



# Federal Air Pollutant Emission Regulations and Preliminary Estimates of Potential-to-Emit from Biorefineries

## Pathway #2: Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels: Fast Pyrolysis and Hydrotreating Bio-oil Pathway

Arpit Bhatt, Yimin Zhang, and Garvin Heath  
*National Renewable Energy Laboratory*

Mae Thomas and Jason Renzaglia  
*Eastern Research Group*

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## Executive Summary

The Energy Independence and Security Act of 2007, through the Renewable Fuel Standard, mandates increased use of biofuels. Although biofuels in general have been found to have lower *life cycle greenhouse gas (GHG) emissions compared to petroleum fuels on a fuel-content basis*, biomass feedstock production, harvesting, transportation, processing, and conversion are expected to emit a wide range of other air pollutants. Air pollution affects both human health and the natural environment. To develop sustainable advanced biofuels, one of the goals of the Bioenergy Technologies Office at the U.S. Department of Energy is to minimize air pollutants from the entire biofuel supply chains, as stated in their Multi-Year Program Plan (EERE 2016).

Biorefineries (refineries that produce biofuels) are subject to environmental laws, including complex air quality regulations that aim to protect and improve the quality of the air. These regulations govern the amount of air pollutants of certain types that can be emitted from different types of emission sources. The federal Clean Air Act (CAA) requires states to regulate stationary and mobile sources that emit pollutants regulated under the CAA pursuant to a U.S. Environmental Protection Agency (EPA)-approved state implementation plan for implementing, maintaining, and enforcing National Ambient Air Quality Standards (NAAQS), which set the ambient concentration for six air pollutants,<sup>1</sup> also called criteria air pollutants. States regulate stationary sources of criteria pollutants (such as biorefineries) through their permitting program to ensure attainment and maintenance of the NAAQS. State permitting of new and modified stationary sources follows federal guidance under the U.S. EPA's New Source Review (NSR) program.<sup>2</sup> The NSR requires most air pollutant-emitting stationary sources to obtain an air permit prior to beginning construction and then another air permit to operate.<sup>3</sup> The type of air permit required can vary depending on the degree of attainment with the NAAQS<sup>4</sup> in the area of the source and the magnitude of the emissions from the facility.

It is important for stakeholders to understand the potential implications on air quality from a growing biofuel industry because of the possibility of an increase in stringency of the air quality standards and the fact that some areas of the country are already out of compliance with one or more of current NAAQS. However, information and knowledge about the type, fate, and magnitude of potential air pollutant emissions from the production of new advanced biofuels is lacking because of the nascent stage of this emerging industry. As a first step to assess the air quality and human health impact of advanced biofuels, this analysis assesses federal air pollutant emission regulations potentially applicable to a type of hypothetical biorefinery and estimates the magnitude of emissions from the pathway design. The Bioenergy Technologies Office chose the design examined for further research and development from several pathways that can produce infrastructure-compatible<sup>5</sup> hydrocarbon biofuels. The biofuel conversion process, described in

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<sup>1</sup> The six air pollutants are ozone, particulate matter, nitrogen dioxide, sulfur dioxide, carbon monoxide, and lead.

<sup>2</sup> For additional information on NSR, refer to EPA's NSR website: <https://www.epa.gov/nsr>.

<sup>3</sup> In some jurisdictions, the permitting authority will issue a combined construction and operating permit.

<sup>4</sup> Each state has a network of stations to monitor ambient concentration of criteria pollutants. The EPA uses monitoring data, as well as other information, to determine each area's attainment status on a pollutant-by-pollutant basis. Areas with ambient concentration below the NAAQS are designated "attainment" while areas exceeding the NAAQS are designated "nonattainment" (with further gradations depending on the severity of nonattainment).

<sup>5</sup> "Infrastructure" refers to fuel transport, storage, and refueling infrastructure.

Jones et al. (2013), is referred to as fast pyrolysis<sup>6</sup> in this document, and the primary product is gasoline-range and diesel-range fuels.

To understand the potential applicability of certain federal air quality regulations and the level of air permitting required, we provide preliminary estimates of uncontrolled potential-to-emit (PTE) and PTE based on the design case (Jones et al. 2013). Uncontrolled PTE reflects the maximum amount of emissions a source (a biorefinery in this analysis) would generate if it were operating continuously at full capacity without any restrictions in place. However, PTE considers legally enforceable limitations (e.g., requirements to use emissions control devices or production rate limitations included in an enforceable air permit), which can also be referred to as post-permit PTE, limited PTE, or controlled PTE for permitted sources.

To determine which federal air emission regulations potentially apply to the fast pyrolysis biorefinery, we first identified which regulated air pollutants are expected to be emitted to the ambient environment by the biorefinery or from specific equipment. Some regulations apply to the entire facility while others apply to specific equipment; different regulations are applicable to different pollutants or classes of pollutants. Based on the design case (Jones et al. 2013), criteria air pollutants and their precursors<sup>7</sup> [including nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), carbon monoxide (CO), volatile organic compounds (VOCs), particulate matter (PM) and lead], hydrogen sulfide (H<sub>2</sub>S), various hazardous air pollutants (HAPs), and GHG emissions (mainly carbon dioxide) are expected to be emitted from the fast pyrolysis biorefinery.

Once the regulated air pollutants are identified, the next step is to review the applicability criteria of each federal regulation to determine whether the fast pyrolysis biorefinery or specific equipment is subject to it. Due to uncertainties in many design parameters, we analyzed all potentially applicable federal standards that regulate air pollutants emitted from stationary sources, including New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), and air emission permitting programs, including the NSR (construction permit) program and the Title V Operating Permit program.<sup>8</sup> We found that a number of NSPS standards that are potentially applicable to the storage tanks, reactors, distillation operations, equipment leaks, and emergency equipment in the fast pyrolysis biorefinery, depending on whether the specific equipment meets the applicability criteria specified in each NSPS. Because the biorefinery is essentially a chemical process<sup>9</sup> plant and is expected to emit HAP, it is subject to one of two chemical manufacturing NESHAP, depending on whether the design plant is a major<sup>10</sup> or minor (area source) of HAP emissions (refer to

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<sup>6</sup> A more complete name for this process is fast pyrolysis and hydrotreating bio-oil pathway.

<sup>7</sup> Precursors are pollutants that participate in reactions in the atmosphere, forming other pollutants that are subject to NAAQS (e.g., VOC is a precursor to ground level ozone, which is a criteria air pollutant subject to NAAQS).

<sup>8</sup> Each of these programs is described in detail at <https://www.epa.gov/regulatory-information-topic/regulatory-information-topic-air>.

<sup>9</sup> The fast pyrolysis biorefinery will produce hydrocarbon biofuels. The Standard Industrial Classification (SIC) for a similar cellulosic biorefinery to be operational in 2018 in Clinton, North Carolina (Carolina Cellulosic Biofuels) is SIC 286. SIC 286 belongs to the industry producing industrial organic chemicals. The fast pyrolysis biorefinery is expected to fall under SIC 286.

<sup>10</sup> “Major” under NSR is a specifically defined term used to designate the applicability of certain permitting programs to a facility. What constitutes a major source under NSR varies according to what type of permit is involved, the pollutant or pollutants being emitted, and the attainment designation of the area where the source is located. In general, a source is considered a major source for NSR if its emissions exceed certain thresholds.

Section 3.2.1). In addition, there are specific NESHAP that may be applicable to the process heater and the emergency equipment at the biorefinery.

Within the limits of our methods and the available data, a preliminary estimation of uncontrolled PTE and PTE was determined for the regulated air pollutants we identified. Determining the PTE from a new planned but unbuilt facility is often an iterative process between design and environmental engineers. Environmental engineers calculate the emissions and provide feedback to the design engineers when estimated emission levels indicate that regulations or higher levels of permit requirements may be triggered. This gives the design engineers opportunity to explore air pollution control devices (add-on controls) or consider alternative design options for reducing emissions. Some rules (e.g., the more stringent chemical manufacturing NESHAP for major sources of HAP) and permit requirements can be avoided if the source can limit emissions to below certain levels. The environmental engineer will also inform the design engineers when a regulation will require controls to be installed and included in the design of the plant. The PTE estimates presented in this document reflect the inclusion of (1) air pollution controls that are currently planned in the design case (Jones et al. 2013) and (2) air pollution controls that would be required to comply with applicable federal regulations, which can be made federally enforceable in a permit. The preliminary estimates of PTE do not include any additional emission reductions that a source may elect to add to avoid rules or more stringent permit requirements. In addition, the preliminary estimates of PTE do not take into consideration possible emission reductions, which would be required after completing a full determination of best available control technology (BACT)<sup>11</sup> for regulated pollutants, which are subject to prevention of significant deterioration (PSD) review (refer to Footnote 12). Section 5 includes a discussion about possible approaches engineers might adopt regarding further emission reductions.

The estimates of uncontrolled PTE and PTE are considered “preliminary” in this document because of the lack of emissions test data and design information for some specific processes at the biorefinery and numerous assumptions required to perform the PTE calculations. Although, more detailed data specific to the biorefinery process would provide greater assurance on the PTE emissions from the design plant, it is not necessary to have these specifics when applying for a permit. If there is uncertainty in any of the PTE calculations, the permitting authority can require stack testing in the final permit. It is important to estimate emissions as accurately as possible when applying for a permit. If made, inaccurate emission estimates can delay the issuance of the permit. For example, if the PTE indicates a new source is not subject to major source NSR permitting and it is then determined, after construction and stack testing that the source is major and should have applied for a major source NSR permit, the source will have to apply for a new permit, possibly install additional control devices, and be unable to operate until the permitting issue is resolved.

