

**ALLEGHENY COUNTY HEALTH DEPARTMENT  
AIR QUALITY PROGRAM**

March 29, 2021

**SUBJECT:** Allegheny Energy Center (AEC)  
2130 Margaret St. Ext.  
West Newton, PA, 15089  
Allegheny County

**Installation Permit No. 0959-I001**

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### **FACILITY DESCRIPTION:**

Invenergy plans to construct, own, and operate the Allegheny Energy Center (AEC), a 639 megawatt (MW), natural gas-fired combined-cycle power plant Elizabeth Township, Allegheny County. AEC will consist of a one-on-one (1×1), nominal 639 MW power plant that will include one combustion turbine (CT), one heat recovery steam generator (HRSG) with supplemental duct firing, and one steam turbine (ST). The proposed General Electric (GE) model (7HA.02) CT will fire clean low sulfur pipeline-quality natural gas. In addition to the CT and associated pieces of equipment, one auxiliary boiler, one dew point heater, one emergency generator, one fire water pump, and three above-ground storage tanks (AST) including a 20,000-gallon aqueous ammonia storage tank will be included as part of the facility.

The facility is a major source of nitrogen oxides (NO<sub>x</sub>), carbon monoxide (CO), and volatile organic compounds (VOCs) emissions and a minor source of particulate matter, particulate matter < 10 microns in diameter (PM<sub>10</sub>), particulate matter < 2.5 microns in diameter (PM<sub>2.5</sub>), sulfur dioxide (SO<sub>2</sub>), and hazardous air pollutants (HAPs) as defined in section 2101.20 of Article XXI and in 40 CFR Part 51 Subpart 165(a)(1)(iv)(A)(1).

### **INSTALLATION PERMIT DESCRIPTION**

This permit is for the installation of a natural gas-fired combined-cycle power block in a 1×1 configuration with a combustion turbine (CT), a heat recovery steam generator (HRSG) with a supplementary duct burner (DB), and a steam turbine (ST). The CT and the ST will have separate electric generators. Other components include an emergency generator, a fire water pump, an auxiliary boiler, a dew point heater, and four above-ground storage tanks. The principal product of this facility will be electricity.

### **PERMIT APPLICATION COMPONENTS:**

1. Installation Permit application #0959-I001, dated March 20, 2019
2. “Modeling Review of Invenergy LLC (Invenergy) Proposed Natural Gas Combined-Cycle Power Plant Installation Permit” (S. Vozar, ACHD Planning & Analysis Section)
3. Correspondence, dated January 9, 2019 (Questions from 1/4/19 Meeting)
4. Correspondence, dated February 12, 2019 (Invenergy Allegheny Energy Center Air Quality Modeling Protocol-Environmental Justice Areas)
5. Correspondence, dated April 11, 2019 (Emission Reduction Credits)
6. Correspondence, dated April 12, 2019 (NNSR Threshold for Modeling-NNSR for PM<sub>2.5</sub>)
7. Correspondence, dated May 21, 2019 (Request for Applicability of Class I Area AQRV Modeling Analysis)
8. Correspondence, dated May 22, 2019 (Draft Invenergy Modeling Review)
9. Correspondence, dated July 26, 2019 (CT and HRSG Specifications)
10. Correspondence, dated July 29, 2019 (Sulfuric Acid Emissions)

11. Correspondence, dated August 6, 2019 (Storage Tank Specifications and Project PM Emissions)
12. Correspondence, dated August 20, 2019 (Combined Cycle Power Block Emissions)
13. Correspondence, dated September 9, 2019 (Emergency Generator)
14. Correspondence, dated October 2, 2020 (Engine and Boiler Specifications)

**EMISSION SOURCES:**

**Table 1: Emissions Sources**

I.D.	SOURCE DESCRIPTION	CONTROL DEVICE(S)	MAXIMUM CAPACITY	FUEL/RAW MATERIAL	STACK I.D.
Combined Cycle Power Block					
CT01	General Electric 7HA.02 Combustion Turbine	Dry Low NO <sub>x</sub> burner, SCR, Oxidation Catalyst	3,844 MMBtu/hr (626 MW)	Natural Gas	S001
	Heat Recovery Steam Generator with Duct Burner		394 MMBtu/hr		
	Steam Turbine		--		
Ancillary Equipment					
EG01	MTU 16V4000 DS 2000 (or similar) Emergency Generator	None	2,000 kWe	Ultra-Low Sulfur Diesel	S002
WP01	JU6H-UFAD98 282 HP (or similar) Fire Water Pump	None	1.9 MMBtu/hr	Ultra-Low Sulfur Diesel	S003
B001	Custom Built Auxiliary Boiler	Ultra-Low NO <sub>x</sub> burner, Flue Gas Recirculation	88.7 MMBtu/hr	Natural Gas	S004
H001	Dew Point Heater	None	3.0 MMBtu/hr	Natural Gas	S005
T001	Aqueous Ammonia Storage Tank	None	20,000 gallons	Aqueous Ammonia	--
T002	Lubricating Oil Storage Tank	None	11,250 gallons	Lubricating Oil	--
T003	Emergency Generator Diesel Storage Tank	None	3,500 gallons	Ultra-Low Sulfur Diesel	--
T004	Fire Water Pump Diesel Storage Tank	None	500 gallons	Ultra-Low Sulfur Diesel	--
--	Circuit Breakers	None	1,473 pounds	Sulfur Hexafluoride	--

**STACKS:**

**Table 2: Stacks**

Stack ID	Stack Height (ft)	Stack Diameter (ft)	Exhaust Rate (acfm)	Exhaust Temp. (°F)	Lining/Outer Material
S001	180	22	1,710,000	155	pre-manufactured stainless steel
S002	15	1.5	16,100	896	pre-manufactured stainless steel
S003	12.5	0.5	1,400	961	pre-manufactured stainless steel
S004	35	4	22,964	270	pre-manufactured stainless steel
S005	25	1.5	2,208	660	pre-manufactured stainless steel

**METHOD OF DEMONSTRATING COMPLIANCE:**

Methods of demonstrating compliance with the emission standards set in this permit are summarized in Table 3 below. See operating permit No. 0959-I001 for the specific conditions for determining compliance with the applicable requirements. Compliance with the short-term (lb/hr) limits must be maintained at all times, including startup and shutdown unless explicitly stated otherwise in the permit. Any emissions due to startup and/or shutdown are included in facility’s total annual emissions.

**Table 3: Method(s) of Demonstrating Compliance**

TVOP Section	Process	Method(s) of Demonstrating Compliance
V.A.	639 MW Combined Cycle Power Block	<ul style="list-style-type: none"> <li>• annual performance tests for NO<sub>x</sub> emissions</li> <li>• install and certify a NO<sub>x</sub>-diluent CEMS</li> <li>• NO<sub>x</sub> and O<sub>2</sub> shall be determined by the certified CEMs at the outlet stack</li> <li>• perform PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, SO<sub>2</sub>, CO, NH<sub>3</sub>, and VOC emissions testing on the combustion turbine and HRSG stack</li> <li>• monitor the selective catalytic reduction (SCR) system and oxidation catalyst</li> <li>• operate and maintain continuous nitrogen oxides monitoring systems and other monitoring systems to convert data to required reporting units in compliance with 25 PA Code §§139.101 - 139.111 relating to requirements for continuous in-stack monitoring</li> <li>• operate and maintain continuous carbon monoxide monitoring systems and other monitoring systems to convert data to required reporting units in compliance with 25 PA Code §§139.101 - 139.111 and the PADEP’s "Continuous Source Monitoring Manual."</li> <li>• continuously monitor the oxygen content of the flue gas of the combustion turbine and HRSG</li> <li>• monitor the total sulfur content of the fuel being fired in the turbines</li> <li>• keep and maintain records of operation, maintenance, inspections, fuel usage, steam load, and SU/SD events for the combustion turbine and HRSG</li> <li>• maintain records of all air pollution control system performance evaluations and all records of calibration checks, adjustments, and maintenance performed on all equipment</li> <li>• keep a record of the date, time, and cause of the malfunction of all air pollution control systems, and the action taken to correct the malfunction</li> <li>• record start-up and shutdown of each combustion turbine including date, time and duration of each event</li> </ul>
V.B.	Emergency Generator (EG01)	<ul style="list-style-type: none"> <li>• keep and maintain records of operation, maintenance, inspections, and the manufacturer’s certification of the emission standards for the generator</li> <li>• Records of diesel fuel certifications from fuel suppliers shall be maintained per shipment</li> <li>• keep and maintain records of hours of operation and fuel shipments</li> </ul>
V.C.	Auxiliary Boiler (B001)	<ul style="list-style-type: none"> <li>• perform nitrogen oxides emissions testing on the Auxiliary Boiler at least once every five years in order to demonstrate compliance with the emission limitations</li> <li>• keep and maintain records of the amount of natural gas combusted, cold starts, total operating hours, and records of operation, maintenance, inspection, calibration, and/or replacement of equipment</li> </ul>

TVOP Section	Process	Method(s) of Demonstrating Compliance
V.D.	Dew Point Heater (H001)	<ul style="list-style-type: none"> <li>keep and maintain record of fuel consumption and records of operation, maintenance, inspection, calibration and/or replacement of combustion equipment</li> </ul>
V.E.	Aqueous Ammonium Storage Tank (T001)	<ul style="list-style-type: none"> <li>Monthly inspection</li> <li>keep and maintain monthly throughput, and concentration of the aqueous ammonia stored, and records of each inspection performed</li> </ul>
V.F.	Lubricating Oil Storage Tank (T002)	<ul style="list-style-type: none"> <li>Perform routine inspections on the tank annually</li> <li>keep readily accessible records showing the dimension of the diesel fuel storage tanks and an analysis showing its capacity</li> <li>records of throughput</li> </ul>
VI.A.	Fire Water Pump (WP01)	<ul style="list-style-type: none"> <li>Use only ULSD fuel</li> <li>install a non-resettable hour meter</li> <li>keep and maintain records of operation</li> </ul>
VI.B.	Diesel Storage Tanks (T003 & T004)	<ul style="list-style-type: none"> <li>perform routine inspections on the diesel fuel storage tanks annually</li> <li>keep readily accessible records showing the dimension of the diesel fuel storage tanks and an analysis showing its capacity</li> </ul>

**EMISSION CALCULATIONS:**

**639 Megawatt Combined Cycle Power Block**

Unit: Combined cycle power block (CT, HRSG with DB, and ST)  
 I.D.(s): CT01  
 Make: General Electric  
 Model: 7HA-02  
 Fuel: Pipeline quality natural gas only  
 Rating: 639 MW - 3,884 x 10<sup>6</sup> Btu/hr HHV nominal CT; 394 x 10<sup>6</sup> Btu/hr HHV DB  
 Exhaust: Heat recovery steam generator with duct burner  
 Controls: Dry Low-NO<sub>x</sub> burners with SCR and oxidation catalyst  
 Instrumentation: CEMs for fuel flow, exhaust gas flow, nitrogen oxides, oxygen and carbon monoxide

The short-term (hourly) emission rates for the combustion turbine were measured at 15% O<sub>2</sub> dry basis, at standard conditions, and are the manufacturer’s short-term emission rates for the worst operation case scenario tested, Case 15 (in the permit application). Based on manufacturer’s data, only emissions of NO<sub>x</sub>, CO, and VOC are higher during startup and shutdown (SU/SD) events. Emissions of other regulated NSR pollutants are equivalent to steady-state emissions during SU/SD. Annual emissions from the combustion turbine for NO<sub>x</sub>, CO, and VOC were calculated using the manufacturer’s short-term emission rates for the average operation case scenario tested, Case 1, and 8,200 hours of steady-state operation. The SU/SD emissions were then added to the calculated annual emission rates for NO<sub>x</sub>, CO, and VOC. The number of SU/SD events is assumed to be 365 events/year. Hot starts last 20 minutes and shutdowns last 12 minutes with a total SU/SD time lasting one hour. SU/SD time was subtracted from the total number of annual hours to arrive at the number of annual steady-state hours. Emission calculations for the remaining NSR pollutants are based on 8,760 hours of steady-state operation and on emission factors for the average operation case scenario tested, Case 1. Emission calculations for HAPs are based on 8,760 hours of steady-state operation and on emission factors found in U.S. EPA AP-42 Section 3.1: *Stationary Gas Turbines*. The following table summarizes the permitted limits:

**Table 4: Combined Cycle Power Block Emission Limits**

Pollutant	ppm <sub>vd</sub> <sup>1,4</sup>	SU/SD Emission Rates (lbs/event)	Maximum Hourly Emission Limit (lb/hr)	Average Hourly Emission Limit (lb/hr) <sup>2</sup>	Annual Emission Limit (tons/year) <sup>3</sup>
<b>Particulate Matter (Filterable)</b>	--	--	10.55	10.08	44.15
<b>PM<sub>10</sub></b>	--	--	21.11	20.16	88.30
<b>PM<sub>2.5</sub></b>	--	--	21.11	20.16	88.30
<b>Nitrogen Oxides</b>	2.0	90/14	30.90	30.00	141.99
<b>Sulfur Oxides</b>	--	--	5.60	5.40	23.65
<b>Carbon Monoxide</b>	2.0	390/85	18.80	18.30	161.72
<b>Volatile Organic Compounds</b>	1.5	205/125	8.10	7.88	92.51
<b>Sulfuric Acid Mist</b>	--	--	4.00	3.90	17.08
<b>Ammonia</b>	4.0	--	22.90	22.24	97.41
<b>Total HAP</b>	--	--	2.39	--	10.45
<b>Benzene</b>	--	--	0.047	--	0.21
<b>Ethylbenzene</b>	--	--	0.123	--	0.54
<b>Formaldehyde</b>	0.091	--	1.17	--	5.12
<b>Toluene</b>	--	--	0.50	--	2.19
<b>Xylenes</b>	--	--	0.246	--	1.08
<b>Lead</b>	--	--	$1.88 \times 10^{-4}$	--	$8.22 \times 10^{-4}$

<sup>1</sup> @15% O<sub>2</sub> during any three-hour time period at or above 70% of full load for NO<sub>x</sub> and any one-hour time at or above 70% of full load for CO.

<sup>2</sup> Average hourly emissions are used as the basis for total annual emissions.

<sup>3</sup> A year is defined as any consecutive 12-month period. Annual emissions include emissions during startup and shutdown. Maximum operating hours for the turbine are 8,200 hours per year.

<sup>4</sup> Based on a rolling 3-hour average

Example Calculation:

Steady-State (Average Scenario, Case 1):

$$\text{NO}_x = 30.00 \text{ lb/hr} \times 8,200.3 \text{ hr/yr} \div 2,000 \text{ lb/ton} = \mathbf{123.01 \text{ tons NO}_x/\text{yr}}$$

SU/SD:

$$[90 \text{ lbs/event NO}_x \times 365 \text{ events/yr} \div 2,000 \text{ lb/ton}] + [14 \text{ lbs/event NO}_x \times 365 \text{ events/yr} \div 2,000 \text{ lb/ton}] = \mathbf{18.98 \text{ tons NO}_x/\text{yr}}$$

$$\text{NO}_x = \mathbf{123.01 \text{ tons NO}_x/\text{yr} + 18.98 \text{ tons NO}_x/\text{yr} = \mathbf{141.99 \text{ tons/yr}}$$

GHG Mass and CO<sub>2</sub>e Emissions:

Calculations of greenhouse gases (GHG) and CO<sub>2</sub>-equivalent (CO<sub>2</sub>e) emissions are based on performance emissions/specifications from different operation case scenarios for the combustion turbine. The CO<sub>2</sub> emission factor, 439,000 lb/hr, was the average of all the tested operation scenarios (Case 1). The emissions factors for N<sub>2</sub>O and CH<sub>4</sub> are found in 40 CFR Part 98, Subpart C, §98.33(a)(1), Table C-2 and have been converted to lb/MMBtu. The maximum annual fuel consumption of the combustion turbine with the duct burner derived from the tested operation scenarios (Case 1 at 8,760 hours) is 36,079,812 MMBtu/yr.

$$\text{CO}_2: 439,000 \text{ lb/hr} \times 8,760 \text{ hr/yr} \div 2,000 \text{ lb/ton} = 1,922,820 \text{ tons/year}$$

$$\text{N}_2\text{O}: 36,079,812 \text{ MMBtu/yr} \times 2.2 \times 10^{-4} \text{ lb/MMBtu} \div 2,000 \text{ lb/ton} = 4 \text{ tons/year}$$

$$\text{CH}_4: 36,079,812 \text{ MMBtu/yr} \times 2.2 \times 10^{-3} \text{ lb/MMBtu} \div 2,000 \text{ lb/ton} = 40 \text{ tons/year}$$

Global Warming Potential (GWP) Factors (from Part 98, Subpart A, Table A-1):

CO<sub>2</sub> = 1  
 N<sub>2</sub>O = 298  
 CH<sub>4</sub> = 25

$$\text{CO}_2\text{e} = (1,922,820 \times 1) + (4 \times 298) + (40 \times 25) = \mathbf{1,924,999 \text{ tons/year of CO}_2\text{e}}$$

Note: Number is not exact due to rounding.

**Emergency Generator**

Generator Rating: 2,000 kW  
 Fuel Use (100%): 147.3 gal/hr  
 Brake Horse Power: 3,058 bhp  
 Fuel Oil Density: 7.39 lb/gal  
 Fuel Oil Sulfur Limit: 0.0015%  
 Operation: 100 hrs/yr

Calculations of emissions of PM, NO<sub>x</sub>, SO<sub>2</sub>, CO, VOC, and Pb from the generator are based on emission factors found in 40 CFR Part 89 Subpart B, Table 1 and U.S. EPA AP-42 Section 3.4: *Large Stationary Diesel and All Stationary Dual-fuel Engines* and Section 1.3: *Fuel Oil Combustion*.

**Table 5: Emergency Generator Emission Limits**

Pollutant	Emission Factor	Reference	Emission Limit (lb/hr)	Annual Emission Limit (tons/year) <sup>1</sup>
<b>Particulate Matter (Filterable)</b>	0.149 g/bhp-hr <sup>2</sup>	40 CFR §89.112, Table 1	1.01	0.050
<b>PM<sub>10</sub></b>	0.173 g/bhp-hr <sup>2</sup>	AP-42 Table 3.4-2	1.17	0.058
<b>PM<sub>2.5</sub></b>	0.173 g/bhp-hr <sup>2</sup>	AP-42 Table 3.4-2	1.17	0.058
<b>Nitrogen Oxides</b>	4.53 g/bhp-hr <sup>3</sup>	40 CFR §89.112, Table 1	30.56	1.528
<b>Sulfur Oxides</b>	5.50 x 10 <sup>-3</sup> g/bhp-hr <sup>4</sup>	AP-42, Table 3.4-1	0.04	0.002
<b>Carbon Monoxide</b>	2.61 g/bhp-hr <sup>3</sup>	40 CFR §89.112, Table 1	17.59	0.880
<b>Volatile Organic Compounds</b>	0.239 g/bhp-hr <sup>3</sup>	40 CFR §89.112, Table 1	1.61	0.080
<b>Sulfuric Acid Mist</b>	6.74 x 10 <sup>-4</sup> g/bhp-hr	(5)	4.55 x 10 <sup>-3</sup>	2.27 x 10 <sup>-4</sup>
<b>Ammonia</b>	6.62 lb/1,000 gal	(6)	0.99	0.049
<b>Lead</b>	9.0 x 10 <sup>-6</sup> lb/MMBtu	AP-42 Table 1.3-10	1.88 x 10 <sup>-4</sup>	9.39 x 10 <sup>-6</sup>

<sup>1</sup> A year is defined as any consecutive 12-month period.

