295	7/10/2001	DTE ENERGY SERVICES	DTE ENERGY SERVICES	MI	82.4	MW (EACH)	GOOD COMBUSTION. NOT MORE THAN 500 STARTUPS AND SHUTDOWNS PER YEAR.	350	T/YR	BACT-PSD
CO-0050	3/20/2001	TRI-STATE GENERATION & TRANSMISSION - LIMON GEN.	TRI-STATE GENERATION & TRANSMISSION - LIMON GEN.	CO	82	MW	GOOD COMBUSTION PRACTICES. LIMITS PROVIDED IN T/YR ONLY.	396.4	T/YR	BACT-PSD
FL-0310	1/12/2009	SHADY HILLS GENERATING STATION	SHADY HILLS POWER COMPANY	FL	2.5	MW	PURCHASED MODEL IS AT LEAST AS STRINGENT AS THE BACT VALUES UNDER EPA'S CERTIFICATION.	8.5	G/HP-H	BACT-PSD

Table D-4 - RBLC Results for CO Emissions for Simple Cycle Combustion Turbine (Fuel Oil)

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
NV-0036	5/5/2005	TS POWER PLANT	NEWMONT NEVADA ENERGY INVESTMENT, LLC	NV	373.3	MMBTU/H	OXIDATION CATALYST	6	PPMVD	BACT-PSD
TX-0525	9/13/2005	TEXAS GENCO UNITS 1 AND2	TEXAS GENCO	TX	550	MMBTU/H		71	LB/H	BACT-PSD
TX-0525	9/13/2005	TEXAS GENCO UNITS 1 AND2	TEXAS GENCO	TX	550	MMBTU/H		112.5	LB/H	BACT-PSD
OH-0253	3/7/2006	DAYTON POWER AND LIGHT COMPANY	DAYTON POWER AND LIGHT COMPANY	OH	1115	MMBTU/H		350	LB/H	OTHER CASE-BY-CASE
TX-0506	4/19/2006	NRG TEXAS ELECTRIC POWER GENERATION	NRG TEXAS	TX	80	MW		401	LB/H	BACT-PSD
TX-0506	4/19/2006	NRG TEXAS ELECTRIC POWER GENERATION	NRG TEXAS	TX	80	mw		563	LB/H	BACT-PSD
OH-0253	3/7/2006	DAYTON POWER AND LIGHT COMPANY	DAYTON POWER AND LIGHT COMPANY	OH	1115	MMBTU/H		800	LB/H	OTHER CASE-BY-CASE
OH-0333	12/3/2009	DAYTON POWER & LIGHT ENERGY LLC	DAYTON POWER & LIGHT COMPANY	OH	4216	H/YR	efficient combustion technology	800	LB/H	BACT-PSD

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
LA-0219	8/15/2007	CREOLE TRAIL LNG IMPORT TERMINAL	CREOLE TRAIL LNG, LP	LA	30	MW EA.	DRY LOW EMISSIONS (DLE) COMBUSTION TECHNOLOGY WITH LEAN PREMIX OF AIR AND FUEL	2.11	LB/H	BACT-PSD
FL-0261	10/26/2004	ARVAH B. HOPKINS GENERATING STATION	CITY OF TALLAHASSEE	FL	50	mw	CLEAN FUELS	2.45	LB/H	BACT-PSD
*TX-0468	1/23/2003	UNION CARBIDE TEXAS CITY OPERATIONS	UNION CARBIDE CORPORATION - A SUBSIDIARY OF DOW CC	TX	12000	lb/hr		2.6	LB/HR	BACT-PSD
WA-0306	9/11/2001	CLIFFS ENERGY PROJECT	GNA ENERGY, INC.	WA	45	MW, EA	PIPELINE QUALITY NAT GAS AND GOOD COMBUSTION PRACTICES	3	LB/H	BACT-PSD
OH-0262	8/15/2002	ANR	ANR PIPELINE COMPANY	OH	122	MMBTU/H	NATURAL GAS ONLY FUEL, GOOD COMBUSTION	3.2	LB/H	BACT-PSD
OK-0127	6/13/2008	WESTERN FARMERS ELECTRIC ANADARKO	WESTERN FARMERS ELECTRIC COOPERATIVE	OK	462.7	MMBTU/H	NO CONTROLS FEASIBLE.	4	LB/H	BACT-PSD
TX-0388	2/12/2002	SAND HILL ENERGY CENTER	AUSTIN ELECTRIC UTILITY	TX	48	MW (EACH)	GOOD COMBUSTION PRACTICE	4.5	LB/H	Other Case-by-Case
OH-0291	11/17/2004	OHIO EDISON CO.-WEST LORAIN PLANT	FIRST ENERGY	OH	85	MW		5	LB/H	BACT-PSD
TX-0390	8/21/2002	EAST REFINERY	FLINT HILLS RESOURCES, LP	TX	87	MW EACH		5	LB/H	Other Case-by-Case
SC-0069	11/8/2001	DUKE ENERGY MILL CREEK COMBUSTION TURBINE STATION	DUKE ENERGY COMPANY	SC	81.7	MW	COMBUSTION CONTROLS	5	LB/H	BACT-PSD
NJ-0075	9/24/2009	BAYONNE ENERGY CENTER	BAYONNE ENERGY CENTER, LLC	NJ	603	MMBTU/H	BURNING CLEAN FUELS, NATURAL GAS AND ULTRA LOW SULFUR DISTILLATE OIL WITH SULFUR CONTENT OF 15 PPM.	5	LB/H	OTHER CASE-BY-CASE
NJ-0077	9/16/2010	HOWARD DOWN STATION	VINELAND MUNICIPAL ELECTRIC UTILITY (VMEU)	NJ	5000	MMFT3/YR	USE OF CLEAN BURNING FUELS; NATURAL GAS AS PRIMARY FUEL AND ULTRA LOW SULFUR DISTILLATE OIL WITH 15 PPMSULFUR BY WEIGHT AS BACKUP FUEL	5	LB/H	BACT-PSD
NJ-0076	10/27/2010	PSEG FOSSIL LLC KEARNY GENERATING STATION	PSEG FOSSIL LLC	NJ	8940000	MMBtu/year (HHV)	Good combustion practice, Use of Clean Burning Fuel: Natural gas	6	LB/H	BACT-PSD
MS-0079	1/30/2003	WARREN PEAKING POWER FACILITY (WARREN POWER, LLC)	WARREN PEAKING POWER FACILITY (WARREN POWER, LLC)	MS	959.8	mmbtu/h	USE OF CLEAN FUEL: NATURAL GAS	7	LB/H	BACT-PSD
AZ-0045	7/25/2001	PPL SUNDANCE ENERGY, LLC/SUNDANCE ENERGY	PPL SUNDANCE ENERGY, LLC	AZ	450	MW	GOOD COMBUSTION PRACTICE	7	LB/H	BACT-PSD
MS-0063	5/30/2001	WARREN PEAKING POWER FACILITY	WARREN POWER, LLC	MS	959.8	MMBTU/H	LOW ASH FUEL AND GOOD COMBUSTION PRACTICES	7	LB/H	BACT-PSD
LA-0191	10/12/2004	MICHOUD ELECTRIC GENERATING PLANT	ENTERGY NEW ORLEANS, INC.	LA	1595	MMBTU/H ea.	USE OF CLEAN BURNING FUELS (NATURAL GAS)	7.85	LB/H	BACT-PSD
OH-0274	10/1/2002	DPLE TAIT PEAKING STATION	DAYTON POWER AND LIGHT ENERGY	OH	80	mw		8	LB/H	BACT-PSD
OH-0253	6/4/2002	DAYTON POWER AND LIGHT COMPANY	DAYTON POWER AND LIGHT COMPANY	OH	1115	MMBTU/H		8	LB/H	BACT-PSD
OH-0253	6/4/2002	DAYTON POWER AND LIGHT COMPANY	DAYTON POWER AND LIGHT COMPANY	OH	1115	MMBTU/H		8	LB/H	BACT-PSD
NC-0084	1/25/2002	ROWAN GENERATING CO., LLC, ROWAN GENERATING FACILI	ROWAN GENERATING CO., LLC	NC	155	MW	COMBUSTION CONTROL	9	LB/H	BACT-PSD
OK-0044	8/16/2001	SMITH POCOLA ENERGY PROJECT	SMITH COGENERATION OK INC	OK	171.5	MW	USE OF LOW ASH FUEL AND EFFICIENT COMBUSTION	9	LB/H	BACT-PSD
MI-0319	7/23/2001	DETROIT EDISON-GREENWOOD ENERGY CENTER	DETROIT EDISON- GREENWOOD ENERGY CENTER	MI	82.4	MW		9	LB/H	BACT-PSD
MI-0321	7/23/2001	DETROIT EDISON- BELLE RIVER PLANT	DETROIT EDISON- BELLE RIVER PLANT	MI	82.4	MW	GOOD COMBUSTION. NO ADD-ON.	9	LB/H	BACT-PSD
MI-0295	7/10/2001	DTE ENERGY SERVICES	DTE ENERGY SERVICES	MI	82.4	MW (EACH)	NONE INDICATED	9	LB/H	BACT-PSD
MI-0267	6/7/2001	RENAISSANCE POWER LLC	RENAISSANCE POWER LLC	MI	170	MW	GOOD COMBUSTION. 0.0036 LB/MMBTU	9	LB/H	BACT-PSD

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
GA-0139	5/14/2010	DAHLBERG COMBUSDTION TURBINE ELECTRIC GENERATING FACILITY (P	SOUTHERN POWER COMPANY	GA	1530	MW	GOOD COMBUSTION PRACTICES PIPELINE QUALITY NATURAL GAS, ULTRA LOW SULFUR DISTILLATE FUEL	9.1	LB/H	BACT-PSD
OK-0120	3/22/2007	PSO RIVERSIDE JENKS POWER STA	PUBLIC SERVICE CO OF OKLAHOMA	OK			GOOD COMBUSTION PRACTICES IN COMBINATION WITH THE USE OF LOW-ASH FUEL	10	LB/H	BACT-PSD
MS-0074	12/10/2004	MOSELLE PLANT	SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION	MS	1143.3	MMBTU/H		10	LB/H	BACT-PSD
NE-0022	6/22/2004	C. W. BURDICK GENERATING STATION	Grand Island Utilities	NE	1	MILLION SCF/H	LOW ASH CONTENT NG	10	LB/H	Other Case-by-Case
MS-0057	5/29/2003	SMEPA - SILVER CREEK GENERATING	SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MS	1109.3	MMBTU/H	LOW ASH FUEL (NATURAL GAS) AND GOOD COMBUSTION PRACTICES.	10	LB/H	BACT-PSD
VA-0263	3/11/2003	ODEC - LOUISA FACILITY	OLD DOMINION ELECTRIC COOPERATIVE	VA	901	MMBTU/H	GOOD COMBUSTION PRACTICES.	10	LB/H	N/A
VA-0282	3/11/2003	ODEC - LOUISA	Old Dominion Electric Coop - Louisa	VA	901	MMBTU/H	CLEAN FUEL AND GOOD COMBUSTION	10	LB/H	BACT-PSD
VA-0269	1/8/2003	CINCAP MARTINSVILLE	Cinergy Capital & Trading	VA	82	MW	GOOD COMBUSTION PRACTICES.	10	LB/H	Other Case-by-Case
VA-0279	1/8/2003	CINCAP - MARTINSVILLE	Cinergy Capital & Trading	VA	82	MW	GOOD COMBUSTION, CLEAN FUEL	10	LB/H	BACT-PSD
VA-0262	12/6/2002	MIRANT AIRSIDE INDUSTRIAL PARK	MIRANT DANVILLE, LLC	VA	84	MW	GOOD COMBUSTION PRACTICES. DRIFT ELIMINATORS.	10	LB/H	BACT-PSD
NM-0048	8/19/2002	CAMBRAY ENERGY CENTER	DEMING ENERGY, LLC	NM	80	MW	GOOD COMBUSTION PRACTICES, NATURAL GAS AS PRIMARY FUEL.	10	PPH	BACT-PSD
FL-0229	8/15/2001	POMPANO BEACH ENERGY CENTER	POMPANO BEACH ENERGY. LLC	FL	1.91	MMCF/H	PIPELINE NATURAL GAS, GOOD COMBUSTION.	10	LB/H	BACT-PSD
FL-0228	7/15/2001	DEERFIELD BEACH ENERGY CENTER	DEERFIELD BEACH ENERGY CENTER, L.L.C.	FL	1.91	MMCF/H	PIPELINE NATURAL GAS, GOOD COMBUSTION.	10	LB/H	BACT-PSD
FL-0218	2/14/2001	MIDWAY ENERGY CENTER	ENRON/MIDWAY DEVELOPMENT COMPANY, L.L.C.	FL	1700	MMBTU/H	PIPELINE NATURAL GAS GOOD COMBUSTION	10	LB/H (GAS)	BACT-PSD
*TX-0457	6/26/2003	CITY PUBLIC SERVICE LEON CREEK PLANT	CITY PUBLIC SERVICE	TX				11.3	LB/H	BACT-PSD
VA-0258	8/29/2002	WHITE OAK POWER	WHITE OAK POWER COMPANY, LLC	VA	1731	MMBTU/H		13.8	LB/H	BACT-PSD
OH-0253	6/4/2002	DAYTON POWER AND LIGHT COMPANY	DAYTON POWER AND LIGHT COMPANY	OH	1115	MMBTU/H		15	LB/H	BACT-PSD
OH-0253	6/4/2002	DAYTON POWER AND LIGHT COMPANY	DAYTON POWER AND LIGHT COMPANY	OH	1115	MMBTU/H		15	LB/H	BACT-PSD
MO-0067	12/29/2004	SOUTH HARPER PEAKING FACILITY	AQUILA, INC.	MO	1455	mmBtu/h	GOOD COMBUSTION PRACTICES	15.25	LB/H	
MS-0072	12/10/2004	TVA - KEMPER COMBUSTION TURBINE PLANT		MS				15.8	LB/H	BACT-PSD
MS-0072	12/10/2004	TVA - KEMPER COMBUSTION TURBINE PLANT		MS				15.8	LB/H	BACT-PSD
MS-0072	12/10/2004	TVA - KEMPER COMBUSTION TURBINE PLANT		MS				15.8	LB/H	BACT-PSD
MS-0072	12/10/2004	TVA - KEMPER COMBUSTION TURBINE PLANT		MS				15.8	LB/H	BACT-PSD
LA-0258	12/21/2011	CALCASIEU PLANT	ENTERGY GULF STATES LA LLC	LA	1900	MM BTU/H EACH	USE OF PIPELINE NATURAL GAS	17	LB/H	BACT-PSD
OH-0304	1/17/2006	ROLLING HILLS GENERATING PLANT	ROLLING HILLS GENERATING, LLC	OH	209	MW		17.3	LB/H	BACT-PSD
VA-0263	3/11/2003	ODEC - LOUISA FACILITY	OLD DOMINION ELECTRIC COOPERATIVE	VA	1624	MMBTU/H	GOOD COMBUSTION PRACTICES.	18	LB/H	N/A
VA-0282	3/11/2003	ODEC - LOUISA	Old Dominion Electric Coop - Louisa	VA	1624	MMBTU/H	CLEAN FUELS AND GOOD COMBUSTION	18	LB/H	BACT-PSD
VA-0266	2/14/2003	ODEC - MARSH RUN FACILITY	Old Dominion Electric Cooperative	VA	1624	MMBTU/H	GOOD COMBUSTION PRACTICES AND CLEAN BURNING FUEL.	18	LB/H	N/A
VA-0280	2/14/2003	ODEC -MARSH	Old Dominion Electric Cooperative	VA	1624	MMBTU/H	CLEAN FUELS AND GOOD COMBUSTION	18	LB/H	BACT-PSD
LA-0157	3/8/2002	PERRYVILLE POWER STATION	PERRYVILLE ENERGY PARTNERS, LLC	LA	170	MW	GOOD OPERATING PRACTICES AND USE OF NATURAL GAS AS FUEL.	18	LB/H	BACT-PSD
GA-0094	12/27/2001	EFFINGHAM COUNTY POWER, LLC	EFFINGHAM COUNTY POWER, LLC	GA	185	MW	GOOD COMBUSTION PRACTICES/CLEAN FUEL	18	LB/H	BACT-PSD

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
OH-0255	3/29/2001	PSEG WATERFORD ENERGY LLC	PSEG WATERFORD ENERGY LLC	OH	170	MW		18	LB/H	BACT-PSD
MI-0345	7/1/2002	EL PASO MERCHANT ENERGY CO.	EL PASO MERCHANT ENERGY CO.	MI	170	MW	NATURAL GAS ONLY	18.4	LB/H	BACT-PSD
FL-0226	9/11/2001	EL PASO MANATEE ENERGY CENTER	EL PASO MERCHANT ENERGY CENTER	FL	1.79	MMCF/H	NATURAL GAS COMBUSTION CONTROLS	20	LB/H	BACT-PSD
FL-0225	8/17/2001	EL PASO BROWARD ENERGY CENTER	EL PASO MERCHANT ENERGY COMPANY	FL	1.79	MMCF/H	PIPELINE NATURAL GAS COMBUSTION CONTROLS.	20	LB/H	BACT-PSD
VA-0265	1/10/2003	CHICKAHOMINY POWER	DYNEGY	VA	1862	MMBTU/H	CLEAN BURNING FUELS AND GOOD COMBUSTION PRACTICES.	27	LB/H	BACT-PSD
VA-0281	1/10/2003	CHICKAHOMINY POWER	DYNEGY MARKETING AND TRADE COMMERCIAL POWER	VA	182.6	MW	CLEAN FUEL, GOOD COMBUSTION CONTROL	27	LB/H	BACT-PSD
SC-0058	7/2/2001	GENPOWER ANDERSON, LLC	GENPOWER ANDERSON, LLC	SC	640	MW	GOOD COMBUSTION PRACTICES & CLEAN BURNING FUELS	30.1	LB/H	BACT-PSD
OH-0259	9/11/2001	JACKSON COUNTY GENERATING, LLC	ENTERGY CORPORATION	OH	160	MW		34.9	LB/H	BACT-PSD
*ND-0028	2/22/2013	R.M. HESKETT STATION	MONTANA-DAKOTA UTILITIES CO.	ND	986	MMBTU/H	Good Combustion Practices	7.3	LB/H	BACT-PSD
*ND-0028	2/22/2013	R.M. HESKETT STATION	MONTANA-DAKOTA UTILITIES CO.	ND	986	MMBTU/H	Good combustion practices.	7.3	LB/H	BACT-PSD
*ND-0029	5/14/2013	PIONEER GENERATING STATION	BASIN ELECTRIC POWER COOPERATIVE	ND	451	MMBtu/hr		5.4	LB	BACT-PSD
*ND-0030	9/16/2013	LONESOME CREEK GENERATING STATION	BASIN ELECTRIC POWER COOP.	ND	412	MMBtu/hr		5	LB/H	BACT-PSD
*OR-0050	3/5/2014	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	OR	2988	MMBtu/hr	Utilize only natural gas or ULSD fuel; Limit the time in startup or shutdown.	23.6	LB/H TOTAL PM	BACT-PSD
*OR-0050	3/5/2014	TROUTDALE ENERGY CENTER, LLC	TROUTDALE ENERGY CENTER, LLC	OR	1690	MMBtu/hr	Utilize only natural gas or ULSD fuel; Limit the time in startup or shutdown.	9.1	LB/H TOTAL PM	BACT-PSD
IN-0117	1/29/2001	SIGECO A.B. BROWN STATION	SIGECO A.B. BROWN STATION	IN	1110.9	MMBTU/H	GOOD COMBUSTION PRACTICES, LIMIT USE OF DISTILLATE OIL TO < 4268.57 KGAL PER 12 MO PERIOD.	0.0045	LB/MMBTU	BACT-PSD
IN-0096	11/16/2001	SOUTHERN INDIANA- AB BROWN GENERATING STATION	SOUTHERN INDIANA GAS & ELECTRIC COMPANY	IN	1145.8	MMBTU/H	GOOD COMBUSTION PRACTICES	0.005	LB/MMBTU	BACT-PSD
AR-0043	2/27/2001	PINE BLUFF ENERGY LLC	PINE BLUFF ENERGY LLC	AR	170	MW	CLEAN FUELS.	0.005	LB/MMBTU	BACT-PSD
*NV-0046	5/16/2006	GOODSPRINGS COMPRESSOR STATION	KERN RIVER GAS TRANSMISSION COMPANY	NV	97.81	MMBTU/H	NATURAL GAS IS THE ONLY FUEL FOR THE PROCESS.	0.0066	LB/MMBTU	BACT-PSD
OK-0070	6/13/2002	GENOVA OK I POWER PROJECT	GENOVA OKLAHOMA LLC	OK	1872	MMBTU/H	LOW ASH FUEL AND EFFICIENT COMBUSTION	0.0092	LB/MMBTU	BACT-PSD
AL-0187	1/29/2001	TENASKA ALABAMA III GENERATING STATION	TENASKA ALABAMA III PARTNERS LP	AL	170	MW	CLEAN FUELS FIRING	0.0092	LB/MMBTU	BACT-PSD
IA-0058	4/10/2002	GREATER DES MOINES ENERGY CENTER	MIDAMERICAN ENERGY	IA	350	MW		0.0094	LB/MMBTU	BACT-PSD
IN-0088	5/29/2001	DUKE ENERGY KNOX LLC	DUKE ENERGY KNOX LLC	IN	1158	MMBTU/H	GOOD COMBUSTION. LB/H LIMIT FOR EACH CT.	0.0095	LB/MMBTU	BACT-PSD
IA-0060	7/23/2002	HAWKEYE GENERATING, LLC	ENTERGY	IA	33.77	BILLION CF/YR		0.0098	LB/MMBTU	BACT-PSD
IA-0060	7/23/2002	HAWKEYE GENERATING, LLC	ENTERGY	IA	33.77	BILLION CF/YR		0.0098	LB/MMBTU	BACT-PSD
MN-0053	7/15/2004	FAIRBAULT ENERGY PARK	MN MUNICIPAL POWER AGENCY	MN	1663	MMBTU/H	CLEAN FUEL AND GOOD COMBUSTION PRACTICES.	0.01	LB/MMBTU	BACT-PSD
NC-0087	11/20/2001	DUKE ENERGY - BUCK COMBUSTION TURBINE FACILITY	DUKE ENERGY CORPORATION	NC	80	MW	COMBUSTION CONTROL	0.0116	LB/MMBTU	BACT-PSD
MD-0040	11/12/2008	CPV ST CHARLES	COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC	MD				0.012	LB/MMBTU @ 15% O2	BACT-PSD
IN-0114	7/24/2002	MIRANT SUGAR CREEK LLC	MIRANT SUGAR CREEK LLC	IN	1490.5	MMBTU/H		0.012	LB/MMBTU	BACT-PSD
OK-0072	5/6/2002	REDBUD POWER PLT	REDBUD ENERGY LP	OK	1832	MMBTU/H	USE OF NATURAL GAS	0.012	LB/MMBTU	BACT-PSD
IN-0086	5/9/2001	MIRANT SUGAR CREEK, LLC	MIRANT SUGAR CREEK, LLC	IN	170	MW	GOOD COMBUSTION. LB/H LIMIT IS FOR EACH CT.	0.012	LB/MMBTU	BACT-PSD
MD-0040	11/12/2008	CPV ST CHARLES	COMPETITIVE POWER VENTURES, INC./CPV MARYLAND, LLC	MD				0.012	LB/MMBTU @ 15% O2	BACT-PSD

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
OH-0333	12/3/2009	DAYTON POWER & LIGHT ENERGY LLC	DAYTON POWER & LIGHT COMPANY	OH	15020	H/YR		0.013	LB/MMBTU	BACT-PSD
IL-0086	11/27/2002	KENDALL NEW CENTURY DEVELOPMENT, LLC	KENDALL NEW CENTURY DEVELOPMENT, LLC	IL	1000.5	MMBTU/H	GOOD COMBUSTION PRACTICES AND USE OF NATURAL GAS FUEL.	0.014	LB/MMBTU	BACT-PSD
NJ-0056	9/10/2001	CONSOLIDATED EDISON DEVELOPMENT (CED)	CONSOLIDATED EDISON DVPMT.- LAKEWOOD GEN. FACILITY	NJ	1959	MMBTU/H, 174.2 MW		0.017	LB/MMBTU	BACT-PSD
AL-0187	1/29/2001	TENASKA ALABAMA III GENERATING STATION	TENASKA ALABAMA III PARTNERS LP	AL	170	MW	CLEAN FUEL FIRING	0.0172	LB/MMBTU	BACT-PSD
CO-0053	5/31/2001	PLATTE RIVER POWER AUTHORITY- RAWHIDE STATION	PLATTE RIVER POWER AUTHORITY	CO	82	MW	PIPELINE NATURAL GAS AND GOOD COMBUSTION CONTROL PRACTICES	0.021	LB/MMBTU	BACT-PSD
OH-0333	12/3/2009	DAYTON POWER & LIGHT ENERGY LLC	DAYTON POWER & LIGHT COMPANY	OH	4216	H/YR		0.026	LB/MMBTU	BACT-PSD
*IN-0173	6/4/2014	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	283	MMBTU/H, EACH	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	0.0076	LB/MMBTU	BACT-PSD
*IN-0173	6/4/2014	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	283	MMBTU/H, EACH	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	0.0076	LB/MMBTU	BACT-PSD
*IN-0180	6/4/2014	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	283	MMBTU/H, EACH	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	0.0076	LB/MMBTU	BACT-PSD
*IN-0180	6/4/2014	MIDWEST FERTILIZER CORPORATION	MIDWEST FERTILIZER CORPORATION	IN	283	MMBTU/H, EACH	GOOD COMBUSTION PRACTICES AND PROPER DESIGN	0.0076	LB/MMBTU	BACT-PSD
WA-0312	7/18/2003	FREDONIA ENERGY STATION	PUGET SOUND ENERGY	WA	108	MW	GOOD COMBUSTION PRACTICE	0.01	GR/DSCF	BACT-PSD
CA-0952	5/18/2001	LA DEPT OF WATER & POWER	LA DEPT OF WATER & POWER	CA	47.4	MW		0.01	GR/DSCF	Other Case-by-Case
FL-0287	11/17/2006	OLEANDER POWER PROJECT	OLEANDER POWER PROJECT, L.P	FL	190	MW	CLEAN FUELS	1.5	GR S/100 SCF	BACT-PSD
*FL-0279	4/28/2006	TEC/POLK POWER ENERGY STATION	TAMPA ELECTRIC COMPANY (TEC)	FL	1834	MMBtu/hr	FIRING OF NATURAL GAS GOOD COMBUSTION PRACTICES	10	PERCENT OPACITY	BACT-PSD
FL-0279	4/28/2006	TEC/POLK POWER ENERGY STATION	TAMPA ELECTRIC COMPANY (TEC)	FL	1834	MMBTU/H	FIRING OF NATURAL GAS GOOD COMBUSTION PRACTICES	10	% OPACITY	BACT-PSD
FL-0310	1/12/2009	SHADY HILLS GENERATING STATION	SHADY HILLS POWER COMPANY	FL	170	MW		10	% OPACITY	BACT-PSD
FL-0319	3/10/2009	GREENLAND ENERGY CENTER	JACKSONVILLE ELECTRIC AUTHORITY (JEA)	FL	30213	GAL/YR	Use of low ash, low sulfur fuels,	10	OPACITY	BACT-PSD
MN-0075	7/1/2008	GREAT RIVER ENERGY - ELK RIVER STATION	GREAT RIVER ENERGY	MN	2169	MMBTU/H	FUEL LIMITED TO NATURAL GAS AND ULTRA-LOW SULFUR FUEL OIL	0		BACT-PSD
MN-0075	7/1/2008	GREAT RIVER ENERGY - ELK RIVER STATION	GREAT RIVER ENERGY	MN	2169	MMBTU/H	FUEL LIMITED TO NATURAL GAS AND ULTRA-LOW SULFUR FUEL OIL	0		BACT-PSD
*TX-0691	5/20/2014	PH ROBINSON ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	TX	65	MW		0		BACT-PSD
*TX-0694	2/2/2015	INDECK WHARTON ENERGY CENTER	INDECK WHARTON, L.L.C.	TX	220	MW		0		BACT-PSD
*TX-0695	8/1/2014	ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	TX	180	MW		0		BACT-PSD
*TX-0696	9/22/2014	ROANâ€™S PRAIRIE GENERATING STATION	TENASKA ROANâ€™S PRAIRIE PARTNERS (TRPP), LLC	TX	600	MW		0		BACT-PSD
*TX-0701	5/13/2013	ECTOR COUNTY ENERGY CENTER	INVENERGY THERMAL DEVELOPMENT LLC	TX	180	MW	Firing pipeline quality natural gas and good combustion practices	0		BACT-PSD
*TX-0733	5/12/2015	ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	TX	202	MW	Pipeline quality natural gas; limited hours; good combustion practices.	0		BACT-PSD
*TX-0733	5/12/2015	ANTELOPE ELK ENERGY CENTER	GOLDEN SPREAD ELECTRIC COOPERATIVE, INC.	TX	202	MW	Pipeline quality natural gas; limited hours; good combustion practices.	0		BACT-PSD
*FL-0346	4/22/2014	LAUDERDALE PLANT	FLORIDA POWER & LIGHT	FL	2000	MMBtu/hr (approx)	Good combustion practice and low-sulfur fuel	0		BACT-PSD
*MN-0075	7/1/2008	GREAT RIVER ENERGY - ELK RIVER STATION	GREAT RIVER ENERGY	MN	2169	MMBTU/H	FUEL LIMITED TO NATURAL GAS AND ULTRA-LOW SULFUR FUEL OIL			
*MN-0075	7/1/2008	GREAT RIVER ENERGY - ELK RIVER STATION	GREAT RIVER ENERGY	MN	2169	MMBTU/H	FUEL LIMITED TO NATURAL GAS AND ULTRA-LOW SULFUR FUEL OIL			BACT-PSD

