4.0 Emissions Inventory

Potential emissions during normal, startup, and shutdown operations were estimated for the proposed project. Emission estimates are based on AP-42 emission factors, vendor data, and engineering estimates, which are provided in Appendix E and Appendix F.

4.1 Emission Source Summary

Potential emissions were calculated for the following: combustion turbine/HRSG stacks, sulfur recovery system, auxiliary boiler, cooling tower, gasifier preheat vents, emergency generator, emergency fire pump, and material handling sources. A brief description of each is provided below.

<u>Combustion Turbines</u>
Two combustion turbines are utilized to combust both natural gas and syngas to generate electricity. The exhaust from both is used to produce steam that feeds a steam turbine. The proposed combustion turbines are a GE-7FB model and represent a first of a kind turbine designed to optimally consume natural gas and/or syngas. Potential emissions were provided by the vendor for varying turbine loads (60%, 80%, and 100%) and ambient temperatures. Each scenario is evaluated in the air dispersion modeling analysis.

<u>Sulfur Recovery System</u>
The sulfur recovery system is designed to process acid gas streams from the acid gas removal (AGR) system and IGCC process into an elemental sulfur by-product. The resulting tail gas exiting the sulfur recovery system is recycled back to the IGCC process. Associated with the operation of the sulfur recovery process is the integral use of a flare and thermal oxidizer as control devices to provide for the safe and efficient destruction of combustible gas streams. These control devices are primarily utilized intermittently during short-term periods of startup, shutdown, and malfunction operations. A continuous natural gas pilot will be in service on both controls. The thermal oxidizer also controls emissions from various systems during normal operations, including the sulfur pit vent. Potential emissions for the flare and thermal oxidizer are based on AP-42 emission factors and vendor supplied data.

<u>Auxiliary Boiler</u>
A natural gas fired auxiliary boiler is available to provide supplemental steam to the facility during startup and shutdown operations. Potential emissions were derived using AP-42 emission factors.

<u>Cooling Tower</u>
A wet evaporative mechanical draft cooling tower is utilized to support the steam generation system. Potential emissions were calculated using AP-42 emission factors.

<u>Gasifier Preheat Vents</u>
Each gasifier is preheated by natural gas combustion during startup. Combustion gas from the preheating process is emitted from a vent located on each gasifier. Potential emissions were calculated using AP-42 emission factors.

<u>Emergency Generator and Emergency Fire Pump</u>
An emergency generator and emergency fire pump are available to support emergency operations. Both sources will utilize low sulfur diesel fuel and will operate less than 500 hours per year. Potential emissions were derived using AP-42 emission factors.

<u>Material Handling Sources</u>
Material handling sources are designed to transport and store coal and by-products (slag and by-products). Potential emissions were calculated using AP-42 emission factors. The Ohio EPA RACM document (as presented in Fugitive Dust Control Technology by Orlemann et al, 1983), USEPA Document EPA-450/3-88-008 (Control of Open Fugitive Dust Sources), and previously approved AEP PTI applications were used to estimate control efficiencies for various methods of reducing potential fugitive emissions.

4.2 Estimated Potential Emissions During Normal Operations

Potential emissions during normal operations emission are based on the following operating conditions:

- Combustion Turbines (#1 and #2): Natural gas or syngas up to 100% load.
- Sulfur Recovery System: Sulfur recovery system startup operations with the thermal oxidizer and flare emission control systems in service utilizing a natural gas pilot.
- Cooling Tower: 100% capacity.
- Material Handling System: 100% capacity.

The auxiliary boiler, emergency generator, emergency fire pump, and gasifier preheat vents are assumed to not be in service during normal operations. Normal operation emissions are evaluated as part of the air dispersion analysis. Table 4-1 summarizes the modeled potential lb/hr emissions for each source in service during normal operations.