<sup>2</sup> It is assumed that PM<sub>10</sub> = PM<sub>2.5</sub>. PM<sub>10</sub> and PM<sub>2.5</sub> emissions factors account for both the filterable and condensable portions of PM. The filterable portion of PM<sub>10</sub> and PM<sub>2.5</sub> was obtained through vendor supplied information. The condensable portion of PM<sub>10</sub> and PM<sub>2.5</sub> was obtained from AP-42 Chapter 3.4 Table 3.4-2 (10/96).

<sup>3</sup> 40 CFR §89.112, Table 1. E.F. in g/kW-hr x 0.7457 to g/bhp/hr. Published emissions factor is for NO<sub>x</sub>+NMHC. NO<sub>x</sub> emissions are assumed to be 95% of this factor and VOC emissions are 5% based "CARB Emission Factor for CI Diesel Engines - Percent HC in Relation to NMHC + NO<sub>x</sub>" policy.

<sup>4</sup> Diesel fuel content = 0.0015% (15 ppm).

<sup>5</sup> H<sub>2</sub>SO<sub>4</sub> emissions factor conservatively calculated based on 10% conversion of SO<sub>2</sub> to SO<sub>3</sub> and 100% conversion of SO<sub>3</sub> to H<sub>2</sub>SO<sub>4</sub>.

<sup>6</sup> EPA Emission Inventory Improvement Program, "Estimating Ammonia Emissions from Anthropogenic Nonagricultural Sources - Draft Final Report", April 2004.

**Example Calculation:**

$$\text{VOC} = 3,058 \text{ bhp} \times 0.239 \text{ g/bhp-hr} \div 453.6 \text{ g/lb} = 1.61 \text{ lb}_{\text{VOC}}/\text{hr}$$

$$1.61 \text{ lb}_{\text{VOC}}/\text{hr} \times 100 \text{ hrs/yr} \div 2,000 \text{ lb/ton} = \mathbf{0.080 \text{ tons VOC/yr}}$$

**GHG Mass and CO<sub>2</sub>e Emissions:**

Calculations of greenhouse gases (GHG) and CO<sub>2</sub>-equivalent (CO<sub>2</sub>e) emissions are based on the methodology found in 40 CFR Part 98, Subpart C, §98.33(a)(1), and factors found in Table C-1 and Table C-2 of that subpart. Per §98.30(b)(2), stationary fuel combustion sources do not include emergency generators and emergency equipment and was thus not included in the overall GHG calculation.

Total rated heat input capacity of the emergency generator = 20.87 MMBtu/hr × 100 hr/yr = 2,087 MMBtu/yr

Emission Factors:

$$\text{CO}_2 = 73.96 \text{ kg/MMBtu} \times 2.2046 \text{ lb/kg} = 163.05 \text{ lb/MMBtu}$$

$$\text{N}_2\text{O} = 6 \times 10^{-4} \text{ kg/MMBtu} \times 2.2046 \text{ lb/kg} = 1.32 \times 10^{-3} \text{ lb/MMBtu}$$

$$\text{CH}_4 = 3 \times 10^{-3} \text{ kg/MMBtu} \times 2.2046 \text{ lb/kg} = 6.61 \times 10^{-3} \text{ lb/MMBtu}$$

$$\text{CO}_2: 2,087 \text{ MMBtu/yr} \times 163.05 \text{ lb/MMBtu} \div 2,000 \text{ lb/ton} = 170 \text{ tons/year}$$

$$\text{N}_2\text{O}: 2,087 \text{ MMBtu/yr} \times 1.32 \times 10^{-3} \text{ lb/MMBtu} \div 2,000 \text{ lb/ton} = 1.38 \times 10^{-3} \text{ tons/year}$$

$$\text{CH}_4: 2,087 \text{ MMBtu/yr} \times 6.61 \times 10^{-3} \text{ lb/MMBtu} \div 2,000 \text{ lb/ton} = 6.90 \times 10^{-3} \text{ tons/year}$$

Global Warming Potential (GWP) Factors (from Part 98, Subpart A, Table A-1):

$$\text{CO}_2 = 1$$

$$\text{N}_2\text{O} = 298$$

$$\text{CH}_4 = 25$$

$$\text{CO}_2\text{e} = (170 \times 1) + (1.38 \times 10^{-3} \times 298) + (6.90 \times 10^{-3} \times 25) = \mathbf{171 \text{ tons/year of CO}_2\text{e}}$$

*Note: Number is not exact due to rounding.*

**Fire Water Pump**

Brake Horse Power:	282 bhp
Fuel Use (100%):	13.7 gal/hr
Fuel Oil Density:	7.39 lb/gal
Fuel Oil Sulfur Limit:	0.0015%
Operation:	100 hrs/yr

Calculations of emissions of PM, NO<sub>x</sub>, SO<sub>2</sub>, CO, VOC, and Pb from the fire water pump are based on emission factors found in 40 CFR Part 60 Subpart IIII, Table 4 and U.S. EPA AP-42 Sections 3.3: *Gasoline And Diesel Industrial Engines* and Section 1.3: *Fuel Oil Combustion*.

**Table 6: Fire Water Pump Emission Limits**

Pollutant	Emission Factor	Reference	Emission Limit (lb/hr)	Annual Emission Limit (tons/year) <sup>1</sup>
<b>Particulate Matter (Filterable)</b>	0.150 g/bhp-hr <sup>2</sup>	40 CFR §60.4205(c), Table 4	0.093	0.0047
<b>PM<sub>10</sub></b>	0.174 g/bhp-hr	(2)	0.108	0.0054
<b>PM<sub>2.5</sub></b>	0.174 g/bhp-hr	(2)	0.108	0.0054
<b>Nitrogen Oxides</b>	2.85 g/bhp-hr <sup>3</sup>	40 CFR §60.4205(c), Table 4	1.772	0.0886
<b>Sulfur Oxides</b>	0.93 g/bhp-hr <sup>4</sup>	AP-42, Table 3.3-1	0.578	0.0289
<b>Carbon Monoxide</b>	2.60 g/bhp-hr <sup>3</sup>	40 CFR §60.4205(c), Table 4	1.616	0.0808



Pollutant	Emission Factor	Reference	Emission Limit (lb/hr)	Annual Emission Limit (tons/year) <sup>1</sup>
<b>Volatile Organic Compounds</b>	0.150 g/bhp-hr <sup>3</sup>	40 CFR §60.4205(c), Table 4	0.093	0.0047
<b>Sulfuric Acid Mist</b>	0.114 g/bhp-hr	(5)	$7.08 \times 10^{-2}$	0.0035
<b>Ammonia</b>	6.62 lb/1,000 gal	(6)	0.0925	0.0046
<b>Lead</b>	$9.0 \times 10^{-6}$ lb/MMBtu	AP-42 Table 1.3-10	$1.75 \times 10^{-5}$	$8.73 \times 10^{-7}$

<sup>1</sup> A year is defined as any consecutive 12-month period.

<sup>2</sup> It is assumed that PM<sub>10</sub> = PM<sub>2.5</sub>. PM<sub>10</sub> and PM<sub>2.5</sub> emissions factors account for both the filterable and condensable portions of PM. The filterable portion of PM<sub>10</sub> and PM<sub>2.5</sub> was obtained through vendor supplied information. The condensable portion of PM<sub>10</sub> and PM<sub>2.5</sub> was obtained from AP-42 Chapter 3.4 Table 3.4-2 (10/96).

<sup>3</sup> 40 CFR §60.4205(c), Table 4. Published emissions factor is for NO<sub>x</sub>+NMHC. NO<sub>x</sub> emissions are assumed to be 95% of this factor and VOC emissions are 5% based "CARB Emission Factor for CI Diesel Engines - Percent HC in Relation to NMHC + NO<sub>x</sub>" policy.

<sup>4</sup> Diesel fuel content = 0.0015% (15 ppm).

<sup>5</sup> H<sub>2</sub>SO<sub>4</sub> emissions factor conservatively calculated based on 10% conversion of SO<sub>2</sub> to SO<sub>3</sub> and 100% conversion of SO<sub>3</sub> to H<sub>2</sub>SO<sub>4</sub>.

<sup>6</sup> EPA Emission Inventory Improvement Program, "Estimating Ammonia Emissions from Anthropogenic Nonagricultural Sources - Draft Final Report", April 2004.

**Example Calculation:**

$$\text{SO}_2 = 282 \text{ bhp} \times 0.93 \text{ g/bhp-hr} \div 453.6 \text{ g/lb} = 0.578 \text{ lb SO}_2/\text{hr}$$

$$0.578 \text{ lb SO}_2/\text{hr} \times 100 \text{ hrs/yr} \div 2,000 \text{ lb/ton} = \mathbf{0.0289 \text{ tons SO}_2/\text{yr}}$$

**GHG Mass and CO<sub>2</sub>e Emissions:**

Calculations of greenhouse gases (GHG) and CO<sub>2</sub>-equivalent (CO<sub>2</sub>e) emissions are based on the methodology found in 40 CFR Part 98, Subpart C, §98.33(a)(1), and factors found in Table C-1 and Table C-2 of that subpart.

Total rated heat input capacity of the fire water pump = 1.94 MMBtu/hr × 100 hr/yr = 194 MMBtu/yr

Emission Factors:

$$\text{CO}_2 = 73.96 \text{ kg/MMBtu} \times 2.2046 \text{ lb/kg} = 163.05 \text{ lb/MMBtu}$$

$$\text{N}_2\text{O} = 6 \times 10^{-4} \text{ kg/MMBtu} \times 2.2046 \text{ lb/kg} = 1.32 \times 10^{-3} \text{ lb/MMBtu}$$

$$\text{CH}_4 = 3 \times 10^{-3} \text{ kg/MMBtu} \times 2.2046 \text{ lb/kg} = 6.61 \times 10^{-3} \text{ lb/MMBtu}$$

$$\text{CO}_2: 194 \text{ MMBtu/yr} \times 163.05 \text{ lb/MMBtu} \div 2,000 \text{ lb/ton} = 16 \text{ tons/year}$$

$$\text{N}_2\text{O}: 194 \text{ MMBtu/yr} \times 1.32 \times 10^{-3} \text{ lb/MMBtu} \div 2,000 \text{ lb/ton} = 1.28 \times 10^{-4} \text{ tons/year}$$

$$\text{CH}_4: 194 \text{ MMBtu/yr} \times 6.61 \times 10^{-3} \text{ lb/MMBtu} \div 2,000 \text{ lb/ton} = 6.42 \times 10^{-4} \text{ tons/year}$$

Global Warming Potential (GWP) Factors (from Part 98, Subpart A, Table A-1):

$$\text{CO}_2 = 1$$

$$\text{N}_2\text{O} = 298$$

$$\text{CH}_4 = 25$$

$$\text{CO}_2\text{e} = (16 \times 1) + (1.28 \times 10^{-4} \times 298) + (6.42 \times 10^{-4} \times 25) = \mathbf{16 \text{ tons/year of CO}_2\text{e}}$$

Note: Number is not exact due to rounding.

**Fuel Oil No. 2 Storage Tanks**

Emissions from the emergency generator and the fire pump engine ultra-low sulfur diesel storage tanks were estimated using U.S. EPA AP-42 Sections 7.1: *Organic Liquid Storage Tanks* for each tank. See the calculations spreadsheet Appendix A for a complete breakdown for each tank.

**Table 7: Fuel Oil No. 2 Storage Tanks Emissions Limits**

Pollutant	Annual Emission Limit (tons/year)
Volatile Organic Compounds	0.0056

**Aqueous Ammonia Storage Tank**

Emissions from the aqueous ammonia storage tank are considered insignificant.

**Lubricating Oil Storage Tank**

Emissions from the lubricating oil storage tank was estimated using U.S. EPA AP-42 Sections 7.1: *Organic Liquid Storage Tanks* for each tank. See the calculations spreadsheet Appendix A for a complete breakdown for the tank.

**Table 8: Lubricating Oil Storage Tank Emission Limits**

Pollutant	Annual Emission Limit (tons/year)
Volatile Organic Compounds	0.02

**Fugitive Emissions**

Fugitive greenhouse gas emissions were based on 40 CFR Part 98, Subpart W emission factors for fugitive piping and 40 CFR Part 98, Subpart A emission factors for natural gas pipe maintenance and for the circuit breakers, pumping rates (where applicable), and throughput factors to account for actual usage times. See the calculations spreadsheet Appendix A for a complete table of components, pumping rates, throughput factors, and individual emission rates.

**Auxiliary Boiler**

Heating rate: 88.7 MMBtu/hr  
 Natural gas heating value: 1,050 Btu/scf  
 Operation: 4,000 hrs/yr

Emission calculations for PM and Pb were based on emission factors found in U.S. EPA AP-42 Section 1.4: *Natural Gas Combustion (7/98)*; NO<sub>x</sub>, CO, and VOC emissions were based on manufacturer’s data. SO<sub>2</sub> emissions were calculated using a 0.4 gr/100 scf BACT equivalent.

**Table 9: Boiler Emission Limits**

Pollutant	Emission Factor	Reference	Emission Limit (lb/hr)	Annual Emission Limit (tons/year) <sup>1</sup>
<b>Particulate Matter (filterable)</b>	1.81 x 10 <sup>-3</sup> lb/MMBtu	AP-42, Table 1.4-2 (7/98)	0.161	0.321
<b>PM<sub>10</sub></b>	1.49 x 10 <sup>-3</sup> lb/MMBtu	U.S. EPA’s Emission Inventory and Analysis Group guidance 3/30/2012 with 3x safety factor	0.132	0.264
<b>PM<sub>2.5</sub></b>	1.23 x 10 <sup>-3</sup> lb/MMBtu		0.109	0.218
<b>Nitrogen Oxides</b>	0.011 lb/MMBtu	Mfg. data	0.976	1.951
<b>Sulfur Oxides</b>	1.09 x 10 <sup>-3</sup> lb/MMBtu	(2)	0.097	0.193

Pollutant	Emission Factor	Reference	Emission Limit (lb/hr)	Annual Emission Limit (tons/year) <sup>1</sup>
<b>Carbon Monoxide</b>	0.041 lb/MMBtu	Mfg. data	3.637	7.273
<b>Volatile Organic Compounds</b>	0.004 lb/MMBtu	Mfg. data	0.355	0.710
<b>Sulfuric Acid Mist</b>	1.33 x 10 <sup>-4</sup> lb/MMBtu	(3)	0.012	0.024
<b>Ammonia</b>	3.20 lb/MMscf	(4)	0.270	0.541
<b>Lead</b>	5.0 x 10 <sup>-4</sup> lb/MMscf	AP-42, Table 1.4-2 (7/98)	4.22 x 10 <sup>-5</sup>	8.44 x 10 <sup>-5</sup>

<sup>1</sup> A year is defined as any consecutive 12-month period.

<sup>2</sup> SO<sub>2</sub> emissions factor is calculated based on a 0.4 gr/100 scf sulfur content of natural gas (BACT equivalent from the RACT/BACT/LAER Clearinghouse) and converted to lb/MMBtu.

<sup>3</sup> H<sub>2</sub>SO<sub>4</sub> emissions factor conservatively calculated based on 10% conversion of SO<sub>2</sub> to SO<sub>3</sub> and 100% conversion of SO<sub>3</sub> to H<sub>2</sub>SO<sub>4</sub>.

<sup>4</sup> EPA Emission Inventory Improvement Program, "Estimating Ammonia Emissions from Anthropogenic Nonagricultural Sources - Draft Final Report", April 2004.

**Example Calculation:**

$$\text{CO} = 88.7 \text{ MMBtu/hr} \times 0.041 \text{ lb/MMBtu} = 3.64 \text{ lb CO/hr}$$

$$3.64 \text{ lb CO/hr} \times 4,000 \text{ hrs/yr} \div 2,000 \text{ lb/ton} = \mathbf{7.27 \text{ tons CO/yr}}$$

**GHG Mass and CO<sub>2</sub>e Emissions:**

Calculations of greenhouse gases (GHG) and CO<sub>2</sub>-equivalent (CO<sub>2</sub>e) emissions are based on the methodology found in 40 CFR Part 98, Subpart C, §98.33(a)(1), and factors found in Table C-1 and Table C-2 of that subpart.

Total rated heat input capacity of the auxiliary boiler = 88.7 MMBtu/hr × 4,000 hr/yr = 354,800 MMBtu/yr

Emission Factors:

$$\text{CO}_2 = 53.06 \text{ kg/MMBtu} \times 2.2046 \text{ lb/kg} = 116.98 \text{ lb/MMBtu}$$

$$\text{N}_2\text{O} = 1 \times 10^{-4} \text{ kg/MMBtu} \times 2.2046 \text{ lb/kg} = 2.2 \times 10^{-4} \text{ lb/MMBtu}$$

$$\text{CH}_4 = 1 \times 10^{-3} \text{ kg/MMBtu} \times 2.2046 \text{ lb/kg} = 2.2 \times 10^{-3} \text{ lb/MMBtu}$$

$$\text{CO}_2: 354,800 \text{ MMBtu/yr} \times 116.98 \text{ lb/MMBtu} \div 2,000 \text{ lb/ton} = 20,752 \text{ tons/year}$$

$$\text{N}_2\text{O}: 354,800 \text{ MMBtu/yr} \times 2.2 \times 10^{-4} \text{ lb/MMBtu} \div 2,000 \text{ lb/ton} = 0.04 \text{ tons/year}$$

$$\text{CH}_4: 354,800 \text{ MMBtu/yr} \times 2.2 \times 10^{-3} \text{ lb/MMBtu} \div 2,000 \text{ lb/ton} = 0.39 \text{ tons/year}$$

Global Warming Potential (GWP) Factors (from Part 98, Subpart A, Table A-1):

$$\text{CO}_2 = 1$$

$$\text{N}_2\text{O} = 298$$

$$\text{CH}_4 = 25$$

$$\text{CO}_2\text{e} = (20,752 \times 1) + (0.04 \times 298) + (0.39 \times 25) = \mathbf{20,773 \text{ tons/year of CO}_2\text{e}}$$

*Note: Number is not exact due to rounding.*

**Dew Point Heater**

Heating rate: 3.0 MMBtu/hr

Natural gas heating value: 1,050 Btu/scf

Operation: 8,760 hrs/yr

Emission calculations for Pb were based on emission factors found in U.S. EPA AP-42 Section 1.4: *Natural Gas Combustion (7/98)*; PM, NO<sub>x</sub>, CO, and VOC emissions were based on manufacturer's data. SO<sub>2</sub> emissions were calculated using a 0.4 gr/100 scf BACT equivalent.

**Table 10: Dew Point Heater Emission Limits**

Pollutant	Emission Factor	Reference	Emission Limit (lb/hr)	Annual Emission Limit (tons/year) <sup>1</sup>
<b>Particulate Matter</b>	4.80 x 10 <sup>-3</sup> lb/MMBtu	Mfg. data	0.014	0.063
<b>PM<sub>10</sub></b>	1.49 x 10 <sup>-3</sup> lb/MMBtu	U.S. EPA's Emission Inventory and Analysis Group guidance 3/30/2012 with 3x safety factor	4.46 x 10 <sup>-3</sup>	0.020
<b>PM<sub>2.5</sub></b>	1.23 x 10 <sup>-3</sup> lb/MMBtu		3.69 x 10 <sup>-3</sup>	0.016
<b>Nitrogen Oxides</b>	0.011 lb/MMBtu	Mfg. data	0.033	0.145
<b>Sulfur Oxides</b>	1.09 x 10 <sup>-3</sup> lb/MMBtu	(2)	0.003	0.014
<b>Carbon Monoxide</b>	0.037 lb/MMBtu	Mfg. data	0.111	0.486
<b>Volatile Organic Compounds</b>	0.005 lb/MMBtu	Mfg. data	0.015	0.066
<b>Sulfuric Acid Mist</b>	1.33 x 10 <sup>-4</sup> lb/MMBtu	(3)	4.0 x 10 <sup>-4</sup>	0.002
<b>Ammonia</b>	3.20 lb/MMscf	(4)	0.009	0.040
<b>Lead</b>	5.0 x 10 <sup>-4</sup> lb/MMscf	AP-42, Table 1.4-2 (7/98)	1.43 x 10 <sup>-6</sup>	6.26 x 10 <sup>-6</sup>

<sup>1</sup> A year is defined as any consecutive 12-month period.