Table D-5 - RBLC Results for PM10/PM2.5 Emissions for Simple Cycle Combustion Turbine (Natural Gas)

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
FL-0300	12/22/2006	JACKSONVILLE ELECTRIC AUTHORITY/JEA	JACKSONVILLE ELECTRIC AUTHORITY	FL	1804	MMBTU/H	NATURAL GAS AS PRIMARY FUEL WITH 0.05% SULFUR DISTILLATE FUEL OIL AS BACKUP. USE WATER INJECTION WHEN FIRING OIL			BACT-PSD
FL-0244	4/16/2003	FPL MARTIN PLANT	FLORIDA POWER & LIGHT	FL	170	MW	ULTRA LOW SULFUR DISTILLATE FUEL CONTAINS LITTLE ASH OR OTHER CONTAMINANTS			BACT-PSD
FL-0244	4/16/2003	FPL MARTIN PLANT	FLORIDA POWER & LIGHT	FL	170	MW	CLEAN FUEL - PIPELINE NATURAL GAS			BACT-PSD
FL-0245	4/15/2003	FPL MANATEE PLANT - UNIT 3	FLORIDA POWER & LIGHT	FL	170	MW	CLEAN FUEL			BACT-PSD
IN-0111	3/13/2003	DUKE ENERGY VERMILLION STATION	DUKE ENERGY VERMILLION STATION	IN	80	MW	CLEAN FUEL -- NATURAL GAS			BACT-PSD
FL-0227	9/7/2001	EL PASO BELLE GLADE ENERGY CENTER	EL PASO MERCHANT ENERGY CENTER	FL	1.79	MMCF/H	PIPELINE NATURAL GAS, COMBUSTION CONTROLS. NO EMISSION RATE LIMIT, PERMIT LIMIT IS < 1.5 GR S/100 SCF NAT GAS AS FUEL.			BACT-PSD

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
NV-0036	5/5/2005	TS POWER PLANT	NEWMONT NEVADA ENERGY INVESTMENT, LLC	NV	373.3	MMBTU/H	LOW ASH FUEL	13.7	LB/H	BACT-PSD
OH-0253	3/7/2006	DAYTON POWER AND LIGHT COMPANY	DAYTON POWER AND LIGHT COMPANY	OH	1115	MMBTU/H		15	LB/H	OTHER CASE-BY-CASE
OH-0253	3/7/2006	DAYTON POWER AND LIGHT COMPANY	DAYTON POWER AND LIGHT COMPANY	OH	1115	MMBTU/H		15	LB/H	OTHER CASE-BY-CASE
TX-0506	4/19/2006	NRG TEXAS ELECTRIC POWER GENERATION	NRG TEXAS	TX	80	MW		15	LB/H	BACT-PSD
TX-0525	9/13/2005	TEXAS GENCO UNITS 1 AND2	TEXAS GENCO	TX	550	MMBTU/H		15	LB/H	BACT-PSD
TX-0506	4/19/2006	NRG TEXAS ELECTRIC POWER GENERATION	NRG TEXAS	TX	80	mw		19.5	LB/H	BACT-PSD
TX-0525	9/13/2005	TEXAS GENCO UNITS 1 AND2	TEXAS GENCO	TX	550	MMBTU/H		19.5	LB/H	BACT-PSD
OH-0333	12/3/2009	DAYTON POWER & LIGHT ENERGY LLC	DAYTON POWER & LIGHT COMPANY	OH	4216	H/YR		0.026	LB/MMBTU	BACT-PSD
OH-0333	12/3/2009	DAYTON POWER & LIGHT ENERGY LLC	DAYTON POWER & LIGHT COMPANY	OH	4216	H/YR		0.026	LB/MMBTU	BACT-PSD

Table D-7 - RBLC Results for CO_2 Emissions for Simple Cycle Combustion Turbine (Natural Gas)

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
*OR-0050	3/5/2014	E ENERGY CENTER,	ENERGY CENTER,	OR	2988	MMBtu/hr	Thermal efficiency Clean fuels	1000	PER GROSS MWH	BACT-PSD
*TX-0735	05/19/2015 EST	ELK ENERGY	SPREAD ELECTRIC	TX	202	MW	Energy efficiency, good design & combustion practices	1304	LB CO2/MWHR	BACT-PSD
*OR-0050	3/5/2014	E ENERGY CENTER,	ENERGY CENTER,	OR	1690	MMBtu/hr	Thermal efficiency Clean fuels	1707	LB OF CO2 /GROSS MWH	BACT-PSD
*ND-0028	2/22/2013	HESKETT STATION	DAKOTA UTILITIES	ND	986	MMBTU/H		413198	TONS/12 MONTH	BACT-PSD
*ND-0029	5/14/2013	GENERATI NG	ELECTRIC POWER	ND	451	MMBtu/hr		243147	TONS	BACT-PSD
*ND-0030	9/16/2013	E CREEK GENERATI	ELECTRIC POWER	ND	412	MMBtu/hr	High efficiency turbines	220122	TONS	BACT-PSD
*IN-0173	6/4/2014	FERTILIZE R	FERTILIZER CORPORATI	IN	283	MMBTU/H, EACH	PRACTICES AND PROPER DESIGN	12666	BTU/KW-H, MINIMUM	BACT-PSD
*IN-0180	6/4/2014	FERTILIZE R	FERTILIZER CORPORATI	IN	283	MMBTU/H, EACH	PRACTICES AND PROPER DESIGN	12666	BTU/KW-H, MINIMUM	BACT-PSD

Table D-8 - RBLC Results for CO_2 Emissions for Simple Cycle Combustion Turbine (Fuel Oil)

RBLCID	Permit Date	Facility Name	Corporation	State	Throughput	Units	Control Device	Emission Limit 1	Units	Type
No Entries in RBLC										

APPENDIX E – ECONOMIC TABLES

Table E-1
Simple-Cycle Operation NOx BACT - SCR Capital Costs

Item	Value	Basis
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries **[A]**	**$9,500,000**	A
Instrumentation	$950,000	0.10 x A
Freight	$475,000	0.05 x A
Total Purchased Equipment Cost (PEC) [B]	**$10,925,000**	B = 1.15 x A
Direct Installation Costs		
Foundations and supports	$874,000	0.08 x B
Handling and erection	$1,529,500	0.14 x B
Electrical	$437,000	0.04 x B
Piping	$218,500	0.02 x B
Insulation for ductwork	$109,250	0.01 x B
Painting	$109,250	0.01 x B
Total Direct Installation Cost	$3,277,500	0.30 x B
Site Preparation (SP)	$0	As required
Buildings (Bldg.)	$546,250	As required (5-18% PEC)
Total Direct Cost (DC)	**$14,748,750**	1.30B + SP + Bldg.
Indirect Costs (Installation)		
Engineering	$1,092,500	0.10 x B
Construction and field expenses	$546,250	0.05 x B
Contractor fees	$1,092,500	0.10 x B
Start-up	$218,500	0.02 x B
Performance test	$109,250	0.01 x B
Contingencies	$546,250	0.05 x B
CEMs	$70,000	Vendor estimate
PSD Permit	$75,000	Application + Draft Permit
Other	$0	As required
Construction Period	0.5	Years
Interest Rate	7	Percent
Interest during construction (Int.)	$516,206	DC * i * n
Total Indirect Cost (IC)	**$4,266,456**	0.33B + Int. + CEMs + PSD
Total Capital Investment (TCI) = DC + IC	**$19,015,206**	1.63B + Bldg. + Int. + CEMs + PSD

Table E-2
Simple-Cycle Operation NOx BACT - SCR Annual Costs

Item	Value	Basis
Direct Annual Costs (DC)		
Electricity		
Press. Drop (in W.C.)	5.0	Pressure drop - catalyst bed
Power output of Turbine (kW)	167,800	ISO Rating
Power Loss Due to Pressure Drop (%)	0.50%	0.1% for every 1" pressure drop
Power Loss Due to Pressure Drop (kW)	839	
Unit cost ($/kWh)	$0.045	Estimated market value
Cost of Power Loss ($/yr)	$180,167	Based on operation of 4772 hours/yr
Operating Labor		
Catalyst labor req.	$26,843	1/2 hr/shift @ $30/hr
Ammonia delivery requirement (SCR)	$720	24 hr/yr (3 deliveries per year) @ $30/hr
Ammonia recordkeeping and reporting (SCR)	$1,200	40 hours per year @ $30/hr
Catalyst cleaning	$1,200	40 hours per year @ $30/hr
Supervisor	$4,026	15% Operating labor
Total Cost ($/yr)	$33,989	
Ammonia		
Requirement (tons/yr)	681	19% aqueous ammonia
Unit Cost ($/ton)	$275	Estimate
Total Cost ($/yr)	$187,286	
Process Air		
Requirement (scf/lb NH_3)	350	
Requirement (mscf/yr)	1,137,470	
Unit Cost ($/mscf)	$0.20	$0.20 per 1000 scf
Total Cost ($/yr)	$227,494	
Catalyst Maintenance		
Catalyst system maintenance labor	$8,948	1/2 hr/shift @ $30/hr
Ammonia system maintenance labor	$10,950	1 hr/day @ $30/hr
Material	$19,898	100% of maintenance labor
Total Cost ($/yr)	$39,795	
Catalyst Replacement		
Catalyst Cost ($)	$1,113,624	Catalyst modules
Catalyst Disposal Cost ($)	$55,681	Assume 5% of Catalyst Cost
Catalyst replacement labor	$9,600	8 workers, 40 hr, every 3 years
Catalyst Life (yrs)	3	n
Interest Rate (%)	7%	i
CRF	0.381	Amoritization of catalyst over 3 years
Total Cost ($/yr)	$449,224	(Material + Labor Costs) * CRF
Indirect Annual Costs (IC)		
Overhead	$0	OAQPS SCR Assumption
Administrative charges	$0	OAQPS SCR Assumption
Annual Contingency	$0	OAQPS SCR Assumption
Property taxes	$0	OAQPS SCR Assumption
Insurance	$0	OAQPS SCR Assumption
Capital Recovery	$1,794,901	CRF * TCI (20 year life, 7% interest)
Total Indirect Costs ($/yr)	$1,794,901	
Total Annualized Costs (TAC) ($)	**$2,912,855**	
Total Pollutant Controlled (ton/yr) (Natural Gas)	**126.7**	78% Reduction (2 ppm on Natural Gas)
Total Pollutant Controlled (ton/yr) (Fuel Oil)	**47.5**	78% Reduction (9 ppm on Fuel Oil)
COST EFFECTIVENESS ($/ton)	**$22,992**	

Table E-3
Simple-Cycle Operation CO BACT - CO Catalyst Capital Costs

Item	Value	Basis
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries **[A]**	**$4,075,000**	A
Instrumentation	$407,500	0.10 x A
Freight	$225,000	Vendor quote
Total Purchased Equipment Cost (PEC) [B]	**$4,707,500**	B = 1.10 x A
Direct Installation Costs		
Foundations and supports	$376,600	0.08 x B
Handling and erection	$659,050	0.14 x B
Electrical	$188,300	0.04 x B
Piping	$94,150	0.02 x B
Insulation for ductwork	$47,075	0.01 x B
Painting	$47,075	0.01 x B
Total Direct Installation Cost	$1,412,250	0.30 x B
Site Preparation (SP)	$0	As required
Buildings (Bldg.)	$517,825	As required (5-18% PEC)
Total Direct Cost (DC)	**$6,637,575**	1.30B + SP + Bldg.
Indirect Costs (Installation)		
Engineering	$470,750	0.10 x B
Construction and field expenses	$235,375	0.05 x B
Contractor fees	$470,750	0.10 x B
Start-up	$94,150	0.02 x B
Performance test	$47,075	0.01 x B
Contingencies	$235,375	0.05 x B
CEMs	$70,000	Vendor estimate
PSD Permit	$75,000	Application + Draft Permit
Other	$0	As required
Construction Period	0.5	Years
Interest Rate	7	Percent
Interest during construction (Int.)	$232,315	DC * i * n
Total Indirect Cost (IC)	**$1,930,790**	0.33B + Int.+ CEM + PSD
Total Capital Investment (TCI) = DC + IC	**$8,568,365**	1.63B + Bldg. + Int.+ PSD + CEM

Table E-4
Simple-Cycle Operation CO BACT - CO Catalyst Annual Costs

Item	Value	Basis
Direct Annual Costs (DC)		
Electricity		
Press. Drop (in W.C.)	5.0	Pressure drop - catalyst bed
Power output of Turbine (kW)	167.8	ISO Rating
Power Loss Due to Pressure Drop (%)	0.50%	0.1% for every 1" pressure drop
Power Loss Due to Pressure Drop (kW)	0.839	
Unit cost ($/kWh)	$0.045	Estimated market value
Cost of Power Loss ($/yr)	$180	Based on operation of 4772 hours/yr
Operating Labor		All costs based on $30 per hour
Catalyst labor req.	$8,948	1/2 hour per shift
Supervisor	$1,342	15% Operating labor
Total Cost ($/yr)	$10,290	
Catalyst		
Catalyst replacement labor	$3,210	8 workers, 40 hr, every 3 years
Material	$3,210	100% of maintenance labor
Catalyst Cost ($)	$1,000,000	Catalyst modules
Catalyst Disposal Cost ($)	$50,000	Assume 5% of Catalyst Cost
Catalyst Life (yrs)	3	n
Interest Rate (%)	7	i
CRF	0.38	Amoritization of catalyst over 3 years
Total Cost ($/yr)	$400,104	(Material + Labor Costs) * CRF
Indirect Annual Costs (IC)		
Overhead	$0	OAQPS SCR Assumption
Administrative charges	$0	OAQPS SCR Assumption
Annual Contingency	$0	OAQPS SCR Assumption
Property taxes	$0	OAQPS SCR Assumption
Insurance	$0	OAQPS SCR Assumption
Capital Recovery	$808,793	CRF * TCI (20 year life, 7% interest)
Total Indirect Costs ($/yr)	$808,793	
Total Annualized Costs (TAC) ($)	**$1,219,367**	
Total Pollutant Controlled (ton/yr)		
Carbon Monoxide (CO) (Gas)	61.2	2 ppmvd @ 15% O2 (77% Reduction)*
Carbon Monoxide (CO) (Fuel Oil)	7.3	4.4 ppmvd @ 15%O2 (77% Reduction)
COST EFFECTIVENESS ($/ton)	**$17,805**	

APPENDIX F – MODELING PROTOCOL

Prevention of Significant Deterioration Class II Air Dispersion Modeling Protocol

Pleasants Energy, LLC

Pleasants Energy Plant
Project No. 84344

Revision 2
September 2015

Prevention of Significant Deterioration Class II Air Dispersion Modeling Protocol

prepared for

Pleasants Energy, LLC
Pleasants Energy Plant
St. Marys, West Virginia

Project No. 84344

Revision 2
September 2015

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
AQAT	Air Quality Assessment Tool
AQRV	Air Quality Related Value
ARM	Ambient Ratio Method
bhp	brake horsepower
BPIP-PRIME	Building Profile Input Program – Plume Rise Model Enhancements
CFR	Code of Federal Regulations
CO	carbon monoxide
CO_2e	carbon dioxide equivalent (greenhouse gases)
CSAPR	Cross State Air Pollution Rule
EPA	U.S. Environmental Protection Agency
FLAG	Federal Land Managers' Air Quality Related Values Work Group
FLM	Federal Land Manager
GEP	Good Engineering Practice
H_2SO_4 Mist	sulfuric acid mist
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NAD83	North American Datum of 1983
NCDC	National Climatic Data Center
NED	National Elevation Dataset
NO_2	nitrogen dioxide
NOx	nitrogen oxides

Abbreviation	Term/Phrase/Name
OEPA	Ohio Environmental Protection Agency
OLM	Ozone Limiting Method
Pleasants Energy	Pleasants Energy, LLC
PM_{10}	particulate matter less than 10 microns in diameter
$PM_{2.5}$	particulate matter less than 2.5 microns in diameter
PSD	Prevention of Significant Deterioration
PVMRM	Plume Volume Molar Ratio Method
scf	standard cubic feet
SIA	significant impact area
SIL	Significant Impact Level
SO_2	sulfur dioxide
USGS	U.S. Geological Survey
UTM	Universal Transverse Mercator
VOC	volatile organic compounds
WVDEP	West Virginia Department of Environmental Protection
ΔE	relative sensitivity

1.0 INTRODUCTION

Pleasants Energy, LLC (Pleasants Energy) installed two simple-cycle General Electric 7FA combustion turbines at the Pleasants Energy facility in 2002 and is currently operating under permit number R30-07300022-2014. The permit had operational restrictions to limit the facility's potential to emit to fewer than 250 tons per year of any criteria pollutant so the site could be minor for Prevention of Significant Deterioration (PSD). The Pleasants Energy Project (Project) will increase the hours of operation of the combustion turbines. Since the Project will remove the synthetic minor limitation on the combustion turbines and will increase the potential to emit to greater than 250 tons per year, this Project will be subject to PSD. The existing Pleasants Energy facility includes two TurboPhase units that consist of four engines, each and five Tier IV diesel generators.

Since a PSD permit requires an assessment of ambient impacts for those pollutants subject to PSD review, this document presents a Class II air dispersion modeling protocol to be used in developing the PSD application. Submittal of this protocol will allow the West Virginia Department of Environmental Protection (WVDEP) to review and comment on the methodology to be used in the modeling analysis.

Included in this document is a brief description of the Project, proposed model, and input parameters for the proposed model. This modeling protocol has been drafted in accordance with the U.S. Environmental Protection Agency (EPA) and WVDEP modeling guidelines.

2.0 PROJECT DESCRIPTION

The existing combustion turbines at the Pleasants Energy site are currently limited by an annual fuel throughput limit for natural gas and fuel oil. This Project will remove this limitation and will increase the annual operation of each combustion turbines with tons per year limits and/or fuel usage limits. The location of the Pleasants Energy site is shown in Figure A-1 in Appendix A.

Pleasants County is currently designated as an attainment/unclassified area for all criteria pollutants; therefore, the Project is not subject to non-attainment new source review.

The Project emission units, emission unit sizes, number of units, and fuels combusted are displayed in Table 2-1. Note that the hours of operation are approximate at this time and Pleasants Energy will likely be requesting fuel usage limits instead of hours of operation limits for the combustion turbines. Table 2-2 displays the existing equipment at the site, along with the number of units, fuel, size and operational hours.

Table 2-1: Project Emission Units and Approximate Hours of Operation Estimates

Emissions Unit	Size[a]	Number of Units	Fuel	Estimated Operation[b]
Combustion turbine	191.2 MW (gas) 196.9 MW (diesel)	2	Natural gas	19,081,721,568 SCF/year both turbines combined
			Diesel	
			Natural gas	365 start-ups (each)
			Diesel	20 start-ups (each)

(a) MW = megawatts
(b) The air permit application will request fuel usage limits and tons per year limits for both combustion turbines combined. This will include start-up and shutdown emissions as well as fuel oil and natural gas normal operation. The SCF limit includes both diesel and gas where diesel usage equals 889 SCF for every gallon combusted.

Table 2-2: Existing Pleasants Energy Emission Units and Permitted Operation

Emissions Unit	Size[a]	Number of Units	Fuel	Annual Hours of Operation (Estimated)
TurboPhase	2,750 bhp for each of 4 engines that make up a TurboPhase[b]	2	Natural gas	3,250 (each)
Black start generator	3 MW	5	Diesel	500 (each)

(a) MW = megawatts; bhp = brake horsepower
(b) Each TurboPhase unit consists of four engines that are 2750 bhp each.

The preliminary estimated maximum potential air emissions for the combustion turbines are presented in Table 2-3. The emissions include total annual emissions while operating on gas and fuel oil as well as start-up and shutdown emissions.

Table 2-3: Preliminary Estimated Potential Emissions from the Project and PSD Significance Levels

Pollutant[a]	Preliminary Estimated Potential Emissions (Tons per Year)[b]	PSD Significance Levels (Tons per Year)
NO_x	**464.6**	40
CO	**509.5**	100
PM_{10}[c]	**118.7**	15
$PM_{2.5}$[c]	**118.7**	10
VOC	23.8	40
SO_2	39.0	40
CO_2e	**1,231,633**	75,000
H_2SO_4 Mist	3.0	7
Lead	0.008	0.6

(a) NO_x = nitrogen oxides; CO = carbon monoxide; SO_2 = sulfur dioxide; VOC = volatile organic carbons; PM_{10} = particulate matter less than 10 microns in diameter; $PM_{2.5}$ = particulate matter less than 2.5 microns in diameter; CO_2e = carbon dioxide equivalent (greenhouse gases); H_2SO_4 Mist = sulfuric acid mist
(b) Numbers in **bold** indicate the PSD significance level is exceeded
(c) Filterable plus condensable

Based on the preliminary estimated potential emissions shown in the table above, it is expected that nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter less than 10 microns in diameter (PM_{10}), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), and greenhouse gases as carbon dioxide equivalents (CO_2e) will be subject to PSD review.

3.0 PROPOSED MODEL AND MODELING METHODOLOGY

The owner is proposing to use the most current version of the AMS/EPA Regulatory Model (AERMOD) for the air quality analysis (Version 15181). The AERMOD model is an EPA-approved, steady-state Gaussian plume model capable of modeling multiple sources in simple and complex terrain.

The following model options will be used:

- Gradual Plume Rise
- Stack-tip Downwash
- Buoyancy-induced Dispersion
- Calms and Missing Data Processing Routine
- Calculate Wind Profiles
- Calculate Vertical Potential Temperature Gradient
- Rural Dispersion
- NO_2 Modeling (non-default)

Details of the modeling algorithms contained in AERMOD may be found in the User's Guide for AERMOD. The regulatory default option will be selected for this analysis.

3.1 Modeling Parameters

It is expected that NO_x, CO, PM_{10}, $PM_{2.5}$, and CO_2e will be subject to PSD review, and an air quality analysis will be performed for NO_x, CO, PM_{10} and $PM_{2.5}$. Modeling of CO_2e will not be carried out because there are no modeling thresholds for these pollutants.

3.2 Emission Source Parameters

To confirm that the Project will not exceed the National Ambient Air Quality Standards (NAAQS) and PSD Class II Increment, modeling runs will be conducted at full and partial loads (100 percent load, 100 percent load with TurboPhase, 80 percent load, 60 percent) and will also include a start-up scenario for the combustion turbines on natural gas. Fuel oil operation will also be modeled at the same loads including start-up as well. At 100 percent load, the combustion turbines will be modeled with and without TurboPhase. The emission rates modeled will represent the projected worst-case ambient conditions under various operating loads. Combustion turbine annual emissions will be based on worst-case emissions taking into account the fuel usage limit and will include start-up and shutdown emissions as well.

3.3 Good Engineering Practice Stack Height

Sources included in a PSD permit application are subject to Good Engineering Practice (GEP) stack height requirements outlined in 40 CFR Part 51, Sections 51.100 and 51.118. As defined by the regulations, GEP height is calculated as the greater of 65 meters (measured from the ground level elevation at the base of the stack) or the height resulting from the following formula:

$$GEP = H + 1.5L$$

Where,

H = the building height; and

L = the lesser of the building height or the greatest crosswind distance of the building – also known as maximum projected width.

To meet stack height requirements, the proposed point sources will be evaluated in terms of their proximity to nearby structures. The purpose of this evaluation is to determine if the discharge from each stack will become caught in the turbulent wake of a building or other structure, resulting in downwash of the plume. Downwash of the plume can result in elevated ground-level concentrations. In *Guideline for Determination of Good Engineering Practice Stack Height* (EPA 1985), EPA provides guidance for determining whether building downwash will occur. The downwash analysis will be performed consistent with the methods prescribed in this guidance document. The point sources will be evaluated in terms of their proximity to nearby structures.

Calculations for determining the direction-specific downwash parameters will be performed using the most current version of the EPA's Building Profile Input Program – Plume Rise Model Enhancements, otherwise referred to as the BPIP-PRIME downwash algorithm (Version 04274). The BPIP-PRIME files will be submitted to WVDEP as part of the modeling analysis. Modeled stack heights will not exceed the greater of 65 meters or the calculated GEP stack height.

3.4 Emission Factors

Emissions factor (EMISFACT) modeling options in AERMOD allow a user to model emissions only when certain criteria are met. EMISFACT will be used to model the appropriate hourly restrictions on any equipment activities that only occur over a certain number of hours per day or seasons per year. A more detailed breakdown of operation times will be presented with the final modeling analysis, if this option is utilized. The owner understands that hourly restrictions in the modeling will likely result in corresponding permit limitations. The owner will work with the WVDEP and discuss the use of EMISFACT in the modeling prior to submitting the air permit application and modeling analysis.

3.5 Receptor Grid

The overall purpose of the modeling analysis is to demonstrate that operation of the Project will not result in, or contribute to, concentrations above the NAAQS or PSD Class II Increments. The modeling runs will be conducted using the AERMOD model in simple and complex terrain mode within a 20- by 20-kilometer Cartesian grid to determine the significant impact area (SIA) for each pollutant. The grid will incorporate the following spacing between receptors based on guidance from WVDEP: 50-meter out to 1 kilometer, 100-meter from 1 to 3 kilometers, 250-meter from 3 to 10 kilometers, and 500-meter from 10 to 20 kilometers. Receptors will also be placed along the fence line boundary at a spacing of 50 meters. If the SIA exceeds 20 kilometers, the grid will be extended to encompass the entire SIA and 500-meter spacing will be used. If the modeling impacts show “hot spots” outside 1,000 meters, 100-meter grid spacing will be used to encompass the maximum concentrations to check that the maximum impact has been identified.

After reviewing the topography of the Project area, it was determined that terrain elevations should be incorporated into the model. Therefore, the appropriate U.S. Geological Survey (USGS) National Elevation Dataset (NED) will be used to obtain the necessary receptor elevations. North American Datum of 1983 (NAD 83) will be used to develop the Universal Transverse Mercator (UTM) coordinates for this Project.

AERMOD has a terrain preprocessor (AERMAP) which uses gridded terrain data for the modeling domain to calculate not only a XYZ coordinate, but also a representative terrain-influence height associated with each receptor location selected. This terrain-influenced height is called the height scale and is separate for each individual receptor. AERMAP (Version 11103) will utilize the electronic NED data to populate the model with receptor elevations.

3.6 Meteorological Data

AERMOD requires a preprocessor called AERMET (Version 14134) to process meteorological data for 5 years from offsite locations to estimate the boundary layer parameters for the dispersion calculations. AERMET requires the input of surface roughness length, albedo, and Bowen ratio to define land surface characteristics for its calculations; therefore, an AERSURFACE analysis will be performed as discussed in Section 3.6.1. These land surface characteristics will be determined and used to process the raw meteorological data obtained from National Climatic Data Center (NCDC) website[1].

Surface air meteorological data from Parkersburg Wood County Airport, West Virginia (Station ID 03804) and upper air data from Wilmington Airborne Park, Ohio (Station ID 13841) will be used in the analysis. A profile base elevation value of 253.3 meters will be used. The most recent 5-year data set available covers the period of 2010 to 2014. One-minute meteorological data is included in the meteorological files.

Parkersburg Wood County Airport is located fewer than 20 kilometers from the Project site, and the difference in elevation between the station and the Project site is approximately 15 meters. Additionally, Parkersburg Wood County Airport is a regional airport in a fairly rural setting which is similar to the characteristics of the Project site.

Analysis of the site and airport albedo, Bowen ratio, and surface roughness was also prepared for comparison. This is discussed in further detail in Section 3.6.1.

3.6.1 AERSURFACE

The land surface characteristics were generated using the most current version of AERSURFACE (Version 13016). AERSURFACE incorporates the most current recommended procedures for determining land surface characteristics.[2] Because characterizing land use can often be a subjective process, the AERSURFACE program was developed by the EPA to standardize the methodology of determining the surface roughness length, albedo, and Bowen ratio.

The default study radius of 1 kilometer was used as recommended by the AERSURFACE user-guide. The circle of study was divided into 12 equal sectors to provide the best land surface characteristics for surface roughness calculations around the Parkersburg Wood County Airport surface station. USGS National Land Cover Data (1992) for West Virginia was used as land cover input for AERSURFACE. Land surface characteristics were calculated monthly to produce the highest temporal resolution possible.

Surface roughness and albedo were calculated using default settings and standard seasonal definitions. A historical precipitation analysis was performed in order to determine the moisture conditions for AERSURFACE. Thirty years of monthly precipitation data was obtained from the Northeast Regional

[1] ftp1.ncdc.noaa.gov (accessed April 2015)
[2] AERMOD Implementation Guide, March 2009

Climate Center website[3] for the Marietta Wastewater Treatment Plant (WWTP) in Marietta, OH. The Marietta WWTP (Station ID 334927) is part of the Cooperative Observer Network (COOP) and is the closest station to the Pleasants Energy facility that collects historical precipitation data. The precipitation data was analyzed to determine whether the moisture condition for the 5-year period (2010-2014) is wet, dry or average based on historical conditions. Data from this 5-year period was averaged for each month and compared to the monthly 30th and 70th percentile values of the 30-year historical data set. If the average monthly value was less than the 30th percentile value it was designated “dry”, if the average monthly value was greater than the 70th percentile value it was designated “wet”, and if the average monthly value was between the 30th and 70th percentile value, it was designated “average”. The moisture condition with the highest number of months was determined to be the representative moisture condition for the 5-year data set. Based on this analysis, the moisture conditions for the 5-year period was determined to be average. The precipitation analysis is included in Table A-1, Appendix A.