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<sup>11</sup> Refer to Section 5 for emission controls, which would likely be considered BACT.

The facility-wide results of the PTE estimates for the design case are shown in Table ES-1.

**Table ES-1. Preliminary Estimates of Uncontrolled PTE and PTE of Criteria Air Pollutants (and Precursors), Total Unspeciated HAP and GHG Emissions in Tons per Year (tpy) from a Fast Pyrolysis Biorefinery per the Design Case (Jones et al. 2013)**

Pollutant	Uncontrolled PTE (tpy)	PTE (tpy) <sup>a</sup>	Major Source Threshold under NSR or Title V (tpy)
Particulate matter (filterable) (PM <sub>filterable</sub> ) <sup>b</sup>	8,900	330	1.0×10 <sup>2</sup>
Particulate matter with less than 10 micrometers in diameter (PM <sub>10</sub> ) <sup>b</sup>	4,500	190	1.0×10 <sup>2</sup>
Particulate matter with less than 2.5 micrometers in diameter (PM <sub>2.5</sub> ) <sup>b</sup>	1,400	110	1.0×10 <sup>2</sup>
Sulfur dioxide	460	460	1.0×10 <sup>2</sup>
Nitrogen oxides	150	150	1.0×10 <sup>2</sup>
Carbon monoxide	67	67	1.0×10 <sup>2</sup>
Volatile organic compounds	300	85	1.0×10 <sup>2</sup>
Lead	3.9×10 <sup>-4</sup>	3.9×10 <sup>-4</sup>	1.0×10 <sup>2</sup>
GHG (CO <sub>2</sub> equivalent) <sup>c</sup>	890,000	890,000	Not applicable
Hazardous air pollutants (total)	81	24	2.5×10 <sup>1</sup>

<sup>a</sup> Preliminary estimates of PTE account for potential federally enforceable limitations in a permit or federal air regulations, which are discussed in Section 5.

<sup>b</sup> PM is regulated as filterable PM, while PM<sub>10</sub> and PM<sub>2.5</sub> are regulated as the total of filterable PM in the size fraction (i.e., PM<sub>10</sub> or PM<sub>2.5</sub>) and condensable PM. Specifically, PM is measured using EPA Method 5, which measures only filterable PM. PM<sub>10</sub> and PM<sub>2.5</sub> are measured using EPA Method 201A, whereas Method 202 measures condensable PM. All condensable PM is included in the PM<sub>2.5</sub> and PM<sub>10</sub> size fractions.

<sup>c</sup> EPA recently announced that it would be revising the permitting rules to exempt GHG emissions generated from processing waste-derived feedstocks and feedstocks from sustainable forest or agricultural practices (EPA 2014a). The vast majority of GHG emissions from the design plant will likely fit this exemption and will not need to be counted to determine the permitting applicability. Yet, until the permitting rules are final, we provide an estimate of total GHG emissions.

As indicated by the preliminary estimate of PTE (taking into account legally enforceable limitations) reported in Table ES-1, the fast pyrolysis biorefinery would be considered a major source under the NSR program<sup>12</sup> (if no further emission controls are in place) because at least

<sup>12</sup> The NSR permits can be divided into two types of permits, i.e., major (source) and minor (source) NSR permits. Two sets of major NSR permitting provisions can apply to major NSR sources: Prevention of Significant Deterioration (PSD) and nonattainment NSR (NNSR). PSD requirements can apply to any NSR regulated pollutants except for nonattainment pollutants in the area the new source is to be located. The major threshold for PSD to apply to chemical process plants is 100 tons per year (tpy) of any one of PSD regulated air pollutants. In addition to criteria air pollutants, PSD applies to other pollutants, including fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, GHG, and certain contaminants from municipal solid waste plants. NNSR applies when a new

one NSR-regulated non-GHG pollutant (e.g., NO<sub>x</sub>) exceeds the major source threshold. Therefore, the fast pyrolysis biorefinery as currently designed would be required to determine PSD applicability for each regulated pollutant emitted (PM, PM<sub>10</sub>, PM<sub>2.5</sub>, VOC, NO<sub>x</sub>, CO, SO<sub>x</sub>, and GHG emissions) by using their respective “significant emissions rates” (SERs).<sup>13</sup> If the design biorefinery were located in a non-attainment area, it would be subject to

1. Nonattainment New Source Review (NNSR) for the nonattainment<sup>14</sup> pollutant(s) with a PTE greater than 100 tpy (or lower, depending on the nonattainment severity classification)
2. PSD review for attainment pollutants and other NSR regulated pollutants<sup>15</sup> with PTE greater than SER, as long as one attainment pollutant has a PTE greater than 100 tpy.

Because any facility with a major source permit under PSD or NNSR is required to obtain a Title V permit, the fast pyrolysis biorefinery would then be subject to Title V permitting requirements. In addition to air pollutants regulated by NSR program, the Title V operating permit program also addresses HAP and pollutants included in Section 112(r) of the CAA.<sup>16</sup> Our preliminary estimates of PTE, shown in Table ES-1, indicate that HAP emissions from the fast pyrolysis biorefinery could be reduced to below the major threshold for HAP, which for the purpose of Title V permitting, is 10 tpy for a single HAP or 25 tpy for any combination of HAP.

It should be noted that the current design of the fast pyrolysis biorefinery (Jones et al. 2013) did not have a design goal to minimize air pollutant emissions. (The goal of the current design is to estimate fuel-selling price, which does not require specifications that are as detailed as is necessary for an accurate estimation of air pollutant emissions.) It is reasonable to expect that emissions from the biorefinery could be reduced as the technology matures and the entire process continues to be optimized. Caution is advised in using the preliminary estimates reported here for decision making because there are significant uncertainties with regard to many design parameters relevant to estimating air pollutant emissions. In addition, because the cellulosic biorefineries (such as fast pyrolysis) are only beginning to enter commercial operation, there is a lack of emissions measurements from facilities using similar processes to the novel ones envisioned in the design case (Jones et al. 2013), which can be used to validate our estimates. Control strategies (i.e., control methods and devices) that can be used to reduce air pollutants emitted from unit operations at the biorefinery will be investigated in our future work. While results are preliminary, they help inform process design and provide information to evaluate how incorporating necessary emission controls may impact biofuel production cost. Moreover, this

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source meets two criteria: 1) the source is to be constructed in a nonattainment area, and 2) The source is a major source for the nonattainment pollutant. The NNSR major source threshold is 100 tpy (or lower in some nonattainment areas depending on nonattainment severity classifications) for a nonattainment pollutant.

<sup>13</sup> Refer to Appendix A for SERs for regulated air pollutants under the NSR program.

<sup>14</sup> Non-attainment areas refer to areas in which air quality is lower than NAAQS levels.

<sup>15</sup> A source would not be required to obtain a PSD permit on the sole basis of their PTE of GHG emissions exceeding the threshold as per a recent U.S. Supreme Court ruling (U.S. Supreme Court 2014).

<sup>16</sup> Section 112(r) of the Clean Air Act Amendments of 1990 refers to the Accidental Release Prevention Requirements: Risk Management Program Requirements. This regulation covers many pollutants, often referred to as 112(r) pollutants. (See Appendix B for a list of these pollutants.) An estimate of PTE for these pollutants must be included in a Title V Operating permit application, but, generally, no other requirements apply to these pollutants with respect to a Title V permit.



work helps biorefinery developers understand permitting requirements and therefore mitigate uncertainty in the air permitting process.

### *Report Structure*

In Section 1, we review federal air pollutant emissions regulations with a focus on those that potentially apply to stationary sources such as the fast pyrolysis biorefinery examined here. Section 2 provides a brief overview of the conversion process employed by the fast pyrolysis biorefinery per the design case (Jones et al. 2013). Section 3 reviews and analyzes the federal air regulations potentially applicable to the fast pyrolysis biorefinery. Section 4 documents the approaches, data, and assumptions used for estimating the preliminary uncontrolled PTE and PTE of regulated air pollutants expected to be emitted from each emission unit at the design biorefinery described in Jones et al. (2013). In Section 5, we summarize the results of the preliminary estimation of facility-wide PTE and discuss the federally enforceable limitations upon which PTE is based and possible additional emission reductions a design biorefinery might consider.