<sup>2</sup> SO<sub>2</sub> emissions factor is calculated based on a 0.4 gr/100 scf sulfur content of natural gas (BACT equivalent from the RACT/BACT/LAER Clearinghouse) and converted to lb/MMBtu.

<sup>3</sup> H<sub>2</sub>SO<sub>4</sub> emissions factor conservatively calculated based on 10% conversion of SO<sub>2</sub> to SO<sub>3</sub> and 100% conversion of SO<sub>3</sub> to H<sub>2</sub>SO<sub>4</sub>.

<sup>4</sup> EPA Emission Inventory Improvement Program, "Estimating Ammonia Emissions from Anthropogenic Nonagricultural Sources - Draft Final Report", April 2004.

Example Calculation:

$$\text{VOC} = 3.0 \text{ MMBtu/hr} \times 0.005 \text{ lb/MMBtu} = 0.015 \text{ lb VOC/hr}$$

$$0.015 \text{ lb VOC/hr} \times 8,760 \text{ hrs/yr} \div 2,000 \text{ lb/ton} = \mathbf{0.066 \text{ tons VOC/yr}}$$

GHG Mass and CO<sub>2</sub>e Emissions:

Calculations of greenhouse gases (GHG) and CO<sub>2</sub>-equivalent (CO<sub>2</sub>e) emissions are based on the methodology found in 40 CFR Part 98, Subpart C, §98.33(a)(1), and factors found in Table C-1 and Table C-2 of that subpart.

Total rated heat input capacity of the dew point heater = 3.0 MMBtu/hr × 8,760 hr/yr = 26,280 MMBtu/yr

Emission Factors:

$$\text{CO}_2 = 53.06 \text{ kg/MMBtu} \times 2.2046 \text{ lb/kg} = 116.98 \text{ lb/MMBtu}$$

$$\text{N}_2\text{O} = 1 \times 10^{-4} \text{ kg/MMBtu} \times 2.2046 \text{ lb/kg} = 2.2 \times 10^{-4} \text{ lb/MMBtu}$$

$$\text{CH}_4 = 1 \times 10^{-3} \text{ kg/MMBtu} \times 2.2046 \text{ lb/kg} = 2.2 \times 10^{-3} \text{ lb/MMBtu}$$

$$\text{CO}_2: 26,280 \text{ MMBtu/yr} \times 116.98 \text{ lb/MMBtu} \div 2,000 \text{ lb/ton} = 1,537 \text{ tons/year}$$

$$\text{N}_2\text{O}: 26,280 \text{ MMBtu/yr} \times 2.2 \times 10^{-4} \text{ lb/MMBtu} \div 2,000 \text{ lb/ton} = 2.9 \times 10^{-3} \text{ tons/year}$$

$$\text{CH}_4: 26,280 \text{ MMBtu/yr} \times 2.2 \times 10^{-3} \text{ lb/MMBtu} \div 2,000 \text{ lb/ton} = 0.03 \text{ tons/year}$$

Global Warming Potential (GWP) Factors (from Part 98, Subpart A, Table A-1):

$$\text{CO}_2 = 1$$

$$\text{N}_2\text{O} = 298$$

$$\text{CH}_4 = 25$$

$$\text{CO}_2\text{e} = (1,537 \times 1) + (2.9 \times 10^{-3} \times 298) + (0.03 \times 25) = \mathbf{1,539 \text{ tons/year of CO}_2\text{e}}$$

*Note: Number is not exact due to rounding.*

**Sources of Minor Significance/Miscellaneous Sources**

Table 11 lists sources determined to be of minor significance.

**Table 11: Sources of Minor Significance/Miscellaneous Sources**

ID	SOURCE DESCRIPTION	CONTROL DEVICE(S)	MAXIMUM CAPACITY	FUEL/RAW MATERIAL	STACK ID
WP01	JU6H-UFAD98 282 HP Water Pump	Tier 3	282 bhp/1.9 MMBtu/hr	Ultra-Low Sulfur Diesel	S04
T003	Emergency Generator Diesel Storage Tank	Uncontrolled	3,500 gallons	Diesel	--
T004	Fire Water Pump Diesel Storage Tank	Uncontrolled	500 gallons	Diesel	--
--	Natural Gas Piping Fugitives	Uncontrolled	--	Natural Gas	--
--	Natural Gas Maintenance + SU/SD Venting	Uncontrolled	--	Natural Gas	--
--	SF6 Circuit Breakers	Uncontrolled	1,474 lb/yr	Sulfur Hexafluoride	--

**APPLICABILITY ANALYSIS FOR NONATTAINMENT NEW SOURCE REVIEW (NSR)**

Because the AEC is a new source and a major source under Title V, Nonattainment New Source Review (NSR) applies. The regulations for NSR can be found under 25 Pa. Code §127.203a (as referenced under Article XXI, §2102.06.a), and apply to pollutants for which Allegheny County is designated as being in nonattainment. These include ozone (NO<sub>x</sub> and VOC) and PM<sub>2.5</sub>. With respect to ozone precursors, the Project is a major source for NO<sub>x</sub> and VOC. Therefore, the facility’s potential project-related emissions of NO<sub>x</sub> and VOC will trigger major source NSR requirements as precursor emissions to O<sub>3</sub>, and NO<sub>x</sub> emissions will trigger NSR requirements as precursor emissions to PM<sub>2.5</sub>. Project SO<sub>2</sub> and direct PM<sub>2.5</sub> emissions do not exceed the major NSR thresholds, therefore NSR is not triggered for SO<sub>2</sub> or PM<sub>2.5</sub>.

The applicability analysis for NSR is a two-step process. Step 1 is to calculate the emissions increases only and determine if they exceed the significant increase threshold. Step 2 is to calculate the net emissions increase (project increases + contemporaneous increases – contemporaneous decreases) and determine if they exceed the significant increase threshold. No netting analysis is necessary, in this case, because the facility is a new major source.

**NSR Step 1 – Increases Due to Project**

Step 1 is to calculate the emissions increase due to the project and compare to the NSR significant increase threshold values. Different calculation methodologies are used for existing and new units. Since the facility is a new source, all units are new emission units under 40 CFR §52.21(b)(7)(i) and 25 PA Code §121.1.

Under §127.203a(a)(1)(i)(B), the emissions increase for new emission units (i.e., the combustion turbine, HRSG, and all ancillary equipment) is the potential to emit.

**Table 12: Nonattainment New Source Review Applicability**

Pollutant	NO <sub>x</sub>	VOC	SO <sub>2</sub>	PM <sub>2.5</sub>
Total Project Emissions (tpy)	145.70	93.40	23.89	88.60
NSR Major Source Threshold	100	50	100	100
Subject to NSR Review?	Yes	Yes	No	No

**NSR Step 2 – Netting Analysis**

No netting analysis is required since this is a new major source.

**LAER Analysis**

As shown in the table above AEC proposed project potential emissions of NO<sub>x</sub> and VOC exceed the NSR major source thresholds. NSR requirements for NO<sub>x</sub> and VOC and include Lowest Achievable Emission Rate (LAER) and purchasing Emission Reduction Credits (ERCs). A complete LAER analysis can be found in Section 5 of the application. A summary of the LAER analysis can be found in Appendix B of this document.

LAER for this facility includes an SCR, dry low-NO<sub>x</sub> combustors, and catalytic oxidation on the CT and HRSG, ultra-low NO<sub>x</sub> burners and FGR on the Auxiliary Boiler, ultra-low sulfur diesel on the Emergency Generator and Fire Water Pump, and good engineering practice.

**Emission Reduction Credits**

Per §127.205(4), the facility is required to purchase Emission Reduction Credits (ERCs) prior to commencement of operation of any sources at the facility to offset the total of the net increase in potential to emit.

**Table 13: Emissions Reduction Credits**

Pollutant	Total Project-Wide Emissions (tpy)	Offset Ratio	ERC Offsets (tons)
NO <sub>x</sub>	146	1.15	168
VOC (stack emissions)	93		107
VOC (fugitive emissions)	2.95E-02	1.3	3.83E-02
		<b>Total</b>	<b>275</b>

**Environmental Justice**

According to Appendix A of the Pennsylvania Environmental Justice Public Participation Policy (Document ID #012-0501-002, April 24, 2004), Trigger Air Permits include new major sources of hazardous air pollutants or criteria pollutants. The location of the project is in Elizabeth Borough, Allegheny County, which is not considered an Environmental Justice area. However, the project impacts Smithdale, in Allegheny County, and West Newton and Sutersville, both in Westmoreland County. Therefore, this application is subject to the Enhanced Public Participation Policy. A public information session was held on July 11, 2019.

**Analysis of Alternatives**

In accordance with 25 Pa. Code § 127.205(5), an analysis shall be conducted of alternative sites, sizes, production processes, and environmental control techniques for the proposed facility, which demonstrates that the benefits of the proposed facility significantly outweigh the environmental and social costs imposed within this Commonwealth as a result of its location, construction or modification. A complete Alternatives Analysis can be found in Section 7 of the application. The analysis evaluated alternatives to the current project scope for the following five items:

- Physical location of the proposed project
- Size of the project
- Approach selected to generate electricity
- Type of emissions controls evaluated
- Economic, social, and environmental impacts

Since the emissions profile from the facility has been designed to be as minimally impacting as possible, locating the facility in Allegheny County will have minimal impact on the local air quality related to ozone, PM<sub>2.5</sub>, and SO<sub>2</sub>. Air quality modeling and other analyses that have been conducted for the project also support a

demonstration of minimal concentrations of ozone, PM<sub>2.5</sub>, and SO<sub>2</sub> resulting from AEC emissions. Considering alternate project sites in place of the proposed site would not significantly improve the surrounding air quality since regional sources located outside of Allegheny County are likely contributors to existing ozone and PM<sub>2.5</sub> concentration levels.

**APPLICABILITY ANALYSIS FOR PREVENTION OF SIGNIFICANT DETERIORATION (PSD)**

Because the AEC is a new source and a major source under Title V, New Source Review Prevention of Significant Deterioration (PSD) applies. The regulations for PSD can be found under 40 CFR, §52.21 (as referenced under Article XXI, §2102.07.a), and apply to pollutants for which Allegheny County is designated as being in attainment or unclassified. These include NO<sub>2</sub>, SO<sub>x</sub> (as SO<sub>2</sub>), CO, and CO<sub>2e</sub>. Additionally, PSD applies only to those sources considered a major source under PSD. For this facility, the major source threshold is 100 tpy of any regulated NSR pollutant.

PSD permitting requirements for major sources as defined in 40 CFR 52.21(b)(1)(i)(a) are triggered because the facility’s potential project-related emissions of NO<sub>x</sub> and CO exceed the major source applicability threshold of 100 tons per year (tpy). Therefore, PSD significant emissions rates (SER) as defined in 40 CFR 52.21(b)(23) apply to emissions of sulfuric acid mist (H<sub>2</sub>SO<sub>4</sub>), CO, PM, PM<sub>10</sub>, and NO<sub>x</sub> (which is assessed as nitrogen dioxide (NO<sub>2</sub>) for air quality modeling purposes). Additionally, potential emissions of greenhouse gases (CO<sub>2e</sub>) are greater than 100,000 tpy, and therefore the project is also subject to PSD for CO<sub>2e</sub>. Lead (Pb) emissions do not exceed the PSD SER, therefore, PSD is not triggered for Pb. Total HAPs emissions from the Project will not exceed 25 tpy and individual HAP emissions will not exceed 10 tpy. Therefore, the AEC Facility will not be a major stationary source of HAPs.

The applicability analysis for PSD is a two-step process. Step 1 is to calculate the emissions increases only and determine if they exceed the significant increase threshold. If the emissions in Step 1 exceed the significant increase threshold, Step 2 is to calculate the net emissions increase (project increases + contemporaneous increases – contemporaneous decreases) and determine if they exceed the significant increase threshold. No netting analysis is necessary because the facility is a new major source.

**PSD Step 1 – Increases Due to Project**

As in NSR Step 1, PSD Step 1 is to calculate the emissions increase due to the project and compare to the PSD significant increase threshold values. Since the facility is a new source, all units are new emission units and future allowable emissions for the new units are calculated using the PTE are compared to the SERs.

Under §52.21(b)(41)(ii)(d), the emissions increase for new emission units (i.e., the combustion turbine, HRSG, and all ancillary equipment) is the potential to emit.

**Table 14: Prevention of Significant Deterioration Applicability**

Pollutant	NO <sub>x</sub>	CO	PM/PM <sub>10</sub>	H <sub>2</sub> SO <sub>4</sub>	Pb	CO <sub>2e</sub>
Total Project Emissions (tpy)	145.70	170.44	44.59/88.65	17.11	9.23×10 <sup>-4</sup>	1,948,493
PSD Significant Emissions Threshold	40	100	25/15	7	0.6	75,000
Subject to PSD Review?	Yes	Yes	Yes	Yes	No	Yes

**PSD Step 2 – Netting Analysis**

No netting analysis is required since this is a new major source.

**BACT Analysis**

As shown in the table above AEC proposed project potential emissions of NO<sub>x</sub>, CO, PM, PM<sub>10</sub>, and H<sub>2</sub>SO<sub>4</sub> exceed the PSD thresholds. PSD requirements include Best Available Control Technology (BACT). A complete BACT analysis can be found in Section 5 of the application. A summary of the BACT analysis can be found in Appendix B of this document.

BACT for this facility includes catalytic oxidation on the CT and HRSG, low sulfur fuels in the combustion equipment, ultra-low sulfur diesel in the Emergency Generator and Fire Water Pump, a fugitive dust prevention and control plan, and good engineering practice.

### **Air Quality Modeling Analysis**

In accordance with the Prevention of Significant Deterioration (PSD) rules in 40 CFR § 52.21 and ACHD Article XXI §2102.07(a), a full air quality analysis was performed by AEC and reviewed by ACHD. A summary of the analysis may be found in Appendix C of this document. Detailed analyses may be found in Section 6 of the application and in the document “Modeling Review of Invenergy LLC (Invenergy) Proposed Natural Gas Combined-Cycle Power Plant Installation Permit”.

### **Federal Land Managers**

In accordance with 40 CFR §52.21(p), written notice of Allegheny Energy Center’s proposed facility has been provided to the Federal Land Managers (FLMs) from the U.S Forest Service (USFS) and the National Park Service (NPS) of nearby Class I areas as well as initial screening calculations. Both indicated that no negative impacts to visibility and air quality related values in nearby Class I areas as a result of the Project were anticipated; and therefore, no Air Quality Related Values (AQRV) analysis was requested.

### **REGULATORY APPLICABILITY:**

1. **Article XXI Requirements for Issuance:**

See Permit Application No. 0959, Section 5. The requirements of Article XXI, Parts B and C for the issuance of operating permits have been met for this facility. Article XXI, Part D, Part E & Part H will have the necessary sections addressed individually.

2. **Testing Requirements:**

Testing for criteria pollutants, as well as sulfuric acid and formaldehyde is required on the combustion turbine (CT) once every two years in order to demonstrate compliance with the emission limitations of this permit. Testing is also required for NO<sub>x</sub> on the Auxiliary Boiler at least once every five (5) years. The Department reserves the right to require additional testing if necessary in the future to assure compliance with the terms and conditions of this Title V Operating Permit.

3. **Applicable New Source Performance Standards (NSPS):**

The facility is subject to the following NSPS:

- 40 CFR Part 60 Subpart KKKK – *Standards of Performance for Stationary Combustion Turbines,*
- 40 CFR Part 60, Subpart TTTT – *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units,* and
- 40 CFR Part 60, Subpart IIII – *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.*

Because the facility will be subject to NSPS, it will be required to comply with the applicable requirements of 40 CFR Part 60, Subpart A – *Standards of Performance for New Stationary Sources, General Provisions.*

4. **Non-Applicable New Source Performance Standards (NSPS):**

Because the proposed petroleum liquid storage vessels associated with the Project have individual capacities less than 75 m<sup>3</sup> (i.e., 19,813 gallons) the storage vessels are not subject to the requirements of 40 CFR Part 60, Subpart Kb - *Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.*



Because the proposed auxiliary boiler will meet the 40 CFR §60.41c definition of a steam generating unit and will have a maximum design heat input of 88.7 MMBtu/hr, which is less than 100 MMBtu/hr, but greater than 10 MMBtu/hr, the requirements of 40 CFR Part 60, Subpart Dc - *Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units* apply. Since the auxiliary boiler will fire natural gas only, the facility will comply with the notification and recordkeeping requirements in accordance with 40 CFR §60.48c(g)(2), by recording the amount of fuel combusted during each month.

The proposed dew point heater, which will have a maximum design heat input of 3.0 MMBtu/hr is not subject to Subpart Dc per 40 CFR §60.40c(e). The proposed CT and HRSG with DB are not subject to Subpart Dc per 40 CFR §60.40c(e) as the requirements of 40 CFR Part 60, Subpart KKKK apply to the proposed CT and HRSG with DB.

5. **Applicable NESHAP and MACT Standards:**

The facility will be subject to 40 CFR Part 63, Subpart YYYY - *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines* when the regulation is finalized by the EPA. This facility proposes to implement a limit on formaldehyde to remain a minor source of hazardous air pollutants.

The facility is subject to 40 CFR Part 63, Subpart ZZZZ – *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines* for the emergency generator and the fire water pump.

Because the engines driving the emergency generator and the fire water pump are CI RICE, demonstrating compliance with the requirements of 40 CFR Part 60, Subpart IIII ensures that the requirements of 40 CFR Part 63, Subpart ZZZZ are met.

Because the facility is subject to 40 CFR Part 63 Subparts, the requirements of Subpart A will apply. The facility will comply with each of the applicable sections of the General Provisions as specified in 40 CFR Part 63, Subpart A – *National Emission Standards for Hazardous Air Pollutants for Source Categories, General Provisions*.

6. **Non-Applicable NESHAP and MACT Standards:**

Because the facility is considered an area source of HAPs, the emissions standards of 40 CFR Part 63, Subpart YYYY – *National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines* and 40 CFR Part 63, Subpart DDDDD – *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters* will not apply because these rules regulate major sources of HAPs.

The auxiliary boiler is not subject to 40 CFR Part 63, Subpart JJJJJ – *National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources* per §63.11195(e) because combusts only natural gas and is defined as “gas-fired boiler” under §63.11237. In addition, the proposed HRSG with DB meets the definition of a “waste heat boiler” and the proposed dew point heater meets the definition of a “process heater” and are excluded from the definition of a “boiler” per 40 CFR §63.11237.

7. **Risk Management Plan; CAA Section 112(r):**

Aqueous ammonia, used by the SCR system for NO<sub>x</sub> emissions control, is a Regulated Substance under Section 112(r). The threshold quantity in the RMP Rule List of Regulated Substances pursuant to 40 CFR §68.130 for aqueous ammonia is 20,000 pounds with a concentration 20% or greater. Because aqueous ammonia will be stored on-site in one storage tank with a capacity of 20,000 gallons with a concentration of less than 20% by weight, the concentration applicability criteria will not be met and 40 CFR Part 68 – *Chemical Accident Prevention Provisions* does not apply.