AERSURFACE was run for both the Project site and Parkersburg Wood County Airport location and the surface roughness, Bowen ratio, and albedo for each are compared on a sector-by-sector basis and a seasonal basis in Table A-2, Appendix A. Based on guidance from WVDEP, a sensitivity analysis was performed. AERSURFACE inputs for both the Project site and the Parkersburg Wood County Airport were used to generate meteorological data for both sets of AERSURFACE inputs. The significance model was run with both sets of meteorological data (all loads and fuel scenarios for the Project). The results of this analysis show that the AERSURFACE inputs for the Project site produce the worst-case results for all pollutants and averaging periods modeled for the Project (as described in Section 3.1). Therefore, the Project site AERSURFACE analysis was used to generate the meteorological data for the air dispersion modeling analysis. .

3.7 Land Use Parameters

Based on the Auer scheme, the existing land use for a 3-kilometer area surrounding the Project site is more than 50 percent rural. Also, the population density is fewer than 750 people per square kilometer for the same area. Because this area is considered rural, the rural dispersion coefficients option in the AERMOD model will be selected. The land use surrounding the Project is shown in Figure A-2, Appendix A.

[3] http://www.nrcc.cornell.edu/ (accessed September 2015)

3.8 Modeling Thresholds

The NAAQS, modeling/monitoring significance levels, and PSD Class II Increment thresholds for the modeled pollutants are shown in Table 3-1.

Table 3-1: NAAQS, Significance, and Monitoring Levels and PSD Class II Increment

Pollutant[a]	Averaging Period	NAAQS[a]	Modeling Significance Level[b]	Monitoring Significance Level[c]	PSD Class II Increment
			Micrograms per Cubic Meter		
NO_2	Annual	100	1	14	25
	1-hour	188.7	7.5[d]	NA	NA
CO	8-hour	10,000[e]	500	575	NA
	1-hour	40,000[e]	2,000	NA	NA
PM_{10}	Annual	NA	1	NA	17
	24-hour	150[d]	5	10	30[d]
$PM_{2.5}$	Annual	12	0.3[b]	NA	4
	24-hour	35	1.2[b]	4[c]	9[d]

(a) NO_2 = nitrogen dioxide; CO = carbon monoxide; PM_{10} = particulate matter less than 10 microns in diameter; $PM_{2.5}$ = particulate matter less than 2.5 microns in diameter; NAAQS = National Ambient Air Quality Standard
(b)United States Court of Appeals for the District of Columbia Circuit on January 22, 2013, vacated and remanded portions of the EPA rule establishing significant impact levels and vacated the rule establishing the significant monitoring concentration for PM2.5 however, the PM2.5 significant impact levels may still be used for Class II modeling analyses.
(c) The $PM_{2.5}$ 24-hour Significant Monitoring Concentration vacated by the United States Court of Appeals for the District of Columbia Circuit on January 22, 2013, is not considered valid in West Virginia. However, representative local monitoring data is available for use.
(d) The 1-hour NO_2 significance value is an interim value that the DEP has adopted and the DEP is in agreement with the EPA that this is the de minimis value.
(e) The pollutants that are allowed one NAAQS exceedance per year and one PSD Class II Increment exceedance per year.

Section 3.10.5 in this protocol displays the background values to be used with the NAAQS modeling. Because the background values plus the PSD significance levels are less than the NAAQS, the PSD significance levels are appropriate to use when determining compliance with the NAAQS and the NAAQS will be protected.

Although the United States Court of Appeals for the District of Columbia Circuit vacated and remanded portions of the rule establishing significant impact levels (SILs) for $PM_{2.5}$, they are appropriate to use for this analysis as per the EPA Guidance for $PM_{2.5}$ Modeling memo.[4] The margin between $PM_{2.5}$ NAAQS

[4] May 20, 2014 EPA Memo from Stephen D. Page. Guidance for PM2.5 Modeling

and the representative background $PM_{2.5}$ concentrations shown in Table 3-3 are greater the SILs for both the 24-hour and annual averaging periods. Therefore, using the previously established SILs for annual and 24-hr $PM_{2.5}$ shown in Table 3-1 will be protective of the NAAQS.

The modeled values will be modeled using the appropriate form of the standard for each pollutant and averaging period. For significance modeling, all short-term and annual averaging periods will be compared to the highest first high except for the 24-hour and annual $PM_{2.5}$, which is the highest average first high over five years[3]. For PSD Class II Increment, the PM_{10} 24-hour and $PM_{2.5}$ 24-hour will be compared to the highest second high, and the annual standards will be compared to the highest first high. The NAAQS thresholds will be modeled using the highs shown in Table 3-2 for each averaging period.

Table 3-2: NAAQS Modeled Highs

Pollutant[a]	Averaging Period	Modeled High
NO_2	Annual	Annual mean
	1-hour	Highest eighth high
CO	8-hour	Highest second high
	1-hour	Highest second high
PM_{10}	24-hour	Highest sixth high
$PM_{2.5}$	Annual	Annual mean
	24-hour	Highest eighth high

(a) NO_2 = nitrogen dioxide; CO = carbon monoxide; PM_{10} = particulate matter less than 10 microns in diameter; $PM_{2.5}$ = particulate matter less than 2.5 microns in diameter

3.9 Ambient Monitoring

The modeling analysis for emission sources for the Project will also address the pre-construction monitoring provision of the PSD regulations. The regulations specify monitoring *de minimis* levels for each PSD pollutant that, if exceeded, trigger the requirement to perform 1 year of pre-construction ambient air monitoring. If any predicted concentrations reach or exceed the monitoring *de minimis* levels, the owner will consult with the WVDEP to determine if pre-construction ambient air monitoring will be required. If modeled values exceed their respective monitoring *de minimis* values, the owner will request a waiver to use local ambient monitoring data to fulfill the pre-construction monitoring provisions of the PSD regulations or develop an acceptable monitoring plan at that time. For any impacts predicted to be below the monitoring *de minimis* levels, the owner will request an exemption from pre-construction ambient air monitoring, given that representative monitors in the area may be used for appropriate background concentrations.

3.10 Background Air Quality

As stated previously, if any pollutant exceeds its respective PSD significance level, a refined analysis (cumulative analysis) will be performed for that pollutant and averaging period. This analysis will be used to determine compliance with the PSD Class II Increments and the NAAQS. The NAAQS are set up to protect the air quality for all sensitive populations, and attainment is determined by the comparison to the NAAQS thresholds. As such, there are existing concentrations of each criteria pollutant that are present in ambient air that must be included in an analysis to account for items such as mobile source emissions that are not accounted for in the model. Monitored ambient emission levels will be added to the modeled ground level impacts to account for these sources. Significance modeling was performed and the only pollutants and averaging periods listed in Table 3-1 that exceed the modeling significance level are 1-hour NO_2 and 24-hour $PM_{2.5}$. Therefore, only the background values for 1-hour NO_2 and 24-hour $PM_{2.5}$ were determined for this analysis.

The EPA and the WVDEP collect ambient air quality pollutant concentrations from monitors that are placed throughout the State (as do other state agencies, in their respective states). The data that is collected by the monitors is available on the EPA website (http://www.epa.gov/airdata/). Background values for 1-hour NO2 and 24-hour $PM_{2.5}$ were identified from the monitors in the area. The monitored background levels will be added to the modeled impacts, as previously discussed.

In accordance with EPA documentation[5], there are three criteria that should be considered when selecting a representative existing ambient air monitor to represent ambient air concentrations for a Project. These three criteria are:

- Monitor location
- Data quality
- Currentness of data

Further discussion on these three criteria is presented below.

3.10.1 Monitor Location and Currentness of Data

The selected monitors for the Project are located in West Virginia and Pennsylvania, as noted in Figure A-3, Appendix A. For each pollutant, the closest and most current monitor was selected. Land use was considered in the selection of representative monitors for the proposed Project. Monitored concentrations

[5] U.S EPA. Ambient Air Monitoring Guidelines for Prevention of Significant Deterioration (PSD). EPA-450/4-87-007. May 1987.

should represent the land use within the immediate vicinity of the site, as much as is practicable. The land use surrounding the Project and each of the selected monitors are shown in Figures A-2, A-4, and A-5 in Appendix A. As demonstrated in the figures, the monitors appear to be located in more urban areas, which commonly have higher (more conservative) air emissions concentrations. Therefore, the chosen sites would likely have conservative values compared to the emissions at the Project site.

3.10.2 Data Quality

Data quality was a factor in the selection of the proposed monitor. The selected monitors were reviewed for completeness, and it was determined that all data years for each pollutant are more than 80 percent complete. Therefore, the monitors meet the requirement for 80 percent completeness per EPA documentation.[6]

3.10.3 Charleroi, Pennsylvania (Monitor 42-125-0005)

The most representative monitor for the 1-hour NO_2 background concentration is the Charleroi, Pennsylvania monitor (AIRS No. 42-125-0005) located in Washington County, Pennsylvania, shown in Figure A-4. This is the closest operating NO_2 monitor that is also representative of the Project site. This monitor is located approximately 95 miles northeast from the Project. Figure A-4 displays the land-use near the monitor. The land use is more urban than the area surrounding the Project site so monitored values are expected to be conservative when used for the Project. The regional background concentration that will be used for the 1-hour NO_2 emissions from this monitor is listed in Table 3-3.

3.10.4 Vienna, West Virginia (Monitor 54-107-1002)

The most representative monitor for the $PM_{2.5}$ background concentration is the Vienna, West Virginia monitor (AIRS No.54-107-1002) located in Wood County, West Virginia, shown in Figure A-5. This is the closest operating $PM_{2.5}$ monitor and is most representative of the Project site. This monitor is located approximately 10 miles west from the Project. This monitor is located in a similar land-use area (Figure A-5) as the land use near the proposed Project (Figure A-2). The regional background concentration that will be used for $PM_{2.5}$ emissions from this monitor is listed in Table 3-4.

3.10.5 Background Concentration Values

The background value determined for the 1-hour NO_2 averaging period and other supporting information is listed in Table 3-3. This background concentration will be added to the 1-hour NO_2 modeled impacts

[6] U.S. EPA. Ambient Air Monitoring Guidelines for Prevention of Significant Deterioration (PSD). EPA-450/4-87-007. May 1987.

for NAAQS modeling compliance determinations. This value represents the most recent data available from the Charleroi monitor (2012-2014).

Table 3-3: 1-Hour NO_2 Background Concentration

Pollutant and Averaging Period	1-hour NO_2
Monitor Name	Charleroi, PA
Monitor ID	Monitor 42-125-0005
Form of the standard	98th percentile averaged over years 2012 to 2014
2012	36 parts per billion
2013	34 parts per billion
2014	39 parts per billion
Average[a]	36.3 parts per billion
	68.3 $\mu g/m^3$

Source: http://www.epa.gov/airdata/
(a) $\mu g/m^3$ = micrograms per cubic meter

The background value determined for the 24-hour $PM_{2.5}$ averaging period and other supporting information is listed in Table 3-4. This background concentration will be added to the 24-hour $PM_{2.5}$ modeled impacts for NAAQS modeling compliance determinations. This value represents the most recent data available from the Vienna monitor (2012-2014).

Table 3-4: 24-Hour $PM_{2.5}$ Background Concentration

Pollutant and Averaging Period	24-hour $PM_{2.5}$
Monitor Name	Vienna, WV
Monitor ID	Monitor 54-107-1002
Form of the standard	98th percentile averaged over years 2012 to 2014
2012[a]	19.7 $\mu g/m^3$
2013[a]	20.5 $\mu g/m^3$
2014[a]	18.1 $\mu g/m^3$
Average[a]	19.4 $\mu g/m^3$

Source: http://www.epa.gov/airdata/
(a) $\mu g/m^3$ = micrograms per cubic meter

Data obtained from the EPA Air Data website used to determine these background values is found in Appendix H (modeling CD) to the Prevention of Significant Deterioration Air Permit Application for Pleasants Energy.

3.11 NAAQS and PSD Class II Increment Analysis

Per discussions with WVDEP, all major stationary sources that emit pollutants subject to this analysis within 20 kilometers of the Project site will be addressed for the cumulative modeling analysis for pollutants that exceed their respective significant impact level. WVDEP also recommended including sources located 20 to 25 kilometers from the site on a case-by-case basis. The inventories of sources will be developed in accordance with applicable EPA guidance, input from the WVDEP, and the Ohio Environmental Protection Agency (OEPA). A list of inventory sources considered for the cumulative modeling is located in Table A-3 in Appendix A, as provided by the WVDEP and OEPA. Table A-3 lists the sources from the WVDEP- and OEPA –provided lists that were excluded from the inventory list, including the methodology for removing them. All inventory sources modeled for NO_2 and $PM_{2.5}$ are shown in Tables A-4 and A-5, respectively. Maps that display the locations of the inventory sources that will be included in the refined modeling are shown in Figures A-7 and A-8 in Appendix A, for NO_2 and $PM_{2.5}$, respectively. Once the emissions and stack parameters have been determined for the inventory sources from permits, emission inventories and other information, the final modeling inventory will be determined in conjunction with the WVDEP prior to final models being submitted.

Background air quality concentrations were selected (as described in the previous section) to add to model-predicted concentrations for comparison to the NAAQS and are shown in Table 3-3 and Table 3-4. If the refined analysis does not result in any concentrations above the NAAQS or PSD Class II Increments, no further modeling will be conducted.

3.12 NO_2 Modeling – Multi-Tiered Screening Approach

The annual emissions presented in Table 2-3 represent operations at worst-case ambient conditions under various operating capacities. The AERMOD model gives the emission results for all pollutants, including NO_x. However, impacts of nitrogen dioxide (NO_2) must be examined for comparison to the NAAQS, PSD Class II Increments, and significance values. Therefore, a three-step process is proposed to analyze the 1-hour and annual NO_x modeled impacts. Step 1 uses the AERMOD regulatory default options and assumes all NO_x emissions are NO_2 (Tier I methodology). If Step 1 produces unacceptable results, then Step 2 will be used. Step 2 uses the AERMOD regulatory default options and assumes 75 percent of the NO_x emissions are in the form of NO_2 for the annual average and 80 percent of the NO_x emissions are in the form of NO_2 for the 1-hour standard (Tier II methodology). If Step 2 produces unacceptable results, then Step 3 will be used. Step 3 proposes to use Tier III methodology as presented in EPA's March 2011 memo[7], the Ozone Limiting Method (OLM) or the Plume Volume Molar Ratio Method (PVMRM). If Tier III is used, a separate modeling protocol specific to the Tier III methodology will be submitted to the WVDEP.

Based on preliminary modeling, it has been determined that the Tier III methodology - OLM will be used for the NO_2 1-hour air dispersion modeling. The OLM modeling protocol is shown in Appendix B.

In addition, in accordance with EPA's March 2011 memo, the applicant proposes to only model continuous operation for the 1-hour standard. The combustion turbine back-up fuel oil operation will not be included in the 1-hour modeling analysis as fuel oil will only be used in emergency situations when natural gas is curtailed and for testing purposes. This includes start-up emissions from fuel oil which will be at most, 20 starts per turbine per year. These operations will not contribute significantly to the annual distribution of the daily maximum 1-hour concentrations. All other load and fuel operating scenarios will be modeled for the meteorological record. Table 3-5 shows the sources that are considered intermittent and will not be modeled for the 1-hour standard.

Table 3-5: Operating Scenarios Not Included in 1-hour Modeling Analysis

Operating Scenario	Reason Not Modeled for the 1-hour Standard
Fuel oil combustion in the combustion turbines	Fuel oil will be combusted only when natural gas is curtailed or for testing. It is not predictable as to when this will occur and it is expected that it will happen infrequently..
Fuel oil start-up for combustion turbines	Fuel oil is a backup fuel and is only used when natural gas is curtailed. At most 20 starts per year expected for up to 2 hours for each start-up.

The modeled concentrations of annual NO_x will be adjusted using the EPA-approved Ambient Ratio Method (ARM) (Tier II methodology). Tier II of the ARM allows the use of an empirically derived NO_2/NO_x ratio of 0.75, which means that approximately 75 percent of the NO_x emissions will be converted to NO_2, the regulated pollutant. This factor will be applied to the annual modeled results for NO_x to determine the predicted ground-level concentration of NO_2.

[7] March 1, 2011 EPA Memo from Tyler Fox. Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard

4.0 CLASS I AREA IMPACTS

Recent Federal Land Manager (FLM) guidance requires that a proposed major source, in the course of a PSD application, perform an assessment of air quality impacts at Class I areas if these areas are located within approximately 300 kilometers of the Project. There are four Class I Areas that are within 300 kilometers of the Project:

- Otter Creek Wilderness (130 kilometers)
- Dolly Sods Wilderness (160 kilometers)
- Shenandoah National Park (200 kilometers)
- James River Face Wilderness (253 kilometers)

The locations of the Project site and the Class I Areas are shown in Figure A-6, Appendix A.

4.1 Visibility and Deposition

Following the most recent Federal Land Managers' Air Quality Related Values Work Group (FLAG) Workshop procedures (June 2010), the use of the Screening Procedure (Q/D) to determine if the Project could opt (screen) out of an Air Quality Related Value (AQRV) assessment for visibility and deposition with CALPUFF was made. Following the screening procedures in FLAG, the emissions of NO_x, sulfur dioxide (SO_2), PM_{10}/$PM_{2.5}$, and sulfuric acid mist (H_2SO_4 mist) were summed. An adjustment was made to the combustion turbine emissions to reflect full time operation because the Project potential to emit will be limited on an annual basis with the limit on fuel usage. A conservative hours of operation was used to ratio the emissions to full-year operation (5100 hours per year). The screening analysis is summarized below for the four Class I areas located within 300 kilometers of the Project:

Table 4-1: Class I Screening Analysis

Class I Area	Q[a] (Tons per Year)	D (Kilometers)	Q/D
Otter Creek Wilderness	1,079	130	8.3
Dolly Sods Wilderness	1,079	160	6.7
Shenandoah National Park	1,079	200	5.4
James River Face Wilderness	1,079	253	4.3

(a) Q=sum(NO_x+$PM_{10/2.5}$+SOx+H_2SO_4)*(8,760/5,100)

In accordance with the FLAG Guidance, if Q/D is less than 10, then no AQRV analysis is required. Based on the ratio of Q/D, the Class I areas do not require further analysis of AQRV. Thus, no CALPUFF analysis is anticipated for impacts to AQRVs.

4.2 PSD Class I Increment

The screening assessment does not apply to Class I Increments, which will be assessed as required. Class I PSD Increment will be analyzed with AERMOD by placing receptors at a 50-kilometer distance from the Project in the direction of each of the Class I areas beyond 50 kilometers and within 300 kilometers of the Project. If the modeled impacts are less than the applicable Class I significant impact levels, then the Project is assumed to below the Class I Increment at the Class I areas.

5.0 ANALYSIS OF SECONDARY $PM_{2.5}$ FORMATION

In addition to direct emissions of $PM_{2.5}$, other pollutants, chiefly NO_x and SO_2, can lead to formation of $PM_{2.5}$ further downwind. The photochemical reactions that transform these pollutants into nitrates and sulfates, which become the major species of $PM_{2.5}$, take place over hours or days. The Project is estimated to be significant for NO_x precursors (greater than 40 tons per year) for the formation of secondary $PM_{2.5}$, so this analysis is focusing only on the NOx emission and secondary $PM_{2.5}$ from the NOx emissions from this project.

As is the case with almost all $PM_{2.5}$ modeling, the highest impacts are closest to the fenceline and the sources, while the high from the NOx emissions are usually much farther out from the source and fenceline. Further, the NOx emissions that form particulate, namely particulate nitrates would be formed farther out from the site as well. This secondary $PM_{2.5}$ analysis will focus on the likelihood of the formation of particulate nitrates and how regional emissions of NOx have historically been predicted to be insignificant on monitored and modeled values of $PM_{2.5}$ in the region.

A review of regional monitors that show speciation of $PM_{2.5}$ show that nitrate is a very small percentage of the overall $PM_{2.5}$ in the area. Three monitors were examined. On an annual average for years 2012-2014, the $PM_{2.5}$ speciation showed that sulfates made up approximately 20.5 to 29.5% of the $PM_{2.5}$ Organic carbon made up 19.7 to 29.1% of the $PM_{2.5}$ and 4.3 to 20.6% is nitrates. Nitrates made up a small portion of the overall $PM_{2.5}$ in these three closest speciated $PM_{2.5}$ monitors. This shows that nitrates does not play a significant role in the $PM_{2.5}$ formation in the area.

Further, a more refined analysis of $PM_{2.5}$ and nitrates was performed on a seasonal basis. Table 5-1 displays the contribution of nitrate seasonally on the $PM_{2.5}$ monitored values and Table 5-2 displays the overall annual distribution of $PM_{2.5}$ over the seasons. The tables show that $PM_{2.5}$ is higher in the warmer months and lower in the winter months, however more nitrate contributes to the overall $PM_{2.5}$ values in the colder months (due to the volatility of ammonium nitrates). Overall these tables show that nitrate has a small contribution to the overall $PM_{2.5}$ values in the region, especially when reviewed on a seasonal basis.

Table 5-1: Average Percent Nitrate Contributions to Total $PM_{2.5}$

2012					
Monitor	**Winter**	**Spring**	**Summer**	**Fall**	**Annual**
Guthrie	7.0%	2.5%	1.9%	7.4%	4.3%
South Charleston	9.8%	5.0%	3.3%	8.1%	6.5%
Moundsville	9.1%	3.7%	2.4%	8.8%	6.1%
2013					
Monitor	**Winter**	**Spring**	**Summer**	**Fall**	**Annual**
Guthrie	12.3%	2.1%	1.6%	6.4%	5.1%
South Charleston	10.7%	5.0%	2.4%	13.5%	7.0%
Moundsville	15.7%	4.0%	2.3%	12.2%	8.5%
2014					
Monitor	**Winter**	**Spring**	**Summer**	**Fall**	**Annual**
Guthrie	14.9%	3.4%	1.8%	10.2%	6.8%
Moundsville	28.3%	5.2%	2.3%	14.7%	10.3%

Table 5-2: Seasonal Total $PM_{2.5}$ Contribution

2012					
Monitor	**Winter**	**Spring**	**Summer**	**Fall**	**Annual**
Guthrie	24.2%	26.8%	31.4%	17.5%	100.0%
South Charleston	23.9%	26.1%	29.4%	20.6%	100.0%
Moundsville	25.2%	23.8%	26.1%	24.9%	100.0%
2013					
Monitor	**Winter**	**Spring**	**Summer**	**Fall**	**Annual**
Guthrie	19.8%	22.3%	35.5%	22.4%	100.0%
South Charleston	24.3%	25.0%	28.5%	22.1%	100.0%
Moundsville	24.2%	26.6%	26.8%	22.4%	100.0%
2014					
Monitor	**Winter**	**Spring**	**Summer**	**Fall**	**Annual**
Guthrie	23.6%	25.0%	33.2%	18.2%	100.0%
South Charleston	23.9%	25.7%	28.9%	21.5%	100.0%
Moundsville	28.6%	23.9%	30.0%	17.5%	100.0%

Another way to review the potential impact of NOx on $PM_{2.5}$ concentrations is to perform an analysis using regional modeling. Because of the well-established relationship between NO_x, regional transport, and the formation of $PM_{2.5}$, to assist states to meet the $PM_{2.5}$ NAAQS, EPA finalized the Cross State Air Pollution Rule (CSAPR). Although CSAPR was vacated in August 2012 and has since been reinstated, the rule included extensive modeling to support the emissions reductions necessary in each state to achieve the $PM_{2.5}$ NAAQS in the eastern United States that is relevant to this analysis.

EPA used a regional model, CAMx, and the Air Quality Assessment Tool (AQAT) to determine levels of reduction from electric generating units necessary to achieve the NAAQS at every site. The documentation includes extensive tables showing impacts at all $PM_{2.5}$ monitoring sites in the eastern United States and emission reduction levels necessary to achieve those results.

To examine the possible secondary $PM_{2.5}$ impacts of the Project, the modeling EPA used to establish the final 2014 budgets in CSAPR is used for this analysis. The CSAPR website is located at http://www.epa.gov/airtransport/. Using these models, one can take the difference in ground-level modeled $PM_{2.5}$ annual values to see the reduction in $PM_{2.5}$ as a result of the SO_2 and NO_x reductions. This modeling will be used to determine $PM_{2.5}$ secondary concentrations due to the NOx emissions from this Project.

Tables showing projected base case 2014 $PM_{2.5}$ concentrations at existing monitoring sites versus control strategy $PM_{2.5}$ concentrations are located in AQModeling.pdf,[8] Appendix B. The expected resulting reductions in ground level annual $PM_{2.5}$ values for monitors close to the site were analyzed. Information regarding SO_2 emission reductions necessary to achieve the future year modeled design values can be found in the "Final June Revisions Rule Significant Contribution Assessment TSD,"[9] Table 1, page 7. This table shows the base case annual SO_2 emissions for West Virginia by 2014 were projected to be 498,507 tons, and remedy control scenario annual SO_2 emissions by 2014 to be 84,344 tons. The difference between these is 414,163 tons. The NO_x values are found in the excel workbook "TransportRuleFinal_EmissionsSummaries" in docket EPA-HQ-OAR-2009-0491-4206 on www.regulations.gov.[10] See Table 5-3 for a table of these values. This table shows the base case annual NO_x emissions for West Virginia by 2014 were projected to be 166,094 tons, and remedy control scenario annual SO_2 emissions by 2014 to be 155,245 tons. The difference between these is 10,849 tons. All surrounding states make similar significant reductions.

[8] http://www.epa.gov/airtransport/pdfs/AQModeling.pdf, accessed on January 3, 2013.
[9] http://www.epa.gov/airtransport/pdfs/FinalJuneRevisionsRuleSignificantContributionssessmentTSD.pdf, dated June 2012 and accessed on January 3, 2013.
[10] http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2009-0491-4206, accessed on January 3, 2013.

Table 5-3: EPA's Cross-state Air Pollution Rule Emission Summary for West Virginia

State	Pollutant	2014 Base (tons)	2014 Remedy (tons)	EGU Reduction (tons)
Maryland	SO_2	498,507	84,344	414,163
Maryland	NO_x	166,094	155,245	10,849
			Total	425,012

One can take the difference in ground-level modeled $PM_{2.5}$ annual values to see the reduction in $PM_{2.5}$ as a result of the SO_2 and NO_x reductions. As an example, the maximum annual modeled concentrations for Wood County are 13.2 μg/m³ for the 2014 base case and 10.87 μg/m³ for the 2014 control scenario. This is a reduction of 2.33 μg/m³. In order for this modeled annual concentration reduction to occur, West Virginia EGUs modeled annual SO_2 and NOx emissions by 2014 were reduced by 425,012 tons of SO_2 and NO_x.

This particular monitoring site is not necessarily impacted by every EGU in West Virginia, but in the surrounding states, hundreds of thousands of tons of annual SO_2 emission reductions have also occurred by 2014, according to the modeling, many of which would impact this site. Therefore, to estimate the impact of the Project on modeled concentrations, the ratio of the maximum Project SO_2 and NO_x emissions / 425,012 tons of SO_2 and NO_x can be compared to the ratio of the Project $PM_{2.5}$ impact / 2.33 μg/m³ of $PM_{2.5}$. See Table 5-4.

The calculation to estimate secondary formation is as follows:

$$\frac{(503.6\ tons\ SO2\ \&NOx\ from\ Project)}{(425{,}012\ tons\ SO2\ \&NOx\ from\ State)} = \frac{(Project's\ impact\ \mu g/m3\ )}{(State\ reduction\ of\ 2.33\ \mu g/m3\ )}$$

Project $PM_{2.5}$ impact = (503.6 tons / 425,012 tons) x (2.33 μg/m³ of $PM_{2.5}$) = 0.00276 μg/m³ of $PM_{2.5}$

Table 5-4: EPA's Cross-State Air Pollution Rule Modeling Results & Estimated Project Impact

Monitor ID	County	2014 Base	2014 Remedy	2014 Base-Remedy (μg/m³)	Source Impact (μg/m³)	Source Impact (%)
541071002	Wood	13.2	10.87	2.33	0.00276	0.28%

Since this concentration is well below measurable values, there would be no change in projected modeled $PM_{2.5}$ concentrations at this site.

Other nearby monitors in West Virginia in other counties were evaluated as well. This comparison is done in Table 5-5 and shows that all concentrations are well below measurable values, and that there would be no change in projected modeled $PM_{2.5}$ concentrations at these sites.

Table 5-5: EPA's Cross-State Air Pollution Rule Annual $PM_{2.5}$ Modeling Results & Estimated Project Impact

Monitor ID	State	County	2014 Base	2014 Remedy	2014 Base-Remedy (µg/m^3)	Source Impact (µg/m^3)	Source Impact (%)
541071002	West Virginia	Wood	13.2	10.87	2.33	0.00276	0.28%
540330003	West Virginia	Harrison	12.9	9.49	3.41	0.00404	0.40%
540511002	West Virginia	Marshall	12.87	10.17	2.7	0.00320	0.32%

Given emission levels from the facility and local emission inventories, no further analysis of secondary formation are necessary for this Project.