Table 4-1: Estimated Potential Emissions During Normal Operations (modeled lb/hr emission rates)

Emission Source	SO_2	NO_x	CO	Particulate Emissions	VOC	H_2SO_4
Combustion Turbine/HRSG Stack #1:	51.3 lb/hr	170.3 lb/hr (100% syngas) 188.9 lb/hr (100% natural gas)	93.3 lb/hr	18 lb/hr (PM10 - filterable)	3.2 lb/hr	11.3 lb/hr
Combustion Turbine/HRSG Stack #2:	51.3 lb/hr	170.3 lb/hr (100% syngas) 188.9 lb/hr (100% natural gas)	93.3 lb/hr	18 lb/hr (PM10 - filterable)	3.2 lb/hr	11.3 lb/hr
Sulfur Recovery System:						
Thermal Oxidizer:	19.9 lb/hr	0.4 lb/hr	0.3 lb/hr	0.03 lb/hr (PM10 - filterable)	0.02 lb/hr	---
Flare:	---	0.12 lb/hr	0.1 lb/hr	0.009 lb/hr (PM10 - filterable)	0.006 lb/hr	---
Cooling Tower:	---	---	---	6.4 lb/hr (PM10 - filterable)	---	---
Material Handling System:	---	---	---	See Section 4.6	---	---

4.3 Estimated Potential Emissions During Startup Operations

Potential startup emissions will vary depending on the disposition of each system in the IGCC process when startup begins. The duration and scope of potential emission sources in service during warm-startup conditions will vary depending on the length and type of shutdown condition, along with the time required to safely startup. As a result, the emission profile will vary with each scenario. However, potential emission estimates associated with a cold-startup of the entire IGCC process are expected to represent the worst-case conditions for all pollutants, and were calculated for air dispersion modeling purposes. Actual startup emissions may vary depending on the disposition of each system when startup commences. The following operating conditions are the basis for estimating emissions associated with a cold startup:

- Combustion Turbines (#1 & #2): Natural gas and/or syngas up to 100% load.
- Sulfur Recovery System: Sulfur recovery system startup operations with the thermal oxidizer and flare emission control systems in service utilizing a natural gas pilot.
- Auxiliary Boiler: 100% capacity utilizing natural gas.
- Gasifier Preheat Vents (#1 & #2): 100% preheating capacity using natural gas.
- Cooling Tower: 100% capacity.
- Material Handling System: 100% capacity.

The emergency generator and emergency fire pump are assumed to not be in service during startup operations.

Table 4-2: Estimated Potential Emissions During Cold-Startup Operations (modeled lb/hr emission rates)

Emission Source	SO_2	NO_x	CO	Particulate Emissions	VOC	H_2SO_4
Combustion Turbine/HRSG Stack #1:	51.3 lb/hr	291 lb/hr	2,092 lb/hr	20.8 lb/hr (PM10 - filterable)	503 lb/hr	11.3 lb/hr
Combustion Turbine/HRSG Stack #2:	51.3 lb/hr	291 lb/hr	2,092 lb/hr	20.8 lb/hr (PM10 - filterable)	503 lb/hr	11.3 lb/hr
Sulfur Recovery System:						
Thermal Oxidizer:	151 lb/hr	8.7 lb/hr	7.4 lb/hr	0.7 lb/hr (PM10 - filterable)	0.5 lb/hr	---
Flare:	685 lb/hr	59.4 lb/hr	313 lb/hr	0.2 lb/hr (PM10 - filterable)	0.2 lb/hr	---
Auxiliary Boiler:	0.22 lb/hr	15 lb/hr	24.7 lb/hr	2.2 lb/hr (PM10 - filterable)	1.6 lb/hr	---
Gasifier Preheat Vent #1:	0.01 lb/hr	1.87 lb/hr	1.57 lb/hr	0.14 lb/hr (PM10 - filterable)	0.1 lb/hr	---
Gasifier Preheat Vent #2:	0.01 lb/hr	1.87 lb/hr	1.57 lb/hr	0.14 lb/hr (PM10 - filterable)	0.1 lb/hr	---
Cooling Tower:	---	---	---	6.4 lb/hr (PM10 - filterable)	---	---
Material Handling System:	---	---	---	See Section 4.6	---	---

Notes:
[1] Potential emission estimates associated with a cold-startup of the entire IGCC process were calculated for air dispersion modeling purposes. Actual startup emissions may vary depending on the disposition of each system when startup commences.

4.4 Estimated Potential Emissions During Shutdown Operations

Potential startup emissions will vary depending on the disposition each system in the IGCC process when shutdown begins. For example, the duration and scope of potential emission sources in service during shutdown will vary depending on the number of systems to be brought out of service, the operating condition of systems when shutdown commences, and the time required to safely shutdown. As a result, the emission profile will vary with each potential shutdown scenario.