8. **Greenhouse Gas Reporting (40 CFR Part 98):**

Because the facility will emit more than 25,000 metric tons of CO<sub>2</sub>e, the facility is subject to 40 CFR Part 98, Subpart D – *Electricity Generation*. The Mandatory GHG Reporting requirements, promulgated at 40 CFR Part 98, were published by U.S. EPA on October 30, 2009 and require facilities that emit greater than 25,000 metric tons per year of carbon dioxide equivalent (CO<sub>2</sub>e) to provide an annual reporting of GHG emissions.

9. **Compliance Assurance Monitoring (40 CFR Part 64):**

The facility will be a major stationary source (i.e., it will be required to obtain a 40 CFR Part 70 permit under ACHD air quality regulations); therefore, CAM applicability must be addressed. The facility will include the following control devices: SCR for control of NO<sub>x</sub> emissions and oxidation catalysts for the control of CO emissions. The facility proposes to use continuous emissions monitoring systems (CEMs) to demonstrate compliance with the NO<sub>x</sub> and CO emissions limits. As a result, the CAM regulations will not apply for demonstrating compliance with the facility emissions limits.

10. **Continuous Emission Monitoring (40 CFR Part 75):**

To demonstrate compliance with Cross State Air Pollution Rule (CSAPR), the permittee will implement NO<sub>x</sub> CEMS requirements in accordance with 40 CFR Part 75, Subpart B – *Monitoring Provisions* section §75.12 and Subpart H – *NO<sub>x</sub> Mass Emissions Provisions*. In addition, the permittee will implement fuel flow based SO<sub>2</sub> monitoring system requirements for gas-fired units pursuant to 40 CFR Part 75, Subpart B §75.11(d)(2) and Appendix D. The facility will comply with the fuel flow and heat input monitoring system requirements for gas-fired units pursuant to 40 CFR Part 75, Appendix D. By complying with the applicable monitoring requirements identified in 40 CFR Part 75, the facility will meet the requirements of 40 CFR §§97.430 – 97.434 and 40 CFR §§97.530 through 97.534. The CSAPR application for the Project is provided in Appendix G of the permit application.

11. **Acid Rain Program (Title IV Acid Rain Permit, §2103.22,j, and 40 CFR 72 through 40 CFR 78):**

NO<sub>x</sub> emissions from the combined cycle combustion turbine and steam generator shall be limited to 30.9 lb/hr and SO<sub>2</sub> emissions shall be limited to 23.65 tons/year (plus or minus based on emissions trading). A Designated Representative for the facility, for the purposes of the Acid Rain Program, must be identified on a certificate of representation form; and this Designated Representative shall certify all Acid Rain Submissions (40 CFR §72.20-72.24).

12. **CAIR NO<sub>x</sub> and SO<sub>2</sub> Trading Programs (40 CFR Part 97 and 25 Pa Code § 145):**

The permittee shall comply with all requirements of 40 CFR PART 97 (relating to Federal NO<sub>x</sub> Budget Trading Program and CAIR NO<sub>x</sub> and SO<sub>2</sub> Trading Programs) and 25 Pa Code § 145 (relating to Interstate Pollution Transport Reduction). The permittee is subject to Subpart B - *NO<sub>x</sub> Authorized Account Representative for NO<sub>x</sub> Budget Sources*, Subpart H – *Monitoring and Reporting*, Subpart AAAA – *CAIR NO<sub>x</sub> Ozone Season Trading Program General Provisions*, Subpart BBBB – *CAIR Designated Representative for CAIR NO<sub>x</sub> Ozone Season Sources*, and Subpart CCCC – *Permits*. The permittee is subject to the standard requirements of 40 CFR § 97.106, 40 CFR § 97.206 and 40 CFR § 97.306. The requirements are hereby incorporated by reference in the permit. This program has replaced Pa Code §123.102-123.120(§2105.100).

13. **Prevention of Significant Deterioration (PSD):**

Potential facility-related emissions of sulfuric acid mist (H<sub>2</sub>SO<sub>4</sub>), CO, PM, PM<sub>10</sub>, greenhouse gases (GHG), and NO<sub>x</sub>, assessed as nitrogen dioxide NO<sub>2</sub> for air quality modeling purposes, associated with the facility are major for PSD purposes and trigger PSD permitting requirements. Therefore, in addition to meeting BACT, air dispersion modeling that incorporated ACHD approved air quality modeling procedures was used to demonstrate that the Project will not cause or contribute to any violation of the National Ambient Air Quality Standards (NAAQS) and will not cause any PSD increments to be exceeded.

14. **Air Toxics**

The facility's emissions of air toxics exceed the de minimis levels established pursuant to ACHD's "Policy for Air Toxics Review of Installation Permit Applications." An air toxics modeling analysis was performed

to evaluate carcinogenic and non-carcinogenic health risks of the Project. The results of this analysis show that the cumulative Maximum Individual Carcinogenic Risk (MICR) is less than  $1 \times 10^{-5}$  and the Hazard Quotient (HQ) and Cumulative Hazard Index (HI) were less than 1.0 and 2.0, respectively, and therefore no cumulative air toxics analysis is required. See the document “Modeling Review of Invenergy LLC (Invenergy) Proposed Natural Gas Combined-Cycle Power Plant Installation Permit” for the full modeling analysis.

**EMISSIONS SUMMARY:**

**Table 15: Emissions Summary for Allegheny Energy Center**

Pollutant	Total (tpy*)
Particulate Matter (filterable)	44.59
Particulate Matter <10 µm (PM <sub>10</sub> )	88.65
Particulate Matter <2.5 µm (PM <sub>2.5</sub> )	88.60
Nitrogen Oxides (NO <sub>x</sub> )	145.70
Sulfur Oxides (SO <sub>x</sub> )	23.89
Carbon Monoxide (CO)	170.44
Volatile Organic Compounds (VOC)	93.40
Sulfuric Acid Mist	17.11
Ammonia	98.05
Hazardous Air Pollutants (HAP)	10.50
Benzene	0.21
Ethylbenzene	0.54
Formaldehyde	5.18
Toluene	2.20
Xylenes	1.08
Lead	$9.23 \times 10^{-4}$
Greenhouse Gases (CO <sub>2</sub> e)	1,948,493

\* A year is defined as any consecutive 12-month period.

**RECOMMENDATION:**

All applicable Federal, State, and County regulations have been addressed in the permit application, and the facility is not in violation of the provisions of Article XXI, §2102.04.k. The Installation Permit for Allegheny Energy Center LLC should be approved with the emission limitations, terms and conditions in Permit No. 0959-1001.

**APPENDIX A – EMISSIONS CALCULATIONS**

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**Appendix A: Emission Calculations**  
**Project Summary**

Company Name: Allegheny Energy Center  
 Address: 2130 Margaret St. Ext., West Newton, PA 15089  
 Title V Operating Permit: 0959-1001  
 Date: March 29, 2021

Pollutants (tpy)	NO <sub>x</sub>	CO	VOC	SO <sub>2</sub>	PM	PM <sub>10</sub>	PM <sub>2.5</sub>	H <sub>2</sub> SO <sub>4</sub>	Pb	Formaldehyde	NH <sub>3</sub>	GHGs (CO <sub>2</sub> e)	Total HAPs
Combustion Turbine w/ Duct Burner	141.99	161.72	92.51	23.65	44.15	88.30	88.30	17.08	8.22E-04	5.12	97.41	1,924,999.44	10.45
Auxiliary Boiler	1.95	7.27	0.71	0.19	0.32	0.26	0.22	0.02	8.45E-05	4.90E-02	0.54	20,772.99	0.05
Dew Point Heater	0.14	0.49	0.07	0.01	0.06	0.02	0.02	1.75E-03	6.28E-06	3.63E-03	0.04	1,538.65	3.81E-03
Emergency Generator	1.53	0.88	0.08	1.86E-03	0.05	0.06	0.06	2.27E-04	9.39E-06	8.23E-05	0.05	170.73	1.69E-03
Fire Pump	0.09	0.08	4.66E-03	2.89E-02	4.66E-03	5.41E-03	5.41E-03	3.54E-03	8.73E-07	1.15E-04	4.63E-03	15.87	3.81E-04
Diesel and Lubricating Oil Tanks	-	-	0.03	-	-	-	-	-	-	-	-	-	-
Natural Gas Piping Fugitives	-	-	-	-	-	-	-	-	-	-	-	274.73	-
Natural Gas Maintenance + SU/SD Venting	-	-	-	-	-	-	-	-	-	-	-	794.82	-
SF <sub>6</sub> Circuit Breakers	-	-	-	-	-	-	-	-	-	-	-	96.58	-
<b>Total Project Emissions</b>	<b>145.70</b>	<b>170.44</b>	<b>93.40</b>	<b>23.89</b>	<b>44.59</b>	<b>88.65</b>	<b>88.60</b>	<b>17.11</b>	<b>9.23E-04</b>	<b>5.18</b>	<b>98.05</b>	<b>1,948,493.09</b>	<b>10.50</b>
NSR Major Source Threshold	100	100	100	100	100	100	100	100	100	100	100	100,000	10/25
Major Source	Y	Y	Y	N	N	N	N	N	N	N	N	Y	N <sup>(a)</sup>
PSD Significant Net Emission Rate	40	100	N/A <sup>(c)</sup>	N/A <sup>(d)</sup>	25	15	N/A <sup>(d)</sup>	7	0.6		N/A <sup>(f)</sup>	75,000	
Subject to PSD Review	Y <sup>(b)</sup>	Y	Y	Y	Y	Y	Y <sup>(e)</sup>	Y <sup>(e)</sup>	N			Y	
Nonattainment Major Source Threshold	100		50	100			100				100		
NNSR	Y <sup>(g)</sup>		Y	N			N				N		

<sup>(a)</sup> The AEC Facility and Project would be considered an area source for HAPs with respect to NESHAP because the PTE HAP emissions are less than 10 tons per year (tpy) for a single HAP and less than 25 tpy for total (combined) HAPs.  
<sup>(b)</sup> PSD applies for NO<sub>x</sub> because NO<sub>2</sub> has a NAAQS and the Project is proposed in a NO<sub>2</sub> attainment area.  
<sup>(c)</sup> PSD does not apply for VOC because the Project is proposed in the Northeast OTR which is managed as nonattainment area and VOC is a precursor pollutant of ozone.  
<sup>(d)</sup> PSD does not apply for SO<sub>2</sub> or PM<sub>2.5</sub> because the Project is proposed in a PM<sub>2.5</sub> and SO<sub>2</sub> nonattainment area.  
<sup>(e)</sup> Major source thresholds for NO<sub>x</sub> and CO triggered therefore PSD significant net emissions rates applicable to NSR regulated pollutants subject to PSD.  
<sup>(f)</sup> The Project is proposed in a PM<sub>2.5</sub> nonattainment area which was determined NH<sub>3</sub> is a precursor pollutant to PM<sub>2.5</sub>. Therefore NH<sub>3</sub> is a regulated NSR pollutant which is subject to NNSR.  
<sup>(g)</sup> The Project is proposed in the Northeast OTR which is managed as a nonattainment area and NO<sub>x</sub> is a precursor pollutant of ozone.

**Appendix A: Emission Calculations**  
**Combustion Emissions for Combustion Turbine 3,844 MMBtu/hr**

TSD Appendix A: Page 2 of 14

Company Name: Allegheny Energy Center  
 Address: 2130 Margaret St. Ext., West Newton, PA 15089  
 Title V Operating Permit: 0959-1001  
 Date: March 29, 2021

**Maximum Hourly Heat Input and Emissions During  
 Steady-State Operations for CT and DB**

<b>Gross Maximum Electrical Capacity<sup>(a)</sup></b>	639 MW total	
<b>Net Maximum Power</b>	626 MW total	
<b>Maximum CT Heat Input (HHV)</b>	3,844 MMBtu/hr HHV	
<b>Maximum DB Heat Input (HHV)</b>	394 MMBtu/hr HHV	
<b>Parameter</b>	<b>Maximum Short Term Emissions Rates<sup>(b)</sup></b>	
	<b>CT w/o DB</b>	<b>CT w/ DB</b>
NO <sub>x</sub> ppmvd @ 15% O <sub>2</sub>	2.00	2.00
NO <sub>x</sub> lb/hr as NO <sub>2</sub>	27.90	30.90
CO ppmvd @ 15% O <sub>2</sub>	2.00	2.00
CO lb/hr	17.00	18.80
VOC ppmvd @ 15% O <sub>2</sub>	1.00	1.50
VOC lb/hr as methane	4.90	8.10
CO <sub>2</sub> lb/hr	395,000.0	467,000.0
NH <sub>3</sub> Slip ppmvd @15% O <sub>2</sub>	4.00	4.00
NH <sub>3</sub> Slip lb/hr	20.64	22.90
SO <sub>x</sub> lb/hr as SO <sub>2</sub>	5.10	5.60
SO <sub>2</sub> lb/MMBtu	0.0014	0.0014
PM <sub>10</sub> /PM <sub>2.5</sub> lb/hr	16.49	21.11
PM <sub>10</sub> /PM <sub>2.5</sub> lb/MMBtu	0.0084	0.0058
PM filterable lb/hr	8.24	10.55
PM filterable lb/MMBtu	0.0042	0.0029
H <sub>2</sub> SO <sub>4</sub> lb/hr	3.60	4.00
H <sub>2</sub> SO <sub>4</sub> lb/MMBtu	0.00101	0.00100
Pb lb/MMBtu	negligible	4.76E-07
Formaldehyde lb/MMBtu	2.76E-04	2.66E-04

<sup>(a)</sup> Nominal value.

<sup>(b)</sup> No emissions of fluoride (F), hydrogen sulfide (H<sub>2</sub>S), or total reduced sulfur (TRS) are expected to occur.

**Appendix A: Emission Calculations**  
**Combustion Emissions for Combustion Turbine 3,799 MMBtu/hr**

TSD Appendix A: Page 3 of 14

Company Name: Allegheny Energy Center  
 Address: 2130 Margaret St. Ext., West Newton, PA 15089  
 Title V Operating Permit: 0959-1001  
 Date: March 29, 2021

**Average Hourly Heat Input and Emissions During  
 1 GT @ 100% load, DB 80.9%**

<b>Gross Maximum Electrical Capacity<sup>(a)</sup></b>	639 MW total	
<b>Net Maximum Power</b>	626 MW total	
<b>Maximum CT Heat Input (HHV)</b>	3,799 MMBtu/hr HHV	
<b>Maximum DB Heat Input (HHV)</b>	319 MMBtu/hr HHV	
<b>Parameter</b>	<b>Average Short Term Emissions Rates<sup>(b)</sup></b>	
	<b>CT w/o DB</b>	<b>CT w/ DB</b>
NO <sub>x</sub> ppmvd @ 15% O <sub>2</sub>	2.00	2.00
NO <sub>x</sub> lb/hr as NO <sub>2</sub>	27.60	30.00
CO ppmvd @ 15% O <sub>2</sub>	2.00	2.00
CO lb/hr	16.80	18.30
VOC ppmvd @ 15% O <sub>2</sub>	1.00	1.50
VOC lb/hr as methane	4.80	7.88
CO <sub>2</sub> lb/hr	373,000.00	439,000.00
NH <sub>3</sub> Slip ppmvd @ 15% O <sub>2</sub>	4.00	4.00
NH <sub>3</sub> Slip lb/hr	20.40	22.24
SO <sub>x</sub> lb/hr as SO <sub>2</sub>	5.00	5.40
SO <sub>2</sub> lb/MMBtu	0.0014	0.0014
PM <sub>10</sub> /PM <sub>2.5</sub> lb/hr	16.40	20.16
PM <sub>10</sub> /PM <sub>2.5</sub> lb/MMBtu	0.0045	0.0051
PM filterable lb/hr	8.19	10.08
PM filterable lb/MMBtu	0.0023	0.0026
H <sub>2</sub> SO <sub>4</sub> lb/hr	3.60	3.90
H <sub>2</sub> SO <sub>4</sub> lb/MMBtu	0.0010	0.0010
Pb lb/MMBtu	negligible	4.76E-07
Formaldehyde lb/MMBtu	2.65E-04	2.64E-04

<sup>(a)</sup> Nominal value.

<sup>(b)</sup> No emissions of fluoride (F), hydrogen sulfide (H<sub>2</sub>S), or total reduced sulfur (TRS) are expected to occur.

**Appendix A: Emission Calculations**  
**Combustion Emissions for Combustion Turbine 3,844 MMBtu/hr**

TSD Appendix A: Page 4 of 14

Company Name: Allegheny Energy Center  
 Address: 2130 Margaret St. Ext., West Newton, PA 15089  
 Title V Operating Permit: 0959-1001  
 Date: March 29, 2021

**1. Process Description**

	Unit Description	Gross Max. Electric Power (MW)	Total Heat Input Capacity (MMBtu/hr)	Maximum Potential Throughput (MMCF/yr)	Btu/CF	Max. hrs/yr	Steady-State hrs/yr <sup>(c)</sup>
CT-001	Combined Cycle Power Block <sup>(a)</sup>	639	3844	32069.94	1,050	8,760	8200.3
DB-001	Duct Burner <sup>(b)</sup>	NA	394	3287.09	1,050	8,760	8200.3
	<b>Total</b>	<b>639</b>	<b>4238</b>	<b>35357.03</b>	<b>1,050</b>	<b>8,760</b>	<b>8200.3</b>

<sup>(a)</sup> The Combined Cycle Power Block Consists of the Combustion Turbine, a Duct Burner, a Heat Recovery Steam Generator, and a Steam Turbine.

<sup>(b)</sup> The Duct burner must be used during all operations.

<sup>(c)</sup> Steady state = 8,760 hrs - [365 hr + (32 min × 1hr/60 min × 365 hr)]; See Section 3. below.

**2. Steady-State Combustion Emissions - Criteria Pollutants**

Potential to Emit (lbs/hr) <sup>(a)</sup>											
PM	PM <sub>10</sub>	PM <sub>2.5</sub>	NO <sub>x</sub>	VOC	CO	SO <sub>2</sub>	CO <sub>2</sub>	NH <sub>3</sub>	H <sub>2</sub> SO <sub>4</sub>	Pb <sup>(b)</sup>	Formaldehyde
10.08	20.16	20.16	30.00	7.88	18.30	5.40	439,000	22.24	3.90	1.88E-04	1.17

Potential to Emit (lbs/yr)											
PM	PM <sub>10</sub>	PM <sub>2.5</sub>	NO <sub>x</sub>	VOC	CO	SO <sub>2</sub>	CO <sub>2</sub>	NH <sub>3</sub>	H <sub>2</sub> SO <sub>4</sub>	Pb	Formaldehyde
88,301	176,602	176,602	246,010	64,578	150,066	47,304	3,845,640,000	194,822	34,164	1.64	10,246.47

Potential to Emit (tons/yr)											
PM	PM <sub>10</sub>	PM <sub>2.5</sub>	NO <sub>x</sub>	VOC	CO	SO <sub>2</sub>	CO <sub>2</sub>	NH <sub>3</sub>	H <sub>2</sub> SO <sub>4</sub>	Pb	Formaldehyde
44.15	88.30	88.30	123.01	32.29	75.03	23.65	1,922,820	97.41	17.08	8.22E-04	5.12

<sup>(a)</sup> Manufacturer's Data; average short term steady-state emission rates with duct burner

<sup>(b)</sup> AP-42, Table 1.4-2

**3. SU/SD - Criteria Pollutants**

Annual No. of SU/SD Events = 365

**Emissions Per Event<sup>(a)</sup>:**

CT Startup to Minimum Emissions Compliance Load <sup>(b)</sup>				
Event	Fuel	NO <sub>x</sub>	CO	VOC
	MMBtu/event	lb/event	lb/event	lb/event
Hot Start	495	90	390	205
Shutdown	170	14	85	125

<sup>(a)</sup> Events per year is assumed to be 365.