6.0 ADDITIONAL IMPACT ANALYSIS

The additional impacts analysis requirement under PSD will include the ambient air quality impact analysis, soils and vegetation impacts, visibility impairment, and growth analysis on Class II areas. This analysis will follow EPA's guidance provided in the New Source Review Workshop Manual (October 1990 draft).

The growth analysis will quantify the number of employees, the availability of housing in the area, associated commercial and industrial growth, and construction related activities and mobile sources. The number of employees is not envisioned to be large enough to result in a quantifiable increase in emissions from residential, commercial, or industrial growth.

While there are no Class II visibility standards, a visual plume blight analysis will be performed in accordance with the guidelines set forth in EPA-454/R-92-023, Workbook for Plume Visual Impact Screening and Analysis (Revised). Pleasants Energy proposes to perform a visual plume blight analysis on two nearby areas of visual interest, North Bend State Park and Blennerhassett Island State Historical Park located approximately 25 kilometers east-southeast and 24 kilometers west-southwest, respectively of the Project site. In the EPA document, the model VISCREEN is recommended for plume visibility analysis. Several refinement levels of VISCREEN are described. The first level VISCREEN analysis uses worst-case meteorological conditions (F-class stability, 1 meter per second wind speed). This level of screening results in the most conservative (worst-case) visibility results. The impacts of the plume are compared to screening criteria to determine if they are perceptible. The screening criteria are a change in relative sensitivity (ΔE) value of 2.0 and a green absolute contrast value of 0.05. If the plume is determined to be imperceptible, the visibility modeling is complete; otherwise, a second-level VISCREEN analysis that uses actual meteorological data and refined particle characteristics will be performed. The second-level model will result in a more realistic visibility analysis. If this plume visibility still does not meet sky and terrain contrast levels, a third-level model may be required that adds more statistical analysis.

7.0 REFERENCES

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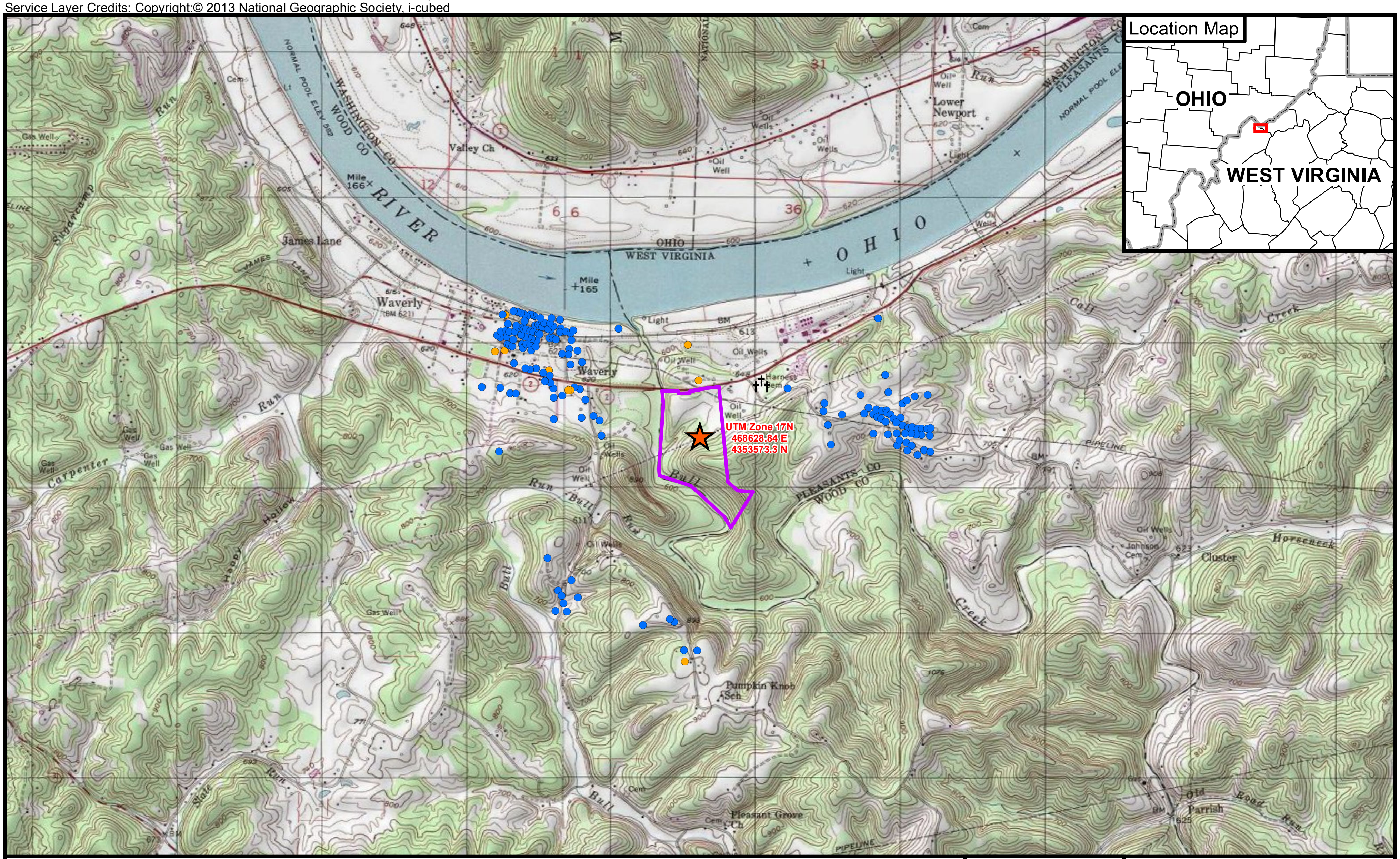
APPENDIX A – TABLES AND FIGURES

Path: R:\GDF_Suez\79835_Pleasants_Engn\GIS\DataFiles\ArcDocs\Modeling Protocol\Figure A-1 - Project Location.mxd kasamuelson 4/28/2015



Project Location

Property Boundary

Business

House

Cemetery

NORTH

3,000 1,500 0 3,000

Scale in Feet

BURNS McDONNELL

Figure A-1
Project Location
Pleasants Energy, LLC

Source: ESRI, Burns & McDonnell

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Table A-1: Precipitation (inches) Amount for 30 Years at Marietta Wastewater Treatment Plant, Marietta, OH*

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1985	2.13	1.54	2.48	1.14	4.86	1.78	6.97	3.13	0.84	3.55	7.65	2.09
1986	1.49	3.98	2.48	2.05	M	7.84	3.84	1.55	3.14	3.93	5.93	3.61
1987	1.59	1.4	2.23	3.52	2.3	6.57	1.55	3.27	2.21	1.49	1.98	3.61
1988	1.99	2.87	3.63	2.67	1.54	0.92	5.21	2.81	4.73	2.19	4.46	2.6
1989	3.57	5.65	6.28	5.61	4.58	5.5	2.37	10.68	6.63	4.15	1.84	2.29
1990	3.17	3.69	2.37	2.1	8.28	5.23	5.09	6.75	3.7	4.26	2.28	7.94
1991	3.37	M	4.96	4.37	1.64	4	4.07	6.52	5.01	1.1	3.35	5.74
1992	1.9	1.47	4.89	2.05	2.37	2.07	6.81	3.56	M	0.7	3.68	2.6
1993	M	2.31	5.37	2.47	1.73	4.15	2.76	3.79	3.32	3.64	3.39	2.08
1994	6.57	4.47	5.13	5.64	3.26	3.61	6.7	4.47	1.77	0.92	2.47	2.86
1995	4.61	M	M	M	M	5.18	M	3.97	M	M	M	M
1996	M	3.57	4.53	2.99	8.4	5.31	6.6	2.43	6.29	M	3.02	3.78
1997	2.27	1.58	8.93	1.8	3.57	6.57	6.61	5.12	2.26	1.35	2.2	2.56
1998	4.37	3.92	3.23	4.62	3.7	11.76	2.23	0.88	3.85	2.26	1.76	2.11
1999	6.25	3.23	3.36	2.84	2.28	1.69	2.54	3.14	1.26	3.44	3.18	3.52
2000	2.44	6.58	3.37	4.35	5.37	2.9	6.76	3.6	5.21	1.21	1.27	2.97
2001	2.09	0.95	3	3.85	6.09	4.39	4.38	3.76	1.92	2.01	3.47	2.51
2002	3.02	1.17	6.43	5.32	4.77	4.73	3.49	0.52	3.09	4.95	3.45	2.37
2003	2.06	3.99	M	3.25	6.4	8.93	8.81	4.99	7.08	3.24	5.81	2.95
2004	4.27	2.03	3.7	4.77	4.88	2.62	3.48	3.78	8.51	3.08	3.27	2.29
2005	5.79	1.88	4.16	5.28	2.94	1.4	4.01	3.72	1.29	3.88	2.69	2.18
2006	3.76	0.6	2.1	3.99	3.57	3.66	5.6	3.06	5.44	6.63	2.38	1.84
2007	3.69	2.51	3.14	3.38	0.92	2.19	4.73	3.44	0.91	2.67	3.29	5.11
2008	2.29	4.2	5.92	2.55	4.2	6.18	4.11	2.6	1.17	2.25	2.24	5.73
2009	4.39	M	1.67	4.22	M	6.93	3.67	2.12	2.07	3.74	1.2	3.88
2010	2.37	2.34	2.8	1.03	7.03	6.09	7.19	1.52	1.43	1.84	2.97	3.41
2011	2	4.09	6.09	7.04	3.43	5.98	3.63	5.06	7.03	6.2	4.98	2.97
2012	4.63	1.69	4.48	1.79	6.07	2.74	2.99	3.33	6.37	4.34	0.47	6.8
2013	2.49	1.58	2.74	1.52	2.05	6.16	9.39	6.69	1.75	2	3.88	5.09
2014	2.19	3.89	2.5	M	4.83	5.31	4.15	3.4	0.94	4.43	1.92	3.72
2010-2014 Avg.	2.74	2.72	3.72	2.85	4.68	5.26	5.47	4.00	3.50	3.76	2.84	4.40
30th percentile	2.20	1.67	2.82	2.48	2.83	3.40	3.65	3.11	1.79	2.03	2.26	2.53
70th percentile	3.75	3.90	4.85	4.34	4.86	6.01	6.20	3.84	4.98	3.87	3.43	3.68
Average / Dry / Wet ?	Average	Average	Average	Average	Average	Average	Average	Wet	Average	Average	Average	Wet

Data obtained from http://www.nrcc.cornell.edu/ Accessed 9/3/2015
*M stands for missing data

 # Wet Months **2**
 # Dry Months **0**
 # Average Months **10**

5-year conditions are Average

Table A-2: Surface Characteristics for Project Site vs. Parkersburg Wood County Airport

		Project Site			Parkersburg Wood County Airport		
Month	**Sector**	**Albedo**	**Bowen Ratio**	**Roughness**	**Albedo**	**Bowen Ratio**	**Roughness**
January	1 of 12	0.16	0.78	0.034	0.17	0.83	0.105
January	2 of 12	0.16	0.78	0.098	0.17	0.83	0.265
January	3 of 12	0.16	0.78	0.117	0.17	0.83	0.369
January	4 of 12	0.16	0.78	0.160	0.17	0.83	0.272
January	5 of 12	0.16	0.78	0.484	0.17	0.83	0.166
January	6 of 12	0.16	0.78	0.339	0.17	0.83	0.172
January	7 of 12	0.16	0.78	0.325	0.17	0.83	0.151
January	8 of 12	0.16	0.78	0.224	0.17	0.83	0.240
January	9 of 12	0.16	0.78	0.156	0.17	0.83	0.183
January	10 of 12	0.16	0.78	0.104	0.17	0.83	0.444
January	11 of 12	0.16	0.78	0.044	0.17	0.83	0.309
January	12 of 12	0.16	0.78	0.020	0.17	0.83	0.175
February	1 of 12	0.16	0.78	0.034	0.17	0.83	0.105
February	2 of 12	0.16	0.78	0.098	0.17	0.83	0.265
February	3 of 12	0.16	0.78	0.117	0.17	0.83	0.369
February	4 of 12	0.16	0.78	0.160	0.17	0.83	0.272
February	5 of 12	0.16	0.78	0.484	0.17	0.83	0.166
February	6 of 12	0.16	0.78	0.339	0.17	0.83	0.172
February	7 of 12	0.16	0.78	0.325	0.17	0.83	0.151
February	8 of 12	0.16	0.78	0.224	0.17	0.83	0.240
February	9 of 12	0.16	0.78	0.156	0.17	0.83	0.183
February	10 of 12	0.16	0.78	0.104	0.17	0.83	0.444
February	11 of 12	0.16	0.78	0.044	0.17	0.83	0.309
February	12 of 12	0.16	0.78	0.020	0.17	0.83	0.175
March	1 of 12	0.15	0.52	0.046	0.15	0.54	0.134
March	2 of 12	0.15	0.52	0.140	0.15	0.54	0.368
March	3 of 12	0.15	0.52	0.175	0.15	0.54	0.494
March	4 of 12	0.15	0.52	0.247	0.15	0.54	0.343
March	5 of 12	0.15	0.52	0.739	0.15	0.54	0.200
March	6 of 12	0.15	0.52	0.509	0.15	0.54	0.249
March	7 of 12	0.15	0.52	0.495	0.15	0.54	0.199
March	8 of 12	0.15	0.52	0.341	0.15	0.54	0.288
March	9 of 12	0.15	0.52	0.216	0.15	0.54	0.232
March	10 of 12	0.15	0.52	0.147	0.15	0.54	0.651
March	11 of 12	0.15	0.52	0.061	0.15	0.54	0.457
March	12 of 12	0.15	0.52	0.027	0.15	0.54	0.232
April	1 of 12	0.15	0.52	0.046	0.15	0.54	0.134
April	2 of 12	0.15	0.52	0.140	0.15	0.54	0.368
April	3 of 12	0.15	0.52	0.175	0.15	0.54	0.494
April	4 of 12	0.15	0.52	0.247	0.15	0.54	0.343
April	5 of 12	0.15	0.52	0.739	0.15	0.54	0.200
April	6 of 12	0.15	0.52	0.509	0.15	0.54	0.249
April	7 of 12	0.15	0.52	0.495	0.15	0.54	0.199
April	8 of 12	0.15	0.52	0.341	0.15	0.54	0.288
April	9 of 12	0.15	0.52	0.216	0.15	0.54	0.232
April	10 of 12	0.15	0.52	0.147	0.15	0.54	0.651
April	11 of 12	0.15	0.52	0.061	0.15	0.54	0.457
April	12 of 12	0.15	0.52	0.027	0.15	0.54	0.232
May	1 of 12	0.15	0.52	0.046	0.15	0.54	0.134
May	2 of 12	0.15	0.52	0.140	0.15	0.54	0.368
May	3 of 12	0.15	0.52	0.175	0.15	0.54	0.494
May	4 of 12	0.15	0.52	0.247	0.15	0.54	0.343
May	5 of 12	0.15	0.52	0.739	0.15	0.54	0.200
May	6 of 12	0.15	0.52	0.509	0.15	0.54	0.249
May	7 of 12	0.15	0.52	0.495	0.15	0.54	0.199
May	8 of 12	0.15	0.52	0.341	0.15	0.54	0.288
May	9 of 12	0.15	0.52	0.216	0.15	0.54	0.232
May	10 of 12	0.15	0.52	0.147	0.15	0.54	0.651
May	11 of 12	0.15	0.52	0.061	0.15	0.54	0.457
May	12 of 12	0.15	0.52	0.027	0.15	0.54	0.232

Table A-2: Surface Characteristics for Project Site vs. Parkersburg Wood County Airport

		Project Site			Parkersburg Wood County Airport		
Month	**Sector**	**Albedo**	**Bowen Ratio**	**Roughness**	**Albedo**	**Bowen Ratio**	**Roughness**
June	1 of 12	0.16	0.33	0.106	0.16	0.35	0.272
June	2 of 12	0.16	0.33	0.362	0.16	0.35	0.563
June	3 of 12	0.16	0.33	0.439	0.16	0.35	0.698
June	4 of 12	0.16	0.33	0.564	0.16	0.35	0.484
June	5 of 12	0.16	0.33	1.075	0.16	0.35	0.253
June	6 of 12	0.16	0.33	0.736	0.16	0.35	0.383
June	7 of 12	0.16	0.33	0.676	0.16	0.35	0.367
June	8 of 12	0.16	0.33	0.584	0.16	0.35	0.423
June	9 of 12	0.16	0.33	0.452	0.16	0.35	0.391
June	10 of 12	0.16	0.33	0.313	0.16	0.35	0.913
June	11 of 12	0.16	0.33	0.138	0.16	0.35	0.629
June	12 of 12	0.16	0.33	0.060	0.16	0.35	0.380
July	1 of 12	0.16	0.33	0.106	0.16	0.35	0.272
July	2 of 12	0.16	0.33	0.362	0.16	0.35	0.563
July	3 of 12	0.16	0.33	0.439	0.16	0.35	0.698
July	4 of 12	0.16	0.33	0.564	0.16	0.35	0.484
July	5 of 12	0.16	0.33	1.075	0.16	0.35	0.253
July	6 of 12	0.16	0.33	0.736	0.16	0.35	0.383
July	7 of 12	0.16	0.33	0.676	0.16	0.35	0.367
July	8 of 12	0.16	0.33	0.584	0.16	0.35	0.423
July	9 of 12	0.16	0.33	0.452	0.16	0.35	0.391
July	10 of 12	0.16	0.33	0.313	0.16	0.35	0.913
July	11 of 12	0.16	0.33	0.138	0.16	0.35	0.629
July	12 of 12	0.16	0.33	0.060	0.16	0.35	0.380
August	1 of 12	0.16	0.33	0.106	0.16	0.35	0.272
August	2 of 12	0.16	0.33	0.362	0.16	0.35	0.563
August	3 of 12	0.16	0.33	0.439	0.16	0.35	0.698
August	4 of 12	0.16	0.33	0.564	0.16	0.35	0.484
August	5 of 12	0.16	0.33	1.075	0.16	0.35	0.253
August	6 of 12	0.16	0.33	0.736	0.16	0.35	0.383
August	7 of 12	0.16	0.33	0.676	0.16	0.35	0.367
August	8 of 12	0.16	0.33	0.584	0.16	0.35	0.423
August	9 of 12	0.16	0.33	0.452	0.16	0.35	0.391
August	10 of 12	0.16	0.33	0.313	0.16	0.35	0.913
August	11 of 12	0.16	0.33	0.138	0.16	0.35	0.629
August	12 of 12	0.16	0.33	0.060	0.16	0.35	0.380
September	1 of 12	0.16	0.78	0.106	0.16	0.83	0.265
September	2 of 12	0.16	0.78	0.362	0.16	0.83	0.559
September	3 of 12	0.16	0.78	0.439	0.16	0.83	0.693
September	4 of 12	0.16	0.78	0.564	0.16	0.83	0.472
September	5 of 12	0.16	0.78	1.075	0.16	0.83	0.234
September	6 of 12	0.16	0.78	0.736	0.16	0.83	0.363
September	7 of 12	0.16	0.78	0.676	0.16	0.83	0.358
September	8 of 12	0.16	0.78	0.584	0.16	0.83	0.414
September	9 of 12	0.16	0.78	0.452	0.16	0.83	0.381
September	10 of 12	0.16	0.78	0.313	0.16	0.83	0.909
September	11 of 12	0.16	0.78	0.138	0.16	0.83	0.608
September	12 of 12	0.16	0.78	0.060	0.16	0.83	0.367
October	1 of 12	0.16	0.78	0.106	0.16	0.83	0.265
October	2 of 12	0.16	0.78	0.362	0.16	0.83	0.559
October	3 of 12	0.16	0.78	0.439	0.16	0.83	0.693
October	4 of 12	0.16	0.78	0.564	0.16	0.83	0.472
October	5 of 12	0.16	0.78	1.075	0.16	0.83	0.234
October	6 of 12	0.16	0.78	0.736	0.16	0.83	0.363
October	7 of 12	0.16	0.78	0.676	0.16	0.83	0.358
October	8 of 12	0.16	0.78	0.584	0.16	0.83	0.414
October	9 of 12	0.16	0.78	0.452	0.16	0.83	0.381
October	10 of 12	0.16	0.78	0.313	0.16	0.83	0.909
October	11 of 12	0.16	0.78	0.138	0.16	0.83	0.608
October	12 of 12	0.16	0.78	0.060	0.16	0.83	0.367

Table A-2: Surface Characteristics for Project Site vs. Parkersburg Wood County Airport

		Project Site			Parkersburg Wood County Airport		
Month	**Sector**	**Albedo**	**Bowen Ratio**	**Roughness**	**Albedo**	**Bowen Ratio**	**Roughness**
November	1 of 12	0.16	0.78	0.106	0.16	0.83	0.265
November	2 of 12	0.16	0.78	0.362	0.16	0.83	0.559
November	3 of 12	0.16	0.78	0.439	0.16	0.83	0.693
November	4 of 12	0.16	0.78	0.564	0.16	0.83	0.472
November	5 of 12	0.16	0.78	1.075	0.16	0.83	0.234
November	6 of 12	0.16	0.78	0.736	0.16	0.83	0.363
November	7 of 12	0.16	0.78	0.676	0.16	0.83	0.358
November	8 of 12	0.16	0.78	0.584	0.16	0.83	0.414
November	9 of 12	0.16	0.78	0.452	0.16	0.83	0.381
November	10 of 12	0.16	0.78	0.313	0.16	0.83	0.909
November	11 of 12	0.16	0.78	0.138	0.16	0.83	0.608
November	12 of 12	0.16	0.78	0.060	0.16	0.83	0.367
December	1 of 12	0.16	0.78	0.034	0.17	0.83	0.105
December	2 of 12	0.16	0.78	0.098	0.17	0.83	0.265
December	3 of 12	0.16	0.78	0.117	0.17	0.83	0.369
December	4 of 12	0.16	0.78	0.160	0.17	0.83	0.272
December	5 of 12	0.16	0.78	0.484	0.17	0.83	0.166
December	6 of 12	0.16	0.78	0.339	0.17	0.83	0.172
December	7 of 12	0.16	0.78	0.325	0.17	0.83	0.151
December	8 of 12	0.16	0.78	0.224	0.17	0.83	0.240
December	9 of 12	0.16	0.78	0.156	0.17	0.83	0.183
December	10 of 12	0.16	0.78	0.104	0.17	0.83	0.444
December	11 of 12	0.16	0.78	0.044	0.17	0.83	0.309
December	12 of 12	0.16	0.78	0.020	0.17	0.83	0.175
	Sector 1 Average	**0.158**	**0.603**	**0.073**	**0.160**	**0.638**	**0.194**
	Sector 2 Average	**0.158**	**0.603**	**0.241**	**0.161**	**0.638**	**0.439**
	Sector 3 Average	**0.158**	**0.603**	**0.293**	**0.161**	**0.638**	**0.564**
	Sector 4 Average	**0.158**	**0.603**	**0.384**	**0.161**	**0.638**	**0.393**
	Sector 5 Average	**0.158**	**0.603**	**0.843**	**0.161**	**0.638**	**0.213**
	Sector 6 Average	**0.158**	**0.603**	**0.580**	**0.161**	**0.638**	**0.292**
	Sector 7 Average	**0.158**	**0.603**	**0.543**	**0.161**	**0.638**	**0.269**
	Sector 8 Average	**0.158**	**0.603**	**0.433**	**0.161**	**0.638**	**0.341**
	Sector 9 Average	**0.158**	**0.603**	**0.319**	**0.161**	**0.638**	**0.297**
	Sector 10 Average	**0.158**	**0.603**	**0.219**	**0.161**	**0.638**	**0.729**
	Sector 11 Average	**0.158**	**0.603**	**0.095**	**0.161**	**0.638**	**0.501**
	Sector 12 Average	**0.158**	**0.603**	**0.042**	**0.161**	**0.638**	**0.289**
	Seasonal Category 1 Average	**0.160**	**0.330**	**0.459**	**0.160**	**0.350**	**0.480**
	Seasonal Category 2 Average	**0.160**	**0.780**	**0.459**	**0.160**	**0.830**	**0.469**
	Seasonal Category 4 Average	**0.160**	**0.780**	**0.175**	**0.170**	**0.830**	**0.238**
	Seasonal Category 5 Average	**0.150**	**0.520**	**0.262**	**0.150**	**0.540**	**0.321**

% difference between Project Site and Parkersburg Wood County Airport

Sector	Albedo	Bowen Ratio	Roughness
Sector 1	1.56%	5.49%	62.37%
Sector 2	2.12%	5.49%	45.19%
Sector 3	2.12%	5.49%	48.09%
Sector 4	2.12%	5.49%	2.29%
Sector 5	2.12%	5.49%	-74.71%
Sector 6	2.12%	5.49%	-49.70%
Sector 7	2.12%	5.49%	-50.51%
Sector 8	2.12%	5.49%	-21.23%
Sector 9	2.12%	5.49%	-6.97%
Sector 10	2.12%	5.49%	69.93%
Sector 11	2.12%	5.49%	80.98%
Sector 12	2.12%	5.49%	85.53%
Seasonal Category 1 Average	0.00%	5.71%	4.36%
Seasonal Category 2 Average	0.00%	6.02%	2.10%
Seasonal Category 4 Average	5.88%	6.02%	26.17%
Seasonal Category 5 Average	0.00%	3.70%	18.30%

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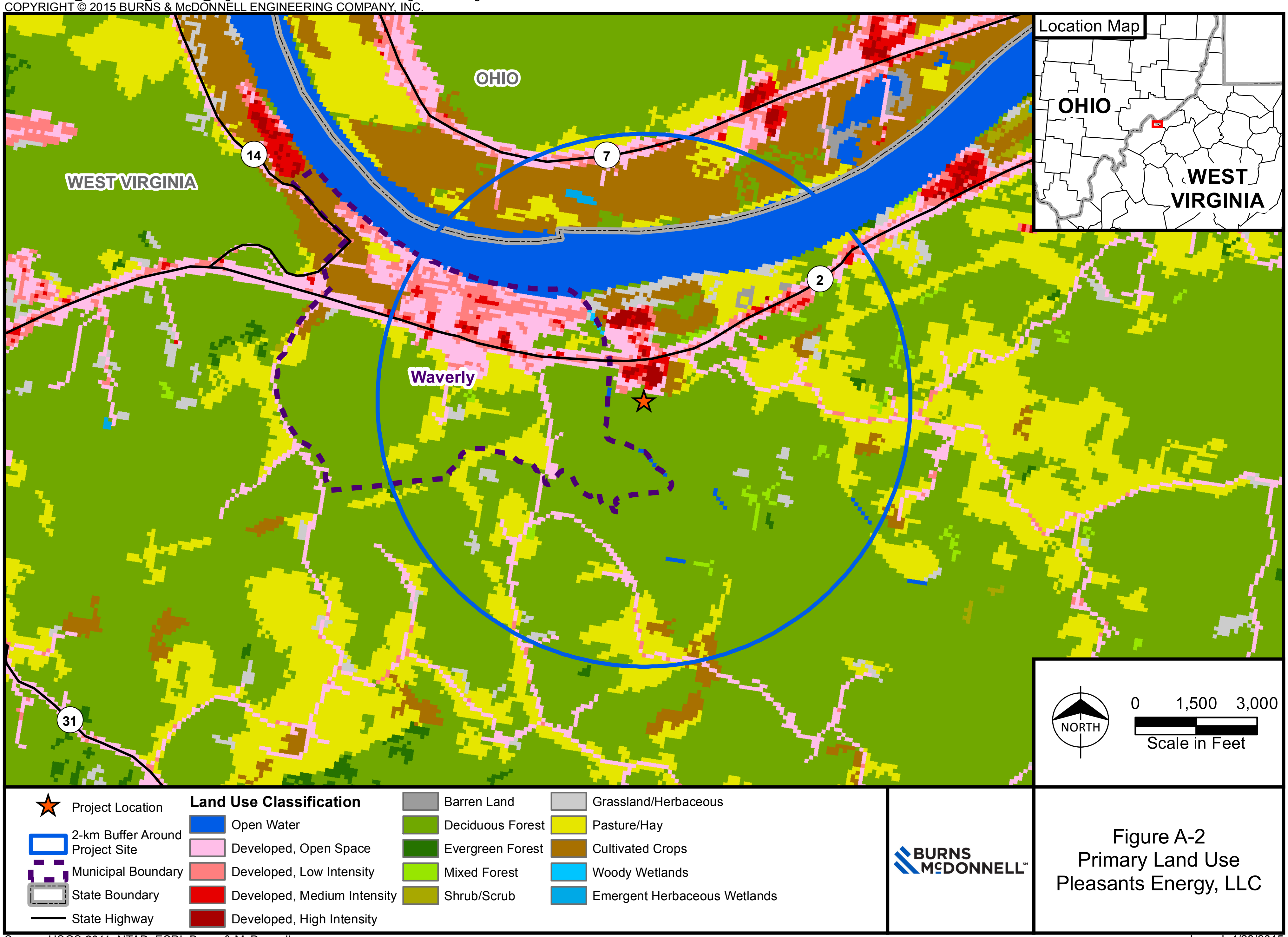