Potential emission estimates associated with a shutdown of the entire IGCC process were calculated for air dispersion modeling purposes. Actual shutdown emissions may vary depending on the disposition of each system when shutdown commences. The following operating conditions are the basis for estimating shutdown emissions:

- Combustion Turbines (#1 & #2): Natural gas or syngas up to 100% load.
- Sulfur Recovery System: Sulfur recovery system shutdown operations with the thermal oxidizer and flare emission control systems in service utilizing a natural gas pilot.
- Auxiliary Boiler: 100% capacity utilizing natural gas.
- Cooling Tower: 100% capacity.
- Material Handling System: 100% capacity.

The gasifier preheat vents, emergency generator, and emergency fire pump are not expected to be in service during shutdown operations.

Table 4-3: Estimated Potential Emissions During Shutdown Operations (modeled lb/hr emission rates)

Emission Source	SO_2	NO_x	CO	Particulate Emissions	VOC	H_2SO_4
Combustion Turbine/HRSG Stack #1:	51.3 lb/hr	170.3 lb/hr	93.3 lb/hr	18 lb/hr (PM10 - filterable)	14.5 lb/hr	11.3 lb/hr
Combustion Turbine/HRSG Stack #2:	51.3 lb/hr	170.3 lb/hr	93.3 lb/hr	18 lb/hr (PM10 - filterable)	14.5 lb/hr	11.3 lb/hr
Sulfur Recovery System:						
Thermal Oxidizer:	235.1 lb/hr	3.6 lb/hr	5.1 lb/hr	0.2 lb/hr (PM10 - filterable)	0.2 lb/hr	---
Flare:	79.2 lb/hr	66.6 lb/hr	362 lb/hr	0.4 lb/hr (PM10 - filterable)	0.3 lb/hr	---
Auxiliary Boiler:	0.22 lb/hr	15 lb/hr	24.7 lb/hr	2.2 lb/hr (PM10 - filterable)	1.6 lb/hr	---
Cooling Tower:	---	---	---	6.4 lb/hr (PM10 - filterable)	---	---
Material Handling System:	---	---	---	See Section 4.6	---	---

Notes:
[1] Potential emission estimates associated with a shutdown of the entire IGCC process were calculated for air dispersion modeling purposes. Actual shutdown emissions may vary depending on the disposition of each system when shutdown commences.

4.5 Emergency Support Equipment Potential Emissions

An emergency generator and emergency fire pump are available to support emergency operations. Both will utilize low sulfur diesel fuel ($\leq$ 0.05%) and will operate less than 500 hours per year. Potential emission rates were derived using AP-42 emission factors and are summarized in the table below.

Table 4-4: Estimated Potential Emissions – Emergency Support Equipment

Emission	Emergency Generator		Emergency Fire Pump	
SO_2	0.9 lb/hr	(0.2 tpy)	0.9 lb/hr	(0.2 tpy)
NO_x	28.6 lb/hr	(7.2 tpy)	13 lb/hr	(3.3 tpy)
CO	12.1 lb/hr	(3 tpy)	2.8 lb/hr	(0.7 tpy)
PM_{10} (filterable)	1.5 lb/hr	(0.4 tpy)	0.9 lb/hr	(0.2 tpy)
VOC	1.5 lb/hr	(0.4 tpy)	1.1 lb/hr	(0.3 tpy)

4.6 Material Handling System Potential Emissions

Material handling sources are designed to transport and store coal, slag, and sulfur by-products. Potential emissions were calculated using AP-42 emission factors. The Ohio EPA RACM document (as presented in Fugitive Dust Control Technology by Orlemann et al, 1983), USEPA Document EPA-450/3-88-008 (Control of Open Fugitive Dust Sources), and previously approved AEP PTI applications were used to estimate control efficiencies for various methods of reducing potential fugitive emissions. Potential emission rates from each material handling source are summarized in the table below and are evaluated in the air dispersion modeling analysis.