<sup>(b)</sup> Manufacturer guarantees.

CT Startup/Shutdown Emissions Rates <sup>(a)(b)</sup>						Max Baseload		Startup+Max Baseload	
Event	Duration Minutes <sup>(c)</sup>	Annual No. of Events <sup>(d)</sup>	Annual No. of Hours	NO <sub>x</sub>	CO	NO <sub>x</sub>	CO	NO <sub>x</sub>	1HR-CO
				lb/event		lb/hr	lb/hr	lb/hr	
Hot Start	20	365	121.67	90.0	390.0	205.0	30.9	18.8	110.6
Shutdown	12	365	73.00	14.0	85.0	125.0	30.9	18.8	38.7

<sup>(a)</sup> SU/SD emissions of NO<sub>x</sub>, CO, and VOC are emission guarantees from the vendor.

<sup>(b)</sup> Based on vendor data, only emissions of NO<sub>x</sub>, CO, and VOC are higher during SU/SD events. Emissions of other regulated NNSR pollutants assumed to be equivalent to the average case steady-state emissions rate guarantees from the manufacturer.

<sup>(c)</sup> 32 min per hot SU/SD provided by manufacturer.

<sup>(d)</sup> Worst case of one hour between SD and SU; 365 SU/SD events = 365 hours per year where the CT is not in operation. See footnote (c) in Process Description above.

Potential to Emit (lbs/yr)			
	NO <sub>x</sub>	VOC	CO
Hot Start	32,850	74,825	142,350
Shutdown	5,110	45,625	31,025

Potential to Emit (tons/yr)			
	NO <sub>x</sub>	VOC	CO
Hot Start	16.43	37.41	71.18
Shutdown	2.56	22.81	15.51
<b>Total</b>	<b>18.98</b>	<b>60.23</b>	<b>86.69</b>

**4. Total Combustion Emissions + SU/SD**

Potential to Emit (tons/yr)												
	PM	PM <sub>10</sub>	PM <sub>2.5</sub>	NO <sub>x</sub>	VOC	CO	SO <sub>2</sub>	CO <sub>2</sub>	NH <sub>3</sub>	H <sub>2</sub> SO <sub>4</sub>	Pb	Formaldehyde
<b>TOTAL</b>	<b>44.15</b>	<b>88.30</b>	<b>88.30</b>	<b>141.99</b>	<b>92.51</b>	<b>161.72</b>	<b>23.65</b>	<b>1,922,820</b>	<b>97.41</b>	<b>17.08</b>	<b>8.22E-04</b>	<b>5.12</b>



**Appendix A: Emission Calculations**  
**Combustion Emissions for Diesel Fired Emergency Generator 2,000 kW**

Company Name: Allegheny Energy Center  
 Address: 2130 Margaret St. Ex., West Newton, PA 15089  
 Title V Operating Permit: 0959-1001  
 Date: March 29, 2021

**1. Process Description**

Emission Unit ID	Unit Description	Power Output (kW)	Max. hrs/yr	BHP	Fuel Consumption (gal/hr)	MMBtu/hr <sup>(e)</sup>	Max. Fuel Consumption (MMBtu/yr)
EG-01	Emergency Generator	2,000	100	3,058	147.3	20.87	2,087

<sup>(a)</sup> Calculated from fuel consumption (gph x fuel density [lb/gal] x fuel heat content [MMBtu/lb]). Ultra Low Sulfur Diesel Fuel = 19,170 Btu/lb and Fuel density = 7.39 lb/gal

**2. Combustion Emissions - Criteria Pollutants**

		Emission Factor (g/bhp/hr)				Emission Factor (lb/MMBtu)		Emission Factor (lb/1,000 gal)		Emission Factor (lbs/MMBtu)	
<b>PM</b>	<sup>(a)</sup> <b>PM<sub>10</sub></b>	<b>PM<sub>2.5</sub></b>	<b>NO<sub>x</sub></b>	<b>VOC</b>	<b>CO</b>	<b>SO<sub>2</sub></b>	<b>H<sub>2</sub>SO<sub>4</sub></b>	<b>Pb</b>	<b>NH<sub>3</sub></b>	<b>Formaldehyde</b>	<b>Formaldehyde</b>
	0.149	0.173	4.534	0.239	2.610	5.50E-03	6.74E-04	9.00E-06	6.62	7.89E-05	7.89E-05
<b>PM</b>	1.01	1.17	30.56	1.61	17.59	0.04	4.55E-03	1.88E-04	0.99	1.65E-03	1.65E-03
<b>Potential to Emit (lbs/hr)</b>											
<b>PM</b>	0.050	0.058	1.528	0.080	0.880	1.86E-03	2.273E-04	9.390E-06	0.0497	8.23E-05	8.23E-05

<sup>(e)</sup> 40 CFR §89.112, Table 1. It is assumed that the PM emissions factor reflects the filterable portion of PM only.

<sup>(f)</sup> It is assumed that PM<sub>10</sub> = PM<sub>2.5</sub>, PM<sub>10</sub> = PM<sub>2.5</sub> emissions factors account for both the filterable and condensable portions of PM. The filterable portion of PM<sub>10</sub> = PM<sub>2.5</sub> was obtained through vendor supplied information. The condensable portion of PM<sub>10</sub> and PM<sub>2.5</sub> was obtained from AP-42 Chapter 3.4 Table 3.4-2 (10/96).

<sup>(c)</sup> 40 CFR §89.112, Table 1. E.F. in g/kW-hr x 0.7457 to g/bhp/hr. Published emissions factor is for NO<sub>x</sub>+NMHC. Invergy assumed that NO<sub>x</sub> emissions are 95% of this factor and VOC emissions are 5% based "CARB Emission Factor for CI Diesel Engines - Percent HC in Relation to NMHC + NO<sub>x</sub>" policy.

<sup>(d)</sup> 40 CFR §89.112, Table 1. E.F. in g/kW-hr x 0.7457 to g/bhp/hr.

<sup>(e)</sup> AP-42, Table 3.4-1. Diesel fuel sulfur content = 0.0015% (15 ppm).

<sup>(f)</sup> H<sub>2</sub>SO<sub>4</sub> emissions factor conservatively calculated based on 10% molar conversion of SO<sub>2</sub> to SO<sub>3</sub> and 100% conversion of SO<sub>3</sub> to H<sub>2</sub>SO<sub>4</sub>.

<sup>(g)</sup> AP-42, Table 1.3-10

<sup>(h)</sup> U.S. EPA Emission Inventory Improvement Program, "Estimating Ammonia Emissions from Anthropogenic Nonagricultural Sources - Draft Final Report", April 2004.

<sup>(i)</sup> AP-42, Table 3.4-3

**Appendix A: Emission Calculations**  
**Combustion Emissions for Diesel Fired Fire Water Pump 1.9 MMBtu/hr**

Company Name: Allegheny Energy Center  
 Address: 2130 Margaret St. Ext., West Newton, PA 15089  
 Title V Operating Permit: 0959-1001  
 Date: March 29, 2021

**1. Process Description**

Emission Unit ID	Unit Description	Max. hrs/yr	BHP	Fuel Consumption (gal/hr)	MMBtu/hr (a)	Max. Fuel Consumption (MMBtu/yr)
WP-01	Fire Water Pump	100	282	13.7	1.94	194

(a) Calculated from fuel consumption (gph x fuel density [lb/gal] x fuel heat content [MMBtu/lb]). Ultra Low Sulfur Diesel Fuel = 19,170 Btu/lb and Fuel density = 7.39 lb/gal.

**2. Combustion Emissions - Criteria Pollutants**

Emission Factor (g/bhp/hr)						
PM (a)	PM <sub>10</sub> (b)	PM <sub>2.5</sub> (b)	NO <sub>x</sub> (c)	VOC (c)	CO (d)	SO <sub>2</sub> (e)
0.150	0.174	0.174	2.850	0.150	2.600	0.930
H <sub>2</sub> SO <sub>4</sub> (f)						
					Pb (g)	NH <sub>3</sub> (h)
					9.00E-06	6.620
					Formaldehyde (i)	
					1.18E-03	
Emission Factor (lb/1,000 gal)						
NH <sub>3</sub> (h)						
6.620						
Emission Factor (lb/MMBtu)						
Pb (g)						
9.00E-06						
Emission Factor (lb/MMBtu)						
Formaldehyde (i)						
1.18E-03						
Potential to Emit (lbs/hr)						
PM	PM <sub>10</sub>	PM <sub>2.5</sub>	NO <sub>x</sub>	VOC	CO	SO <sub>2</sub>
0.093	0.108	0.108	1.772	0.093	1.616	0.578
H <sub>2</sub> SO <sub>4</sub>						
					Pb	NH <sub>3</sub>
					1.75E-05	0.0925
					Formaldehyde	
					2.29E-03	
Potential to Emit (tons/yr)						
PM	PM <sub>10</sub>	PM <sub>2.5</sub>	NO <sub>x</sub>	VOC	CO	SO <sub>2</sub>
0.0047	0.0054	0.0054	0.0886	0.0047	0.0808	0.0289
H <sub>2</sub> SO <sub>4</sub>						
					Pb	NH <sub>3</sub>
					8.73E-07	0.0046
					Formaldehyde	
					1.15E-04	

(e) 40 CFR §60.4205(c), Table 4. It is assumed that the PM emissions factor reflects the filterable portion of PM only.  
 (f) It is assumed that PM<sub>10</sub> = PM<sub>2.5</sub>; PM<sub>10</sub> = PM<sub>2.5</sub> emissions factors account for both the filterable and condensable portions of PM. The filterable portion of PM<sub>10</sub> = PM<sub>2.5</sub> was obtained through vendor supplied information. The condensable portion of PM<sub>10</sub> and PM<sub>2.5</sub> was obtained from AP-42 Chapter 3.4 Table 3.4-2 (10/96).  
 (g) 40 CFR §60.4205(c), Table 4. Published emissions factor is for NO<sub>x</sub>+NMHC. Inventory assumed that NO<sub>x</sub> emissions are 95% of this factor and VOC emissions are 5% based "CARB Emission Factor for CI Diesel Engines - Percent HC in Relation to NMHC + NO<sub>x</sub>" policy.  
 (h) 40 CFR §60.4205(c), Table 4.  
 (i) AP-42, Table 3.3-1. Diesel fuel sulfur content = 0.0015% (15 ppm). Calculated from power output (lb/hr-hr x g/lb [g/bhp/hr]).  
 (j) H<sub>2</sub>SO<sub>4</sub> emissions factor conservatively calculated based on 10% molar conversion of SO<sub>2</sub> to SO<sub>3</sub> and 100% conversion of SO<sub>3</sub> to H<sub>2</sub>SO<sub>4</sub>.  
 (k) AP-42, Table 1.3-10  
 (l) U.S. EPA Emission Inventory Improvement Program, "Estimating Ammonia Emissions from Anthropogenic Nonagricultural Sources - Draft Final Report", April 2004.  
 (m) AP-42, Table 3.3-2

**Appendix A: Emission Calculations**  
**Combustion Emissions for Natural Gas Fired Auxiliary Boiler 88.7 MMBtu/hr**

Company Name: Allegheny Energy Center  
 Address: 2130 Margaret St. Ext., West Newton, PA 15089  
 Title V Operating Permit: 0959-1001  
 Date: March 29, 2021

**1. Process Description**

Emission Unit ID	Unit Description	Total Heat Input Capacity (MMBtu/hr)	Maximum Potential Throughput (MMCF/yr)	Btu/CF	Max. hrs/yr	Max. Fuel Consumption (MMBtu/yr)
B-001	Auxiliary Boiler	88.7	337.90	1,050	4,000	354,800

**2. Combustion Emissions - Criteria Pollutants**

PM (a)	PM <sub>10</sub> (b)	PM <sub>2.5</sub> (b)	Emission Factor (lbs/MMBtu)			Emission Factor (lbs/MMSCF)				
			NO <sub>x</sub> (c)	VOC (c)	CO (c)	SO <sub>2</sub> (d)	H <sub>2</sub> SO <sub>4</sub> (e)	NH <sub>3</sub> (f)	Formaldehyde (a)	
1.810E-03	1.486E-03	1.229E-03	0.011	0.004	0.041	1.09E-03	1.33E-04	5.00E-04	3.20	2.76E-04
<b>Potential to Emit (lbs/hr)</b>										
PM	PM <sub>10</sub>	PM <sub>2.5</sub>	NO <sub>x</sub>	VOC	CO	SO <sub>2</sub>	H <sub>2</sub> SO <sub>4</sub>	Pb	NH <sub>3</sub>	Formaldehyde
0.161	0.132	0.109	0.976	0.355	3.637	0.097	0.012	4.224E-05	0.270	2.45E-02
<b>Potential to Emit (tons/yr)</b>										
PM	PM <sub>10</sub>	PM <sub>2.5</sub>	NO <sub>x</sub>	VOC	CO	SO <sub>2</sub>	H <sub>2</sub> SO <sub>4</sub>	Pb	NH <sub>3</sub>	Formaldehyde
0.321	0.264	0.218	1.951	0.710	7.273	0.193	0.024	8.448E-05	0.541	4.90E-02

(a) AP-42, Table 1.4-2 (7/98). PM emissions factor represents the filterable portion only.  
 (b) U.S. EPA's Emission Inventory and Analysis Group guidance 3/30/2012 with 3x safety factor. PM<sub>10</sub> and PM<sub>2.5</sub> are revised emissions factors for Gas Combustion based upon the NYSERDA dilution sampling test reports. PM<sub>10</sub> and PM<sub>2.5</sub> emissions factors account for both the filterable and condensable portions of PM.  
 (c) Manufacturer's data.  
 (d) SO<sub>2</sub> emissions factor calculated based on a 0.4 gr/100 scf sulfur content of natural gas.  
 (e) H<sub>2</sub>SO<sub>4</sub> emissions factor conservatively calculated based on 10% molar conversion of SO<sub>2</sub> to SO<sub>3</sub> and 100% conversion of SO<sub>3</sub> to H<sub>2</sub>SO<sub>4</sub>.  
 (f) U.S. EPA Emission Inventory Improvement Program, "Estimating Ammonia Emissions from Anthropogenic Nonagricultural Sources - Draft Final Report", Table III-1, April 2004.

**Appendix A: Emission Calculations**  
**Combustion Emissions for Natural Gas Fired Dew Point Heater 3 MMBtu/hr**

Company Name: Allegheny Energy Center  
 Address: 2130 Margaret St. Ext., West Newton, PA 15089  
 Title V Operating Permit: 0959-1001  
 Date: March 29, 2021

**1. Process Description**

Emission Unit ID	Unit Description	Total Heat Input Capacity (MMBtu/hr)	Maximum Potential Throughput (MMCF/yr)	Btu/CF	Max. hrs/yr	Max. Fuel Consumption (MMBtu/yr)
H-001	Dew Point Heater	3.0	25.03	1,050	8,760	26,280

**2. Combustion Emissions - Criteria Pollutants**

PM <sup>(a)</sup>	PM <sub>10</sub> <sup>(b)</sup>	PM <sub>2.5</sub> <sup>(b)</sup>	Emission Factor (lbs/MMBtu)				Emission Factor (lbs/MMSCF)			
			NO <sub>x</sub> <sup>(a)</sup>	VOC <sup>(a)</sup>	CO <sup>(a)</sup>	SO <sub>2</sub> <sup>(c)</sup>	H <sub>2</sub> SO <sub>4</sub> <sup>(d)</sup>	Pb <sup>(e)</sup>	NH <sub>3</sub> <sup>(f)</sup>	Formaldehyde <sup>(a)</sup>
4.800E-03	1.486E-03	1.229E-03	0.011	0.005	0.037	1.09E-03	1.33E-04	5.00E-04	3.20	2.76E-04
<b>Potential to Emit (lbs/hr)</b>										
PM	PM <sub>10</sub>	PM <sub>2.5</sub>	NO <sub>x</sub>	VOC	CO	SO <sub>2</sub>	H <sub>2</sub> SO <sub>4</sub>	Pb	NH <sub>3</sub>	Formaldehyde
0.014	4.457E-03	3.686E-03	0.033	0.015	0.111	0.0033	0.0004	1.43E-06	0.0091	8.28E-04
<b>Potential to Emit (tons/yr)</b>										
PM	PM <sub>10</sub>	PM <sub>2.5</sub>	NO <sub>x</sub>	VOC	CO	SO <sub>2</sub>	H <sub>2</sub> SO <sub>4</sub>	Pb	NH <sub>3</sub>	Formaldehyde
0.063	0.020	0.016	0.145	0.066	0.486	0.014	0.002	6.26E-06	0.040	3.63E-03

<sup>(a)</sup> Manufacturer's data. PM emissions factor represents the filterable portion only.  
<sup>(b)</sup> U.S. EPA's Emission Inventory and Analysis Group guidance 3/30/2012 with 3x safety factor. PM<sub>10</sub> and PM<sub>2.5</sub> are revised emissions factors for Gas Combustion based upon the NYSERDA dilution sampling test reports. PM<sub>10</sub> and PM<sub>2.5</sub> emissions factors account for both the filterable and condensable portions of PM.  
<sup>(c)</sup> SO<sub>2</sub> emissions factor calculated based on a 0.4 gr/100 scf sulfur content of natural gas.  
<sup>(d)</sup> H<sub>2</sub>SO<sub>4</sub> emissions factor conservatively calculated based on 10% molar conversion of SO<sub>2</sub> to SO<sub>3</sub> and 100% conversion of SO<sub>3</sub> to H<sub>2</sub>SO<sub>4</sub>.  
<sup>(e)</sup> AP-42, Table 1.4-2 (7/98)  
<sup>(f)</sup> U.S. EPA Emission Inventory Improvement Program, "Estimating Ammonia Emissions from Anthropogenic Nonagricultural Sources - Draft Final Report", Table III-1, April 2004.