Figure A-2
Primary Land Use
Pleasants Energy, LLC

Source: USGS 2011, NTAD, ESRI, Burns & McDonnell

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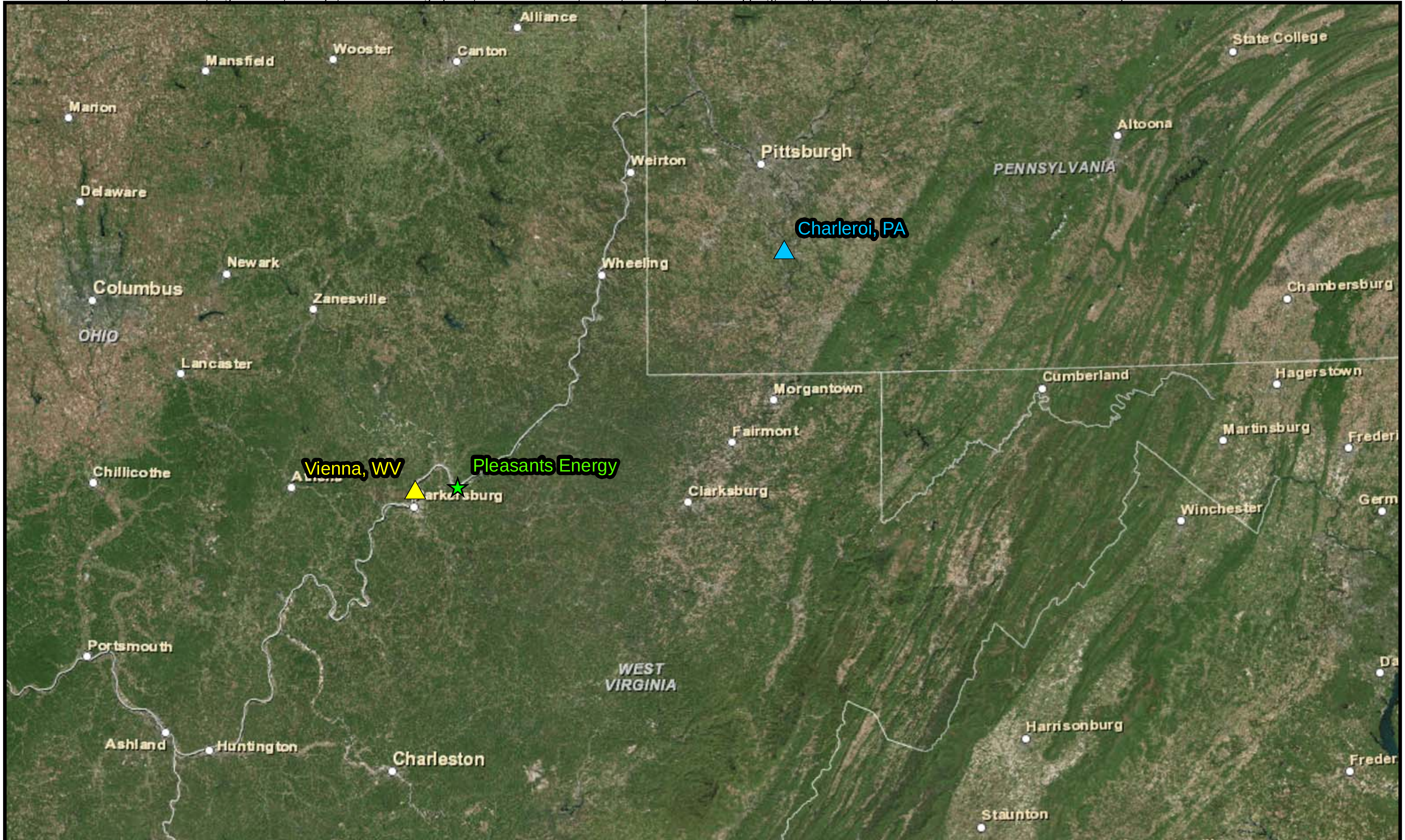

Pleasants Energy (Project Location)
Charleroi (Monitor 42-125-0005)
Vienna (Monitor 54-107-1002)

NORTH
40 20 0 40
Kilometers

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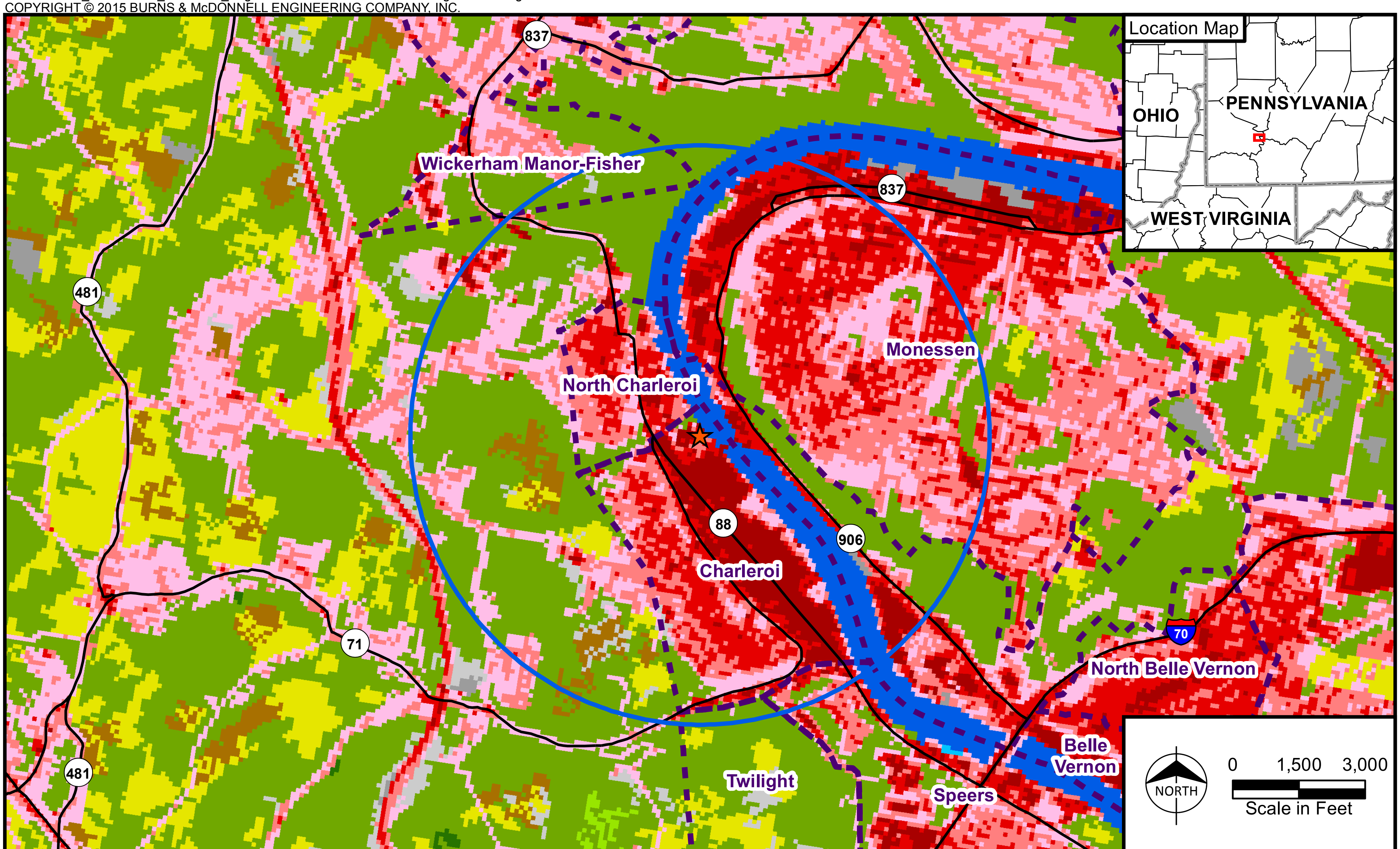
Figure A-3
Monitor Locations
Pleasants Energy, LLC

Path: R:\GDF_Suez\79835_Pleasants_Engn\GIS\DataFiles\ArcDocs\Modeling Protocol\Figure A-4 - Land Use Charleroi.mxd kasamuelson 4/28/2015



Charleroi Location
2-km Buffer Around Charleroi Site
Municipal Boundary
State Boundary
Highway

Land Use Classification

- Open Water
- Developed, Open Space
- Developed, Low Intensity
- Developed, Medium Intensity
- Developed, High Intensity
- Barren Land
- Deciduous Forest
- Evergreen Forest
- Mixed Forest
- Shrub/Scrub
- Grassland/Herbaceous
- Pasture/Hay
- Cultivated Crops
- Woody Wetlands
- Emergent Herbaceous Wetlands

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Figure A-4
Primary Land Use
Surrounding Charleroi
Monitor 42-125-0005

Source: USGS 2011, NTAD, ESRI, Burns & McDonnell

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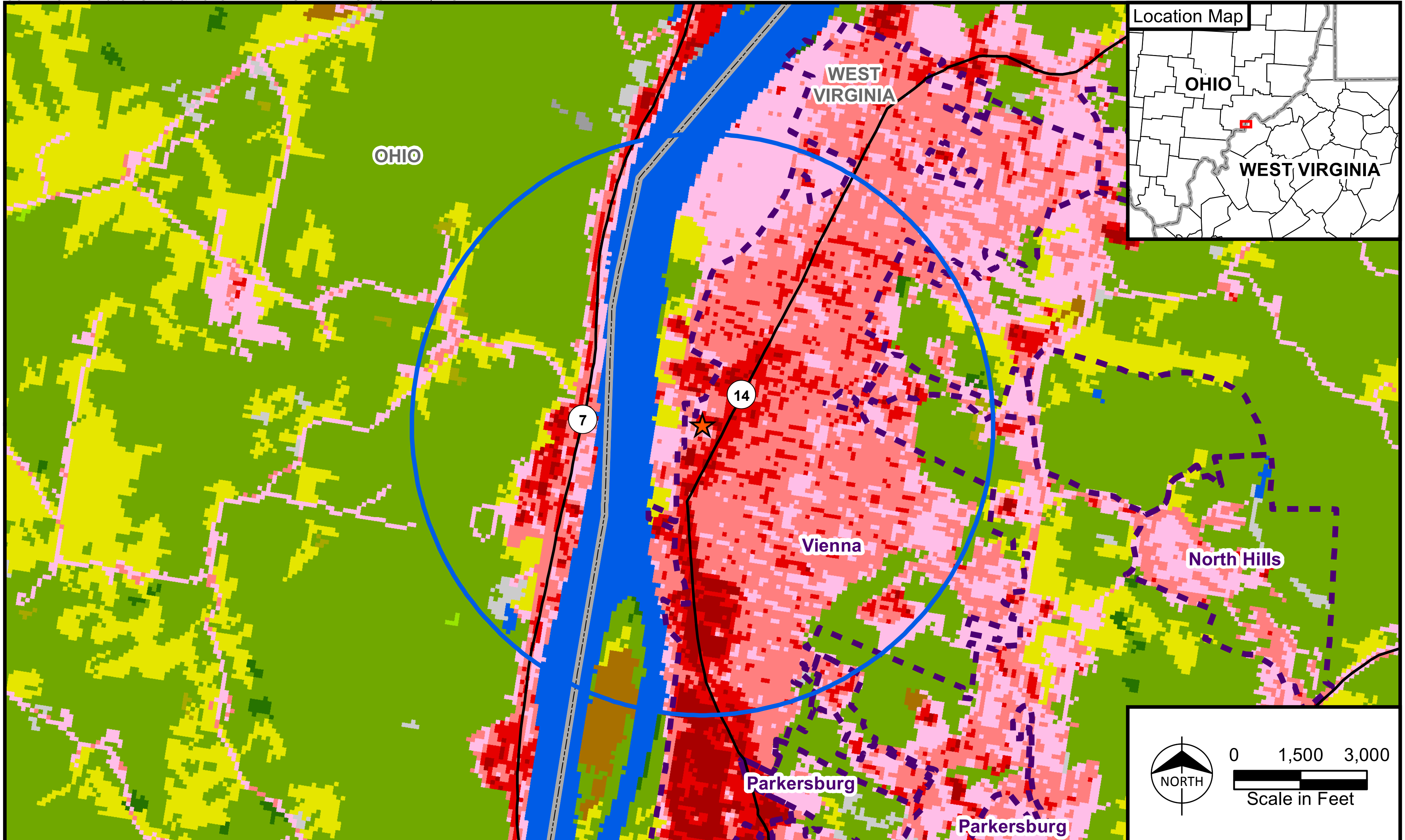
Path: R:\GDF_Suez\79835_Pleasants_Engn\GIS\DataFiles\ArcDocs\Modeling Protocol\Figure A-5 - Land Use Vienna.mxd kasamuelson 4/28/2015



Vienna Location
2-km Buffer Around Vienna Site
Municipal Boundary
State Boundary
Highway

Land Use Classification

- Open Water
- Developed, Open Space
- Developed, Low Intensity
- Developed, Medium Intensity
- Developed, High Intensity
- Barren Land
- Deciduous Forest
- Evergreen Forest
- Mixed Forest
- Shrub/Scrub
- Grassland/Herbaceous
- Pasture/Hay
- Cultivated Crops
- Woody Wetlands
- Emergent Herbaceous Wetlands

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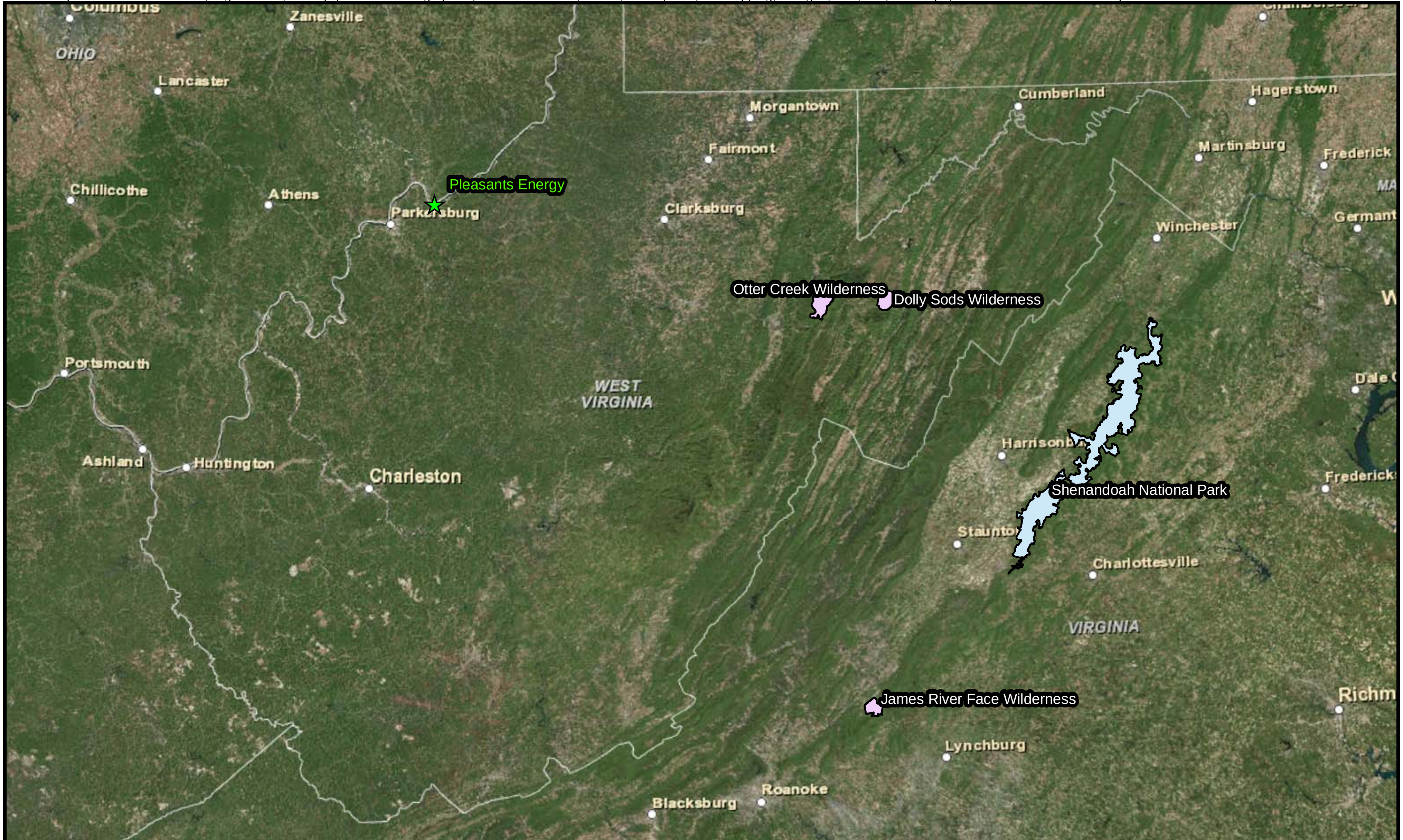
Figure A-5
Primary Land Use
Surrounding Vienna
Monitor 54-107-1002

Source: USGS 2011, NTAD, ESRI, Burns & McDonnell

Issued: 4/28/2015

Path: R:\GDF_Suez\79835_Pleasants_Engn\GIS\DataFiles\ArcDocs\Modeling Protocol\Figure A-6 - Project Location and Class I AreasX.mxd gweger 4/28/2015



Pleasants Energy (Project Location)
USFS Class I
NPS Class I

NORTH

40 20 0 40
Kilometers

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Figure A-6
Project Location & Class I Areas
Pleasants Energy, LLC

Source: ESRI, Burns & McDonnell, USFS Class I, NPS Class I

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Table A-3 All Inventory Sources Considered

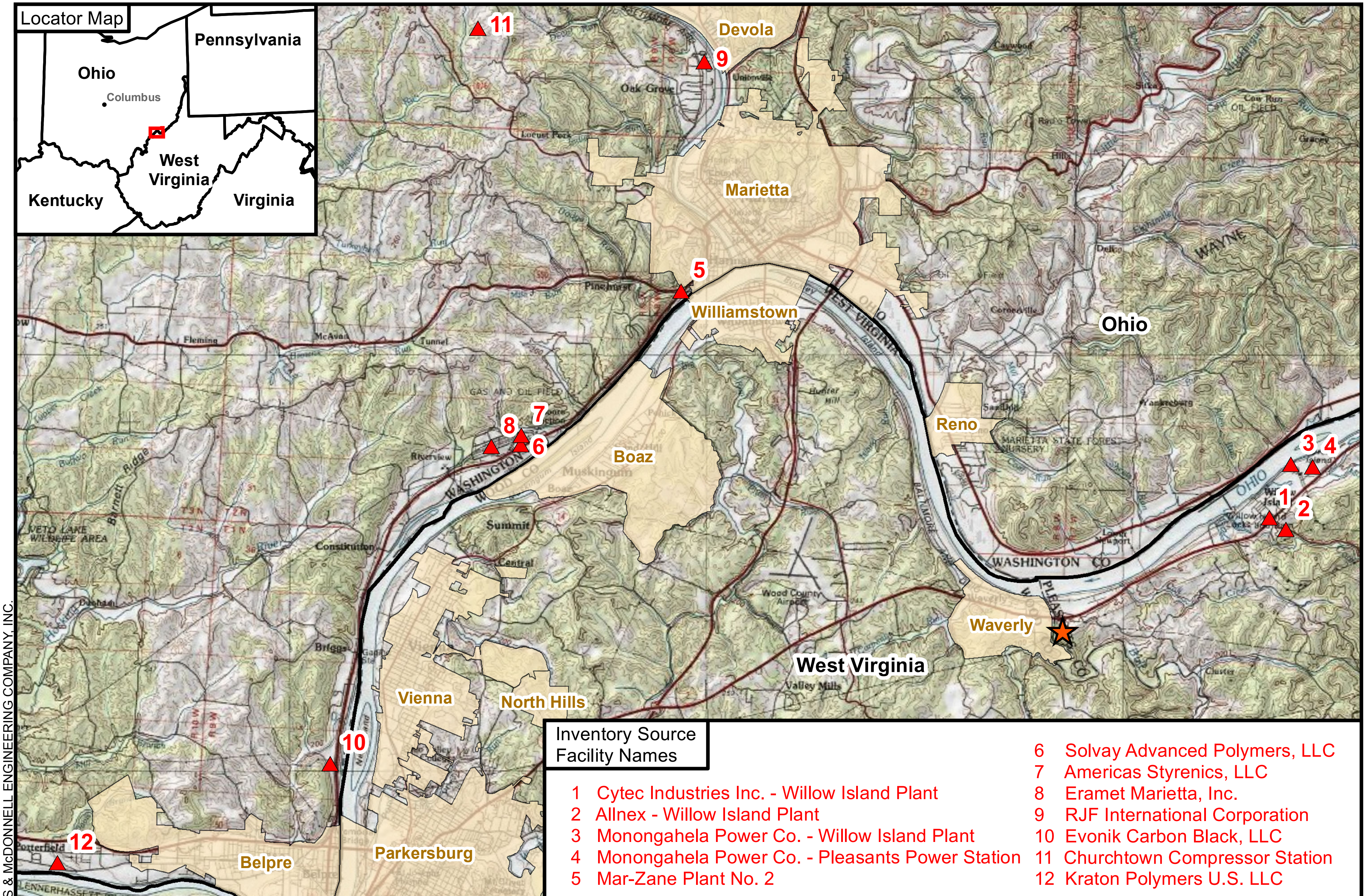
State	Site ID	Facility Site Name	Latitude	Longitude	Easting (X) (meters)	Northing (Y) (meters)	Distance (kilometers)	Included in Modeling?	Reason Not Included
WV	54-073-00003	Cytec Industries Inc. - Willow Island Plant	39.35556	-81.30639	473602.8	4356278.1	5.7	Yes	
WV	54-073-00004	Monongahela Power Co. - Willow Island Plant	39.36722	-81.30056	474109.7	4357571.2	6.8	Yes	
WV	54-073-00005	Monongahela Power Co. - Pleasants Power Station	39.36667	-81.29444	474636.0	4357507.8	7.2	Yes	
WV	54-085-00004	Dominion - Craig Compressor Station	39.07306	-81.09833	491494.2	4324887.5	37	Yes	
WV	54-107-00001	DuPont Washington Works	39.26945	-81.67000	442204.3	4346890.9	27.3	No	> 25 km from Project
WV	54-107-00010	Sabic Innovative Plastics LLC	39.25583	-81.67695	441593.9	4345384.8	28.2	No	> 25 km from Project
WV	54-107-00100	Columbia Gas - Rockport 4C4570	39.06889	-81.55194	452252.7	4324565.4	33.3	No	> 25 km from Project
WV	54-107-00121	Waste Management - Northwestern Landfill	39.24917	-81.49250	457503.7	4344542.1	14.3	Yes	
WV	54-073-00005	Allegheny Energy Supply Co. LLC - Pleasants Power Station	39.36680	-81.29440	474639.8	4357522.5	7.2	Yes	
WV	54-073-00030	Allnex Willow Island Plant	39.35305	-81.30177	474000.3	4355999.1	5.9	Yes	
OH	0684020001	Americas Styrenics, LLC (0684020001)	39.37278	-81.51527	455616	4358272	14	Yes	
OH	0684000213	Columbus Southern Power Company - Waterford Plant (0684000213)	39.53333	-81.71694	438387	4376208	38	No	> 25 km from Project
OH	0684020006	Eramet Marietta, inc. (0684020006)	39.37028	-81.52361	454896	4357998	14	Yes	
OH	0684010049	Evonik Carbon Black, LLC (0684010049)	39.30139	-81.56805	451020	4350376	18	Yes	
OH	0684000105	Globe Metallurgical Inc. (0684000105)	39.58445	-81.67805	441772	4381856	39	No	> 25 km from Project
OH	0684010011	Kraton Polymers U.S. LLC	39.27945	-81.64389	444464	4347985	25	Yes	
OH	0684000148	Marietta Industrial Enterprises	39.34806	-81.55139	452488	4355547	16	Yes	
OH	0684020005	Mar-Zane Plant No. 2	39.40417	-81.47083	459462	4361735	12	Yes	
OH	0684000000	Muskingum River Power Plant	39.59056	-81.67944	441658	4382535	38	No	> 25 km from Project
OH	0684000149	Ohio Oil Gathering Corporation - Bells Run Terminal	39.37908	-81.28876	475129	4358884	8	No	One fugitive source
OH	0684020037	R. H. Gorsuch Station (0684020037)	39.36722	-81.52084	455133	4357658	14	No	PER Ohio EPA - Gorsuch is shutdown, since 2010.
OH	0684020020	RJF International Corporation	39.45389	-81.46472	460017	4367250	16	Yes	
OH	0684010138	Skyline Steel, LLC (0684010138)	39.32389	-81.56333	451443	4352871	17	Yes	
OH	0684020008	Solvay Advanced Polymers LLC (0684020008)	39.37072	-81.51544	455600	4358043	14	Yes	
OH	0684000212	Washington Energy Facility (0684000212)	39.58222	-81.64889	444274	4381590	37	No	> 25 km from Project
OH	684020025	Churchtown Compressor Station (Cobra Pipeline Co. LTD) (0684020025)	39.460831	-81.528061	454572.06	4368020.5	20	Yes	

Table A-4: NO_2 Inventory Sources Modeled

State	Site ID	Facility Site Name	Easting (X) (meters)	Northing (Y) (meters)	Distance (kilometers)
WV	54-073-00003	Cytec Industries Inc. - Willow Island Plant	473602.8	4356278.1	6
WV	54-073-00030	Allnex - Willow Island Plant	474000.3	4355999.1	6
WV	54-073-00004	Monongahela Power Co. - Willow Island Plant	474109.7	4357571.2	7
WV	54-073-00005	Monongahela Power Co. - Pleasants Power Station	474636.0	4357507.8	7
OH	0684020005	Mar-Zane Plant No. 2	459462.0	4361735.0	12
OH	0684020008	Solvay Advanced Polymers, LLC	455600.0	4358043.0	14
OH	0684020001	Americas Styrenics, LLC	455616.0	4358272.0	14
OH	0684020006	Eramet Marietta, Inc.	454896.0	4357998.0	14
OH	0684020020	RJF International Corporation	460017.0	4367250.0	16
OH	0684010049	Evonik Carbon Black, LLC	451020.0	4350376.0	18
OH	0684020025	Churchtown Compressor Station	454572.1	4368020.5	20
OH	0684010011	Kraton Polymers U.S. LLC	444464.0	4347985.0	25
OH	0684010138	Skyline Steel, LLC (0684010138)	451443	4352871	17

Table A-5: $PM_{2.5}$ Inventory Sources Modeled

State	Site ID	Facility Site Name	Easting (X) (meters)	Northing (Y) (meters)	Distance (kilometers)
WV	54-073-00003	Cytec Industries Inc. - Willow Island Plant	473602.8	4356278.1	6
WV	54-073-00030	Allnex - Willow Island Plant	474000.3	4355999.1	6
WV	54-073-00004	Monongahela Power Co. - Willow Island Plant	474109.7	4357571.2	7
WV	54-073-00005	Monongahela Power Co. - Pleasants Power Station	474636.0	4357507.8	7
OH	0684020001	Americas Styrenics, LLC	455616.0	4358272.0	14
OH	0684020006	Eramet Marietta, Inc.	454896.0	4357998.0	14
OH	0684010049	Evonik Carbon Black, LLC	451020.0	4350376.0	18
OH	0684010011	Kraton Polymers U.S. LLC	444464.0	4347985.0	25
OH	0684000148	Marietta Industrial Enterprises	452488	4355547	16
OH	0684020005	Mar-Zane Plant No. 2	459462.0	4361735.0	12
OH	0684020020	RJF International Corporation	460017.0	4367250.0	16
OH	0684020008	Solvay Advanced Polymers, LLC	455600.0	4358043.0	14
OH	0684010138	Skyline Steel, LLC (0684010138)	451443	4352871	17
OH	0684020025	Churchtown Compressor Station	454572.1	4368020.5	20



Inventory Source Facility Names

1 Cytec Industries Inc. - Willow Island Plant
2 Allnex - Willow Island Plant
3 Monongahela Power Co. - Willow Island Plant
4 Monongahela Power Co. - Pleasants Power Station
5 Mar-Zane Plant No. 2
6 Solvay Advanced Polymers, LLC
7 Americas Styrenics, LLC
8 Eramet Marietta, Inc.
9 RJF International Corporation
10 Evonik Carbon Black, LLC
11 Churchtown Compressor Station
12 Kraton Polymers U.S. LLC

Legend

- Project Location
- InventorySources
- Municipal Boundary
- State Boundary

NORTH

2 1 0 2
Miles

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Figure A-7
NO_2 Inventory Sources
Pleasants Energy, LLC