Table 4-5: Material Handling System Potential Emissions

Emission Source	Source Type	Particulate Emissions (PM10 - filterable)		Particulate Emissions (TSP – total)	
Coal Barge Unloader 1	Area	0.26 lb/hr	1.2 tpy	0.56 lb/hr	2.5 tpy
Transfer House 1A	Area	0.01 lb/hr	0.04 tpy	0.02 lb/hr	0.08 tpy
Transfer House 3	Area	0.02 lb/hr	0.08 tpy	0.04 lb/hr	0.2 tpy
Transfer House 4	Area	0.35 lb/hr	1.5 tpy	0.75 lb/hr	3.3 tpy
Transfer House 5	Area	0.35 lb/hr	1.5 tpy	0.75 lb/hr	3.3 tpy
Transfer House 6	Area	0.35 lb/hr	1.5 tpy	0.75 lb/hr	3.3 tpy
Coal Reclaim System	Point	0.001 lb/hr	0.006 tpy	0.003 lb/hr	0.01 tpy
Crusher Station	Point	0.01 lb/hr	0.05 tpy	0.04 lb/hr	0.2 tpy
Transfer House 7	Area	0.007 lb/hr	0.03 tpy	0.01 lb/hr	0.06 tpy
Transfer House 8	Area	0.007 lb/hr	0.03 tpy	0.01 lb/hr	0.06 tpy
Coal Slurry Prep Building	Area	0.03lb/hr	0.15 tpy	0.07 lb/hr	0.31 tpy
Coal Pile – Wind Erosion	Area	0.12 lb/hr	0.5 tpy	0.12 lb/hr	0.5 tpy
Traffic – Road Segment A	Paved	0.05 lb/hr	0.2 tpy	0.2 lb/hr	1.0 tpy
Traffic – Road Segment B	Paved	0.09 lb/hr	0.4 tpy	0.4 lb/hr	1.9 tpy
Traffic – Road Segment C	Paved	0.008 lb/hr	0.03 tpy	0.04 lb/hr	0.2 tpy
Traffic – Road Segment D	Paved	0.05 lb/hr	0.2 tpy	0.3 lb/hr	1.1 tpy
Traffic – Road Segment E	Unpaved	0.3 lb/hr	1.2 tpy	1.1 lb/hr	4.8 tpy
Traffic – Coal Pile	Unpaved	0.3 lb/hr	1.2 tpy	1.2 lb/hr	5.4 tpy
Parking Lots/Misc. Unit 1 Traffic	Paved	0.001 lb/hr	0.005 tpy	0.007 lb/hr	0.03 tpy
Material Handling Total:		**2.3 lb/hr (10 tpy)**		**6.4 lb/hr (28 tpy)**	

4.7 Potential Annual Emissions

Annual emission estimates were calculated by evaluating the potential emissions for each operating condition and determining the worst case scenario. Potential annual emissions for normal operations were derived using peak hourly emission rates and a 100% capacity factor (8,760 hrs/yr). Potential annual emissions based on startup and shutdown operations were calculated assuming a startup duration of 70 hours and shutdown duration of 48 hours. Assuming a 24 hour period between the end of shutdown and beginning of startup, the estimated startup/shutdown cycle would be 142 hours. Potential annual emissions associated with startup/shutdown operations were calculated assuming 62 cycles per year (8,760 hours per year / 142 hours per cycle). These assumptions are only for estimating potential annual emissions, the actual duration of startup and shutdown operations will vary depending on the disposition of systems when these operations commence. The estimates for each operating scenario are provided in Appendix E. A summary of the worst-case potential annual emissions is provided in Table 4-6.

Table 4-6: Estimated Annual Emissions

Emission Source	SO_2 (tpy)	NO_x (tpy)	CO (tpy)	Particulate Emissions (tpy)	VOC (tpy)	H_2SO_4 (tpy)
Combustion Turbine/HRSG Stack #1	225	746	409	79 (PM10 - filterable)	39	49
Combustion Turbine/HRSG Stack #2	225	746	409	79 (PM10 - filterable)	39	49
Sulfur Recovery System:						
Thermal Oxidizer	87	7	6	1 (PM10 - filterable)	0.4	---
Flare	48	9	48	0.1 (PM10 - filterable)	0.05	---
Auxiliary Boiler	1	39	64	6 (PM10 - filterable)	4	---
Cooling Tower	---	---	---	28 (PM10 - filterable)	---	---
Gasifier Preheat Vent #1	0.02	2	2	0.2 (PM10 - filterable)	0.1	---
Gasifier Preheat Vent #2	0.02	2	2	0.2 (PM10 - filterable)	0.1	---
Material Handling System	---	---	---	10 (PM10 - filterable) 28 (TSP - total)	---	---
Emergency Generator	0.2	7.2	3	0.4 (PM10 - filterable)	0.4	---
Emergency Fire Pump	0.2	3.3	0.7	0.2 (PM10 - filterable)	0.3	---
Facility Wide Total:	**586**	**1562**	**944**	**204** (PM10 - filterable)	**83**	**98**