# Table of Contents

<b>1</b>	<b>Background: Air Pollutant Emissions Addressed by Federal Air Regulations .....</b>	<b>1</b>
<b>2</b>	<b>Overview of the Process for Fast Pyrolysis and Hydrotreating Bio-oil Pathway .....</b>	<b>5</b>
<b>3</b>	<b>Analysis of Air Regulations Potentially Applicable to the Fast Pyrolysis Biorefinery.....</b>	<b>8</b>
3.1	Regulatory Applicability Analysis: Specific NSPS that may Apply to the Biorefinery .....	10
3.1.1	NSPS that may Apply to the Methane Reformer (Area 600).....	11
3.1.2	NSPS that may Apply to Storage Tanks (Area 700).....	12
3.1.3	NSPS that may Apply to the Distillation Operations (Areas 200 and 300) .....	13
3.1.4	NSPS that may Apply to the Reactors (Areas 100, 200, 500).....	13
3.1.5	NSPS that may Apply to Equipment Leaks (Areas 100–600) .....	14
3.1.6	NSPS that may Apply to the Emergency Equipment (Area 700) .....	15
3.1.7	Petroleum Refinery NSPS.....	15
3.1.8	Summary of the NSPS that may Apply to the Biorefinery .....	15
3.2	Regulatory Applicability Analysis: Specific NESHAPs that may Apply to the Biorefinery.....	16
3.2.1	NESHAP that may Apply to the Whole Facility.....	17
3.2.2	NESHAP that may Apply to the Boilers and Process Heaters (Areas 200, 300, and 600) .....	18
3.2.3	NESHAPs that may Apply to the Emergency Equipment (Area 700).....	18
3.2.4	Petroleum Refinery NESHAP .....	18
3.2.5	Summary of the NESHAPs that may Apply to the Biorefinery .....	19
<b>4</b>	<b>Estimation of Potential-to-Emit (PTE) of Regulated Air Pollutant Emissions for the Fast Pyrolysis Biorefinery .....</b>	<b>20</b>
4.1	Definition of PTE.....	20
4.1.1	Maximum Capacity to Emit .....	21
4.1.2	The Physical and Operational Design Factors .....	21
4.1.3	Enforceable Limitations .....	23
4.1.4	Fugitive Emissions .....	23
4.2	General Approach to Estimation of PTE.....	24
4.3	Development of Preliminary Uncontrolled PTE for the Fast Pyrolysis Biorefinery.....	24
4.3.1	Area 100 – Biomass Feedstock Transfer and Storage Operations, Dryer and Sand Heater, Ash and Sand Handling Operations.....	25
4.3.2	Area 100 – Fast Pyrolysis Reactor .....	27
4.3.3	Area 200 – Hydrotreating Reactors.....	28
4.3.4	Areas 200 and 300 – Distillation Columns .....	28
4.3.5	Area 200 – Fired Heater .....	29
4.3.6	Area 300 – Fired Reboiler.....	30
4.3.7	Area 500 – Hydrocracking Reactor.....	31
4.3.8	Area 600 – Methane Reformer.....	32
4.3.9	Area 700 – Wastewater Treatment Plant.....	33
4.3.10	Area 700 – Storage Tanks .....	34
4.3.11	Area 700 – Loading Operations .....	36
4.3.12	Area 700 – Emergency Generator, Emergency Fire Pump, and Cooling Tower .....	37
4.3.13	Emissions from Leaking Equipment .....	40
4.3.14	Emissions from Truck Traffic .....	41
<b>5</b>	<b>Results of Facility-Wide PTE of Regulated Air Pollutants and Discussion of Implications and Limitations.....</b>	<b>43</b>
5.1	Preliminary Estimates of Facility-Wide Uncontrolled PTE of Regulated Air Pollutant Emissions .....	43
5.2	Development of Preliminary PTE .....	46
5.2.1	PTE of Hazardous Air Pollutants (HAPs).....	48

5.2.2	PTE of Particulate Matter (PM)	50
5.2.3	PTE of Carbon Monoxide (CO)	52
5.2.4	PTE of Volatile Organic Compounds (VOCs)	52
5.2.5	PTE of Nitrogen Oxides (NO <sub>x</sub> )	54
5.2.6	PTE of Lead	54
5.2.7	PTE of Sulfur Dioxide (SO <sub>2</sub> )	54
5.2.8	PTE of Greenhouse Gases (GHGs)	55
5.2.9	Facility-Wide PTE	55
<b>6</b>	<b>Concluding Notes</b>	<b>60</b>
	<b>References</b>	<b>61</b>

## List of Tables

Table ES-1. Preliminary Estimates of Uncontrolled PTE and PTE of Criteria Air Pollutants (and Precursors), Total Unspeciated HAP and GHG Emissions in Tons per Year (tpy) from a Fast Pyrolysis Biorefinery per the Design Case (Jones et al. 2013) .....	vi
Table 1. Air Pollutants Addressed by Federal Permitting Programs .....	4
Table 2. Equipment/Operations Likely to Generate Air Pollutants (by Plant Area as Specified in Jones et al. 2013).....	8
Table 3. NSPS Potentially Applicable to Certain Equipment at the Fast Pyrolysis Biorefinery.....	15
Table 4. NESHAPs Potentially Applicable to the Fast Pyrolysis Biorefinery .....	19
Table 5. Preliminary Estimates of Uncontrolled PTE of PM, PM <sub>10</sub> , PM <sub>2.5</sub> , NO <sub>x</sub> , SO <sub>2</sub> , VOC, HAP, and GHGs from the Dryer and Sand Heater in Area 100 .....	26
Table 6. Preliminary Estimates of Uncontrolled PTE of PM, PM <sub>10</sub> , PM <sub>2.5</sub> , NO <sub>x</sub> , SO <sub>2</sub> , CO, VOC, HAP, and GHGs from the Fired Heater in Area 200 .....	30
Table 7. Preliminary Estimates of Uncontrolled PTE of PM, PM <sub>10</sub> , PM <sub>2.5</sub> , NO <sub>x</sub> , SO <sub>2</sub> , CO, VOC, HAP, and GHG Emissions from the Fired Reboiler in Area 300. ....	31
Table 8. Preliminary Estimates of Uncontrolled PTE of PM, PM <sub>10</sub> , PM <sub>2.5</sub> , NO <sub>x</sub> , SO <sub>2</sub> , CO, VOC, HAP, and GHGs from the Methane Reformer in Area 600 .....	33
Table 9. Preliminary Estimates of Uncontrolled PTE of VOC and HAP from WWTP in Area 700 ...	34
Table 10. Preliminary Estimates of Uncontrolled PTE of VOC and HAP from Storage Tanks in Area 700 .....	35
Table 11. Preliminary Estimates of Uncontrolled PTE of VOC, and HAP from Loading Operations in Area 700 .....	37
Table 12. Preliminary Estimates of Uncontrolled PTE of Criteria Air Pollutants, GHGs, and HAP emissions from Area 700.....	39
Table 13. Preliminary Estimates of Uncontrolled PTE of VOC and HAP Emissions from Equipment Leaks in Areas 100, 200, 300, 400, 500, and 600 .....	40
Table 14. Preliminary Estimates of Uncontrolled PTE of PM, PM <sub>10</sub> , and PM <sub>2.5</sub> from Truck Traffic ..	42
Table 15. Preliminary Estimates of Facility-Wide Uncontrolled PTE of Criteria Air Pollutants (and precursors), HAPs, and GHG Emissions from the Design Biorefinery (tpy).....	44
Table 16. Federal Air Regulations Potentially Applicable to the Fast Pyrolysis Biorefinery .....	47
Table 17. Uncontrolled PTE and Preliminary PTE for HAP .....	49
Table 18. Uncontrolled PTE and Preliminary PTE for PM, PM <sub>10</sub> , and PM <sub>2.5</sub> .....	51
Table 19. Uncontrolled PTE and Preliminary PTE for VOCs .....	54
Table 21. Factors Considered for PTE Estimation and Preliminary Determination of Status .....	58
Table A-1. PSD Significant Emission Rates (SERs).....	65
Table B-1. Regulated Pollutants.....	66
Table E-1. Insert Caption Here.....	82
Table F-1. Standards of Performance for Volatile Organic Liquid Storage Vessels (NSPS Subpart Kb) .....	83
Table F-2. Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE) (NSPS Subpart IIII) .....	84
Table G-1. List of HAPs used to Determine Applicability of CMAS (NESHAP Subpart VVVVVV).....	85
Table H-1. Standards of Performance for Chemical Manufacturing Area Sources (NESHAP Subpart VVVVVV) .....	86
Table H-2a. Standards of Performance for Stationary Reciprocating Internal Combustion Engines (RICE) (NESHAP Subpart ZZZZ).....	91
Table H-2b. Standards of Performance for Stationary Reciprocating Internal Combustion Engines (RICE) (Subpart ZZZZ) .....	92

# 1 Background: Air Pollutant Emissions Addressed by Federal Air Regulations

The United States Congress established much of the basic structure of the Clean Air Act (CAA) in 1970, which set in motion a nationwide effort to improve the country's air quality. Subsequent revisions were made in 1977 and 1990 to improve the effectiveness of the CAA and to target newly identified air pollution concerns such as acid rain and the damage of ozone depleting substances to the stratospheric ozone layer (EPA 2013). The CAA charges the EPA with developing and implementing a wide range of regulatory programs targeted at various air pollution problems.

The CAA requires EPA to set and revise National Ambient Air Quality Standards (NAAQS) for certain common and widespread pollutants, known as criteria pollutants (i.e., sulfur dioxide [SO<sub>2</sub>], carbon monoxide [CO], particulate matter [PM], nitrogen oxides [NO<sub>x</sub>], ozone, and lead). Implementing the air quality standard is a joint responsibility of states and EPA; states are responsible for developing enforceable state implementation plans to meet and maintain air quality that meets the NAAQS while EPA assists states' efforts by providing technical and policy guidance and reviewing states' plans to ensure they comply with the CAA. If a state fails to adopt and implement an adequate plan, EPA is required to issue a federal implementation plan (EPA 2013). Ultimately, federal highway funds can be withheld should a state not develop an adequate plan.

Because atmospheric air pollutant concentrations cannot be directly controlled to maintain compliance with the NAAQS, the EPA is authorized to set standards for allowable emissions from various types of sources while also considering current air quality conditions of a particular location. In this context, EPA sets emissions standards for new and modified stationary pollution sources in source categories that could significantly endanger air quality. These rules are referred to as New Source Performance Standards (NSPS). They typically apply to industrial facilities such as manufacturing facilities and power plants, but they can also apply to smaller equipment such as wood stoves. The NSPS limit emissions and/or currently available specify technology that limits emissions; however, the NSPS generally only apply to new sources built after a specified date.