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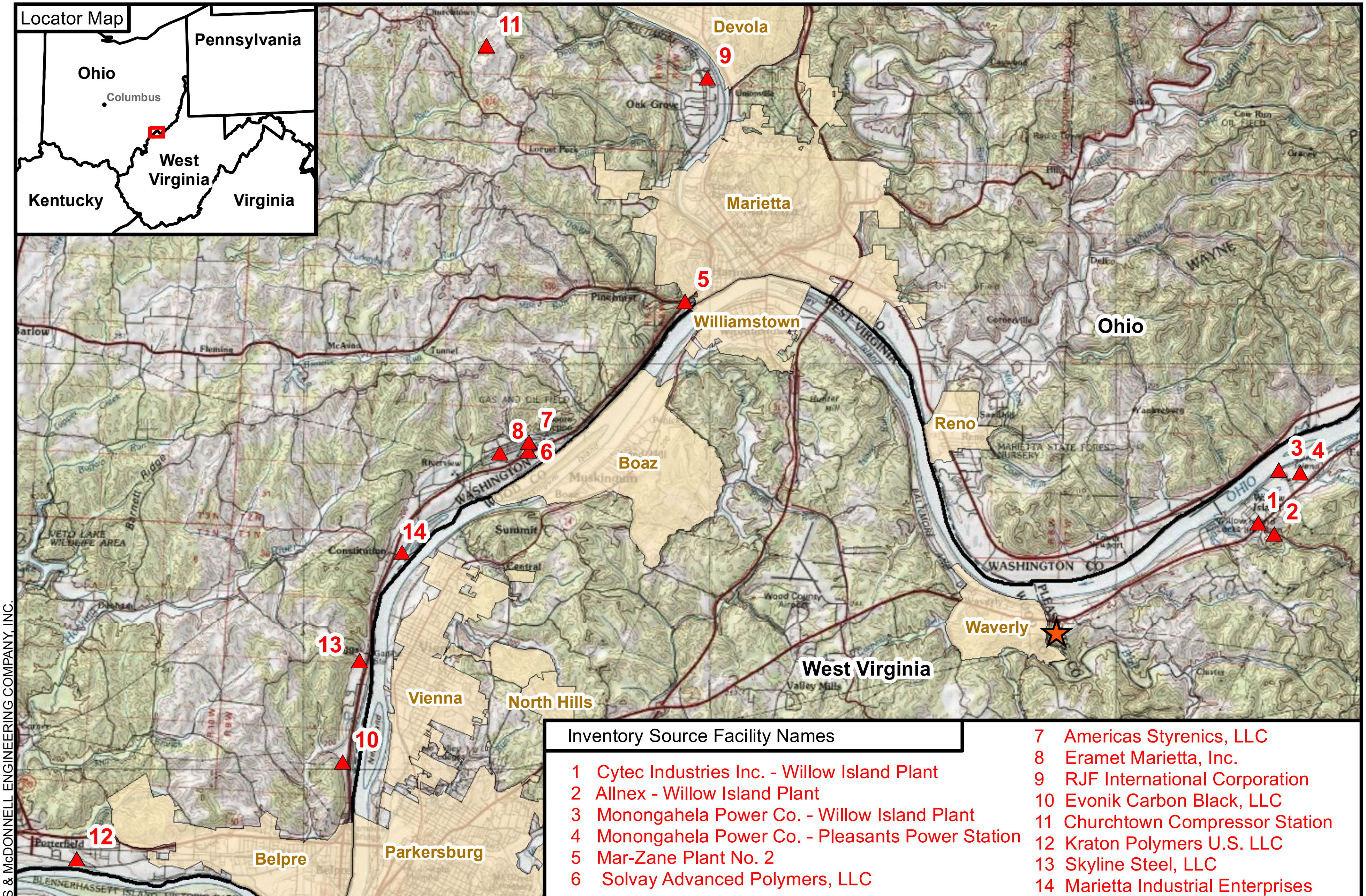
Source: 2013 National Geographic Society, i-cubed, Burns & McDonnell

Issued: 7/22/2015



Legend

- Project Location
- InventorySources
- Municipal Boundary
- State Boundary

NORTH

2 1 0 2

Miles

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Figure A-8
$PM_{2.5}$ Inventory Sources
Pleasants Energy, LLC

Source: 2013 National Geographic Society, i-cubed, Burns & McDonnell

Issued: 9/15/2015

APPENDIX B – OZONE LIMITING METHOD MODELING PROTOCOL

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APPENDIX B

Ozone Limiting Method Modeling Protocol for AERMOD

Pleasants Energy, LLC

Pleasants Energy Project
Project No. 84344

Revision 2
September 2015

Ozone Limiting Method Modeling Protocol for AERMOD

prepared for

Pleasants Energy, LLC
Pleasants Energy Project
St. Marys, West Virginia

Project No. 84344

Revision 2
September 2015

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

TABLE OF CONTENTS

LIST OF TABLES

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
$\mu g/m^3$	micrograms per cubic meter
AERMOD	AMS/EPA Regulatory Model
AQS	air quality system
ARM	Ambient Ratio Method
EPA	U.S. Environmental Protection Agency
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
OLM	Ozone Limiting Method
PSD	Prevention of Significant Deterioration
PVMRM	Plume Volume Molar Ratio Method
WVDEP	West Virginia Department of Environmental Protection

1.0 INTRODUCTION

Pleasants Energy, LLC (Pleasants Energy) installed two simple-cycle General Electric 7FA combustion turbines at the Pleasants Energy facility in 2002 and is currently operating under permit number R30-07300022-2014. The permit had operational restrictions to limit the facility's potential to emit to fewer than 250 tons per year of any criteria pollutant so the site could be minor for Prevention of Significant Deterioration (PSD). The Pleasants Energy Project (Project) will increase the hours of operation of the combustion turbines. Since the Project will remove the synthetic minor limitation on the combustion turbines and will increase the potential to emit to greater than 250 tons per year, this Project will be subject to PSD. The existing Pleasants Energy facility includes two TurboPhase units that consist of four engines, each and five Tier IV diesel generators.

This modeling protocol addresses the Ozone Limiting Method (OLM) methodology that will be used for the nitrogen dioxide (NO_2) 1-hour air dispersion modeling for the Project. This modeling protocol has been drafted in accordance with the U.S. Environmental Protection Agency (EPA) and West Virginia Department of Environmental Protection (WVDEP) modeling guidelines.

2.0 PROPOSED MODEL AND MODELING METHODOLOGY

The applicant proposes using the most current version of the AMS/EPA Regulatory Model (AERMOD) for the air quality analysis (Version 15181). The AERMOD model is an EPA-approved, steady-state Gaussian plume model capable of modeling multiple sources in simple and complex terrain.

The following model options will be used:

- Gradual Plume Rise
- Stack-tip Downwash
- Buoyancy-induced Dispersion
- Calms and Missing Data Processing Routine
- Calculate Wind Profiles
- Calculate Vertical Potential Temperature Gradient
- Rural Dispersion
- NO_2 Modeling

Details of the modeling algorithms contained in AERMOD may be found in the User's Guide for AERMOD. The regulatory non-default option will be selected for the OLM NO_2 modeling. The OLM modeling parameters that will be used in the model are discussed in the following sections.

Per WVDEP guidance and EPA's March 2011 memo[1] the applicant proposes to only model continuous operation for the 1-hour standard. The combustion turbine back-up fuel oil operation will not be included in the 1-hour modeling analysis as fuel oil will only be used in emergency situations when natural gas is curtailed and for testing purposes. In addition, start-up emissions from the combustion turbines on fuel oil will not be modeled for the 1-hour NO_2 standard, either, as it is expected that there will be at most 20 starts per turbine per year which will be only in emergency situations and for testing purposes. These operations will not contribute significantly to the annual distribution of the daily maximum 1-hour concentrations. All other load and fuel operating scenarios will be modeled for the meteorological record. Table 2-1 shows the sources that are considered intermittent and will not be modeled for the 1-hour standard.

[1] March 1, 2011 EPA Memo from Tyler Fox. Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard

Table 2-1: Operating Scenarios Not Included in 1-hour Modeling Analysis

Operating Scenario	Reason Not Modeled for the 1-hour Standard
Combustion turbines operating on fuel oil	Fuel oil is a backup fuel and is only used when natural gas is curtailed.
Fuel oil start-up on combustion turbines	Fuel oil is a backup fuel only. At most 20 starts per year expected.

2.1 1-hour NO_2 Averaging Period - Ozone Limiting Method

The modeled emission rates will represent operations at worst-case ambient conditions under various operating capacities. The AERMOD model predicts ground-level concentrations of any generic pollutant without chemical transformations. Thus, the modeled nitrogen oxides (NO_X) emission rate will give ground-level modeled concentrations of NO_X. National Ambient Air Quality Standard (NAAQS) values are presented as NO_2.

The EPA has a three-tier approach to modeling NO_2 concentrations:

- Tier I – total conversion, or all $NO_x = NO_2$
- Tier II – use a default NO_2/NO_x ratio
- Tier III – case-by-case detailed screening methods, such as OLM and Plume Volume Molar Ratio Method (PVMRM)

Initial screening modeling was performed using both Tier I and Tier II methodologies. It was determined from these modeling iterations that less conservative methods for determining 1-hour NO_2 compliance would be needed for the Project. To account for the conversion of NO_x to NO_2 in the modeling, the Tier III approach using the OLM method will be used for the 1-hour NO_2 PSD significance and refined (cumulative) air dispersion modeling. The PSD significance threshold will be compared to the modeled first high, while the NAAQS threshold will be compared to the 5-year average modeled 98th percentile of the annual distribution of maximum daily 1-hour values.

The amount of NO_2 present in the stack gases was determined from published data for each piece of equipment being modeled. The in-stack NO_2/NO_x ratios shown in Table 2-2 will be used for the Project emission sources.

Table 2-2: NO_2/NO_x Ratios

Emission Source	NO_2/NO_x Ratio	Reference
Natural gas-fired/fuel oil-fired combustion turbine	0.5	Default in-stack NO_2/NO_x ratio[a]

(a) Default in-stack NO_2/NO_x ratio per EPA's March 2011 memo.

Upon review of the EPA In-Stack Ratio database, there were no exact matches for the sources at the Pleasants Energy facility. Therefore, to be conservative, a default in-stack NO_2/NO_x ratio of 0.5 was used for all onsite emission units based on EPA's March 2011 memo. Based on guidance from WVDEP, an in-stack NO_2/NO_x ratio of 0.2 will be used for inventory sources farther than 1-3 kilometers away from the project site. Otherwise, the default in-stack NO_2/NO_x of 0.5 will be used unless source-specific data is available.

Additionally, an equilibrium NO_2/NO_x ratio of 0.90 will be used per EPA's March 2011 memo.

2.2 Annual NO_2 Averaging Period

If Tier I and Tier II methodologies produce unacceptable results for the annual averaging period, then the Tier III methodology may be applied to the NO_2 annual averaging period. For the Tier II methodology, the modeled concentrations of annual NO_X will be adjusted using the EPA-approved Ambient Ratio Method (ARM). Tier II of the ARM allows the use of an empirically derived NO_2/NO_X ratio of 0.75, which means that approximately 75 percent of the NO_X emissions will be converted to NO_2, the regulated pollutant. This factor will be applied to the annual modeled results for NO_X to determine the predicted ground-level concentration of NO_2 if Tier II is used.

2.3 Specifying Combined Plumes

When using the OLM option, the model includes an option for specifying which sources are to be modeled as combined plumes (NO_x within the plumes competes for the available ambient ozone). A group ID of ALL will be selected for this modeling analysis, which means that the OLM will be applied on a combined plume basis to all sources within a specified source group. The use of this option is in accordance with the methodology presented in EPA's June 2010 memo which states, "Applications of the OLM option in AERMOD, subject to approval under Section 3.2.2e of Appendix W, should routinely utilize the 'OLMGROUP ALL' option for combining plumes."[2]

[2] June 28, 2010 EPA Memo from Tyler Fox. Applicability of Appendix W Modeling Guidance for the 1-hour NO2 National Ambient Air Quality Standard.

2.4 Background Ozone

The selected monitor to be used for the 1-hour hourly ozone background is the West Virginia Air Pollution Control Commission monitoring station located in Vienna, Wood County, West Virginia (Air Quality System [AQS] ID: 54-107-1002). The applicant was advised by WVDEP to use this monitor for ozone season data as it is representative of the Project site. Additionally, the Vienna monitor is located in a similar land-use area (Figure A-5 in Appendix A to the Prevention of Significant Deterioration Class II Air Dispersion Modeling Protocol) as the land-use near the proposed Project (Figure A-2 in Appendix A of the full report); therefore, the monitor will provide data that is representative of the ozone concentrations in the Project area.

Because the Vienna monitor only has ozone season data available, two other monitors were selected for the non-ozone season data: the Lawrenceville monitoring station located in Pittsburg, Pennsylvania (AQS ID: 43-003-0008), and the Quaker City monitoring station located in Quaker City, Ohio (AQS ID: 39-121-9991). The Quaker City monitoring station is located closer to the Project site (approximately 70 kilometers from the Project site) than the Lawrenceville Station (approximately 170 kilometers from the Project site). The Quaker City station was deemed the most representative for the non-ozone season data due to its close proximity to the Project site. However, 2010 non-ozone season data is not available at the Quaker City station so data from the Lawrenceville station was used for this time period. Ozone data from the Lawrenceville station should be conservative due to its location in an urban area. Data from the Quaker City station was used for the non-ozone season hourly data for years 2011-2014.

Hourly background ozone concentrations were obtained from the EPA Technology Transfer Network Air Quality System for the Vienna monitoring station located in Wood County, West Virginia (AQS ID: 54-107-1002), the Lawrenceville monitoring station located in Pittsburg, Pennsylvania (AQS ID: 43-003-0008), and the Quaker City monitoring station located in Ohio (AQS ID: 39-121-9991). Data from each monitoring station was used for the time periods previously discussed. The background data was formatted for use in the AERMOD model and processed for years 2010 to 2014 to match the meteorological data years used in the modeling. The following steps and assumptions were used to create the hourly ozone data:

- One to six missing values: The average of the previous and following value was used.
- More than six missing values: Data was substituted based the maximum of the ozone concentrations measured during that hour in the month of the missing values.

2.5 NAAQS and NO_2 Background Value

The NO_2 1-hour background air quality concentration was selected for years 2012 to 2014 for the Charleroi, Pennsylvania, monitoring station (AQS ID: 42-125-005) located at the Charleroi Waste Treatment Plant in Charleroi, Pennsylvania. The 3-year average monitored 98th percentile for NO_2 is 68.3 micrograms per cubic meter ($\mu g/m^3$).

This background concentration will be added to the model-predicted concentration (98th percentile) for comparison to the 1-hour NO_2 NAAQS concentration of 188.0 $\mu g/m^3$.

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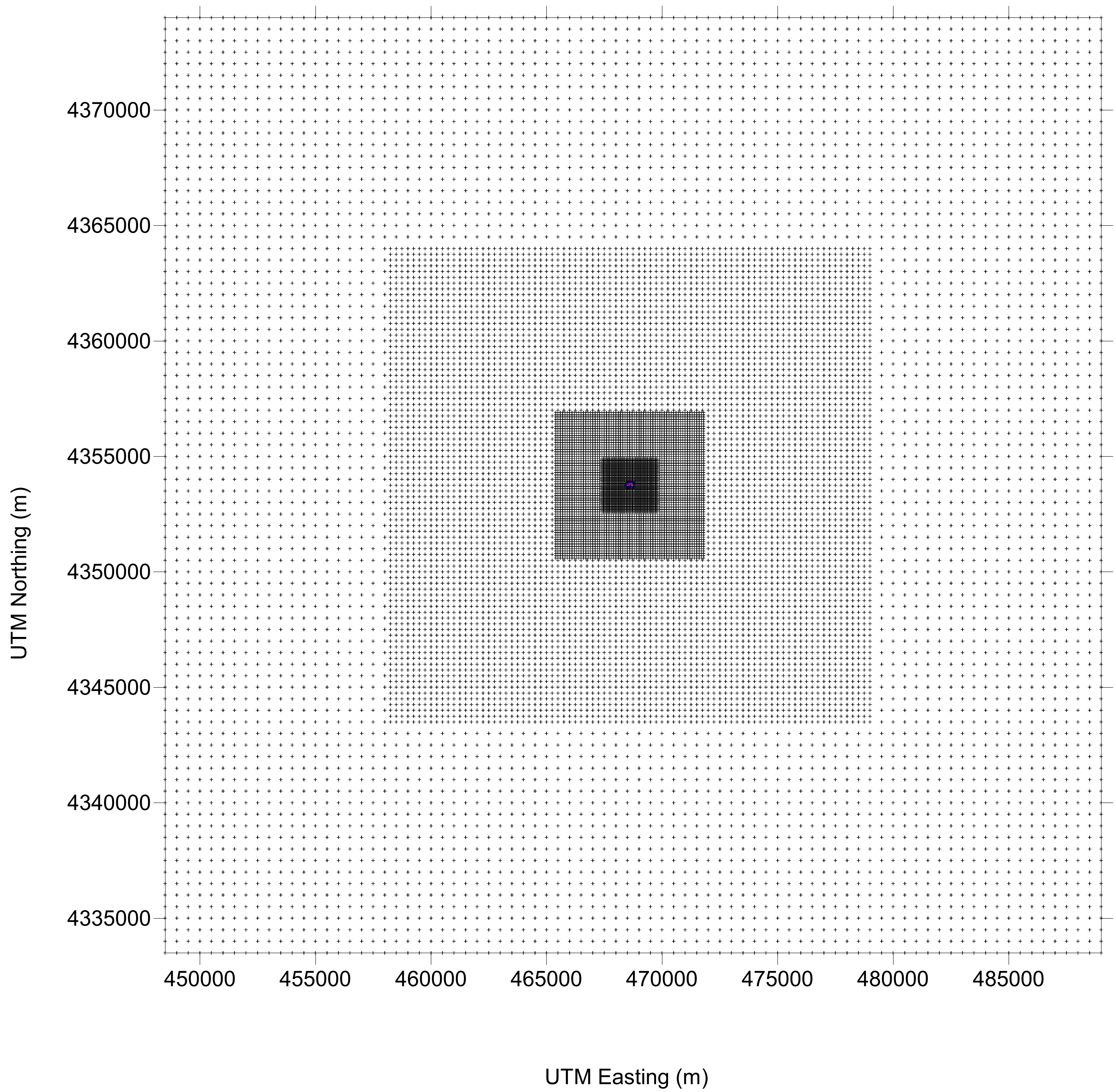
APPENDIX G – MODELING FIGURES

Figure G-1: 20 kilometer by 20 kilometer Cartesian Grid



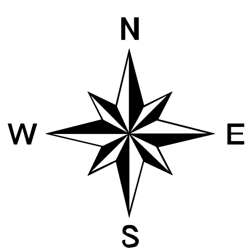


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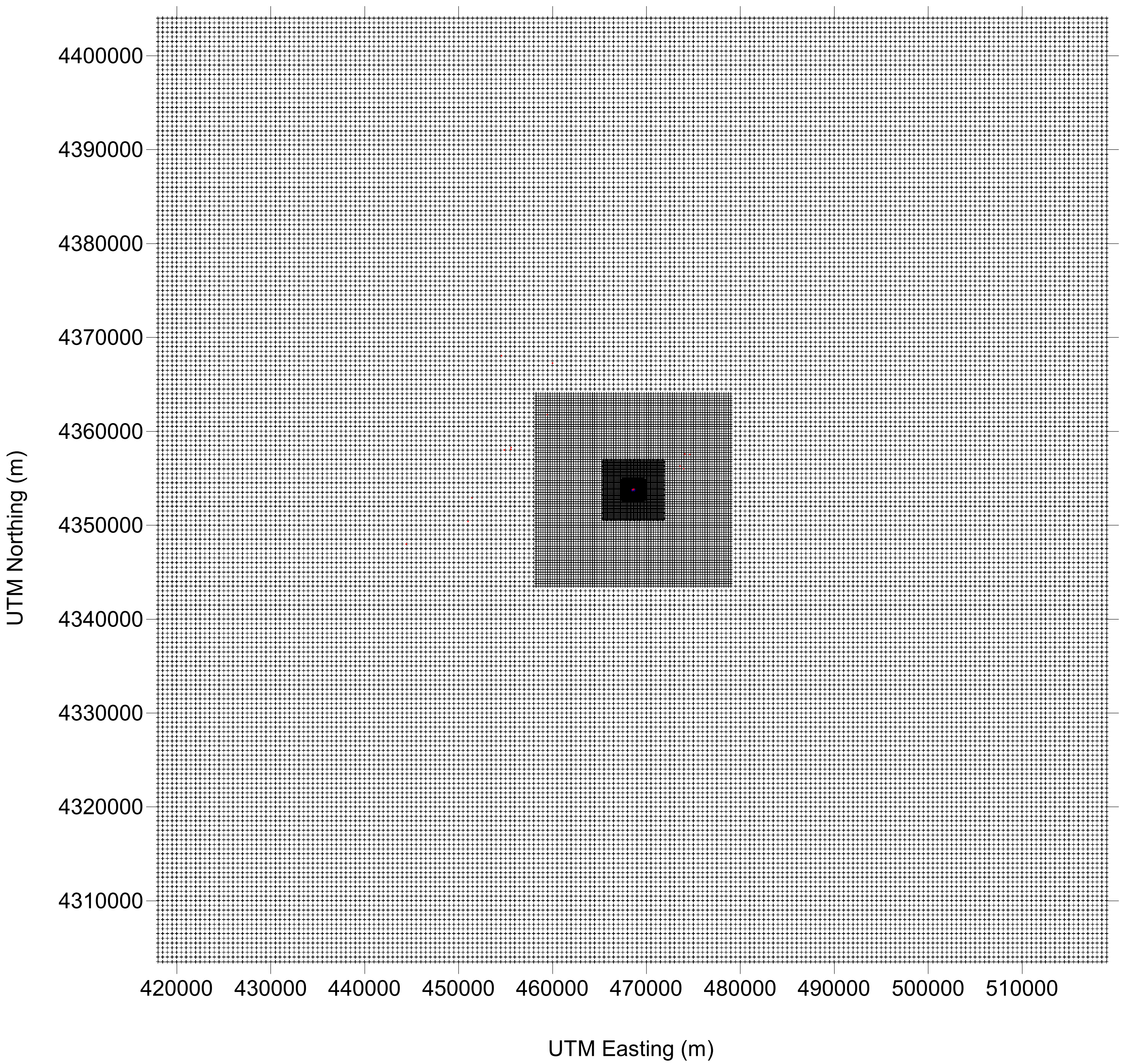
Figure G-2: 50 kilometer by 50 kilometer Cartesian Grid



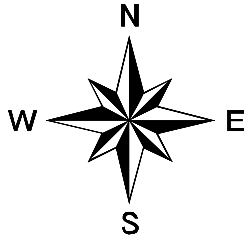


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Figure G-3: Parkersburg Wood County Airport (Station ID 03804) Wind Speed and Wind Direction (Blowing From) for Years 2010 to 2014

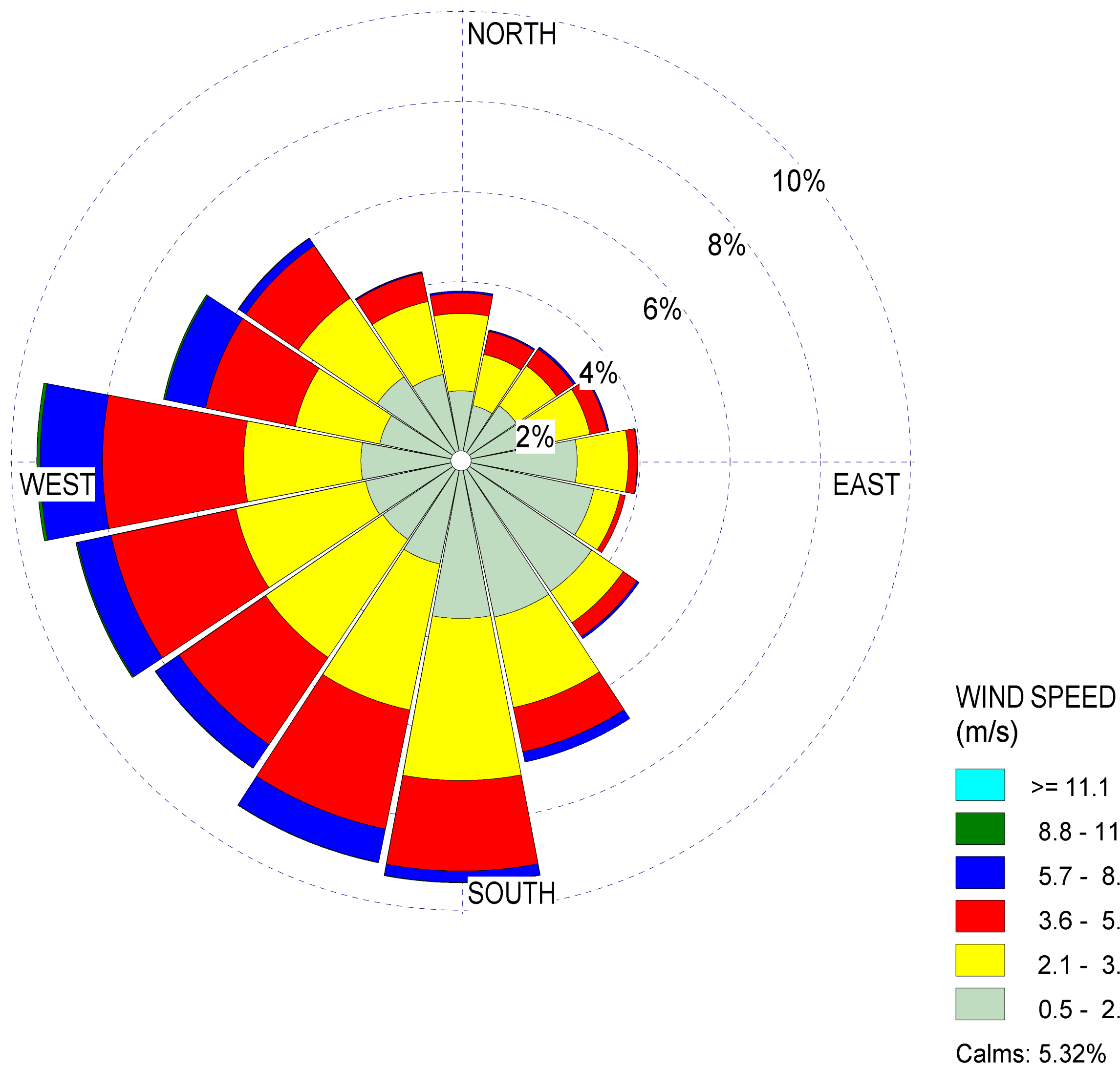

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Figure G-4: NO_2 Annual Significance
Natural Gas 60% Load (2010)

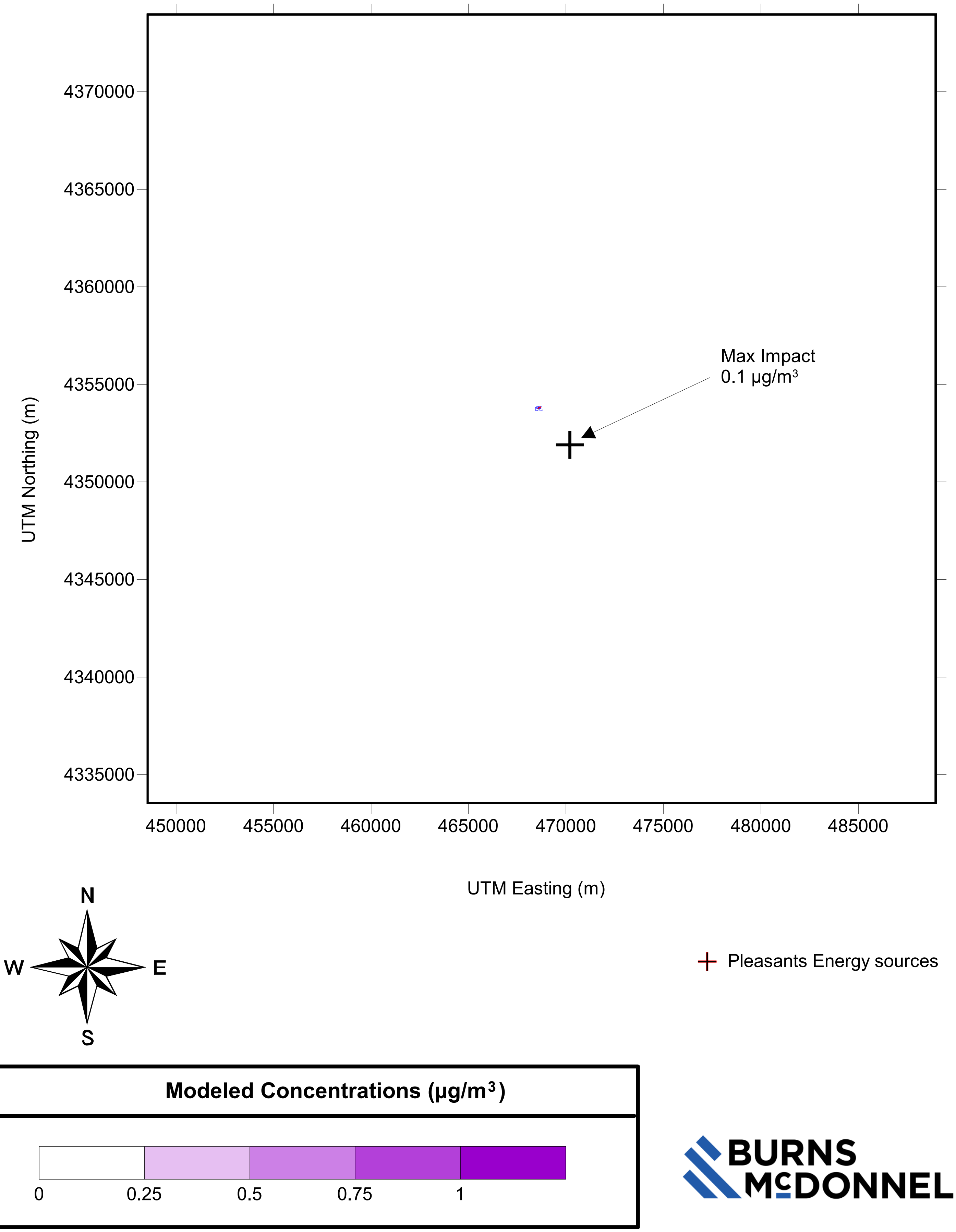

Figure G-5: NO_2 1-hour Significance
Natural Gas Start-up (5 years)