4.8 Potential to Emit Air Modeling Inputs

The potential emissions presented for each source on a lb/hour and annual basis for normal, startup, shutdown, and emergency operations are each evaluated in the air dispersion modeling analysis. Additionally, in order to assess each ambient air quality standard in the modeling analysis, 3-hour, 8-hour, and 24-hour emission rates for certain pollutants are utilized. The following summarizes the potential emissions from each emission source for these averaging periods:

Table 4-7: Modeled Emission Rates for Normal Operations

Emission Source	[3-hour Ave] SO2	[8-hour Ave] CO	[24-hour Ave] SO2	[24-hour Ave] Particulate Emissions
Combustion Turbine #1	51.3 lb/hr	93.3 lb/hr	51.3 lb/hr	36 lb/hr (PM10 – filterable)
Combustion Turbine #2	51.3 lb/hr	93.3 lb/hr	51.3 lb/hr	36 lb/hr (PM10 – filterable)
Sulfur Recovery System:				
Thermal Oxidizer	19.9 lb/hr	0.3 lb/hr	19.9 lb/hr	0.03 lb/hr (PM10 – filterable)
Flare	---	0.1 lb/hr	---	0.009 lb/hr (PM10 – filterable)
Cooling Tower	---	---	---	6.38 lb/hr (PM10 – filterable)

Table 4-8: Modeled Emission Rates for Emergency Operations

Emission Source	[3-hour Ave] SO2	[8-hour Ave] CO	[24-hour Ave] SO2	[24-hour Ave] Particulate Emissions
Emergency Generator	0.9 lb/hr	12.1 lb/hr	0.9 lb/hr	1.5 lb/hr (PM10 – filterable)
Emergency Fire Pump	0.9 lb/hr	2.8 lb/hr	0.9 lb/hr	0.9 lb/hr (PM10 – filterable)

Table 4-9: Modeled Emission Rates for Startup Operations

Emission Source	[3-hour Ave] SO2	[8-hour Ave] CO	[24-hour Ave] SO2	[24-hour Ave] Particulate Emissions
Combustion Turbine #1	51.3 lb/hr	645.4 lb/hr	44.7 lb/hr	32.9 lb/hr (PM10 – filterable)
Combustion Turbine #2	51.3 lb/hr	645.4 lb/hr	44.7 lb/hr	32.9 lb/hr (PM10 – filterable)
Sulfur Recovery System:				
Thermal Oxidizer	136.3 lb/hr	5.6 lb/hr	36.7 lb/hr	0.46 lb/hr (PM10 – filterable)
Flare	236 lb/hr	59.8 lb/hr	58.2 lb/hr	0.04 lb/hr (PM10 – filterable)
Auxiliary Boiler	0.2 lb/hr	24.7 lb/hr	0.2 lb/hr	2.2 lb/hr (PM10 – filterable)
Gasifier Preheat Vent #1	0.01 lb/hr	1.57 lb/hr	0.01 lb/hr	0.14 lb/hr (PM10 – filterable)
Gasifier Preheat Vent #2	0.01 lb/hr	1.57 lb/hr	0.01 lb/hr	0.14 lb/hr (PM10 – filterable)
Cooling Tower	---	---	---	6.38 lb/hr (PM10 – filterable)