The CAA includes a list of hazardous air pollutants (or HAPs—also known as toxic air pollutants). The EPA is required to regulate these pollutants from each category of sources that emit one or more HAPs via regulations called National Emission Standards for Hazardous Air Pollutants (NESHAP). The regulations must be based on the average performance of the top 12% best performing sources in a source category. This is referred to Maximum Achievable Control Technology (MACT). The CAA requires the EPA to review the MACT rule eight years after the compliance date of the MACT standard and to revise the MACT standards, if necessary, based on an assessment of the potential residual health risk to populations exposed to any HAP emissions that are still emitted from the sources in a source category. The CAA also requires EPA to perform a review to determine whether any improvements in technology have occurred since the MACT was established that would lower the potential emissions from the source category. This is referred to as a technology review, and it is performed simultaneously with the risk review (as a “risk and technology review”). The NESHAP implementation and enforcement

is typically delegated to the states, but both EPA and the states can implement and enforce the standards (EPA 2013).

In addition to the NSPS and NESHAP pollutants, other air pollutants that may be emitted from the fast pyrolysis biorefinery may also be regulated by the CAA. These include 112(r) pollutants (see Footnote 16 in the Executive Summary) and greenhouse gases (GHG), as follows:<sup>17</sup>

- When Congress passed the CAA Amendments of 1990, Section 112(r) required EPA to publish regulations and guidance for preventing chemical accidents at facilities using substances that pose the greatest risk of harm from accidental releases. These regulations require facilities of all sizes that use certain regulated flammable and toxic substances to develop a “risk management program” or RMP (EPA 2009). These plans must be revised and resubmitted to EPA every five years; see Appendix B for a list of these chemicals.
- In 2009, EPA determined that GHGs threaten public health and welfare, and in 2010, issued a regulation that is applicable to mobile sources to reduce GHG emissions. EPA proposed a plan to cut carbon pollution from existing power plants on June 2, 2014, using the authority under Section 111 of the CAA. Future GHG regulations that apply to power plants or other types of industrial sources will also use the authority under Section 111 of the CAA. The regulated pollutant, GHG, is the combination of emissions of carbon dioxide (CO<sub>2</sub>), nitrous oxide (N<sub>2</sub>O), methane (CH<sub>4</sub>), hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

As part of the amendments to the CAA in 1977, Congress established the New Source Review (NSR) program, which requires a facility<sup>18</sup> to apply for a construction (or pre-construction) permit *before* a project is built or modified. The NSR permit is a legal document that the facility must abide by. And, the source may have to meet one or more of the three types of NSR permitting requirements:

1. Prevention of Significant Deterioration (PSD) permits,<sup>19</sup> which are required for new sources<sup>20</sup> that are major for at least one pollutant, for which the area is in compliance with the NAAQS

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<sup>17</sup> The CAA also requires EPA to phase out the production and import of listed ozone-depleting substances, including halons, chlorofluorocarbons, and hydrochlorofluorocarbon. EPA is required to issue regulations that (1) reduce the use and the emissions of these substances and (2) prohibit replacement (provided EPA has identified an alternative that is available and poses lower risk) of any ozone-depleting substance with a substitute substance that EPA determines may present negative effects to human health or the environment. However, the design case is not expected to emit these ozone-depleting substances.

<sup>18</sup> A facility is generally defined as any source of air pollution. In this document, “facility” is used to mean a combination of all operations at one location.

<sup>19</sup> PSD permits are also required for major modifications at major PSD sources; however, this document focuses on construction of new sources and does not address modifications of existing sources and the applicability of PSD.

<sup>20</sup> A “major” PSD source is a source that has a PTE greater than or equal to the following thresholds of a pollutant for which the area is in attainment with the pollutants’ NAAQS:

- 100 tpy if it is part of the 28 listed source categories (see Appendix C)
- 250 tpy if it is not part of the 28 listed source categories.

2. Nonattainment NSR (NNSR) permits,<sup>21</sup> which are required for new sources<sup>22</sup> that are major for a pollutant, for which the area is in nonattainment with the NAAQS,<sup>23</sup>
3. Minor source permits.

If a source has a potential-to-emit (PTE)<sup>24</sup> one or more pollutants over the major source threshold, the source is considered major. A new major source must perform a PSD review (i.e., PSD permit) for all attainment pollutants that have a PTE greater than their respective SER (see Appendix A for the SERs). For example, the SER for NO<sub>x</sub> is 40 tpy, which is lower than the 100-tpy major source threshold for chemical process plants. (Because the biorefinery produces hydrocarbon biofuels, it would be deemed a chemical process plant.) If a planned source has a PTE of CO of 120 tpy and a PTE of NO<sub>x</sub> of 50 tpy *and* it will be located in a CO and NO<sub>x</sub> attainment area, it will be required to perform a PSD review for both CO and NO<sub>x</sub> because the source is a major PSD source and the PTE of CO and NO<sub>x</sub> exceeds the SER for both CO and NO<sub>x</sub>. The SER values for all regulated air pollutants under the NSR program are equal to or below 100 tpy; therefore, any pollutant with a PTE at a major source level also exceeds its SER value.

Furthermore, the 1990 CAA amendments require all *major* sources (see Appendix D) of air pollution and certain other sources to apply for and obtain *operating permits* that assure compliance with all of their CAA requirements. This kind of operating permit, required under Title V of the CAA, is called a Title V operating permit. The primary purpose of the Title V permit program is to develop permits that contain all the emission standards, monitoring, record keeping, and reporting requirements that apply to a source.

Many facilities may want to avoid having to obtain a Title V permit because of the fees and complexity of developing annual emission estimates. It is possible for a Title V source to become non-Title V source by taking federally enforceable limits on the pollutants for which the source is major. Both the NSR permits (also known as construction permits) and Title V operating permits generally are issued by state and local permitting agencies under EPA-approved programs (EPA 2013).

To summarize, Table 1 shows the regulated pollutants addressed by federal permitting programs. For a complete list of regulated pollutants, refer to Appendix B.

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<sup>21</sup> NNSR permits are also required for major modifications at major NNSR sources; however, this document focuses on construction of new sources and does not address modifications of existing sources and the applicability of NNSR.

<sup>22</sup> A major NNSR source is a source that has a PTE greater than or equal to the applicable major source threshold, listed in Appendix E, of a pollutant for which the area is in nonattainment with the pollutants' NAAQS.

<sup>23</sup> A nonattainment area is any area that does not meet—or that contributes to ambient air quality in a nearby area that does not meet—the NAAQS for the pollutant.

<sup>24</sup> Refer to Section 4.1 for a definition of PTE.

**Table 1. Air Pollutants Addressed by Federal Permitting Programs**

<b>Air Pollutants</b>	<b>NSR Regulated Pollutants (Pollutants addressed in NSR Permits, aka pre-construction permits)</b>	<b>Regulated Pollutants (Pollutants addressed in Title V Operating Permits)</b>
Criteria pollutants and their precursors	✓	✓
NSPS pollutants	✓ <sup>a</sup>	✓
HAP	—	✓
Ozone depleting substances	✓	✓
112(r) pollutants	—	✓
GHG	✓	✓

<sup>a</sup> Excluding total suspended particulates, which are also referred to as PM



## 2 Overview of the Process for Fast Pyrolysis and Hydrotreating Bio-oil Pathway

Implementation of the Renewable Fuel Standard is expected to result in construction of new biofuel facilities using advanced technologies. A fast pyrolysis and hydrotreating bio-oil pathway (Jones et al. 2013) led by the Pacific Northwest National Laboratory (PNNL) is one plausible technology pathway (Jones et al. 2013). The design case documented in Jones et al. (2013) is used as the basis for quantifying potential emissions of regulated air pollutants for this conversion technology. Such a biorefinery is considered a point source of air pollutant emissions.

The fast pyrolysis biorefinery uses a thermochemical process for converting biomass into liquid transportation fuels (gasoline and diesel blendstock) via fast pyrolysis process followed by the hydroprocessing (hydrotreating and hydrocracking) of the condensed pyrolysis oil (Jones et al. 2013). The designed biorefinery is divided into seven areas briefly described as follows (adapted from Jones et al. 2013).

### ***Area 100: Fast Pyrolysis***

Biomass feedstock is unloaded from trucks to a storage area. Screw conveyors are used to transfer the feedstock from the storage area to the dryer and from the dryer to the pyrolysis reactor. It is assumed that these unloading, transfer, and storage operations are completely enclosed such that the only vent to the atmosphere from these operations is through the dryer.

Pyrolysis is the thermal decomposition of carbonaceous material in the absence of oxygen to produce solid char, gas, and liquid product (Jones et al. 2013). Based on the design case (Jones et al. 2013), sand is heated in a sand heater. The hot sand is then mixed with biomass in a pyrolysis reactor to reach a temperature of about 932°F (500°C). The mixture of biomass and sand is rapidly cooled to stop the reaction. The products of this process include solid char, condensable gas, and non-condensable gas. The solid char (and spent sand) are separated from the condensable and non-condensable gas with a cyclone and sent back to the sand heater. The solid char (and a portion of the gas) is burned as fuel in the sand heater; the spent sand is reused. The condensable and non-condensable gas is sent through a series of quench columns where some of the gas is condensed into a bio-oil and sent to be hydrotreated (Area 200). And, the non-condensable gas either (1) is sent back through a pyrolysis reactor or a sand heater, or (2) is used as fuel in the hydrogen production process (Area 600).