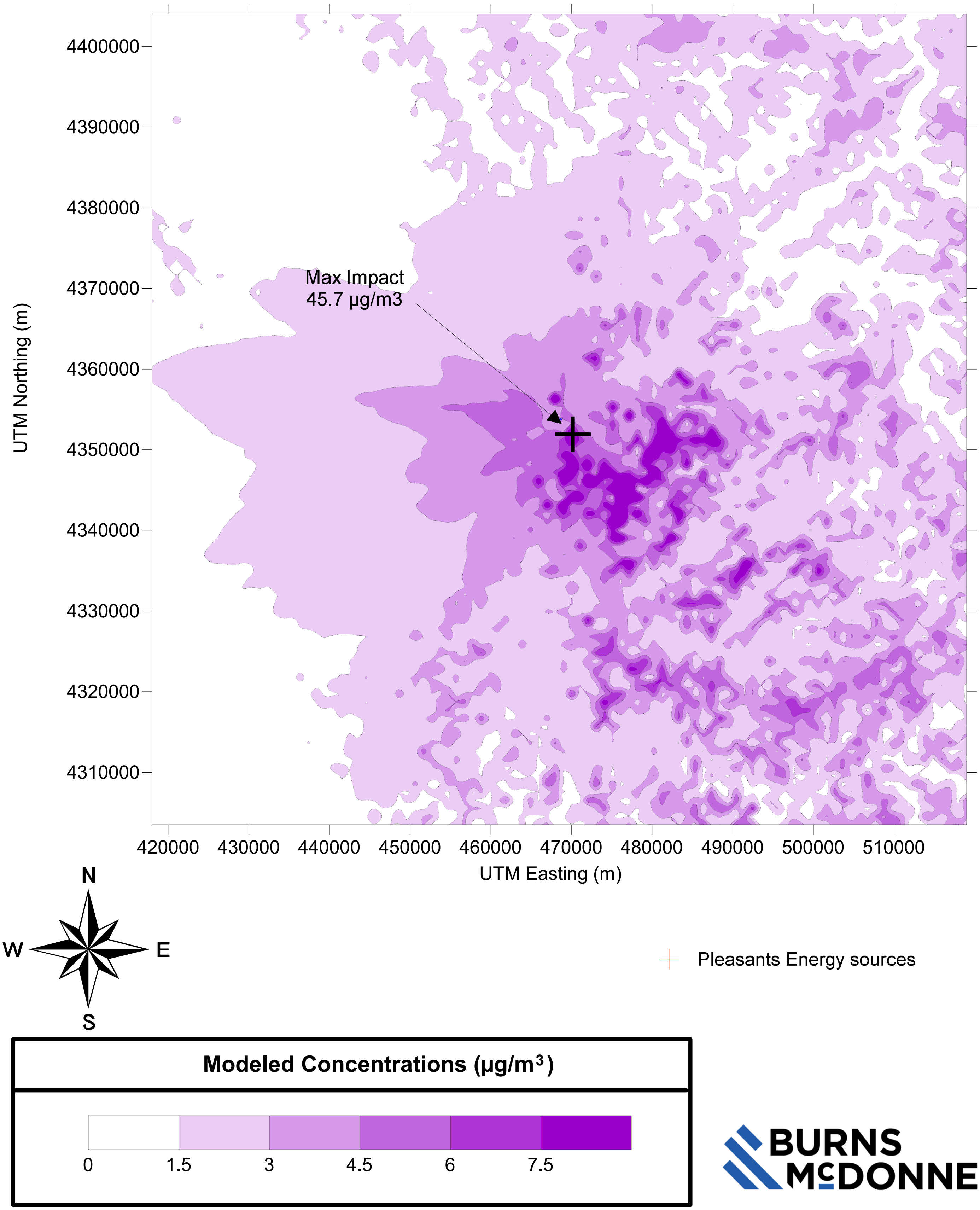

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Figure G-6: CO 1-Hour Significance
Natural Gas Start-up (2012)

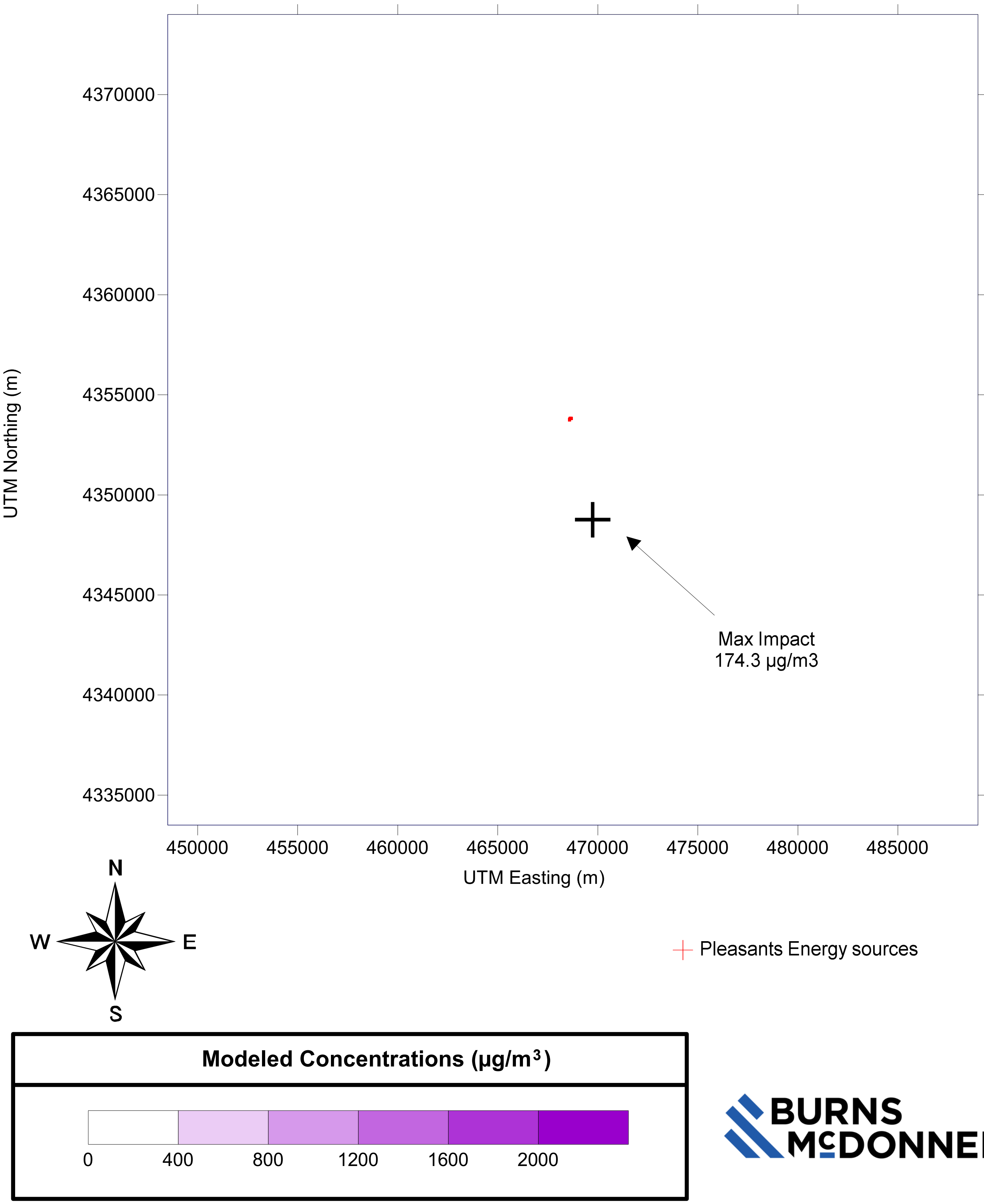

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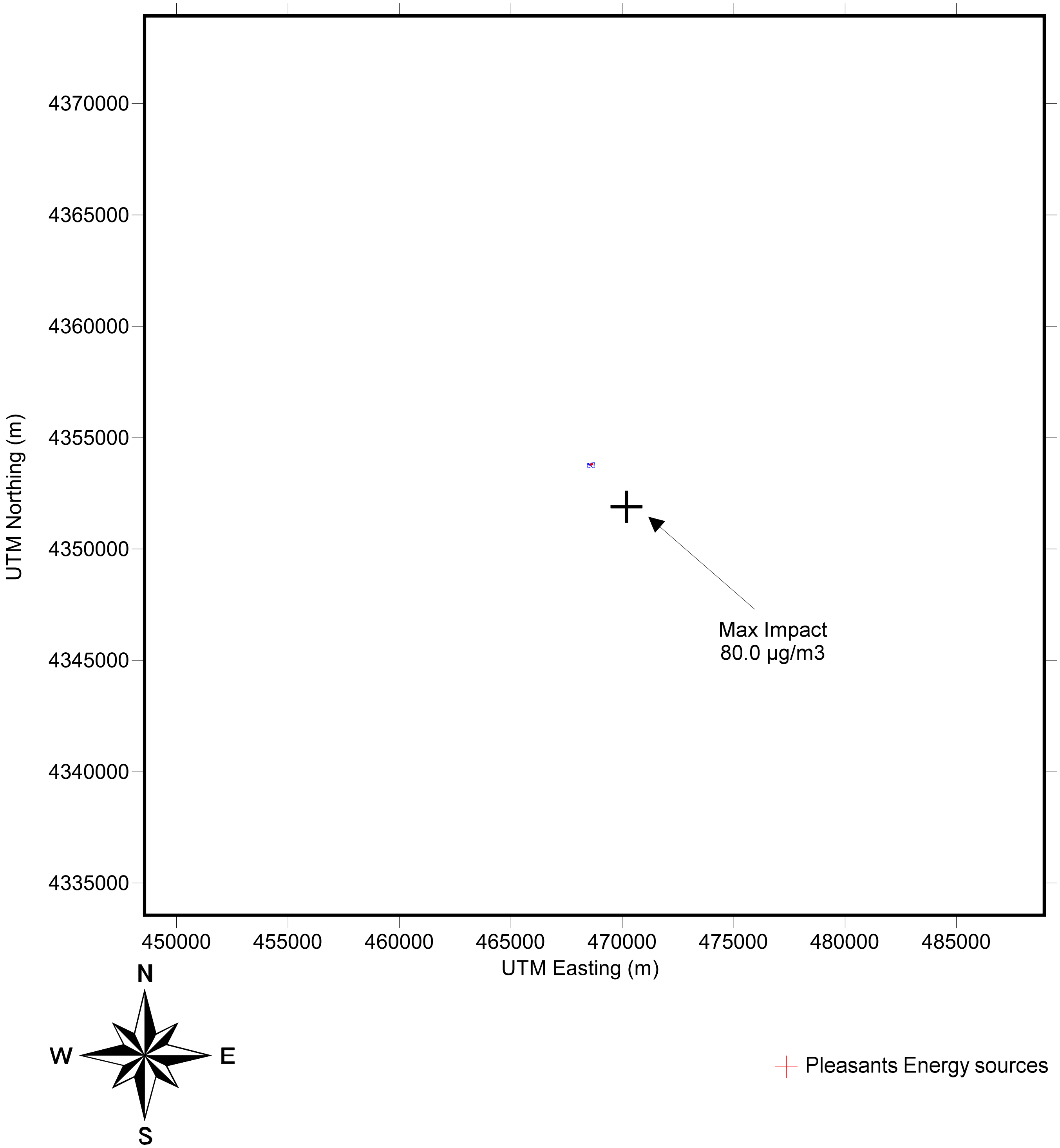
Figure G-7: CO 8-Hour Significance Natural Gas Start-up (2011)



Modeled Concentrations (µg/m³)

0 100 200 300 400 500

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Figure G-8: PM$_{10}$ Annual Significance
Natural Gas 60% Load (2010)

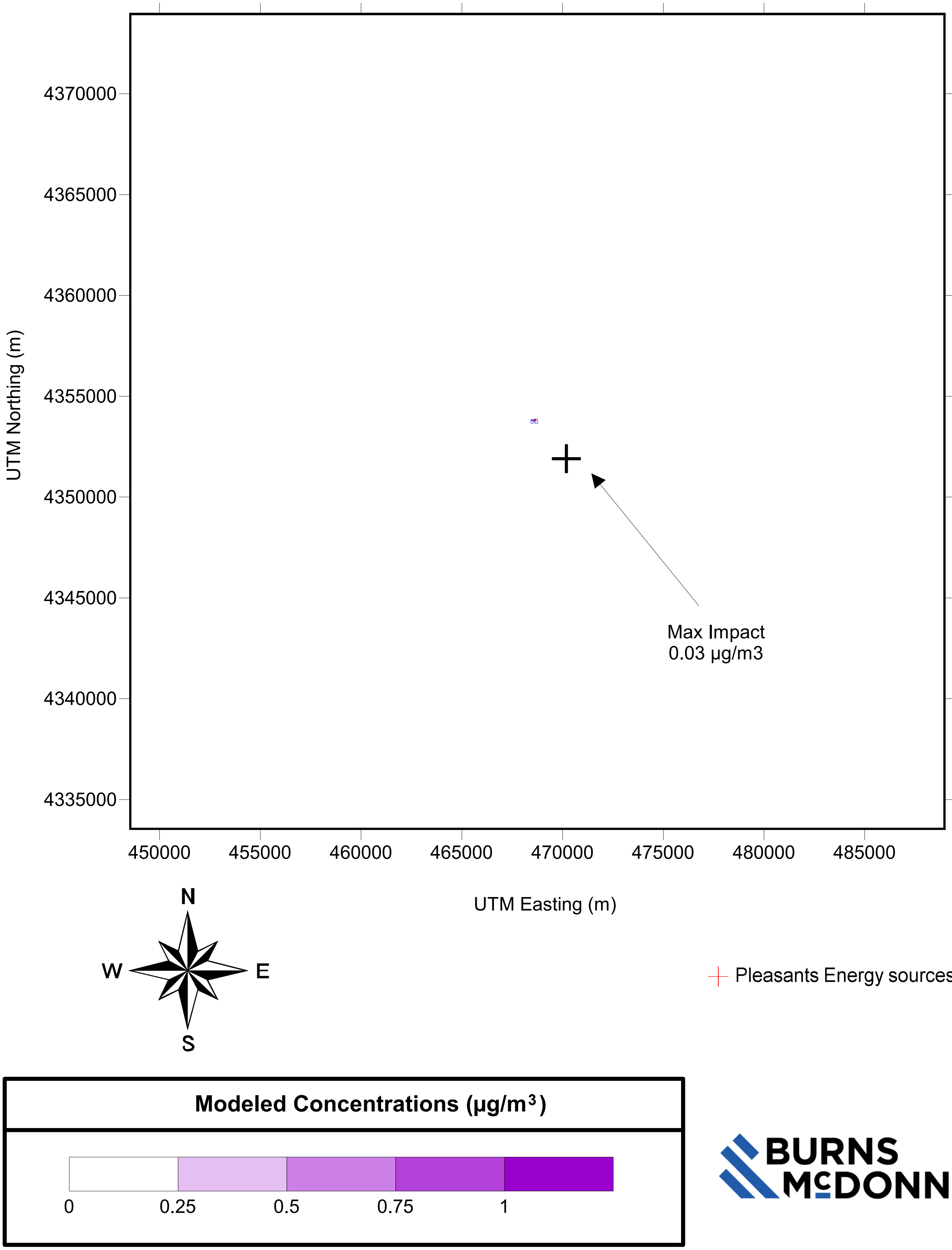

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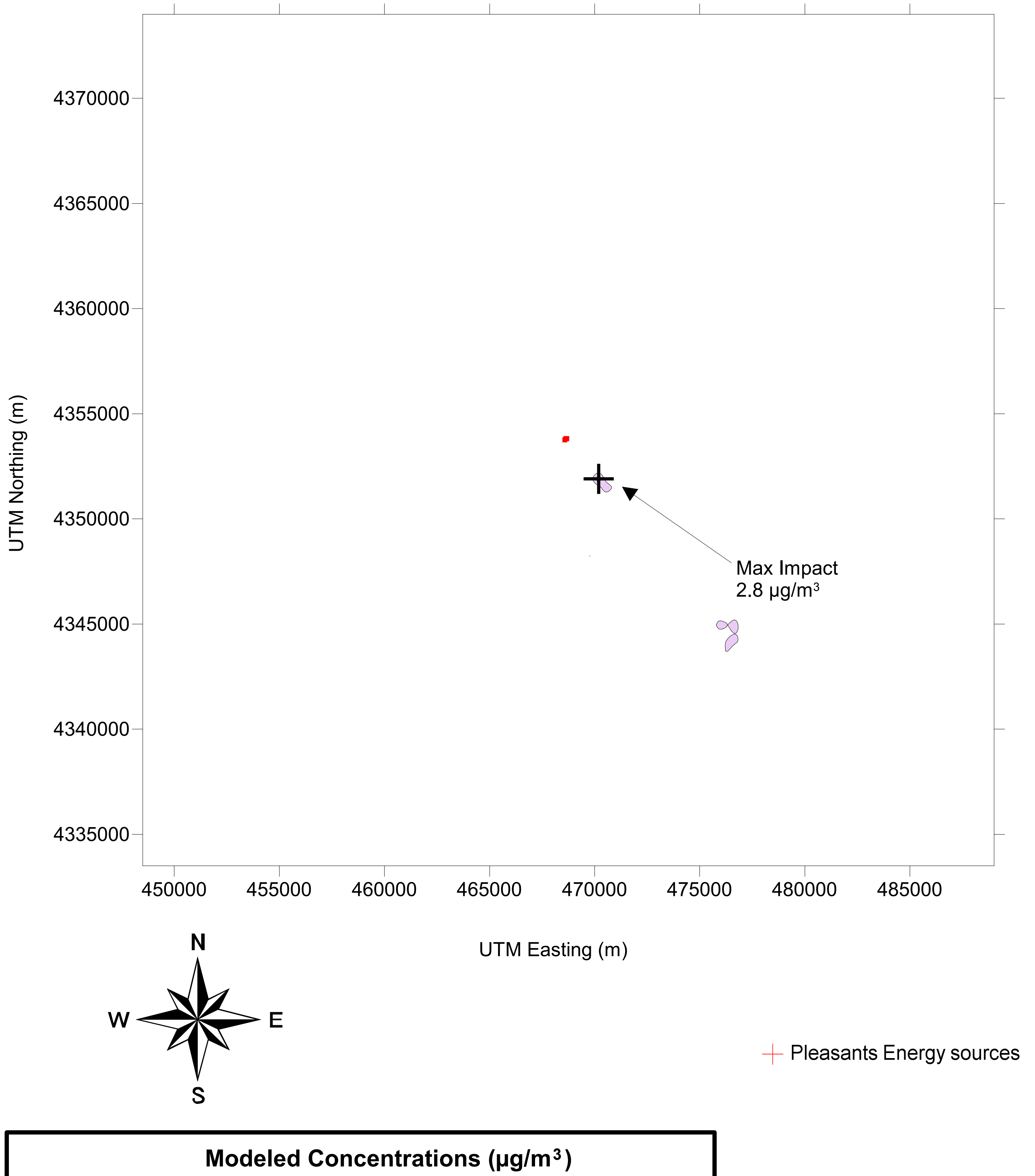
Figure G-9: PM_{10} 24-Hour Significance
Fuel Oil 60% Load (2011)



Modeled Concentrations (µg/m³)

0 1 2 3 4 5

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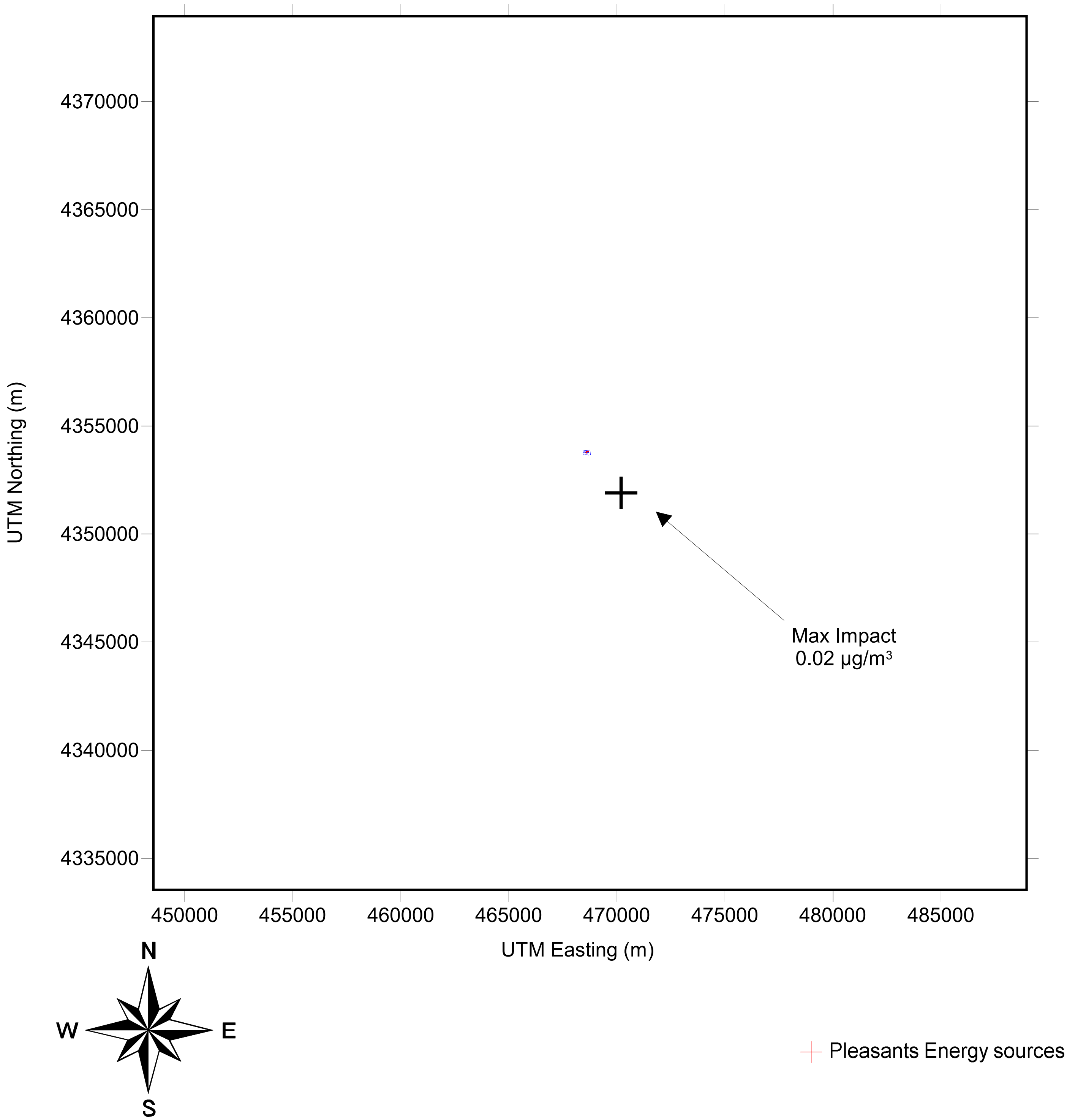
Figure G-10: $PM_{2.5}$ Annual Significance
Natural Gas Start-up (5 years)



Modeled Concentrations (µg/m³)

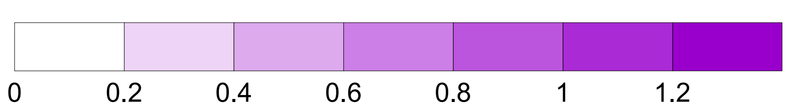


Figure G-11: $PM_{2.5}$ 24-hour Significance
Fuel Oil 60% (5 years)

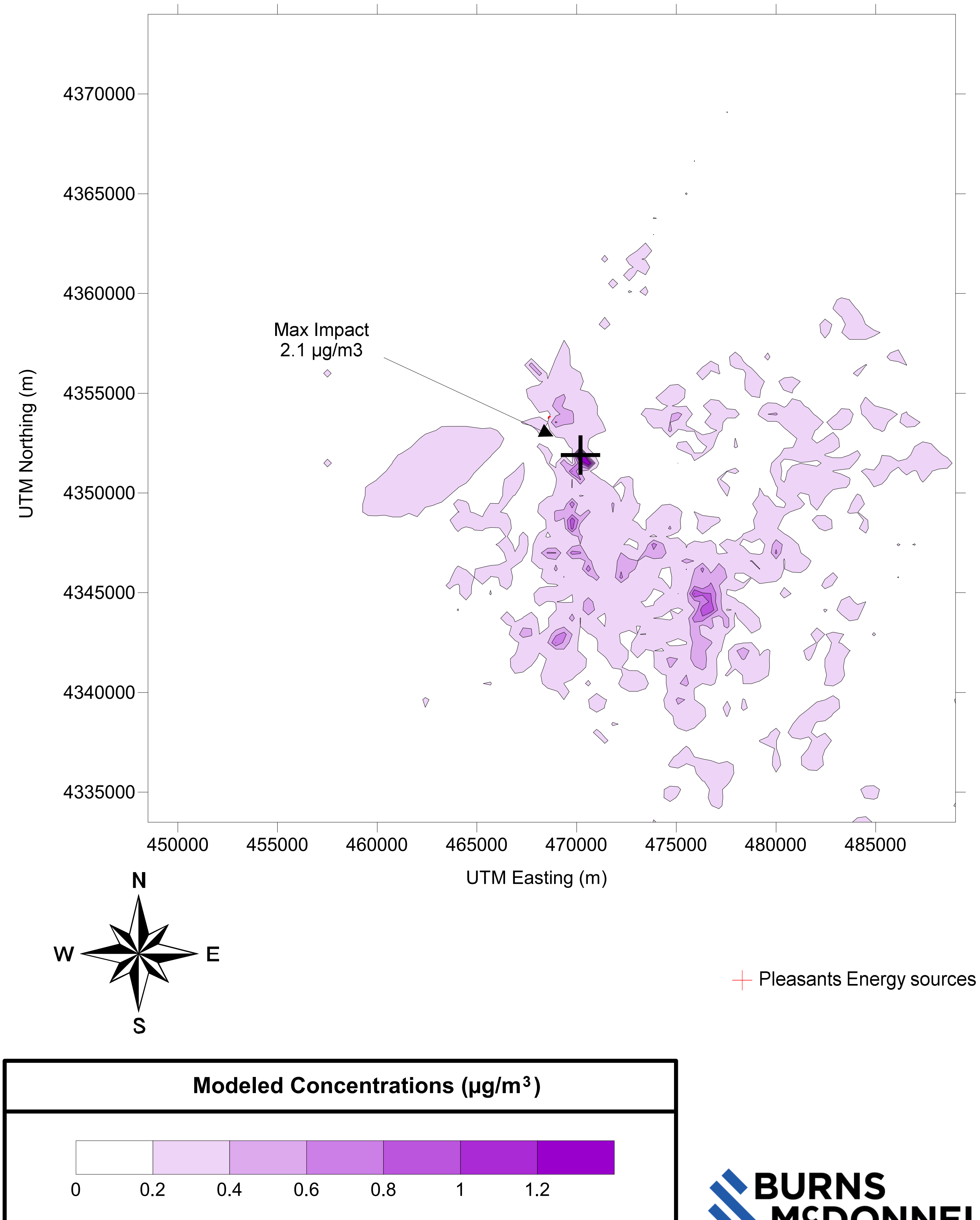


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Figure G-12: Class II Increment $PM_{2.5}$ 24-hour
Fuel Oil 60% Load (2013)