Table 4-10: Modeled Emission Rates for Shutdown Operations

Emission Source	[3-hour Ave] SO2	[8-hour Ave] CO	[24-hour Ave] SO2	[24-hour Ave] Particulate Emissions
Combustion Turbine #1	35.6 lb/hr	33.6 lb/hr	4.4 lb/hr	3.2 lb/hr (PM10 – filterable)
Combustion Turbine #2	35.6 lb/hr	33.6 lb/hr	4.4 lb/hr	3.2 lb/hr (PM10 – filterable)
Sulfur Recovery System:				
Thermal Oxidizer	165.3 lb/hr	2.8 lb/hr	24 lb/hr	0.06 lb/hr (PM10 – filterable)
Flare	45.6 lb/hr	80.2 lb/hr	5.7 lb/hr	0.04 lb/hr (PM10 – filterable)
Auxiliary Boiler	0.2 lb/hr	24.7 lb/hr	0.2 lb/hr	2.2 lb/hr (PM10 – filterable)
Cooling Tower	---	---	---	6.38 lb/hr (PM10 – filterable)

4.9 Potential HAPS Emissions

Potential emissions of hazardous air pollutants (HAPS) will be negligible from the proposed IGCC facility as a result of inherent reductions associated with the gasification process, syngas cleanup system, and combustion characteristics in the combustion turbines. As discussed below, all potential HAP emissions are well below the applicability thresholds of the OEPA Air Toxics Policy.

Minimal historic performance data is available from prior gasification demonstration projects or existing processes that can be used to reasonably estimate potential HAP emissions associated with the combustion of syngas at the proposed facility. Design and operational differences between historic gasification processes and the proposed project provides for minimal, if any, comparisons of potential performance or emissions. In addition, AP-42 does not include any HAP emission factors for syngas combustion. Because of the unavailability of reliable emission factors, calculations of syngas related HAP emissions is limited to qualitative estimates of potential lead and mercury emissions. These were selected as indicator HAPS because lead is a criteria pollutant and mercury has an associated new source performance standard applicable to the proposed project.

USEPA finalized a report in July, 2006 that evaluates the environmental performance of IGCC and pulverized coal technologies. The report (titled *Environmental Footprints and Costs of Coal-Based IGCC and Pulverized Coal Technologies*) includes a discussion on the limited availability of HAP emissions data associated with the IGCC process by noting:

> "Measurement of HAPS has proven to be difficult with existing instrumentation used for the IGCC system." (p. 3-7)
>
> "The energy and material balance for HAPS and the measurement of HAP emissions is complex and difficult to forecast accurately until more operating data becomes available." (p 3-8)

The USEPA report does include emission factors for trace metals from a report titled *A Study of Toxic Emissions from a Coal-Fired Gasification Plant* (December 1995), which was performed for the Department of Energy and others. This study included field measurements to evaluate the HAP emissions associated with the Louisiana Gasification Technology Inc. (LGTI) facility. LGTI is part of the Dow Chemical petrochemical facility in Plaquemine, Louisiana. LGTI produces process steam and synthetic gas for power at the Dow facility through the gasification of subbituminous coal.

The emission factors presented by USEPA from the LGTI study are not readily applicable to the proposed AEP IGCC process for several reasons, including the use of different fuel types and syngas cleanup systems. The LGTI emission factors represent an aggregate syngas/natural gas blend in the combustion turbines, along with tail gas or non-specification acid gas from the AGR being consumed by an incinerator. The Executive Summary of the LGTI study is provided in Attachment E.

The LGTI study notes concerns with the test results by stating:

> "…confidence in some of the results is not as high for the following reasons…
> - No standard or validated methods are available or exist for sampling some of the substances…
> - Some of the streams were sampled and analyzed by more than one method. When compared, the results from different methods, in some instances, were conflicting.
> - Comparisons between different streams (...mass balance) sometimes produced illogical results." (Page ES-6)

Conclusions presented in the final LGTI study report state:

- "LGTI's emission of hazardous air pollutants were quite low…
- The particulate emissions from the turbine stack were very low….
- The majority of trace and major elements present in the coal were found in the slag." (Page ES-6)

The limited value of the emission factors towards estimating potential emissions from other projects is noted in the conclusion of the LGTI study as well, which notes:

> "The reader [of this report] should keep in mind that….the emission factors presented….are **not** directly comparable to those of a conventional coal-fired power plant….[because]…..the syngas is co-fired with natural gas in two gas turbines…..It is known that a fully natural gas fired turbine can produce significant, measurable levels of HAPs. Unfortunately, at LGTI it is impossible to know how much of the emissions are attributable to the co-firing of natural gas. As a result, the emission factors have been prepared as total mass out (turbine and incinerator) divided by the total Btu content in (coal + incinerator natural gas + turbine natural gas)." (Page ES-10)

Because of the uncertainties with the data collected and the differences with the LGTI process design, the emission factors referenced by the USEPA report from the LGTI study will not provide reasonably representative estimates of potential HAP emissions associated with syngas combustion at the proposed AEP project.