The exhaust from the sand heater is sent through a bag filter where ash is collected and then disposed. After passing through the bag filter, this exhaust is sent through the dryer, which is used to dry the biomass feed that enters the pyrolysis reactor.

### ***Area 200: Hydrotreating***

The fast pyrolysis liquid product or bio-oil is deoxygenated by catalytic hydrotreating at elevated pressures in an excess of hydrogen. The output from the hydrotreating process is a three-phase mixture consisting of a non-condensable gas containing hydrocarbons and an immiscible liquid, including an organic phase and an aqueous phase. The organic portion of the liquid is hydrocarbon oil and the aqueous phase is primarily water with some soluble organic components possibly present. The water is separated from the three-phase mixture and sent to the wastewater

treatment plant. The non-condensable gas is separated from the bio-oil using a three-phase separator and distillation column. The upgraded bio-oil is sent to Area 300 for product recovery. The non-condensable gas containing hydrocarbons is collected and sent to the hydrogen production process; a part of the non-condensable gas is reformed to hydrogen with the remaining part used as fuel by the methane reformer burners in Area 600. Because sulfiding agent (dimethyl sulfide) is used to maintain the catalyst in a sulfide state (Jones et al. 2013, p. 16), hydrogen sulfide (H<sub>2</sub>S) is generated during hydrotreating and is present in the gas stream sent to hydrogen production plant.

### ***Area 300: Product Recovery***

The bio-oil (from Area 200) is split into gasoline and diesel blendstocks using distillation columns. The condensers used on the distillation columns could vent non-condensables (potentially containing volatile organic compounds [VOCs] and HAPs) to the atmosphere. Or, they could be released through storage tanks, but no vents are shown in the design case (Jones et al. 2013). The design report does not specifically identify storage tanks for the gasoline or diesel blendstocks, but tanks would be necessary to hold these products. Emissions of VOC and HAP would be expected from these tanks.

### ***Area 400: Fuel Gas Collection***

Off-gas from fast pyrolysis (Area 100) and upgrading (Area 200) is collected in this area and routed to the hydrogen plant (Area 600) and process heaters onsite. There is no planned exhaust point in Area 400, but air pollutants could be released to the atmosphere as fugitive emissions through leaking equipment.

### ***Area 500: Hydrocracking***

The heavy hydrocarbon fraction from hydrotreated oil is processed in a hydrocracking reactor in Area 500 and sent back through the distillation columns in Area 300 to obtain additional gasoline and diesel blendstocks. No vents are shown in Area 500 in the design case (Jones et al. 2013). However, there are condensers used after the hydrocracker that could vent non-condensable gases (potentially containing VOC and HAP) to the atmosphere.

### ***Area 600: Hydrogen Production***

In Area 600, hydrogen for hydroprocessing (hydrotreating and hydrocracking) is produced via steam reforming of a combination of process off-gas (generated from fast pyrolysis and hydroprocessing) and supplemental natural gas. A part of off-gas from hydroprocessing is used as fuel to fire the methane reformer burners. A flare is listed in the equipment list (Jones et al. 2013, p. 63). It is assumed that the flare is used for emergencies only (i.e., not as an emission control device).

### ***Area 700: Balance of the Plant***

#### ***Wastewater Treatment***

Wastewater from various parts of the fast pyrolysis biorefinery is sent to the wastewater treatment plant (WWTP). A portion of the VOC and HAP produced in these areas would be expected to be present in the wastewater and could potentially be (1) released from the wastewater either as fugitive emissions (i.e., when wastewater is open to the atmosphere and/or wastewater vapors leak through sewers, drains, or other equipment in the WWTP) or

(2) vented from treatment process equipment. Sufficient information is not available in the design report to determine speciated VOC and/or HAP compounds. The WWTP also uses an aerobic digester that releases CO<sub>2</sub>.

### *Storage*

The design case includes two product storage tanks, both of which have capacities over 500,000 gallons; presumably, these tanks are to hold the liquid blendstock products that are similar to gasoline and diesel (Jones et al. 2013, p. 63). These tanks would be expected to emit VOC and HAP. The biorefinery would also need equipment for loading these liquid products into tank trucks or railcars, although the design report does not mention such equipment. Loading operations would also emit VOC and HAP.

### *Utilities*

This area includes a cooling water system, chilled water system, process water manifold, and emergency equipment.

### 3 Analysis of Air Regulations Potentially Applicable to the Fast Pyrolysis Biorefinery

The first step to determine which federal air regulations potentially apply to the fast pyrolysis biorefinery is to identify the type of regulated air pollutants emitted to the environment by the biorefinery or specific equipment.<sup>25</sup> The operations and equipment documented in the Jones et al. (2013) design case are used as the basis for identifying regulated pollutants that could be emitted from the facility and specific equipment. The potentially emitted pollutants include six criteria air pollutants from various equipment (e.g., hydrotreating reactor, fired heater, fired reboiler, methane reformer), including NO<sub>x</sub>, SO<sub>2</sub>, CO, VOC,<sup>26</sup> lead, and PM with diameter less than or equal to 2.5 micrometers [PM<sub>2.5</sub>]/ particulate matter with diameter less than or equal to 10 micrometers [PM<sub>10</sub>].

In addition, some HAPs are likely to be generated from emission points, including storage tanks, the heat exchange systems (e.g., cooling towers), and equipment leakage. GHG emissions (mainly CO<sub>2</sub>) are also expected to be emitted from several areas of the biorefinery. Table 2 summarizes the equipment likely to generate air pollutants from the fast pyrolysis biorefinery. In most cases, the equipment does not necessarily emit air pollutants directly to the atmosphere; instead, the air pollutants from the equipment are collected and then fed to other portions of the process and released through the atmospheric vents of other equipment.

**Table 2. Equipment/Operations Likely to Generate Air Pollutants (by Plant Area as Specified in Jones et al. 2013)**

Plant Area	Equipment	Air Pollutants
Area 100: Fast pyrolysis	Biomass feedstock transfer and storage	PM, PM <sub>10</sub> , PM <sub>2.5</sub>
	Dryer (C-101)	PM, PM <sub>10</sub> , PM <sub>2.5</sub> , VOC, HAP
	Sand heater (R-124)	PM, PM <sub>10</sub> , PM <sub>2.5</sub> , SO <sub>2</sub> , NO <sub>x</sub> , CO <sub>2</sub>
	Ash and sand handling operations	PM, PM <sub>10</sub> , PM <sub>2.5</sub>
	Pyrolysis reactor (R-110)	PM, PM <sub>10</sub> , PM <sub>2.5</sub> , VOC, HAP
	Leaking equipment <sup>a</sup>	VOC, HAP
Area 200: Hydrotreating	Hydrotreating reactors (R-220 and R-225)	VOC, HAP, H <sub>2</sub> S
	Distillation column (T-290)	VOC, HAP
	Fired heater (H-222)	PM, PM <sub>10</sub> , PM <sub>2.5</sub> , NO <sub>x</sub> , SO <sub>2</sub> , CO, CO <sub>2</sub> , VOC, HAP
	Leaking equipment <sup>a</sup>	VOC, HAP
Area 300: Product recovery	Distillation columns (T-310 and T-320)	VOC, HAP

<sup>25</sup> Some regulations apply to the entire facility while others apply to specific equipment.

<sup>26</sup> A VOC is defined in Code of Federal Regulations 40 CFR 51.100 as any compound of carbon, excluding several compounds listed in the definition, such as carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate— which participates in atmospheric photochemical reactions .

Plant Area	Equipment	Air Pollutants
	Fired reboiler (E-3200)	PM, PM <sub>10</sub> , PM <sub>2.5</sub> , NO <sub>x</sub> , SO <sub>2</sub> , CO, CO <sub>2</sub> , VOC, HAP
	Leaking equipment <sup>a</sup>	VOC, HAP
Area 400: Fuel gas collection	Leaking equipment <sup>a</sup>	VOC, HAP
Area 500: Hydrocracking	Hydrocracking reactor (R-510)	VOC, HAP
	Leaking equipment <sup>a</sup>	VOC, HAP
Area 600: Hydrogen production	Methane reformer (R-600)	PM, PM <sub>10</sub> , PM <sub>2.5</sub> , NO <sub>x</sub> , SO <sub>2</sub> , CO, CO <sub>2</sub> , VOC, HAP
	Leaking equipment <sup>a</sup>	VOC, HAP
Area 700: Wastewater treatment	Aerobic digester	CO <sub>2</sub> , VOC, HAP
Area 700: Storage	Product storage tanks	VOC, HAP
	Tank farm	VOC, HAP
	Equipment for loading products	VOC, HAP
Area 700: Utilities	Cooling tower	PM, PM <sub>10</sub> , PM <sub>2.5</sub> , VOC, HAP
	Emergency fire pump	PM, PM <sub>10</sub> , PM <sub>2.5</sub> , NO <sub>x</sub> , SO <sub>2</sub> , CO, CO <sub>2</sub> , VOC, HAP
	Emergency generator	PM, PM <sub>10</sub> , PM <sub>2.5</sub> , NO <sub>x</sub> , SO <sub>2</sub> , CO, CO <sub>2</sub> , VOC, HAP
Area 700: Truck traffic	Dust from trucks hauling feedstock, other raw materials, waste, and product <sup>a</sup>	PM, PM <sub>10</sub> , PM <sub>2.5</sub>

<sup>a</sup> These air pollutants are released to the atmosphere as fugitive emissions.