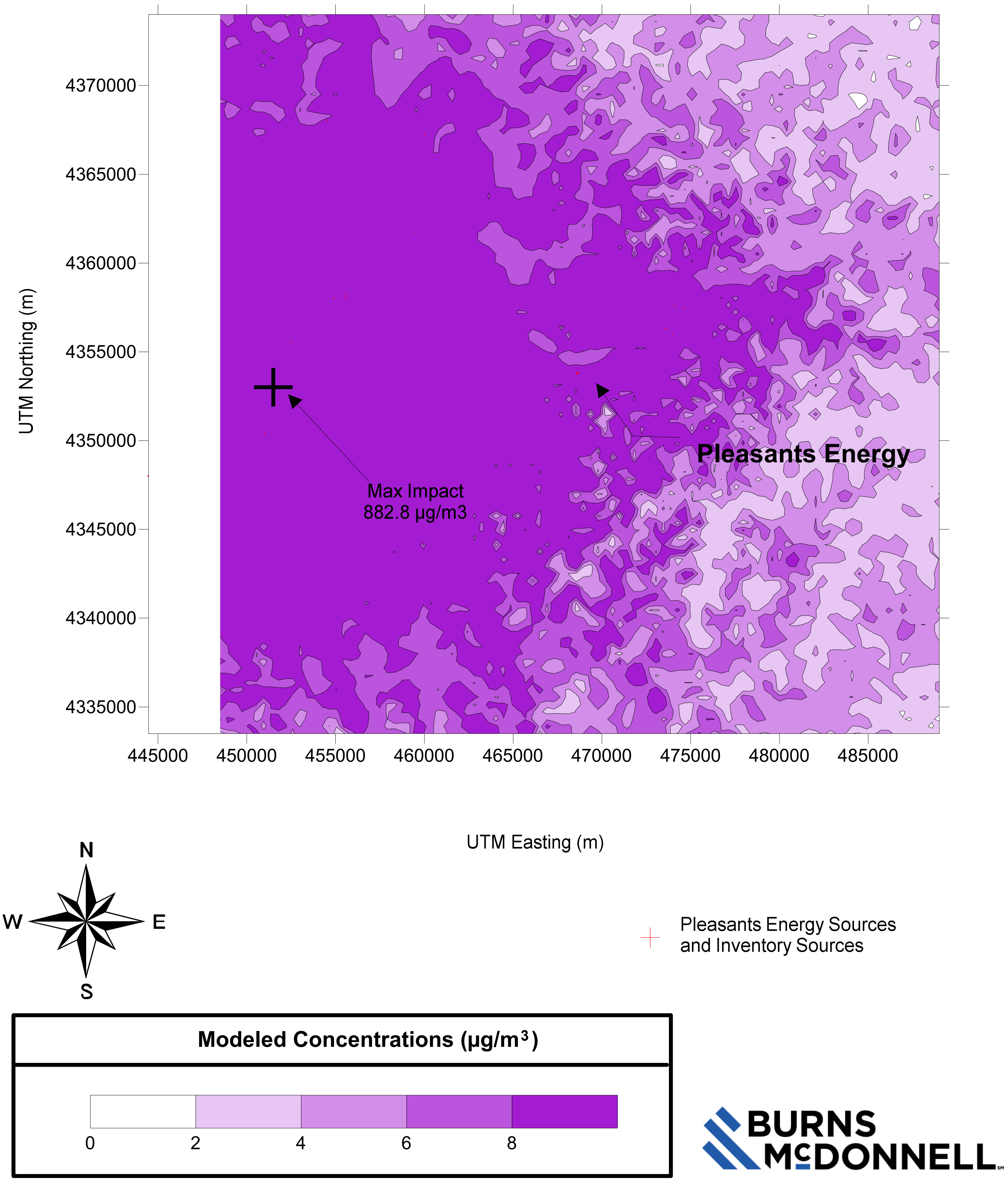

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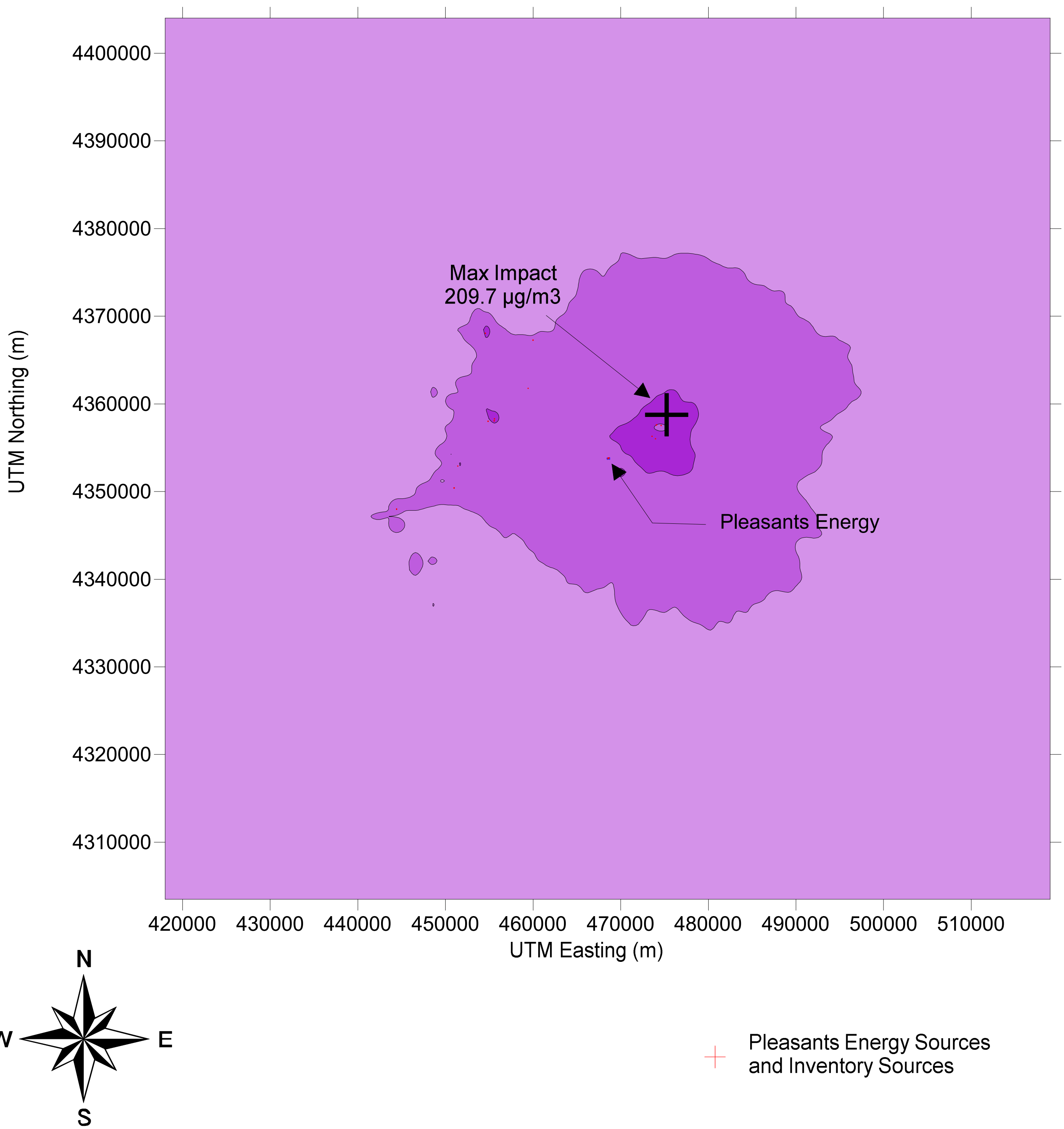
Figure G-13: NAAQS NO_2 1-hour With Background (5 years)



Modeled Concentrations (µg/m³)

0 40 80 120 160

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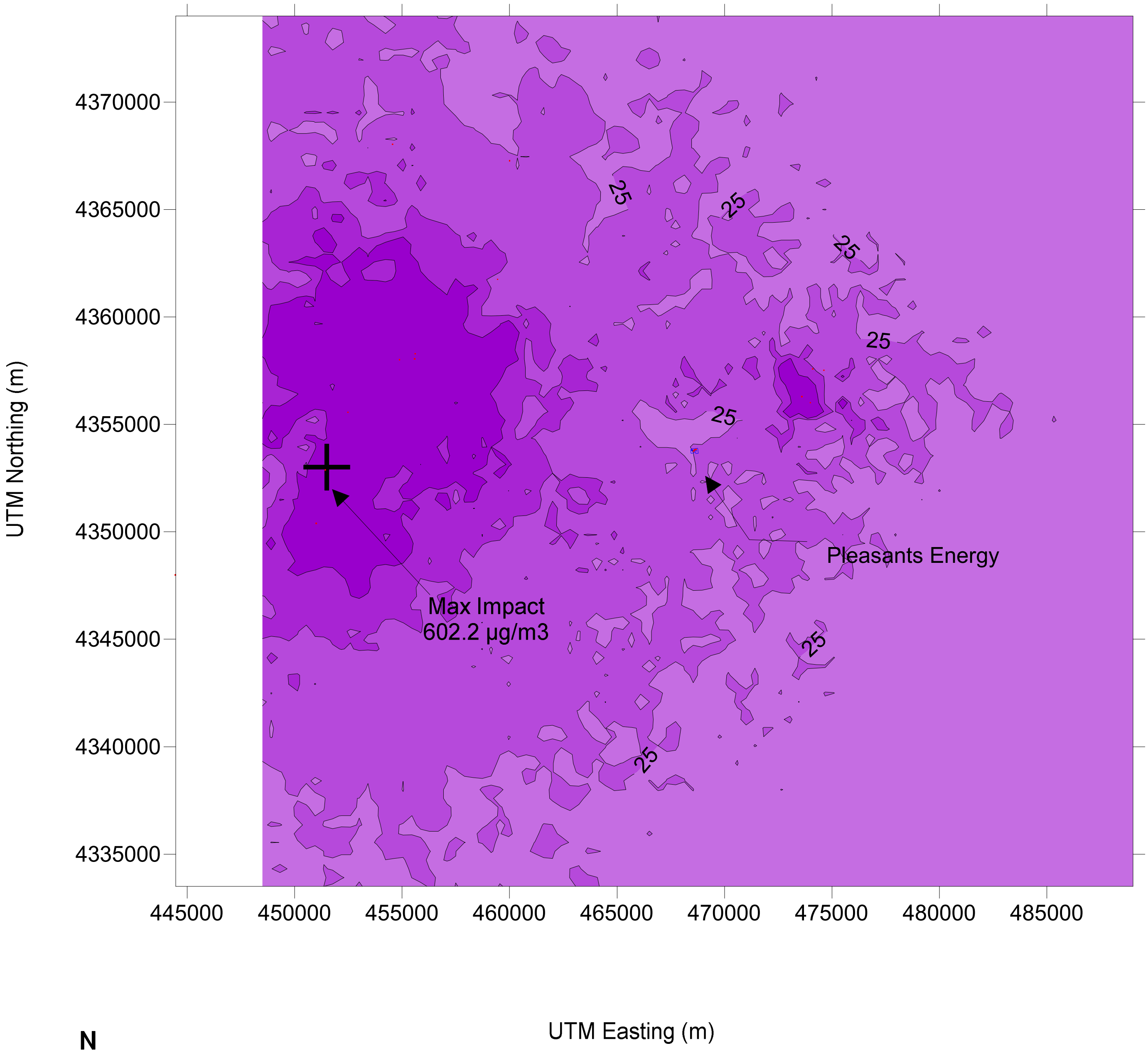
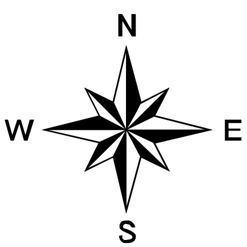
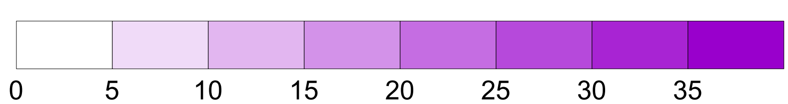
Figure G-14: NAAQS $PM_{2.5}$ 24-hour With Background (5 years)





Pleasants Energy Sources and Inventory Sources

Modeled Concentrations (µg/m³)



APPENDIX H – MODELING FILES

APPENDIX I – ADDITIONAL IMPACTS ANALYSIS

VISCREEN
Level I

Visual Effects Screening Analysis for
Source: Pleasants Energy
Class I Area: North Bend State Park

*** Level-1 Screening ***

Input Emissions for

Particulates	118.70	TON/YR
NOx (as NO2)	464.60	TON/YR
Primary NO2	0.00	TON/YR
Soot	0.00	TON/YR
Primary SO4	0.00	TON/YR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	0.04 ppm
Background Visual Range:	40.00 km
Source-Observer Distance:	25.00 km
Min. Source-Class I Distance:	25.00 km
Max. Source-Class I Distance:	25.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability: 6	
Wind Speed: 1.00 m/s	

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	25.0	84.	2.00	2.106*	0.05	0.005
SKY	140.	84.	25.0	84.	2.00	0.819	0.05	-0.013
TERRAIN	10.	84.	25.0	84.	2.00	1.220	0.05	0.014
TERRAIN	140.	84.	25.0	84.	2.00	0.251	0.05	0.008

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	168.	2.00	2.890*	0.05	0.031
SKY	140.	0.	1.0	168.	2.00	0.413	0.05	-0.020
TERRAIN	10.	0.	1.0	168.	2.00	3.545*	0.05	0.040
TERRAIN	140.	0.	1.0	168.	2.00	0.982	0.05	0.038

Visual Effects Screening Analysis for
Source: Pleasants Energy
Class I Area: Blennerhassett Island

*** Level-1 Screening ***

Input Emissions for

Particulates	118.70	TON/YR
NOx (as NO2)	464.60	TON/YR
Primary NO2	0.00	TON/YR
Soot	0.00	TON/YR
Primary SO4	0.00	TON/YR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	0.04 ppm
Background Visual Range:	40.00 km
Source-Observer Distance:	24.00 km
Min. Source-Class I Distance:	24.00 km
Max. Source-Class I Distance:	24.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	24.0	84.	2.00	2.186*	0.05	0.005
SKY	140.	84.	24.0	84.	2.00	0.854	0.05	-0.014
TERRAIN	10.	84.	24.0	84.	2.00	1.308	0.05	0.015
TERRAIN	140.	84.	24.0	84.	2.00	0.266	0.05	0.008

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	168.	2.00	3.147*	0.05	0.034
SKY	140.	0.	1.0	168.	2.00	0.450	0.05	-0.022
TERRAIN	10.	0.	1.0	168.	2.00	3.886*	0.05	0.045
TERRAIN	140.	0.	1.0	168.	2.00	1.068	0.05	0.041

VISCREEN
Level II

Visual Effects Screening Analysis for
Source: Pleasants Energy
Class I Area: North Bend State Park

*** User-selected Screening Scenario Results ***

Input Emissions for

Particulates	118.70	TON/YR
NOx (as NO2)	464.60	TON/YR
Primary NO2	0.00	TON/YR
Soot	0.00	TON/YR
Primary SO4	0.00	TON/YR

PARTICLE CHARACTERISTICS

	Density	Diameter
Primary Part.	2.5	6
Soot	2.0	1
Sulfate	1.5	4

Transport Scenario Specifications:

Background Ozone:	0.04 ppm
Background Visual Range:	40.00 km
Source-Observer Distance:	25.00 km
Min. Source-Class I Distance:	25.00 km
Max. Source-Class I Distance:	25.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	5
Wind Speed:	4.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	25.0	84.	2.29	0.296	0.05	0.001
SKY	140.	84.	25.0	84.	2.00	0.115	0.05	-0.002
TERRAIN	10.	84.	25.0	84.	2.00	0.172	0.05	0.002
TERRAIN	140.	84.	25.0	84.	2.00	0.035	0.05	0.001

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	168.	2.00	0.645	0.05	0.005
SKY	140.	0.	1.0	168.	2.00	0.118	0.05	-0.006
TERRAIN	10.	0.	1.0	168.	2.00	0.731	0.05	0.010
TERRAIN	140.	0.	1.0	168.	2.00	0.198	0.05	0.009

Visual Effects Screening Analysis for
Source: Pleasants Energy
Class I Area: Blennerhassett Island

*** User-selected Screening Scenario Results ***

Input Emissions for

Particulates	118.70	TON/YR
NOx (as NO2)	464.60	TON/YR
Primary NO2	0.00	TON/YR
Soot	0.00	TON/YR
Primary SO4	0.00	TON/YR

PARTICLE CHARACTERISTICS

	Density	Diameter
Primary Part.	2.5	6
Soot	2.0	1
Sulfate	1.5	4

Transport Scenario Specifications:

Background Ozone:	0.04 ppm
Background Visual Range:	40.00 km
Source-Observer Distance:	24.00 km
Min. Source-Class I Distance:	24.00 km
Max. Source-Class I Distance:	24.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	3.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	24.0	84.	2.00	0.743	0.05	0.002
SKY	140.	84.	24.0	84.	2.00	0.291	0.05	-0.005
TERRAIN	10.	84.	24.0	84.	2.00	0.445	0.05	0.005
TERRAIN	140.	84.	24.0	84.	2.00	0.089	0.05	0.003

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

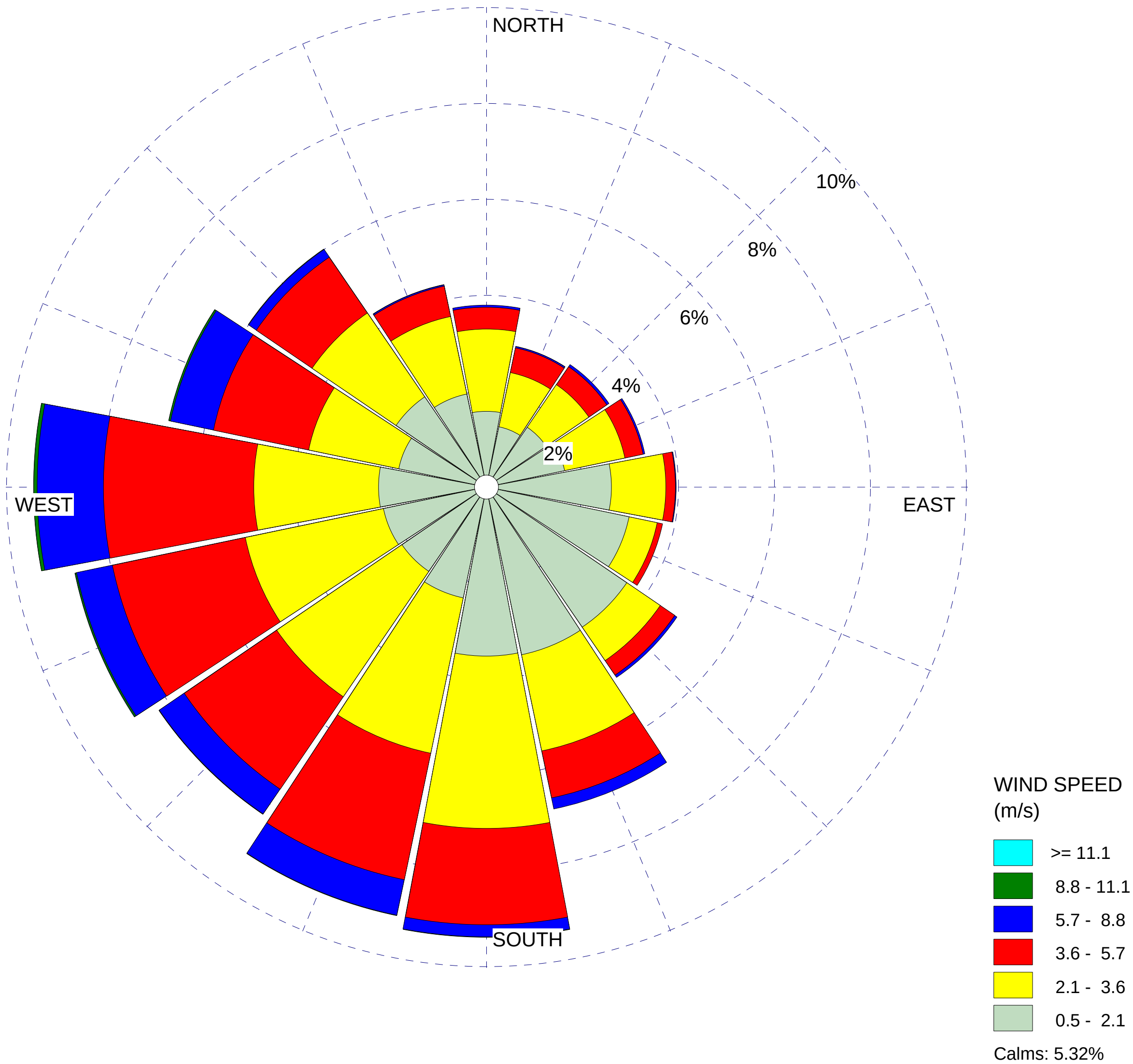
					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	168.	2.00	1.290	0.05	0.012
SKY	140.	0.	1.0	168.	2.00	0.201	0.05	-0.010
TERRAIN	10.	0.	1.0	168.	2.00	1.561	0.05	0.019
TERRAIN	140.	0.	1.0	168.	2.00	0.414	0.05	0.017

WIND ROSE PLOT:

Wind Rose for Parkersburg Wood County Airport (Station ID 03804)

DISPLAY:

Wind Speed
Direction (blowing from)



COMMENTS:

DATA PERIOD:

Start Date: 1/1/2010 - 00:00
End Date: 12/31/2014 - 23:00

CALM WINDS:

5.32%

TOTAL COUNT:

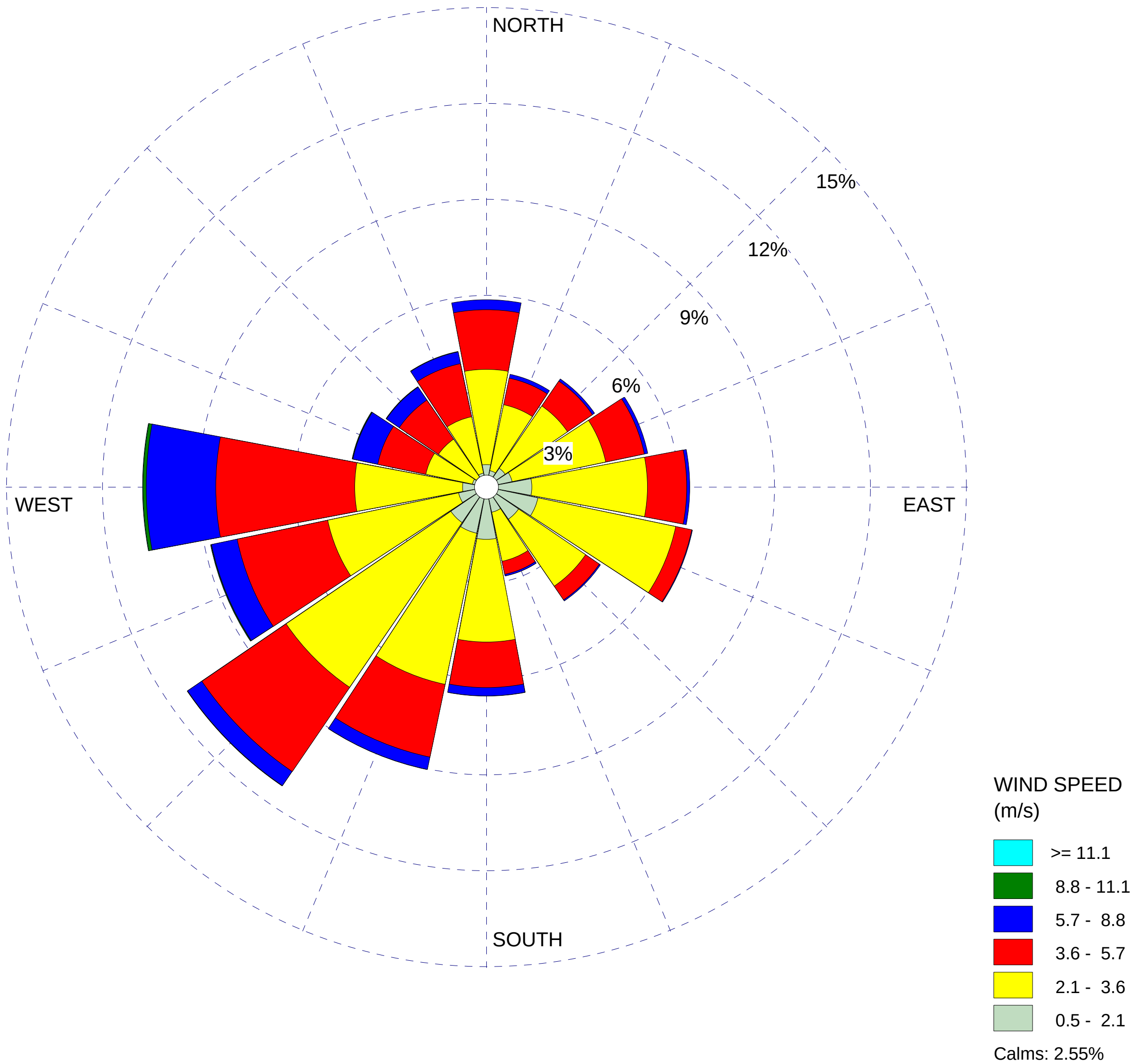
42136 hrs.

AVG. WIND SPEED:

2.63 m/s

PROJECT NO.:

WIND ROSE PLOT:	DISPLAY:
Wind Rose for Huntington Tri-State (Station ID 03860)	**Wind Speed** **Direction (blowing from)**



COMMENTS:	DATA PERIOD:		
	Start Date: 1/1/1986 - 00:00 **End Date: 12/31/1990 - 23:00**		
	CALM WINDS: **2.55%**	TOTAL COUNT: **43820 hrs.**	
	AVG. WIND SPEED: **3.02 m/s**		PROJECT NO.:

WRPLOT View - Lakes Environmental Software

North Bend State Park Joint Frequency Distribution*

Class	σ_y	σ_z	u	$\sigma_y\sigma_z u$	Transport Time (hr)	Probability							
						0 -6 hr		7-12 hr		13-18 hr		19-24 hr	
						%	Cumulative %	%	Cumulative %	%	Cumulative %	%	Cumulative %
F,1	609.75	85.68	1.00	52240.50	13.9	0.00	0.00	0.01	0.01	0.00	0.00	0.02	0.02
F,2	609.75	85.68	2.00	104481.01	4.6	0.10	0.10	0.01	0.02	0.00	0.00	0.13	0.15
E,1	915.66	141.85	1.00	129882.76	13.9	0.00	0.10	0.00	0.02	0.00	0.00	0.01	0.16
F,3	609.75	85.68	3.00	156721.51	2.8	0.26	0.36	0.00	0.02	0.00	0.00	0.27	0.43
E,2	915.66	141.85	2.00	259765.52	4.6	0.04	0.39	0.05	0.07	0.01	0.01	0.09	0.52
D,1	1222.78	255.11	1.00	311942.35	13.9	0.02	0.41	0.00	0.07	0.00	0.01	0.00	0.52
E,3	915.66	141.85	3.00	389648.28	2.8	0.27	0.68	0.05	0.13	0.04	0.05	0.34	0.86
E,4	915.66	141.85	4.00	519531.04	2.0	0.17	0.86	0.00	0.13	0.06	0.11	0.39	1.25
D,2	1222.78	255.11	2.00	623884.71	4.6	0.13	0.99	0.20	0.33	0.10	0.21	0.12	1.37
E,5	915.66	141.85	5.00	649413.80	1.5	0.12	1.11	0.01	0.34	0.01	0.22	0.13	1.50
D,3	1222.78	255.11	3.00	935827.06	2.8	0.31	1.42	0.46	0.79	0.61	0.83	0.51	2.01
D,4	1222.78	255.11	4.00	1247769.41	2.0	0.39	1.81	0.55	1.34	0.85	1.68	0.44	2.45
D,5	1222.78	255.11	5.00	1559711.77	1.5	0.38	2.19	0.48	1.83	0.69	2.37	0.42	2.87
D,6	1222.78	255.11	6.00	1871654.12	1.3	0.28	2.47	0.54	2.37	0.88	3.25	0.38	3.25
D,7	1222.78	255.11	7.00	2183596.47	1.1	0.17	2.65	0.36	2.72	0.72	3.97	0.31	3.56
D,8	1222.78	255.11	8.00	2495538.83	0.9	0.12	2.77	0.11	2.83	0.28	4.26	0.08	3.64

*Huntington/Tri-State Airport (Station ID 03860) was used for years 1986 to 1990

Blennerhassett Island State Historical Park Joint Frequency Distribution*

Class	σ_y	σ_z	u	$\sigma_y\sigma_z u$	Transport Time (hr)	Probability							
						0 -6 hr		7-12 hr		13-18 hr		19-24 hr	
						%	Cumulative %	%	Cumulative %	%	Cumulative %	%	Cumulative %
F,1	588.25	83.79	1.00	49289.23	13.3	0.10	0.10	0.01	0.01	0.00	0.00	0.05	0.05
F,2	588.25	83.79	2.00	98578.47	4.4	0.33	0.43	0.05	0.05	0.00	0.00	0.31	0.37
E,1	883.38	138.57	1.00	122414.03	13.3	0.02	0.45	0.03	0.08	0.00	0.00	0.05	0.41
F,3	588.25	83.79	3.00	147867.70	2.7	1.17	1.62	0.05	0.14	0.00	0.00	1.13	1.54
E,2	883.38	138.57	2.00	244828.05	4.4	0.15	1.76	0.16	0.30	0.00	0.00	0.11	1.65
D,1	1179.69	248.49	1.00	293140.53	13.3	0.01	1.77	0.06	0.37	0.00	0.00	0.04	1.69
E,3	883.38	138.57	3.00	367242.08	2.7	0.63	2.40	0.21	0.58	0.06	0.06	0.87	2.56
E,4	883.38	138.57	4.00	489656.11	1.9	0.35	2.75	0.05	0.62	0.06	0.13	0.43	2.99
D,2	1179.69	248.49	2.00	586281.06	4.4	0.17	2.92	0.35	0.97	0.16	0.28	0.25	3.23
E,5	883.38	138.57	5.00	612070.14	1.5	0.13	3.05	0.00	0.97	0.01	0.29	0.20	3.43
D,3	1179.69	248.49	3.00	879421.59	2.7	0.78	3.83	1.12	2.09	1.01	1.31	0.72	4.16
D,4	1179.69	248.49	4.00	1172562.12	1.9	0.54	4.37	0.84	2.93	0.98	2.28	0.57	4.72
D,5	1179.69	248.49	5.00	1465702.65	1.5	0.21	4.58	0.27	3.21	0.48	2.77	0.38	5.11
D,6	1179.69	248.49	6.00	1758843.18	1.2	0.16	4.73	0.17	3.38	0.16	2.92	0.15	5.25
D,7	1179.69	248.49	7.00	2051983.72	1.0	0.06	4.79	0.04	3.42	0.05	2.98	0.06	5.32
D,8	1179.69	248.49	8.00	2345124.25	0.9	0.03	4.82	0.02	3.43	0.02	3.00	0.00	5.32

*Huntington/Tri-State Airport (Station ID 03860) was used for years 1986 to 1990

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