Qualitative estimates of potential lead and mercury emissions were derived as follows. Lead emissions are assumed to be emitted as part of the PM_{10} filterable mass. Estimates of potential lead emissions were derived from fuel quality data by using the ratio of estimated to potential PM_{10} filterable emissions. The resulting lead emissions associated with syngas combustion is estimated to be less than 0.04 tons per year. Potential lead emissions from other sources at the facility, which utilize natural gas or low sulfur diesel fuel are negligible. Therefore, the potential lead emissions from the facility are less than 0.04 tons per year, which is well below the PSD applicability threshold of 0.6 tpy and well below the applicability threshold of the Ohio EPA Air Toxics Policy. These are considered worst-case potential emission estimates from syngas combustion regardless of the emission source in the IGCC process. Calculations for these estimates are provided in Appendix E.

Mercury concentration in coal varies between coal types and within individual coal seams. The proposed facility is designed to accommodate a fuel specification for a broad range of coal types having varying potential mercury concentrations. The design will include a state-of-the-art mercury removal system that is expected to remove greater than 90% of mercury from the syngas. Because of varying potential coal types and removal efficiencies, potential mercury emissions were calculated using the applicable new source performance standards for IGCC units of 20×10^{-6} lb/MWh (rolling 12-month average). Utilizing a nominal gross generating capacity of 784 MWh, the potential mercury emissions were estimated to be less than 0.07 tpy. The proposed facility will be subject to the Clean Air Mercury Rule and will be required to quantify mercury emissions through the use of continuous emission monitors on each combustion turbine/HRSG stack. Allowances will have to be obtained for all mercury emissions quantified by these monitors.

Potential HAP emissions due to the combustion of natural gas or diesel fuel at the proposed facility will be well below applicable significance thresholds, including those established by the Ohio EPA Air Toxics Policy. Formaldehyde has the highest potential emission factor among those HAPS listed in AP-42 for natural gas and diesel fuel combustion, and will be significantly greater than any other potential HAP. Estimates of formaldehyde emissions are used as an indicator to demonstrate that potential HAPS from the proposed facility will be negligible.

AP-42 notes that formaldehyde is identified as the most significant HAP emission associated with natural gas combustion by combustion turbines:

"...Available data indicate that emission levels of HAPS are lower for gas turbines than for other combustion sources. This is due to the high combustion temperatures reached during normal operation. The emissions data also indicates that formaldehyde is the most significant HAP emitted from combustion turbines. For natural gas fired turbines, formaldehyde accounts for about two-thirds of the total HAP emissions…" [AP-42: Section 3.1.3.5]

The vendor supplied emission rates for maximum potential formaldehyde emissions when utilizing natural gas as fuel in the combustion turbines. No reliable emission factors are available for estimating potential formaldehyde emissions, if any, from syngas combustion in the combustion turbines.

The auxiliary boiler, gasifier pre-heaters, thermal oxidizer pilot, and flare pilot will utilize natural gas. AP-42 Section 1.4 provides the applicable emission factors for these sources. Emission factors from this section were used to calculate potential lead and formaldehyde emissions from the auxiliary boiler and gasifier pre-heaters.

AP-42 Sections 3.3 and 3.4 provide emission factors applicable to combustion of diesel fuel. The vendor utilized this section to estimate potential formaldehyde emissions from the proposed emergency generator and emergency fire pump. No data was available from AP-42 to estimate any potential lead emissions for either source.

Utilizing the available formaldehyde emission factors for each source, the potential annual emissions from the facility were estimated to be 0.5 tons/year of formaldehyde, which is well below the Ohio Air Toxics Policy applicability threshold. Associated calculations are provided in Appendix E.

No potential HAP emissions are associated with the proposed cooling tower or material handling system.