Once the regulated air pollutants are identified, the next step is to review the applicability criteria of each federal standard to determine whether a facility or specific equipment is subject to it. Two types of federal standards regulate air pollutants from industrial plants: New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP). The complete set of the NSPS is codified in Title 40, Part 60 of the Code of Federal Regulations (CFR). The complete set of the NESHAP is codified in Title 40, Parts 61 and 63 of the CFR.<sup>27</sup>

NSPS and NESHAP can apply to a facility as a whole or to only a portion of the facility (e.g., a federal standard may only apply to a specific piece of equipment at the facility). As part of the regulatory analysis for the fast pyrolysis biorefinery, all of the NSPS and NESHAP were reviewed to identify which may apply to the fast pyrolysis biorefinery as well as the equipment used in the biorefinery.

<sup>27</sup> The federal rules can be accessed at [http://www.ecfr.gov/cgi-bin/text-idx?SID=de83df0816d6189bf8c0a725ddace344&tpl=/ecfrbrowse/Title40/40tab\\_02.tpl](http://www.ecfr.gov/cgi-bin/text-idx?SID=de83df0816d6189bf8c0a725ddace344&tpl=/ecfrbrowse/Title40/40tab_02.tpl).

### 3.1 Regulatory Applicability Analysis: Specific NSPS that may Apply to the Biorefinery

Although biorefinery developers should consider all NSPS when planning compliance measures for their facility, the NSPS listed below are likely to be all of the NSPS that could apply to the biorefineries that use the fast pyrolysis process described in Jones et al. (2013) based on the review of NSPS and EPA's Applicability Determination Index.<sup>28</sup> NSPS under the CAA dictate the level of pollution that a new source may produce.

- Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Db)<sup>29</sup>
- Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Dc)<sup>30</sup>
- 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 (40 CFR 60, Subpart Kb)<sup>31</sup>
- Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations (40 CFR 60, Subpart NNN)<sup>32</sup>
- Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes (40 CFR 60, Subpart RRR)<sup>33</sup>
- Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 (40 CFR 60, Subpart VVa)<sup>34</sup>
- Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (40 CFR 60, Subpart IIII)<sup>35</sup>
- Standards of Performance for Petroleum Refineries (40 CFR 60, Subpart J)<sup>36</sup>

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<sup>28</sup> The Applicability Determination Index database can be found at <https://www.fedcenter.gov/Bookmarks/index.cfm?id=4759>.

<sup>29</sup> 40 CFR 60, Subpart Db can be found at [http://www.ecfr.gov/cgi-bin/text-idx?SID=bc450da143f94c92100c39b241a05697&mc=true&node=sp40.7.60.d\\_0b&rgn=div6](http://www.ecfr.gov/cgi-bin/text-idx?SID=bc450da143f94c92100c39b241a05697&mc=true&node=sp40.7.60.d_0b&rgn=div6)

<sup>30</sup> 40 CFR 60, Subpart Dc can be found at [http://www.ecfr.gov/cgi-bin/text-idx?node=sp40.7.60.d\\_0c](http://www.ecfr.gov/cgi-bin/text-idx?node=sp40.7.60.d_0c).

<sup>31</sup> 40 CFR 60, Subpart Kb can be found at [http://www.ecfr.gov/cgi-bin/text-idx?node=sp40.7.60.k\\_0b](http://www.ecfr.gov/cgi-bin/text-idx?node=sp40.7.60.k_0b).

<sup>32</sup> 40 CFR 60, Subpart NNN can be found at <http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr;sid=dd4e12f59b76d216ec3d7735bb72fc9f;rgn=div6;view=text;node=40%3A7.0.1.1.1.81;idno=40;cc=ecfr>.

<sup>33</sup> 40 CFR 60, Subpart RRR can be found at <http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=&SID=a9b6190943a0d335fce9afbcba219374&mc=true&n=pt40.8.60&r=PART&ty=HTML#sp40.8.60.rrr>.

<sup>34</sup> 40 CFR 60, Subpart VVa can be found at [http://www.ecfr.gov/cgi-bin/text-idx?node=sp40.7.60.vv\\_0a](http://www.ecfr.gov/cgi-bin/text-idx?node=sp40.7.60.vv_0a).

<sup>35</sup> 40 CFR 60, Subpart IIII can be found at <http://www.ecfr.gov/cgi-bin/text-idx?node=sp40.7.60.iiii>.

<sup>36</sup> 40 CFR 60, Subpart J can be found at <http://www.ecfr.gov/cgi-bin/text-idx?node=sp40.7.60.j>.

- Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (40 CFR 60, Subpart Ja).<sup>37</sup>

Using the specific information available from the design case, including capacity and size of equipment (Jones et al. 2013), more specific applicability determinations can be made, as is discussed in Sections 3.1.1 through 3.1.8.

### 3.1.1 NSPS that May Apply to the Methane Reformer (Area 600)

There are two boiler NSPS; one is the Boiler NSPS for Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Db) and the other is the Boiler NSPS for Small Industrial-Commercial-Institutional Steam Generating Units (40 CFR 60, Subpart Dc). The applicability of these two boiler NSPS depends on the design rate of the boiler. NSPS 40 CFR 60, Subpart Db applies to steam generating units that have a heat input capacity between 100 and 250 million British thermal units (Btu) per hour (MMBtu/hr). And, 40 CFR 60, Subpart Dc applies to steam generating units that have a heat input capacity between 10 and 100 MMBtu/hr. NSPS 40 CFR 60, Subpart Db may apply to the methane reformer being used at the fast pyrolysis biorefinery because the total heat input capacity of the methane reformer is 160.9 MMBtu/hr which is greater than the applicability threshold of 100 MMBtu/hr. However, a closer review of the definitions in Subpart Db at 40 CFR 60.41b is necessary to make a final applicability determination.

Subpart Db at 40 CFR 60.41b defines a “steam generating unit” as “a device that combusts any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium.” This term includes any municipal-type solid waste incinerator with a heat recovery steam-generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. *The term does not include process heaters, as they are defined in this subpart.* A “process heater” is defined by 40 CFR 60, Subpart Db as “a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.” Process heaters are specifically exempt from complying with 40 CFR 60, Subpart Db. The methane reformer uses indirect heating to promote a chemical reaction of process off-gases, natural gas, and steam in the presence of a catalyst to form hydrogen. Steam is used in the methane reformer as one of the reactants. Heat is also recovered from the methane reformer, producing steam. Some of the steam is used in the methane reformer as a reactant, but some of the steam is used as process heat elsewhere at the plant. Although the methane reformer does produce steam used as a heat transfer medium, this is not the main purpose of the reformer. The definition of process heater indicates that the primary function of the device should be considered when determining whether the device is a process heater. Therefore, the methane reformer is not likely to be considered a “steam generating unit,” but rather a “process heater.” For this reason, the fast pyrolysis biorefinery is *not* expected to be subject to the NSPS for steam generating units (40 CFR 60, Subpart Db or 40 CFR 60, Subpart Dc).<sup>38</sup>

<sup>37</sup> Subpart Ja can be found at [http://www.ecfr.gov/cgi-bin/text-idx?node=sp40.7.60.j\\_0a](http://www.ecfr.gov/cgi-bin/text-idx?node=sp40.7.60.j_0a).

<sup>38</sup> This applicability determination is similar to one made by the New York State Department of Environmental Conservation regarding the applicability of 40 CFR 60, Subpart Dc for the construction of a new steam methane

### 3.1.2 NSPS that May Apply to Storage Tanks (Area 700)

Storage tanks in the biorefinery could be subject to control requirements under the NSPS for Volatile Organic Liquid Storage Vessels (40 CFR 60, Subpart Kb). The design report (Jones et al. 2013) indicates that the biorefinery will have a “tank farm”; however, the design report does not provide the number of tanks or the size or contents of each tank that will be located at the “tank farm.” Therefore, it is impossible to determine whether any tank would be subject to the NSPS for Volatile Organic Liquid Storage Vessels (40 CFR 60, Subpart Kb). To be subject to the control requirements in 40 CFR 60, Subpart Kb, a tank must meet certain capacity specifications, and it must store organic liquid with certain vapor pressure specifications. Refer to Table E-1 in Appendix F for details regarding applicability (including the capacity and vapor pressure specifications) of 40 CFR 60, Subpart Kb.

The equipment list in Jones et al. (2013) indicates that the biorefinery will have an ammonia storage tank and a hydrazine storage tank. However, these storage tanks would not be subject to the control requirements in 40 CFR 60, Subpart Kb because ammonia and hydrazine are not organic liquids.