**Appendix A: Emission Calculations**  
**Storage Tank VOC Emissions**  
 Company Name: Allegheny Energy Center  
 Address: 2130 Margaret St. Ext., West Newton, PA 15089  
 Title V Operating Permit: 0959-1001  
 Date: March 29, 2021

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Description	Notes	Abbreviation	Units	Tank 1	Tank 2	Tank 3
<b>General Tank Information</b>						
Tank ID		-	-	ULSD Storage Tank	Lubricating Oil Tank	Fire Pump Engine ULSD Day Tank
Material		-	-	Distillate Fuel Oil No. 2	Residual Oil No. 6	Distillate Fuel Oil No. 2
Orientation		-	-	Vertical	Horizontal	Vertical
Vessel Shape		-	-	Cylindrical	Cylindrical	Cylindrical
Roof Type		-	-	Fixed	Fixed	Fixed
Tank Color		-	-	White	White	White
Roof Construction		-	-	Welded	Welded	Welded
Shell Construction		-	-	Welded	Welded	Welded
Product Days			Days	365	365	365
Capacity			Bbl	83.33	267.86	11.90
Capacity			Gal	3500	11250	500
Diameter		De <sup>(6)</sup>	ft	7.5	16.43	5.29
Height		He <sup>(6)</sup>	ft	13	6.28	3.14
Length			ft		26.5	5.5
Width			ft		8	4
<b>Emission Factors for Fixed Roof Tanks (AP-42 Table 7.1, Organic Liquid Storage Tanks)</b>						
Tank Radius		Rs	ft	3.75	8.21	2.65
Tank Roof Slope	(a)	Sr	ft/ft	0.06	0.06	0.06
Tank Roof Height		Hr	ft	0.23	0.51	0.17
Roof Outage		Hro	ft	0.08	0.17	0.06
Liquid Height		HL	ft	12.48	6.03	3.02
Tank Shell Height		Hs	ft	13.00	6.28	3.14
Vapor Space Outage		Hvo	ft	0.60	2.01	0.18
Tank Diameter		D	ft	7.50	16.43	5.29
Vapor Space Volume		Vv	ft <sup>3</sup>	26.42	426.49	3.98
Paint Solar Absorbance For Fixed Roof Tanks	(b)	alpha	-	0.1	0.1	0.1
Daily Maximum Ambient Temperature	(c)	Tax	deg R	521.07	521.07	521.07
Daily Minimum Ambient Temperature	(c)	Tan	deg R	502.27	502.27	502.27
Daily Average Ambient Temperature	(c)	Taa	deg R	511.67	511.67	511.67
Liquid Bulk Temperature	(c)	Tb	deg R	511.27	511.27	511.27
Daily Total Solar Insolation Factor	(d)	I	BTU/ft <sup>2</sup>	1068.90	1068.90	1068.90
Daily Average Liquid Surface Temperature	(e)	TLa	deg R	512.29	512.29	512.29
Daily Maximum Liquid Surface Temperature	(f)	TLx	deg R	516.42	516.42	516.42
Constant in Vapor Pressure Equation	(g)	A	-	7.82	7.82	7.82
Constant in Vapor Pressure Equation	(g)	B	-	1800.03	1800.03	1800.03
Constant in Vapor Pressure Equation	(g)	C	-	246.89	246.89	246.89
Vapor Pressure at Daily Average Liquid Surface Temperature	(h)	Pva	psia	0.1362	0.1362	0.1362
Vapor Pressure at Daily Maximum Liquid Surface Temperature	(h)	Pva	psia	0.1569	0.1569	0.1569
Average Vapor Molecular Weight		Mv	lb/lb-mole	188	387	188
Ideal Gas Constant		R	psi*ft <sup>3</sup> /mole*R	10.731	10.731	10.731
Vapor Density		Wv	lb/ft <sup>3</sup>	0.004658982	0.009590565	0.004658982
Atmospheric Pressure		Pa	psia	14.7	14.7	14.7
Breather Vent Vacuum Setting	(i)	Pbv	psig	-0.03	-0.03	-0.03
Breather Vent Pressure Setting	(i)	Pbp	psig	0.03	0.03	0.03
Breather Vent Pressure Setting Range		Pb	psig	0.06	0.06	0.06
Daily Ambient Temperature Range		Ta	deg R	18.8	18.8	18.8
Daily Vapor Temperature Range		Tv	deg R	16.53	16.53	16.53
Daily Vapor Pressure Range		Pv	psi	4.29E-06	4.29E-06	4.29E-06
Vapor Space Expansion Factor		Ke	-	0.03	0.03	0.03
Vented Vapor Saturation Factor		Ks	-	1.00	0.99	1.00
Vapor Molecular Weight		Mv	lb/lb-mole	188	387	188
Total Vapor Pressure of the Stored Liquid		Pva	psia	0.136	0.136	0.136
Annual Throughput Rate	(j)	Q	gallons/yr	14730	5000	1370
Annual Throughput Rate		Q	Bbl/Yr	350.71	119.05	32.62
Turnover Factor	(k)	Kn	-	1.00	1.00	1.00
Working Loss Product Factor	(l)	Kp	-	1.00	1.00	1.00
Standing Losses	(m)	Ls	lb/yr	1.26	41.42	0.19
Standing Losses		Ls	lb/hr	1.44E-04	4.73E-03	2.17E-05
Standing Losses		Ls	tpy	6.30E-04	0.02	9.51E-05
Working Losses	(n)	Lw	lb/yr	8.98	6.28	0.84
Working Losses		Lw	lb/hr	1.03E-03	7.17E-04	9.54E-05
Working Losses		Lw	tpy	4.49E-03	3.14E-03	4.18E-04
<b>Total Tank Loss</b>	(o)	Lt	<b>lb/hr</b>	<b>1.17E-03</b>	<b>5.44E-03</b>	<b>1.17E-04</b>
<b>Total Tank Loss</b>		Lt	<b>tpy</b>	<b>5.12E-03</b>	<b>0.02</b>	<b>5.13E-04</b>

<sup>(6)</sup> If unknown, use the value of 0.0625 ft/ft.  
<sup>(7)</sup> AP-42 Chapter 7.1 Table 7.1-6 for aluminum paint color in good condition.  
<sup>(8)</sup> Annual average, minimum and maximum temperatures are for Pittsburgh, PA obtained from <https://www.usclimatedata.com/climate/pittsburgh/pennsylvania/united-states/uspa3601>.  
<sup>(9)</sup> Total solar insolation factor was obtained for Pittsburgh, PA from the Insolation Data Manual and Direct Normal Solar Radiation Data Manual, as prepared by the Solar Radiation Resource Assessment, Solar Energy Research Institute (July 1990).  
<sup>(10)</sup> Equation 1-26 (0.44T<sub>AA</sub>+0.56T<sub>B</sub>+0.0079\*α<sup>1</sup>) on page 7.1-17 of AP-42 Chapter 7.1 was used.  
<sup>(11)</sup> Figure 7.1-17 containing the equation (T<sub>LX</sub> = T<sub>LA</sub> + 0.25\*T<sub>v</sub>) on page 7.1-57 of AP-42 Chapter 7.1 was used.  
<sup>(12)</sup> Each constant, A and B, was derived from the equation in Figure 7.1-15.  
<sup>(13)</sup> Vapor pressures were calculated using Antoine coefficients from *Elementary Principles of Chemical Processes: Third Edition*.  
<sup>(14)</sup> If specific information on the settings for the breather vent pressure setting and vacuum setting was not readily available, therefore, 0.03 psig for PBP and -0.03 psig for PBV were assumed as values, pursuant to guidance provided in AP-42 Chapter 7.1.  
<sup>(15)</sup> Throughput was estimated using plant provided information.  
<sup>(16)</sup> When turnovers are less than or equal to 36, then K<sub>N</sub> = 1, pursuant to guidance provided in AP-42 Chapter 7.1.  
<sup>(17)</sup> For all organic liquids except crude oils, K<sub>P</sub> = 1, pursuant to guidance provided in AP-42 Chapter 7.1.  
<sup>(18)</sup> Equation 1-2 (365\*V<sub>v</sub>\*W<sub>v</sub>\*K<sub>e</sub>\*K<sub>s</sub>) on page 7.1-10 of AP-42 Chapter 7.1 was used. Emissions are routed to a scrubber with 75% efficiency and have been adjusted accordingly.  
<sup>(19)</sup> Equation 1-29 (0.0010\*M<sub>v</sub>\*P<sub>V,A</sub>\*Q\*K<sub>N</sub>\*K<sub>P</sub>) on page 7.1-18 of AP-42 Chapter 7.1 was used.  
<sup>(20)</sup> Equation 1-14 on page 7.1-14 of AP-42 was used for horizontal tanks.  
<sup>(21)</sup> Equation 1-13 on page 7.1-15 of AP-42 was used for horizontal tanks.  
<sup>(22)</sup> Equation 1-13 on page 7.1-15 of AP-42 was used for horizontal tanks.

Conversions	
Constant for Rankine to Celsius Co	491.67
Multiplier for Rankine to Celsius Co	0.556
mmHg to Psia conversion	0.019

**Appendix A: Emission Calculations**  
**Fugitive GHG Emissions From Natural Gas Piping**

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Company Name: Allegheny Energy Center  
 Address: 2130 Margaret St. Ext., West Newton, PA 15089  
 Title V Operating Permit: 0959-1001  
 Date: March 29, 2021

Area	Connections		Valves			Other				Notes
	Flange	Thread	Block	Control	Safety Relief	Open Ended Line	Compressor	Ultrasonic Meter	Orifice Meter	
Primary Knock-out and Metering Yard	22	3	14	4	1	1	0	2	0	
Primary Filtration	44	10	40	4	2	2	0	0	0	Filtration prior to letdown station
Dew Point Heater	38	10	30	11	2	4	0	0	0	Natural Gas Fired
Fuel Gas Compressors/Bypass/Metering	42	16	18	8	4	4	3	0	3	3 x 50% Gas Compressors
Performance Heaters	10	0	2	0	1	1	0	0	0	Feedwater Based Heating
Fuel Gas Scrubbers	22	5	20	2	1	1	0	0	0	1 per CT
CT (inclusive of FG Module)	62	6	28	0	0	8	0	1	1	External to CT package
HRSG (Including BMS skid)	49	14	32	11	2	8	0	0	1	External to HRSG BMS
Auxiliary Boiler	38	10	30	11	2	4	0	0	0	
Subtotal	327	74	214	51	15	33	3	3	5	
Contingency	20%	20%	10%	10%	10%	10%	0%	0%	0%	
<b>TOTAL</b>	<b>392</b>	<b>89</b>	<b>235</b>	<b>56</b>	<b>17</b>	<b>36</b>	<b>3</b>	<b>3</b>	<b>5</b>	

Component	Count	Emissions Factor (scf/hr /comp.) <sup>(a)</sup>	CO <sub>2</sub> (tpy) <sup>(d)</sup>	CH <sub>4</sub> (tpy) <sup>(d)</sup>
Connectors	481	0.003	2.27E-04	0.26
Valves (block and control)	291	0.027	1.24E-03	1.39
Safety Relief Valves	17	0.040	1.07E-04	0.12
Open-ended Lines	36	0.061	3.46E-04	0.39
Compressors	3	13.300	6.29E-03	7.08
Meter <sup>(b)</sup>	3	2.930	1.39E-03	1.56
Orifice Meter <sup>(c)</sup>	5	0.212	-	0.19
<b>Total</b>			<b>9.60E-03</b>	<b>10.99</b>

Vol.% CO<sub>2</sub> in natural gas<sup>(d)</sup>: 0.032%

Vol.% CH<sub>4</sub> in natural gas<sup>(d)</sup>: 97.563%

GHG	Mass Emissions (tpy)	GWP <sup>(e)</sup>	CO <sub>2</sub> e (tpy)
CO <sub>2</sub>	9.60E-03	1	9.60E-03
CH <sub>4</sub>	10.99	25	274.72
<b>Total CO<sub>2</sub>e</b>			<b>274.73</b>

<sup>(a)</sup> Whole gas emissions factors from 40 CFR Part 98, Subpart W, Table W-1A for components in gas service for Eastern U.S., unless otherwise stated.

<sup>(b)</sup> Meter emissions factor from 40 CFR Part 98, Subpart W, Table W-2 for Leaker Emission Factors—Non-Compressor Components, Gas Service.

<sup>(c)</sup> Whole gas emissions factors from 40 CFR Part 98, Subpart W, Table W-7 for Leaker Emission Factors—Transmission-Distribution Transfer Station Components, Gas Service. Emissions factor is for methane emissions.

<sup>(d)</sup> CO<sub>2</sub> and CH<sub>4</sub> fractions based on volume % CO<sub>2</sub> and CH<sub>4</sub> in natural gas.

<sup>(e)</sup> Global warming potentials (GWP) from 40 CFR Part 98, Subpart A, Table A-1.

Fuel comp.	mole% (mole/100 mole)	molec. Wt. (lb/lbmole)	lb/lbmole
CH <sub>4</sub>	97.56	16.04	15.65
C <sub>2</sub> H <sub>6</sub>	2.06	30.07	0.62
C <sub>3</sub> H <sub>8</sub>	0.07	44.09	0.03
C <sub>4</sub> H <sub>10</sub>	0.00	58.12	0.00
C <sub>5</sub> H <sub>12</sub>	0.00	72.15	0.00
C <sub>6</sub> H <sub>14</sub>	0.00	86.17	0.00
CO <sub>2</sub>	0.03	44.01	0.01
N <sub>2</sub>	0.28	28.01	0.08

**Appendix A: Emission Calculations**  
**Fugitive GHG Emissions From Natural Gas Pipe Maintenance and Startup/Shutdown Line Purging**

TSD Appendix A: Page 11 of 14

Company Name: Allegheny Energy Center  
 Address: 2130 Margaret St. Ext., West Newton, PA 15089  
 Title V Operating Permit: 0959-1001  
 Date: March 29, 2021

Process	Initial Conditions			Final Conditions			No. of Purges per Year	Annual Emissions <sup>(c)</sup>	
	Volume <sup>(a)</sup> (ft <sup>3</sup> )	Press. (psig)	Temp. (F)	Press. (psig)	Temp. (F)	Volume <sup>(b)</sup> (ft <sup>3</sup> )		CO <sub>2</sub> (TPY)	CH <sub>4</sub> (TPY)
Full piping system purge (650 psig piping) <sup>(a)</sup>	690	650	60	0	68	35,216	2	1.27E-03	1.43
Full piping system purge (100 psig piping) <sup>(a)</sup>	240	100	60	0	68	1,918	2	6.90E-05	0.08
CT/DB Skids Purges @ Startups/Shutdowns	74	650	60	0	68	3,782	365	2.48E-02	27.96
Auxiliary Boiler Skid Purges # Startups/Shutdowns	39	100	60	0	68	314	365	2.06E-03	2.32
<b>Total</b>								<b>0.03</b>	<b>31.79</b>

Vol.% CO<sub>2</sub> in natural gas<sup>(c)</sup>: 0.032%

Vol.% CH<sub>4</sub> in natural gas<sup>(c)</sup>: 97.56%

GHG	Total Mass Emissions (TPY)	GWP <sup>(d)</sup>	CO <sub>2</sub> e (TPY)
CO <sub>2</sub>	0.028244	1	0.028
CH <sub>4</sub>	31.79177	25	794.79
<b>Total CO<sub>2</sub>e</b>			<b>794.82</b>

Natural Gas Piping Inventory					
Line Description	Size	Quantity	Pressure	Temp	Volume
	inches	ft	psig	F	cu.ft
Aux Boiler Area to Performance Heater Inlet Area	16	85	650	60	118.6
Fuel Gas Conditioning to Aux Boiler Area	16	210	650	60	293.1
Fuel Gas Conditioning to Regulating Skid	12	40	650	60	31.4
Metering Station to Fuel Gas Conditioning	12	40	650	60	31.4
Performance Heater Outlet Area to Filer Sep and CTG Inlet	4	220	650	60	19.2
Piping to Aux Boiler	10	50	650	60	27.3
Utility TP to Metering Station	16	120	650	60	167.5
CT Fuel Gas Skid	16	50	100	60	69.8
CT to Pilot	4	50	100	60	4.4
DB Runner	16	50	100	60	69.8
From Aux. Boiler Area to Aux. Burner Skid	12	50	100	60	39.3
From Aux. Boiler Area to Perf. Heater Area	6	250	100	60	49.1
From Perf. Htr. To DB Skid	4	85	100	60	7.4
Misc. 1"	1	350	650	60	1.9

930.0

Total piping @ 650 psig 690.3

Total piping @ 100 psig 239.6

<sup>(a)</sup> Initial volume is calculated by multiplying the cross-sectional area by the length of pipe using the following formula:  $V_i = \pi * [(diameter\ in\ inches/12)/2]^2 * length\ in\ feet = ft^3$  using the table below.

<sup>(b)</sup> Final volume calculated using the compressibility factor modification of the ideal gas law to account for real gas behavior:  $[(PV/ZT)_i] = (PV/ZT)_f$ .  $V_f = V_i (P_i/P_f) (T_f/T_i) (Z_i/Z_f)$ , where the compressibility factor (Z) for natural gas is estimated based on Dranchuk and Abou-Kassem equation of state using <http://checcalc.com/solved/naturalgasZ.html>:

For 500 psig natural gas at 60F, Z = 0.90

For 35 psig natural gas at 60F, Z = 0.99

For 0 psig natural gas at 68F, Z = 1

<sup>(c)</sup> CO<sub>2</sub> and CH<sub>4</sub> fractions based on volume % CO<sub>2</sub> and CH<sub>4</sub> in natural gas.

<sup>(d)</sup> Global warming potentials (GWP) from 40 CFR Part 98, Subpart A, Table A-1.

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Appendix A: Emission Calculations  
 HAPs Emissions From Combustion Sources

Company Name: Allegheny Energy Center  
 Address: 2130 Margaret St. Ex., West Newton, PA 15089  
 Title V Operating Permit: 0959-1001  
 Date: March 29, 2021