The design report indicates there are two product storage tanks that are each 580,000 gallons in capacity (Jones et al. 2013, p. 62). Presumably, these tanks are to hold the final gasoline and diesel blendstock products from the fast pyrolysis process. The requirements of 40 CFR 60, Subpart Kb do not apply to a storage tank with a capacity greater than or equal to 39,890 gallons as long as it stores liquid with a vapor pressure less than 3.5 kilopascals (kPa). If the tank has (1) a capacity greater than or equal to 39,890 gallons and (2) a vapor pressure equal to or greater than 3.5 kPa but less than 5.2 kPa, the only requirement that would apply is that a record be kept of the material contained in the tank and its vapor pressure. If the capacity of the product tank is greater than or equal to 39,890 gallons and the vapor pressure is equal to or greater than 5.2 kPa, the control requirements of 40 CFR 60, Subpart Kb would apply.<sup>39</sup>

The vapor pressure of the diesel<sup>40</sup> product is expected to be much lower than any of these thresholds are. Therefore, the storage tank for the diesel product at the fast pyrolysis biorefinery is not expected to be subject to 40 CFR 60, Subpart Kb. However, the vapor pressure of gasoline product is expected to be greater than 5.2 kPa.<sup>41</sup> Therefore, a tank with a capacity of 578,000 gallons storing gasoline blendstock at the fast pyrolysis biorefinery would be subject to the control requirements in 40 CFR 60, Subpart Kb. (We assume the gasoline product from fast pyrolysis has a vapor pressure that is the same as that of petroleum gasoline, which is 6.4 pounds per square inch absolute [psia] or 44 kPa at 77°F.) Subpart Kb requires that a tank of this size holding this type of material must have an internal or external floating roof installed *or* that vapors must be collected and routed to a control device achieving 95% emissions reduction.

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reformer plant located in Niagara Falls, New York. Refer to the following link for details:  
<http://www.dec.ny.gov/dardata/boss/afs/permits/929110009600005.pdf> (accessed October 19, 2015)

<sup>39</sup> 40 CFR 60, Subpart Kb (at 60.116 b(d)) requires an owner or operator to notify the administrator within 30 days when the maximum true vapor pressure of the liquid exceeds 5.2kPa.

<sup>40</sup> The vapor pressure of diesel is assumed to be similar to that of petroleum diesel production (Davis and McCormick 2014). The true vapor pressure of No.2 diesel fuel is 0.011 psia (i.e., 0.08 kPa) at 77 F (EPA 2006a).

<sup>41</sup> See Table 7.1-2 in AP 42, Fifth Edition, Volume I: Chapter 7: Liquid Storage Tanks, which can be found at <https://www.epa.gov/ttnchie1/ap42/ch07/final/c07s01.pdf>.



In addition, it is useful to point out for planning purposes that if a storage tank has a capacity between 19,813 gallons and 39,890 gallons, the organic liquid product would need to have a true vapor pressure of 15.0 kPa or greater for 40 CFR 60, Subpart Kb to apply. Tanks with a capacity less than 19,813 gallons are not subject to 40 CFR 60, Subpart Kb.

### **3.1.3 NSPS that May Apply to the Distillation Operations (Areas 200 and 300)**

A distillation operation is defined in 40 CFR 60, Subpart NNN as “an operation separating one or more feed stream(s) into two or more exit stream(s), each exit stream having component concentrations different from those in the feed stream(s). The separation is achieved by the redistribution of the components between the liquid and vapor-phase as they approach equilibrium within the distillation unit.” For 40 CFR 60, Subpart NNN to be applicable, a distillation column must be part of a process unit that produces any of the chemicals listed in §60.667 as a product, co-product, by-product, or intermediate product.<sup>42</sup>

The lights column (T-290), naphtha splitter (T-310), and diesel splitter (T-320) are distillation operations that are part of a process unit that generate process streams that contain “cyclo C5” (e.g., 1,3-cyclopentadiene) and/or “cyclo C6” (e.g., cyclohexane)<sup>43</sup> among others, which are chemicals affected by 40 CFR 60, Subpart NNN (listed in §60.667). However, these chemicals are not considered products, co-products, by-products, or intermediates because they are not isolated for sale or used in another process. Therefore, these distillation operations are not subject to the distillation NSPS (40 CFR 60, Subpart NNN).

To determine whether a process makes one of the listed chemicals a product, the product must be sold or used in another process as the listed chemical.<sup>44</sup> The process streams described above are just process streams in the same process and are not considered products. Also, the products of the process (i.e., the gasoline and diesel type products) may have one or more of the listed chemicals in the product, but the chemical constituents in these products are not sold or used by another process as the listed chemical or chemicals; they are sold as the collective mixture.

### **3.1.4 NSPS that may Apply to the Reactors (Areas 100, 200, 500)**

Reactor processes are defined in reactor NSPS, 40 CFR 60, Subpart RRR as “unit operations in which one or more chemicals, or reactants other than air, are combined or decomposed in such a way that their molecular structures are altered and one or more new organic compounds are formed.” For 40 CFR 60, Subpart RRR to apply, requires a continuous reactor must be part of a process unit that produces any of the chemicals listed in §60.707 as a product, co-product, by-product, or intermediate product.<sup>45</sup>

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<sup>42</sup> Under Subpart NNN, co-products, by-products, and intermediates are all considered products.

<sup>43</sup> Refer to the specifications of Stream IDs 305, 311, and 321 in Appendix A of the design report (Jones et al. 2013).

<sup>44</sup> Letter from John Rasnic, Director, Stationary Source Compliance Division Office of Air Quality Planning and Standards, EPA, to Raymond Hiley, Goodwin, Proctor & Hoar, regarding SOCM I Product/CMPU Definitions, dated April 6, 1994. Applicability Determination Index: Control Number 9700142. <https://cfpub.epa.gov/adi/pdf/adi-nsps-9700142.pdf> (accessed November 2, 2015)

<sup>45</sup> Under Subpart RRR, co-products, by-products, and intermediates are all considered products.

The pyrolysis reactor (R-110), hydrotreating reactors (R-220 and R-225), and hydrocracking process unit (R510) are continuous reactors that are part of a process unit with the process streams containing following chemicals that are affected by 40 CFR 60, Subpart RRR (i.e., are listed in §60.707), among others:

- Ethylene
- Propylene
- “Aldehydes” (e.g., acetaldehyde)
- “Cyclo C5” (e.g., 1,3-cyclopentadiene)
- “Cyclo C6” (e.g., cyclohexane)
- “Cyclo C6 – HCK products” (e.g., cyclohexane and benzene).

However, these chemicals are not considered products, co-products, by-products, or intermediates because they are not isolated for sale or used in another process. Therefore, the pyrolysis reactor, hydrotreating reactors, and hydrocracking process unit are not expected to be subject to the reactor NSPS (40 CFR 60, Subpart RRR).

To determine whether a process makes one of the listed chemicals a product, the product must be sold or used in another process as the listed chemical. The process streams described above are just process streams in the same process and are not considered products. Also, the products of the process (i.e., the gasoline- and diesel- type products) may have one or more of the listed chemicals in the product, but the chemical constituents in these products are not sold or used by another process as the listed chemical or chemicals; they are sold as the collective mixture.

In addition, it is useful to point out for planning purposes that a reactor designed and operated as a batch operation is exempt from 40 CFR 60, Subpart RRR. Under this NSPS, batch operation means, “any non-continuous reactor process that is not characterized by steady-state conditions and in which reactants are not added and products are not removed simultaneously.”

### **3.1.5 NSPS that May Apply to Equipment Leaks (Areas 100–600)**

Equipment leak NSPS, 40 CFR 60, Subpart VVa applies to the synthetic organic chemicals manufacturing industry, which includes any industry that produces, as intermediates or final products, one or more of the chemicals listed in §60.489. According to the design report (Jones et al. 2013), some of the process streams at the design plant contain chemicals that are affected by 40 CFR 60, Subpart VVa (i.e., are listed in §60.489), including ethylene, propylene, “aldehydes” (e.g., acetaldehyde), “cyclo C6” (e.g., cyclohexane), and “cyclo C6 – HCK products” (e.g., cyclohexane and benzene),<sup>46</sup> and other chemicals. However, these chemicals are not considered products, co-products, by-products, or intermediates because they are not isolated for sale or used in another process. Therefore, Subpart VVa does not apply to the fast pyrolysis biorefinery.

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<sup>46</sup> Refer to the specifications of stream IDs 111, 221, 227, and 510 in Appendix A of the design report (Jones et al. 2013).

To determine whether a process makes one of the listed chemicals a product, the product must be sold or used in another process as the listed chemical (see Footnote 40). The process streams described above are just process streams in the same process and are not considered products. Also, the products of the process (i.e., the gasoline and diesel type products) may have one or more of the listed chemicals in the product, but the chemical constituents in these products are not sold or used by another process as the listed chemical or chemicals; they are sold as the collective mixture.

### 3.1.6 NSPS that May Apply to the Emergency Equipment (Area 700)

Although the design report includes the firewater pump and the diesel pump as emergency equipment (Jones et al. 2013, p. 63), it does not specify the size or design of the emergency equipment. Depending on their size and the design of the engine, the firewater pump and diesel pump could be subject to an internal combustion engine NSPS at 40 CFR 60, Subpart IIII. If new equipment is purchased, the internal combustion engines are expected to meet this NSPS. Refer to Table F-2 in Appendix F for details regarding applicability of 40 CFR 60, Subpart IIII.

### 3.1.7 Petroleum Refinery NSPS

Petroleum refineries are defined in 40 CFR 60, Subpart J and 40 CFR 60, Subpart Ja as: "... any facility engaged in producing gasoline, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives." And, the term "petroleum" is defined as "crude oil removed from the earth and the oils derived from tar sands, shale, and coal." Therefore, these rules are not likely applicable to a fast pyrolysis cellulosic biorefinery.

### 3.1.8 Summary of the NSPS that May Apply to the Biorefinery

To summarize, Table 3 lists all NSPS that may be applicable to specific equipment at the fast pyrolysis biorefinery per the design case documented in Jones et al. (2013).