HAPs Pollutant Emitted	Note	CAS Number	Emissions Unit Description										Fire Water Pump				
			Emissions Factors for Natural Gas-Fired Turbines		Emissions Factors for Natural Gas Combustion		Emissions Factors for Large Diesel Engines		Emissions Factors for Small Diesel Engines		Emissions Factors for Trace Metals from Distillate Oil Combustion						
			AP-42 Ch 3.1 (lb/MMBtu)	AP-42 Ch 1.4 (lb/MMBtu)	AP-42 Ch 1.4 (lb/MMBtu)	AP-42 Ch 1.4 (lb/MMBtu)	AP-42 Ch 3.4 (lb/MMBtu)	AP-42 Ch 3.3 (lb/MMBtu)	AP-42 Ch 1.3 (lb/MMBtu)	CT	DB	Auxiliary Boiler		Dew Point Heater	Emergency Generator		
1,3-Butadiene	(a)	106-99-0	4.30E-07	-	-	2.29E-08	-	-	-	-	-	7.24E-03	0.00	0.00	0.00	0.00	3.79E-06
2-Methylheptahthalene	(a)	91-57-6	-	-	-	2.29E-08	-	-	-	-	-	0.00	3.95E-05	4.05E-06	3.00E-07	0.00	0.00
3-Methylchloranthrene	(a)	56-49-5	-	-	-	1.71E-09	-	-	-	-	-	0.00	2.96E-06	3.04E-07	2.25E-07	0.00	0.00
7,12-Dimethylbenz(a)anthracene	(a)	57-97-6	-	-	-	1.52E-08	-	-	-	-	-	0.00	2.63E-05	2.70E-06	2.00E-07	0.00	0.00
Acenaphthylene	(a)	83-32-9	-	-	-	1.71E-09	4.68E-06	1.42E-06	1.42E-06	9.23E-06	5.06E-06	0.00	2.96E-06	3.04E-07	2.25E-08	4.88E-06	1.38E-07
Acenaphthylene	(a)	208-96-8	-	-	-	1.71E-09	9.23E-06	5.06E-06	5.06E-06	9.23E-06	5.06E-06	0.00	2.96E-06	3.04E-07	2.25E-08	4.88E-06	1.38E-07
Acetaldehyde	(a)	75-07-0	4.00E-05	-	-	2.52E-05	1.67E-04	1.67E-04	1.67E-04	1.67E-04	1.67E-04	0.67	0.00	0.00	0.00	2.63E-05	7.44E-05
Anthracene	(a)	120-12-7	-	-	-	2.29E-09	1.23E-06	1.87E-06	1.87E-06	1.23E-06	1.87E-06	0.00	3.95E-06	4.05E-07	3.00E-08	1.28E-06	1.81E-07
Acrolein	(a)	107-02-3	6.40E-06	-	-	-	7.89E-06	9.25E-05	9.25E-05	7.89E-06	9.25E-05	0.11	0.00	0.00	0.00	8.22E-06	8.98E-06
Benz(a)anthracene	(a)	56-55-3	-	-	-	1.80E-06	1.71E-09	6.22E-07	1.68E-06	6.22E-07	1.68E-06	0.00	2.96E-06	3.04E-07	2.25E-08	6.49E-07	1.63E-07
Benzene	(a)	71-43-2	1.20E-05	2.10E-03	2.00E-06	2.00E-06	7.78E-04	9.33E-04	9.33E-04	7.78E-04	9.33E-04	0.20	3.45E-03	3.55E-04	2.63E-05	8.10E-04	9.05E-05
Benzofluoranthene (PAH)	(a)	50-32-8	-	-	-	1.80E-06	1.14E-09	2.57E-07	1.88E-07	1.14E-09	2.57E-07	0.00	1.97E-06	2.03E-07	1.50E-08	2.68E-07	1.82E-08
Benzofluoranthene	(a)	205-99-2	-	-	-	1.80E-06	1.14E-09	1.11E-06	9.91E-08	1.14E-09	1.11E-06	0.00	2.96E-06	3.04E-07	2.25E-08	1.16E-06	9.62E-09
Benzofluoranthene	(a)	191-24-2	-	-	-	1.20E-06	1.14E-09	-	4.89E-07	1.14E-09	-	0.00	1.97E-06	2.03E-07	1.50E-08	0.00	4.75E-08
Benzofluoranthene	(a)	207-08-9	-	-	-	1.80E-06	1.71E-09	2.18E-07	1.55E-07	1.71E-09	2.18E-07	0.00	2.96E-06	3.04E-07	2.25E-08	2.27E-07	1.50E-08
Chrysene	(a)	218-01-9	-	-	-	1.80E-06	1.71E-09	1.53E-06	3.53E-07	1.71E-09	1.53E-06	0.00	2.96E-06	3.04E-07	2.25E-08	1.60E-06	3.43E-08
Dibenz(a,h)anthracene	(a)	53-70-3	-	-	-	1.20E-06	1.14E-09	3.46E-07	5.83E-07	1.14E-09	3.46E-07	0.00	1.97E-06	2.03E-07	1.50E-08	3.61E-07	5.68E-08
Dichlorobenzene	(a)	25321-22-6	-	-	-	1.20E-03	1.14E-06	-	-	1.14E-06	-	0.00	1.97E-03	2.03E-04	1.50E-05	0.00	0.00
Ethylbenzene	(a)	100-41-4	3.20E-05	-	-	-	-	-	-	-	-	0.54	0.00	0.00	0.00	0.00	0.00
Fluoranthene	(a)	206-44-0	-	-	-	2.86E-09	4.03E-06	4.03E-06	7.61E-06	4.03E-06	7.61E-06	0.00	4.94E-06	5.07E-07	3.75E-08	4.20E-06	7.38E-07
Fluorene	(a)	96-73-7	-	-	-	2.67E-09	1.28E-05	1.28E-05	2.92E-05	1.28E-05	2.92E-05	0.00	4.61E-06	4.79E-07	3.59E-08	1.34E-05	2.83E-06
Formaldehyde	(b)	50-00-0	2.76E-04	7.50E-02	2.76E-04	7.89E-05	7.89E-05	1.18E-03	1.18E-03	7.89E-05	1.18E-03	4.64	0.48	0.05	3.62E-03	8.23E-05	1.15E-04
Hexane (n)	(c)	110-54-3	-	-	-	1.30E-03	1.24E-06	-	-	1.24E-06	-	0.00	2.14E-03	2.20E-04	1.63E-05	0.00	0.00
Indeno(1,2,3-cd)pyrene	(a)	193-39-5	-	-	-	1.80E-06	1.71E-09	4.14E-07	3.75E-07	1.71E-09	4.14E-07	0.00	2.96E-06	3.04E-07	2.25E-08	4.32E-07	3.64E-08
Naphthalene	(a)	91-20-3	1.30E-06	6.10E-04	5.81E-07	1.30E-04	8.48E-05	8.48E-05	8.48E-05	1.30E-04	8.48E-05	0.02	1.00E-03	1.03E-04	7.63E-06	1.36E-04	8.23E-06
Phenanthrene	(a)	85-01-8	-	-	-	1.62E-08	4.08E-05	4.08E-05	2.94E-05	4.08E-05	2.94E-05	0.00	2.80E-05	2.87E-06	2.13E-07	4.26E-05	2.85E-06
Propylene Oxide	(a)	75-56-9	2.90E-05	-	-	-	-	-	-	-	-	0.49	0.00	0.00	0.00	0.00	0.00
Pyrene	(a)	129-00-0	-	-	-	5.00E-06	4.76E-09	3.71E-06	4.78E-06	4.76E-09	3.71E-06	0.00	8.23E-06	8.45E-07	6.26E-08	3.87E-06	4.64E-07
Toluene	(a)	108-88-3	1.30E-04	3.40E-03	3.24E-06	3.24E-06	2.81E-04	4.09E-04	4.09E-04	3.24E-06	4.09E-04	2.19	5.59E-03	5.74E-04	4.25E-05	2.93E-04	3.97E-05
Xylenes	(a)	1330-20-7	6.40E-05	-	-	-	1.93E-04	1.93E-04	2.85E-04	1.93E-04	2.85E-04	1.08	0.00	0.00	0.00	2.01E-04	2.77E-05
Arsenic	(a)	7440-38-2	-	-	-	2.0E-04	1.90E-07	-	-	1.90E-07	-	0.00	3.29E-04	3.38E-05	2.50E-06	4.17E-06	3.88E-07
Beryllium	(a)	7440-41-7	-	-	-	1.20E-05	1.14E-08	-	-	1.14E-08	-	0.00	1.87E-05	2.03E-06	1.50E-07	3.13E-06	2.91E-07
Cadmium	(a)	7440-43-9	-	-	-	1.10E-03	1.05E-06	-	-	1.05E-06	-	0.00	2.30E-03	2.37E-04	1.75E-05	3.13E-06	2.91E-07
Chromium	(a)	7440-47-3	-	-	-	1.40E-03	1.33E-06	-	-	1.33E-06	-	0.00	2.30E-03	2.37E-04	1.75E-05	3.13E-06	2.91E-07
Cobalt	(a)	7440-48-4	-	-	-	8.40E-05	8.00E-08	-	-	8.00E-08	-	0.00	1.38E-04	1.42E-05	1.05E-06	0.00	0.00
Lead	(a)	7439-92-1	-	-	-	5.00E-04	4.76E-07	-	-	4.76E-07	-	0.00	8.23E-04	8.45E-05	6.26E-06	3.93E-06	8.73E-07
Manganese	(a)	7439-96-5	-	-	-	3.80E-04	3.62E-07	-	-	3.62E-07	-	0.00	6.25E-04	6.42E-05	4.78E-06	6.26E-06	5.82E-07
Mercury	(a)	7439-97-6	-	-	-	2.60E-04	2.48E-07	-	-	2.48E-07	-	0.00	4.28E-04	4.39E-05	3.25E-06	3.13E-06	2.91E-07
Nickel	(a)	7440-02-0	-	-	-	2.10E-03	2.00E-06	-	-	2.00E-06	-	0.00	3.45E-03	3.55E-04	2.63E-05	3.13E-06	2.91E-07
Selenium	(a)	7782-49-2	-	-	-	2.40E-05	2.29E-08	-	-	2.29E-08	-	0.00	3.95E-05	4.05E-06	3.00E-07	1.57E-05	1.46E-06
												4.64	0.48	0.05	3.62E-03	8.10E-04	1.15E-04
												9.95	0.50	0.05	3.81E-03	1.69E-03	3.81E-04
																	10.50

<sup>(a)</sup> Emissions factors are based on method detection limits from AP-24 Chapter 1.4, Chapter 3.1, Chapter 3.3, or Chapter 3.4.  
<sup>(b)</sup> Formaldehyde standard in 40 CFR Part 63, Subpart YYYYY (0.091 parts per million, volumetric dry [ppmv] @ 15% oxygen [O<sub>2</sub>]).  
<sup>(c)</sup> The AP-42 emissions factor for hexane from natural gas combustion (AP-42 Chapter 1.4 Table 1.4.3 (7/88)) has been designated as poor (i.e. "E" rating). This hexane emissions factor is considered unreasonably high. Therefore, a more realistic hexane emissions factor is being used. The hexane emissions factor is located in Ventura County Air Pollution Control District document AB2588 AB 2588 - Combustion Emission Factors.



**Appendix A: Emission Calculations**  
**Fugitive SF<sub>6</sub> Emissions From Circuit Breakers**

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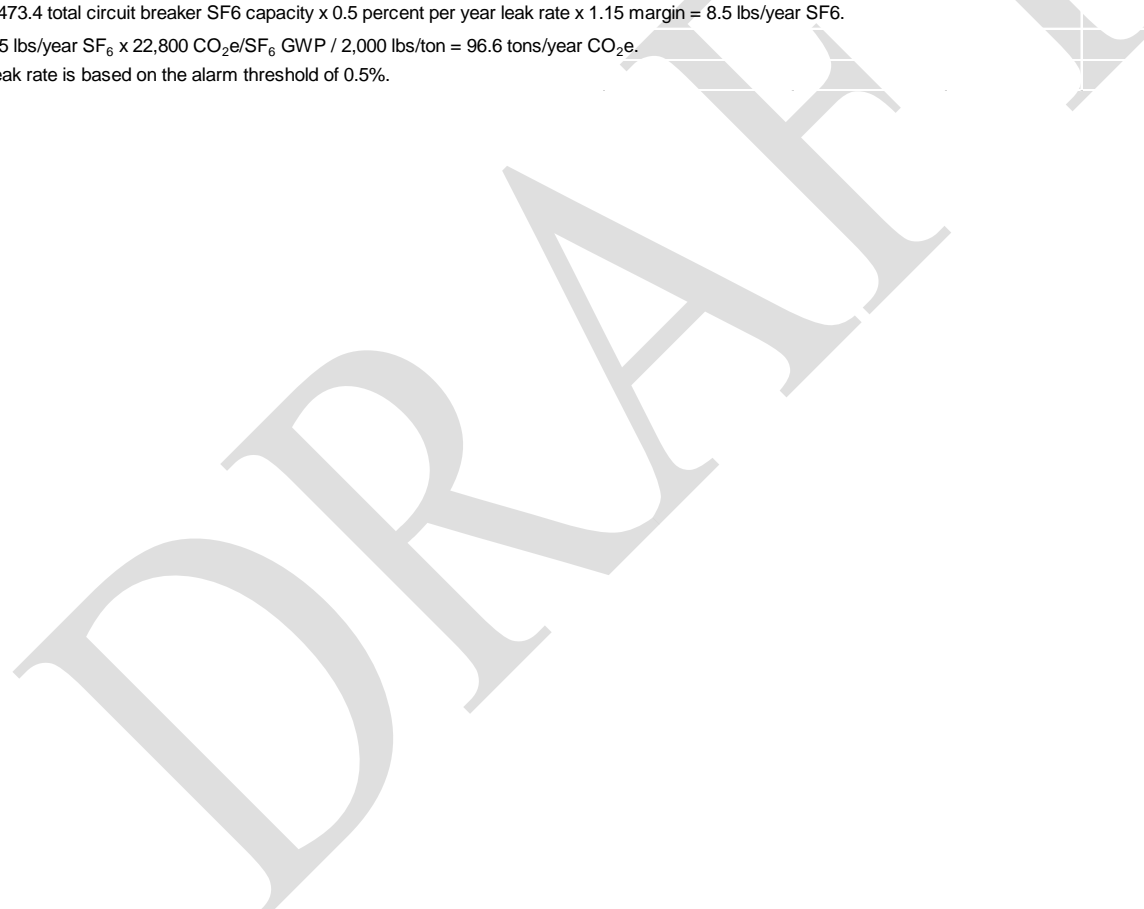
Company Name: Allegheny Energy Center  
 Address: 2130 Margaret St. Ext., West Newton, PA 15089  
 Title V Operating Permit: 0959-1001  
 Date: March 29, 2021

Input Data/Assumptions	138 kV	25 kV
Number of SF <sub>6</sub> Circuit Breakers	3	1
Circuit Breaker SF <sub>6</sub> Capacity, per breaker (lbs)	483.0	24.4
Total SF <sub>6</sub> circuit breaker capacity by size (lbs)	1,449.0	24.4
Total SF <sub>6</sub> capacity	1,473.4	lbs
Fugitive Loss/Leak Rate	0.5	% per year <sup>(c)</sup>
SF <sub>6</sub> Global Warming Potential (40 CFR 98, Subpt. A, Table A-1)	22,800	CO <sub>2e</sub> /SF <sub>6</sub>
Potential Emissions - Fugitive SF <sub>6</sub> <sup>(a)</sup>	8.5	lbs/year
Potential GHG - Fugitive SF <sub>6</sub> in CO <sub>2e</sub> <sup>(b)</sup>	96.6	tons/year

<sup>(a)</sup> 1,473.4 total circuit breaker SF6 capacity x 0.5 percent per year leak rate x 1.15 margin = 8.5 lbs/year SF6.

<sup>(b)</sup> 8.5 lbs/year SF<sub>6</sub> x 22,800 CO<sub>2e</sub>/SF<sub>6</sub> GWP / 2,000 lbs/ton = 96.6 tons/year CO<sub>2e</sub>.

<sup>(c)</sup> Leak rate is based on the alarm threshold of 0.5%.



**Appendix A: Emission Calculations**  
**GHG Emissions From Combustion Sources**

TSD Appendix A: Page 14 of 14

Company Name: Allegheny Energy Center  
 Address: 2130 Margaret St. Ext., West Newton, PA 15089  
 Title V Operating Permit: 0959-1001  
 Date: March 29, 2021

Unit Description	Fuel	Potential Annual Consumption	Fuel Consumption Units	Notes
Combustion Turbine w/ Duct Burner	Natural Gas	36,079,812	MMBtu	Average of Operating Scenarios
Auxiliary Boiler	Natural Gas	354,800	MMBtu	
Dew Point Heater	Natural Gas	26,280	MMBtu	
Emergency Generator	ULSD	2,087	MMBtu	
Fire Water Pump	ULSD	194	MMBtu	

Unit Description	Fuel	CO <sub>2</sub> <sup>(a)</sup>	CH <sub>4</sub> <sup>(b)</sup>	N <sub>2</sub> O <sup>(b)</sup>	PTE CO <sub>2</sub>	PTE CH <sub>4</sub>	PTE N <sub>2</sub> O	PTE CO <sub>2</sub> e <sup>(c)</sup>
		Emissions Factor	Emissions Factor	Emissions Factor				
		lb/MMBtu			TPY			
Combustion Turbine w/ Duct Burner	Natural Gas	439,000	2.20E-03	2.20E-04	1,922,820	40	4	1,924,999.4
Auxiliary Boiler	Natural Gas	116.98	2.20E-03	2.20E-04	20,752	0.39	0.04	20,773.0
Dew Point Heater	Natural Gas	116.98	2.20E-03	2.20E-04	1,537	0.03	2.90E-03	1,538.7
Emergency Generator	ULSD	163.05	6.61E-03	1.32E-03	170	6.90E-03	1.38E-03	170.7
Fire Water Pump	ULSD	163.05	6.61E-03	1.32E-03	15.8	6.42E-04	1.28E-04	15.9
<b>TOTAL</b>								<b>1,947,327</b>

<sup>(a)</sup> The emissions factor for CO<sub>2</sub> for the combustion turbine is from manufacturer's data in lb/hr. The emissions factor for the ancillary equipment is from 40 CFR Part 98, Subpart C, Table C-1 in lb/MMBtu.

<sup>(b)</sup> Emissions Factor Reference: 40 CFR Part 98, Subpart C, Table C-2

<sup>(c)</sup> CO<sub>2</sub>e is carbon dioxide equivalent, calculated according to 40 CFR Part 98 Equation A-1:

$$CO_2e = \sum_{i=1}^n GHG_i \times GWP_i$$

GWP<sub>i</sub> = global warming potential of greenhouse gas i from 40 CFR Part 98 Table A-1 (below):

Pollutant	GWP
CO <sub>2</sub>	1
CH <sub>4</sub>	25
N <sub>2</sub> O	298

**APPENDIX B – BACT/LAER SUMMARY**

**BACT/LAER Summary for the Combustion Turbine and HRSG, with and without Duct Burners**

Pollutant	Control Evaluation Required	Available Control Technologies	Technically Feasible Options	Economically, Environmentally, and Energetically Feasible	Identify BACT/LAER	AEC Proposed BACT/LAER
NO <sub>x</sub>	LAER	Good Combustion Practices	✓	Not applicable (N/A) for a LAER analysis.	✓	AEC proposes to use SCR, DLN combustors, and good combustion practices as NO <sub>x</sub> LAER for the CT and HRSG with and without DBs.
		Water or Steam Injection	✗		✗	
		Dry Low-NO <sub>x</sub> Combustors (DLN)	✓		✓	
		Selective Catalytic Reduction (SCR)	✓		✓	
		Selective Non-Catalytic Reduction (SNCR)	✗		✗	
		Low-NO <sub>x</sub> Burners (LNB)	✓		✗	
		Ultra-Low-NO <sub>x</sub> Burners (ULNB)	✓		✗	
		Oxidation Catalyst	✗		✗	
		XONON™ Catalytic Combustor	✗		✗	
		EMx™ Catalytic Absorption/Oxidation (Formerly SCONOX™)	✗		✗	
CO	BACT	Good Combustion Practices	✓	✓	✓	AEC proposes to use good combustion practices and catalytic oxidation as CO BACT for the CT and HRSG with and without DBs.
		Oxidation Catalyst	✓	✓	✓	
		XONON™ Catalytic Combustor	✗	✗	✗	
		EMx™ Catalytic Absorption/Oxidation (Formerly SCONOX™)	✗	✗	✗	
VOC	LAER	Good Combustion Practices	✓	Not applicable (N/A) for a LAER analysis.	✓	AEC proposes to use good combustion practices and catalytic oxidation as VOC LAER for the CT and HRSG with and without DBs.
		Oxidation Catalyst	✓		✓	
		XONON™ Catalytic Combustor	✗		✗	
		EMx™ Catalytic Absorption/Oxidation (Formerly SCONOX™)	✗		✗	

Pollutant	Control Evaluation Required	Available Control Technologies	Technically Feasible Options	Economically, Environmentally, and Energetically Feasible	Identify BACT/LAER	AEC Proposed BACT/LAER
PM/PM <sub>10</sub> PM <sub>2.5</sub>	BACT ACHD BACT	Good Combustion Practices	✓	✓	✓	AEC proposes to use good combustion practices and the use of low sulfur fuels, as PM, PM <sub>10</sub> , and PM <sub>2.5</sub> BACT for the CT and HRSG with and without DBs.
		Low Sulfur Fuels	✓	✓	✓	
		Fabric Filter Baghouse	✗	✗	✗	
		Electrostatic Precipitator	✗	✗	✗	
		Wet Electrostatic Precipitator	✗	✗	✗	
		Scrubber	✗	✗	✗	
SO <sub>2</sub>	ACHD BACT	Good Combustion Practices	✓	✓	✓	AEC proposes to use good combustion practices and the use of low sulfur fuels, as SO <sub>2</sub> BACT for the CT and HRSG with and without DBs.
		Low Sulfur Fuels	✓	✓	✓	
		Scrubber/Flue Gas Desulfurization	✗	✗	✗	
H <sub>2</sub> SO <sub>4</sub>	BACT	Good Combustion Practices	✓	✓	✓	AEC proposes to use good combustion practices and the use of low sulfur fuels, as H <sub>2</sub> SO <sub>4</sub> BACT for the CT and HRSG with and without DBs.
		Low Sulfur Fuels	✓	✓	✓	
		Flue Gas Desulfurization	✗	✗	✗	
GHG	BACT	Energy efficient and inherently lower-emitting processes/work practices/design	✓	✓	✓	AEC proposes the use of oxidation catalyst in conjunction with energy efficient and inherently lower-emitting processes, work practices, and design for the CT and HRSG with and without DBs.
		Good Combustion Practices	✓	✓	✓	
		Carbon Capture and Sequestration	✓	✗	✗	
		Oxidation Catalyst	✓	✓	✓	
		Thermal Oxidation	✗	✗	✗	

**BACT/LAER Summary for the Auxiliary Boiler**

Pollutant	Control Evaluation Required	Available Control Technologies	Technically Feasible Options	Economically, Environmentally, and Energetically Feasible	Identify BACT	AEC Proposed BACT/LAER
NO <sub>x</sub>	LAER	Good Combustion Practices	✓	Not applicable (N/A) for a LAER analysis.	✓	AEC proposes to use good combustion practices, ULNB, and FGR as LAER for the Auxiliary Boiler.
		Selective Catalytic Reduction (SCR)	✗		✗	
		Selective Non-Catalytic Reduction (SNCR)	✗		✗	
		Low-NO <sub>x</sub> Burners (LNB)	✓		✗	
		Ultra-Low-NO <sub>x</sub> Burners (ULNB)	✓		✓	
		Flue Gas Recirculation (FGR)	✓		✓	
CO	BACT	Good Combustion Practices	✓	✓	✓	AEC proposes to use good combustion practices as CO BACT for the Auxiliary Boiler.
		Oxidation Catalyst	✗	✗	✗	
		Thermal Oxidation	✗	✗	✗	
VOC	LAER	Good Combustion Practices	✓	Not applicable (N/A) for a LAER analysis.	✓	AEC proposes to use good combustion practices and FGR as VOC LAER for the Auxiliary Boiler.
		Oxidation Catalyst	✗		✗	
		Flue Gas Recirculation	✓		✓	
		Thermal Oxidation	✗		✗	
PM/PM <sub>10</sub> PM <sub>2.5</sub>	BACT ACHD BACT	Good Combustion Practices	✓	✓	✓	AEC proposes good combustion practices as BACT for the auxiliary boiler to minimize emissions of PM, PM <sub>10</sub> , and PM <sub>2.5</sub> .
		Low Sulfur Fuels	✓	✓	✓	
		Fabric Filter Baghouse	✗	✗	✗	
		Electrostatic Precipitator	✗	✗	✗	
		Wet Electrostatic Precipitator	✗	✗	✗	
		Scrubber	✗	✗	✗	

Pollutant	Control Evaluation Required	Available Control Technologies	Technically Feasible Options	Economically, Environmentally, and Energetically Feasible	Identify BACT	AEC Proposed BACT/LAER
SO <sub>2</sub>	ACHD BACT	Good Combustion Practices	✓	✓	✓	AEC proposes to use good combustion practices, including the use of low sulfur fuels, to control SO <sub>2</sub> emissions from the Auxiliary Boiler.
		Low Sulfur Fuels	✓	✓	✓	
		Scrubber/Flue Gas Desulfurization	✗	✗	✗	
H <sub>2</sub> SO <sub>4</sub>	BACT	Good Combustion Practices	✓	✓	✓	AEC proposes to use good combustion practices, including the use of low sulfur fuels as H <sub>2</sub> SO <sub>4</sub> BACT for the Auxiliary Boiler.
		Low Sulfur Fuels	✓	✓	✓	
GHG	BACT	Energy efficient and inherently lower-emitting processes/work practices/design	✓	✓	✓	AEC proposes energy efficient and inherently lower-emitting processes, work practices, and design as GHG BACT for the Auxiliary Boiler.

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**BACT/LAER Summary for the Dew Point Heater**

Pollutant	Control Evaluation Required	Available Control Technologies	Technically Feasible Options	Economically, Environmentally, and Energetically Feasible	Identify BACT	AEC Proposed BACT/LAER
NO <sub>x</sub>	LAER	Good Combustion Practices	✓	Not applicable (N/A) for a LAER analysis.	✓	AEC proposes good combustion practices as NO <sub>x</sub> LAER for the Dew Point Heater.
		Selective Catalytic Reduction (SCR)	✗		✗	
		Low-NO <sub>x</sub> Burners (LNB)	✗		✗	
		Ultra-Low-NO <sub>x</sub> Burners (ULNB)	✗		✗	
		Flue Gas Recirculation (FGR)	✗		✗	
CO	BACT	Good Combustion Practices	✓	✓	✓	AEC proposes good combustion practices as CO BACT for the Dew Point Heater.
		Oxidation Catalyst	✗	✗	✗	
		Thermal Oxidation	✗	✗	✗	
VOC	LAER	Good Combustion Practices	✓	N/A for a LAER analysis.	✓	AEC proposes good combustion practices as VOC LAER for the Dew Point Heater.
		Oxidation Catalyst	✗		✗	
		Flue Gas Recirculation	✗		✗	
PM/PM <sub>10</sub> PM <sub>2.5</sub>	BACT ACHD BACT	Good Combustion Practices	✓	✓	✓	AEC proposes good combustion practices and the use of low sulfur fuels, as PM, PM <sub>10</sub> , and PM <sub>2.5</sub> BACT for the Dew Point Heater.
		Low Sulfur Fuels	✓	✓	✓	
		Fabric Filter Baghouse	✗	✗	✗	
		Electrostatic Precipitator	✗	✗	✗	
		Wet Electrostatic Precipitator	✗	✗	✗	
		Scrubber	✗	✗	✗	
SO <sub>2</sub>	ACHD BACT	Good Combustion Practices	✓	✓	✓	AEC proposes good combustion practices and the use of low sulfur fuels, as SO <sub>2</sub> and H <sub>2</sub> SO <sub>4</sub> BACT for the Dew Point Heater.
		Low Sulfur Fuels	✓	✓	✓	
		Scrubber/Flue Gas Desulfurization	✗	✗	✗	
H <sub>2</sub> SO <sub>4</sub>	BACT	Good Combustion Practices	✓	✓	✓	
		Low Sulfur Fuels	✓	✓	✓	

Pollutant	Control Evaluation Required	Available Control Technologies	Technically Feasible Options	Economically, Environmentally, and Energetically Feasible	Identify BACT	AEC Proposed BACT/LAER
GHG	BACT	Energy efficient design and work practices	✓	✓	✓	AEC proposes energy efficient and inherently lower-emitting processes, work practices, and design as GHG BACT for the Dew Point Heater.

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**BACT/LAER Summary for the Emergency Generator**

Pollutant	Control Evaluation Required	Available Control Technologies	Technically Feasible Options	Economically, Environmentally, and Energetically Feasible	Identify BACT	AEC Proposed BACT/LAER
NO <sub>x</sub>	LAER	Good Combustion Practices	✓	Not applicable (N/A) for a LAER analysis.	✓	AEC proposes good combustion practices and the use of ULSD as NO <sub>x</sub> LAER for the Emergency Generator.
		Selective Catalytic Reduction	✗		✗	
CO	BACT	Good Combustion Practices	✓	✓	✓	AEC proposes good combustion practices and the use of ULSD as CO BACT for the Emergency Generator.
		Diesel Oxidation Catalyst	✗	✗	✗	
VOC	LAER	Good Combustion Practices	✓	Not applicable (N/A) for a LAER analysis.	✓	AEC proposes good combustion practices and the use of ULSD as VOC LAER for the Emergency Generator.
		Oxidation Catalyst	✗		✗	
		Non-Selective Catalytic Reduction	✗		✗	
PM/PM <sub>10</sub> PM <sub>2.5</sub>	BACT ACHD BACT	Good Combustion Practices	✓	✓	✓	AEC proposes good combustion practices and the use of ULSD as PM, PM <sub>10</sub> , and PM <sub>2.5</sub> BACT for the Emergency Generator.
		Low Sulfur Fuels	✓	✓	✓	
		Add-On Control Technologies	✗	✗	✗	
SO <sub>2</sub>	ACHD BACT	Good Combustion Practices	✓	✓	✓	AEC proposes good combustion practices and the use of ULSD as SO <sub>2</sub> BACT for the Emergency Generator.
		Low Sulfur Fuels	✓	✓	✓	
		Scrubber/Flue Gas Desulfurization	✗	✗	✗	
H <sub>2</sub> SO <sub>4</sub>	BACT	Good Combustion Practices	✓	✓	✓	AEC proposes good combustion practices and the use of ULSD as H <sub>2</sub> SO <sub>4</sub> BACT for the Emergency Generator.
		Low Sulfur Fuels	✓	✓	✓	
GHG	BACT	Good Combustion Practices	✓	✓	✓	AEC proposes good combustion practices and the use of ULSD as GHG BACT for the Emergency Generator.

**BACT/LAER Summary for the Fire Water Pump Engine**

Pollutant	Control Evaluation Required	Available Control Technologies	Technically Feasible Options	Economically, Environmentally, and Energetically Feasible	Identify BACT	Identify BACT
NO <sub>x</sub>	LAER	Good Combustion Practices	✓	Not applicable (N/A) for a LAER analysis.	✓	AEC proposes good combustion practices and the use of ULSD as NO <sub>x</sub> LAER for the Fire Water Pump.
		Selective Catalytic Reduction	✗		✗	
CO	BACT	Good Combustion Practices	✓	✓	✓	AEC proposes good combustion practices and the use of ULSD as CO BACT for the Fire Water Pump.
		Diesel Oxidation Catalyst	✗	✗	✗	
VOC	LAER	Good Combustion Practices	✓	Not applicable (N/A) for a LAER analysis.	✓	AEC proposes good combustion practices and the use of ULSD as VOC LAER for the Fire Water Pump.
		Oxidation Catalyst	✗		✗	
		Non-Selective Catalytic Reduction	✗		✗	
PM/PM <sub>10</sub> PM <sub>2.5</sub>	BACT ACHD BACT	Good Combustion Practices	✓	✓	✓	AEC proposes good combustion practices and the use of ULSD as PM, PM <sub>10</sub> , and PM <sub>2.5</sub> BACT for the Fire Water Pump.
		Low Sulfur Fuels	✓	✓	✓	
		Add-On Control Technologies	✗	✗	✗	
SO <sub>2</sub>	ACHD BACT	Good Combustion Practices	✓	✓	✓	AEC proposes good combustion practices and the use of ULSD as SO <sub>2</sub> BACT for the Fire Water Pump.
		Low Sulfur Fuels	✓	✓	✓	
		Scrubber/Flue Gas Desulfurization	✗	✗	✗	
H <sub>2</sub> SO <sub>4</sub>	BACT	Good Combustion Practices	✓	✓	✓	AEC proposes good combustion practices and the use of ULSD as H <sub>2</sub> SO <sub>4</sub> BACT for the Fire Water Pump.
		Low Sulfur Fuels	✓	✓	✓	
GHG	BACT	Good Combustion Practices	✓	✓	✓	AEC proposes good combustion practices and the use of ULSD as GHG BACT for the Fire Water Pump.

**BACT/LAER Summary for the Natural Gas Pipeline**

Pollutant	Control Evaluation Required	Available Control Technologies	Technically Feasible Options	Economically, Environmentally, and Energetically Feasible	Identify BACT
GHG	BACT	Implementation of AVO programs for fugitive control	✓	✓	✓

**BACT/LAER Summary for the Storage Tanks**

Pollutant	Control Evaluation Required	Available Control Technologies	Technically Feasible Options	Economically, Environmentally, and Energetically Feasible	Identify BACT
VOC	LAER	Tank Design	✓	✓	✓

**BACT/LAER Summary for the Roadways**

Pollutant	Control Evaluation Required	Available Control Technologies	Technically Feasible Options	Economically, Environmentally, and Energetically Feasible	Identify BACT
PM/PM <sub>10</sub> PM <sub>2.5</sub>	BACT	Fugitive Dust Prevention and Control Plan	✓	✓	✓

## APPENDIX C – AIR QUALITY MODELING ANALYSIS

In accordance with the Prevention of Significant Deterioration (PSD) rules in 40 CFR § 52.21 and ACHD Article XXI §2102.07(a), Allegheny Energy Center LLC has conducted an air quality analysis which utilizes dispersion modeling. Allegheny Energy Center’s air quality analysis satisfies the requirements of the PSD rules and is consistent with the U.S. Environmental Protection Agency’s (EPA) *Guideline on Air Quality Models* (40 CFR Part 51, Appendix W) and the EPA’s air quality modeling policy and guidance.

In accordance with 40 CFR § 52.21(k), Allegheny Energy Center’s air quality analysis demonstrates that the proposed emissions from Allegheny Energy Center’s facility would not cause or contribute to air pollution in violation of the National Ambient Air Quality Standards (NAAQS) for carbon monoxide (CO), nitrogen dioxide (NO<sub>2</sub>), particulate matter less than or equal to 2.5 micrometers in diameter (PM<sub>2.5</sub>), or particulate matter less than or equal to 10 micrometers in diameter (PM<sub>10</sub>).

Allegheny County is designated as nonattainment for the 2012 annual particulate matter less than or equal to 2.5 micrometers in diameter (PM<sub>2.5</sub>) NAAQS. Sections of Allegheny County are also designated as nonattainment for the 1997 24-hour PM<sub>2.5</sub> NAAQS; however, the Elizabeth Township is not one of those sections. In addition, sections of Allegheny County including Elizabeth Township are designated nonattainment with the 2010 1-hour sulfur dioxide (SO<sub>2</sub>) NAAQS. As a result, PM<sub>2.5</sub> and SO<sub>2</sub> are regulated by the Nonattainment New Source Review (NNSR) permitting program. Allegheny Energy Center’s proposed PM<sub>2.5</sub> and SO<sub>2</sub> emissions are below the major source NNSR emissions threshold of 100 tons per year (tpy) and therefore is not subject to NNSR permitting requirements. The Department requested a PM<sub>2.5</sub> air quality modeling demonstration be completed to evaluate impacts to the PM<sub>2.5</sub> nonattainment areas. Allegheny County is also part of the Ozone Transport Region, and as such, ozone is regulated by the NNSR permitting program. NO<sub>2</sub> is a precursor for ozone, and proposed emissions are above the major source threshold of 100 tons per year. An SO<sub>2</sub> air quality modeling demonstration was not requested based on the relatively low amount of SO<sub>2</sub> emissions associated with the project.

A summary of the Class II significant impact level (SIL) air quality modeling analysis and subsequent NAAQS air quality modeling demonstration is provided in the following tables:

**Table C-1 – Allegheny Energy Center SIL Analysis Air Quality Modeling Results**

Pollutant	Averaging Period	AEC Class II SIL Impact	Class II SIL
		µg/m <sup>3</sup>	µg/m <sup>3</sup>
CO	1-Hour	639.55867	2,000
	8-Hour	363.09435	500
NO <sub>2</sub>	1-Hour	28.94776 <sup>(a)</sup>	7.5
	Annual	0.42440	1.0
PM <sub>2.5</sub>	24-Hour	0.99406	1.2
	Annual	0.08367	0.2
PM <sub>10</sub>	24-Hour	1.59703	5.0
	Annual	0.08856	1.0

(a) Allegheny Energy Center’s impact is greater than Class II SIL therefore NAAQS and PSD increment air quality modeling demonstrations were also completed.

**Table C-2 – Allegheny Energy Center NAAQS Air Quality Modeling Demonstration**

Pollutant	Averaging Period	Combined Impact <sup>(a)(b)</sup>	NAAQS
		µg/m <sup>3</sup>	µg/m <sup>3</sup>
NO <sub>2</sub>	1-Hour	62.2	188.0

(a) AEC contribution combined with background concentration from the Charleroi NO<sub>2</sub> ambient monitor (42-125-0005).

(b) Local sources were also evaluated, and a significant contribution analysis was completed that demonstrated that the contribution of NO<sub>2</sub> concentrations due to

AEC-only sources does not cause or contribute to violations of the 1-hour NO<sub>2</sub> NAAQS.

Allegheny Energy Center’s air quality analysis demonstrates that the proposed emissions from Allegheny Energy Center’s facility would not cause or contribute to air pollution in violation of the increments for NO<sub>2</sub>, PM<sub>2.5</sub>, or PM<sub>10</sub>. The degree of Class II and Class I increment consumption expected to result from the operation of Allegheny Energy Center’s facility is provided in the following tables:

**Table C-3 – Degree of Class II Increment Consumption from Operation of Allegheny Energy Center’s Facility**

Pollutant	Averaging Period	Degree of Class II Increment Consumption		Class II Increment
		µg/m <sup>3</sup>	% of Class II Increment	µg/m <sup>3</sup>
NO <sub>2</sub>	Annual	< 0.42736	< 1.71 %	25
PM <sub>2.5</sub>	24-Hour	< 0.99411	< 11.05 %	9
	Annual	< 0.08367	< 2.09 %	4
PM <sub>10</sub>	24-Hour	< 1.59703	< 5.32 %	30
	Annual	< 0.08856	< 0.52 %	17

**Table C-4 – Degree of Class I Increment Consumption from Operation of Allegheny Energy Center’s Facility**

Pollutant	Averaging Period	Degree of Class I Increment Consumption		Class I Increment
		µg/m <sup>3</sup>	% of Class I Increment	µg/m <sup>3</sup>
NO <sub>2</sub>	Annual	< 0.01061	< 0.42 %	2.5
PM <sub>2.5</sub>	24-Hour	< 0.06632	< 3.32 %	2
	Annual	< 0.00712	< 0.71 %	1
PM <sub>10</sub>	24-Hour	< 0.10347	< 1.29 %	8
	Annual	< 0.00713	< 0.18 %	4

In accordance with 40 CFR §52.21(o), Allegheny Energy Center provided a satisfactory analysis of the impairment to visibility, soils, and vegetation that would occur as a result of Allegheny Energy Center’s facility and general commercial, residential, industrial, and other growth associated with Allegheny Energy Center’s facility.

In accordance with 40 CFR §52.21(p), written notice of Allegheny Energy Center’s proposed facility has been provided to the Federal Land Managers of nearby Class I areas as well as initial screening calculations to demonstrate that the proposed emissions from Allegheny Energy Center’s facility would not adversely impact visibility and air quality related values in nearby Class I areas.

A more detailed summary of the air quality modeling analysis is summarized in Section 6 of the permit application and in ACHD’s “Modeling Review of Invenergy LLC (Invenergy) Proposed Natural Gas Combined-Cycle Power Plant Installation Permit” modeling review document prepared by the Planning and Data Analysis Section.

## **ALLEGHENY COUNTY REGULATIONS:**

### Allegheny County Regulations (Article XXI - Air Pollution Control Regulations)

ACHD retains jurisdiction within Allegheny County with full delegation from the EPA to enforce the air quality programs under the CAA. The emission sources presented in this document will comply with applicable ACHD regulations promulgated under Article XXI - Air Pollution Control Regulations. This section highlights the applicable county regulations and citations with regulatory requirements pertinent to the proposed Project and Installation Permit Application.

### Article XXI §2101.10 - Ambient Air Quality Standards

This Chapter sets for the basis for the ACHD incorporating, by reference, the National Ambient Air Quality Standards, as part of the standards in §2101.10(a). The Project's demonstration of compliance with the NAAQS is presented in Section 6 of the Installation Permit Application.

## **RECOMMENDATION:**

Allegheny Energy Center has demonstrated that the proposed natural gas-fired combined cycle power plant located in Elizabeth Township, Allegheny County meets the requirements of 40 CFR Part 52.21 (related to Prevention of Significant Deterioration), ACHD Article XXI §2102.06 (related to New Source Review), and Best Available Control Technology. In addition to the above recordkeeping, testing, reporting, and federal and state regulations the installation permit incorporates additional requirements that may or may not be addressed in this review. Refer to the installation permit for all requirements pertaining to this project. AEC has also demonstrated that the proposed facility will not cause or contribute to air pollution in violation of the NAAQS, will not impair visibility, soils, and vegetation, and will not adversely affect air quality related values (AQRV), including visibility, in federal Class I areas. Based on this analysis the issuance of an installation permit is recommended.