**Table 3. NSPS Potentially Applicable to Certain Equipment at the Fast Pyrolysis Biorefinery**

Design Plant Area	Affected Equipment	Federal Rule	Target Pollutant(s)	Notes Regarding Applicability
Area 700	Gasoline storage tank	Storage tank NSPS, 40 CFR 60, Subpart Kb	VOC	The gasoline storage tank with a capacity of 580,000 gallons would be subject to 40 CFR 60, Subpart Kb based on the design case (Jones et al. 2013).
Area 700	Compression Ignition Internal Combustion Engines	Engine NSPS, 40 CFR 60, Subpart IIII	PM, Non-methane hydrocarbons + NO <sub>x</sub>	The firewater pump and the emergency diesel pump could be subject to an internal combustion engine NSPS at 40 CFR 60, Subpart IIII, depending on the size and design of the engines.

## 3.2 Regulatory Applicability Analysis: Specific NESHAPs that may Apply to the Biorefinery

NESHAP can apply to major sources of HAPs or to certain area sources of HAPs. Major sources of HAP are defined as sources that have PTE greater than 10 tpy of any single HAPs and/or greater than 25 tpy of a combination of HAPs. Area sources are defined as sources that have a PTE less than the major source thresholds of HAPs.<sup>47</sup>

Although biorefinery developers should consider all NESHAPs when planning compliance measures for their facility, the NESHAPs listed below are likely to be all of the NESHAPs that could apply to biorefineries that use a fast pyrolysis process described in Jones et al. (2013).

- National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing (40 CFR 63, Subpart FFFF)<sup>48</sup>
- National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources (40 CFR 63, Subpart VVVVVV)<sup>49</sup>
- National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (40 CFR 63, Subpart DDDDD)<sup>50</sup>
- National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources (40 CFR 63, Subpart JJJJJ)<sup>51</sup>
- National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (40 CFR 63, Subpart ZZZZ)<sup>52</sup>
- National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries (40 CFR 63, Subpart CC)<sup>53</sup>
- National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (40 CFR 63, Subpart UUU).<sup>54</sup>

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<sup>47</sup> The term “area source” is typically the phrasing used in NESHAP; it is synonymous with the phrase “minor source of HAP”.

<sup>48</sup> 40 CFR 63, Subpart FFFF can be found at <http://www.ecfr.gov/cgi-bin/text-idx?SID=eb0d1e29b07dc95135b8bc6314355459&node=40:13.0.1.1.1.13&rgn=div6>.

<sup>49</sup> 40 CFR 63, Subpart VVVVVV can be found at <http://www.ecfr.gov/cgi-bin/text-idx?SID=eb0d1e29b07dc95135b8bc6314355459&node=40:15.0.1.1.1.1.35&rgn=div6>.

<sup>50</sup> 40 CFR 63, Subpart DDDDD can be found at <http://www.ecfr.gov/cgi-bin/text-idx?SID=eb0d1e29b07dc95135b8bc6314355459&node=40:14.0.1.1.1.5&rgn=div6>.

<sup>51</sup> 40 CFR 63, Subpart JJJJJ can be found at <http://www.ecfr.gov/cgi-bin/text-idx?SID=eb0d1e29b07dc95135b8bc6314355459&node=40:15.0.1.1.1.23&rgn=div6>.

<sup>52</sup> 40 CFR 63, Subpart ZZZZ can be found at <http://www.ecfr.gov/cgi-bin/text-idx?SID=d50817ff04a9a3ddd6cd9482f54f3f6&node=40:14.0.1.1.1.1&rgn=div6>.

<sup>53</sup> 40 CFR 63, Subpart CC can be found at <http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr;rgn=div6;view=text;node=40%3A11.0.1.1.1.3;idno=40;sid=d32b1cc8671aec0365154113b9b47d1a;cc=ecfr>.

<sup>54</sup> 40 CFR 63, Subpart UUU can be found at <http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr;sid=f6cb8cf581ea086cd492ef74c2a0a7f3;rgn=div6;view=text;node=40%3A13.0.1.1.1.5;idno=40;cc=ecfr>.

Using the specific information available from the design case (Jones et al. 2013), more specific applicability determinations can be made, as is discussed in Sections 3.2.1 through 3.2.5.

### **3.2.1 NESHAP that may Apply to the Whole Facility**

No NESHAPs are specific to a fast pyrolysis biorefinery process; however, the biorefinery is essentially a chemical processing plant. As such, the biorefinery is subject to one of the following two chemical manufacturing NESHAPs, depending on whether the biorefinery is a major or area source of HAP:

- Miscellaneous Organic Chemical Manufacturing (40 CFR 63, Subpart FFFF), commonly referred to as the “MON”
- NESHAP for Chemical Manufacturing Area Sources (40 CFR 63, Subpart VVVVVV), commonly referred to as “CMAS.”

CMAS applies to area sources of HAP while the MON is applicable to major sources of HAPs. These rules are mutually exclusive, as a facility is classified either major or area based on the expected level of HAP emissions; therefore, the biorefinery would be subject to only one of these rules.

For the MON to be applicable, the biorefinery must be a major source of HAP and fall under the three-digit code North American Industry Classification System (NAICS) 325 or one of the following three-digit Standard Industrial Classification (SIC) codes: 282, 283, 284, 285, 286, 287, 289, or 386. It is likely that the biorefinery will fall under the SIC 286.<sup>55</sup> For the CMAS to be applicable, the biorefinery must be an area source of HAP and make as a byproduct<sup>56</sup> (or use as feedstocks) one of the HAPs listed in Appendix G with a concentration greater than 0.1 weight percent (wt%) in any process vent or liquid stream. The HAP in Table 1 of this rule includes hydrazine, which is used in the hydrogen production process of the fast pyrolysis biorefinery.

MON and CMAS generally have applicability criteria to determine whether an individual emission point is required to be controlled or monitored, or whether only a record of its existence needs to be maintained. For example, the equipment leak provisions in the MON apply only to equipment that are “in organic HAP service,” which is defined as equipment that is in contact with a process stream that contains an individual HAP of at least 5 wt%. Detailed information is needed to identify whether any streams have greater than 5% of an individual HAP. Similarly, information is needed to determine the full applicability for each emission point once the detailed engineering design of a specific biorefinery is available. Refer to Table H-1 in Appendix H for details regarding applicability of NESHAPs (40 CFR 63).

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<sup>55</sup> The SIC for a similar biorefinery that is currently in construction (Carolina Cellulosic Biofuels, LLC in Clinton, North Carolina) is 2869; this was determined by looking at the air permit, which can be obtained at [https://xapps.ncdenr.org/aq/docs/FDOcs\\_Search.jsp](https://xapps.ncdenr.org/aq/docs/FDOcs_Search.jsp). This facility will produce 20 million gallons per year of cellulosic biofuel from locally grown energy crops, agricultural residues, and woody biomass through enzymatic hydrolysis.

<sup>56</sup> CMAS defines “byproduct” as a chemical (liquid, gas, or solid) that is produced coincidentally during the production of the product.

### **3.2.2 NESHAP that may Apply to the Boilers and Process Heaters (Areas 200, 300, and 600)**

Two other NESHAPs could apply to the boilers at the fast pyrolysis biorefinery. NESHAP 40 CFR 63, Subpart DDDDD applies to boilers and process heaters at facilities that are major sources of HAPs. And, 40 CFR 63, Subpart JJJJJ applies to boilers at facilities that are area sources of HAPs. One or the other will likely apply to the fast pyrolysis biorefinery in a mutually exclusive fashion. However, as discussed in Section 3.1.1, the fast pyrolysis biorefinery produces steam via heat integration and does not employ any boilers (Jones et al. 2013).

The fired heater (H-222), fired reboiler (E-3200), and methane reformer (R-600) are likely considered “process heaters” under the 40 CFR 63, Subpart DDDDD. The rule at 40 CFR 63.7575 defines a “process heater” as “an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material (e.g., glycol or a mixture of glycol and water) for use in a process unit instead of generating steam. As defined by Subpart DDDDD, process heaters are devices in which the combustion gases do not come into direct contact with process materials. If the fast pyrolysis biorefinery is determined to be a major source of HAP, the process heaters (H-210, E-3200, and R-600) would be subject to 40 CFR 63, Subpart DDDDD. Because 40 CFR 63, Subpart JJJJJ does not apply to process heaters, the fast pyrolysis biorefinery will not be subject to any boiler or process heater NESHAP if the biorefinery is not a major source of HAP. (See Section 3.1.1 for discussion of why the methane reformer is considered a process heater and not a steam-generating unit.)

### **3.2.3 NESHAPs that may Apply to the Emergency Equipment (Area 700)**

The design case (Jones et al. 2013) includes a firewater pump and a diesel pump as emergency equipment. Depending on their size and design, emergency equipment can be subject to an internal combustion engine NESHAP at 40 CFR 63, Subpart ZZZZ. This regulation applies to engines at both major and area sources of HAPs, but the specific requirements in this rule depend on whether the facility is a major or area source of HAPs. Generally, if new equipment is purchased, the manufacturer of the internal combustion engine will ensure its engines meet this rule. Refer to Table H-2a and Table H-2b in Appendix H for details regarding applicability of 40 CFR 63, Subpart ZZZZ.

### **3.2.4 Petroleum Refinery NESHAP**

Petroleum refineries are defined at 40 CFR 63, Subpart CC and 40 CFR 63, Subpart UUU as:

...an establishment engaged primarily in petroleum refining as defined in the Standard Industrial Classification (SIC) code for petroleum refining (2911) and the North American Industry Classification (NAIC) code 32411, and used mainly for: (1) Producing transportation fuels (such as gasoline, diesel fuels, and jet fuels), heating fuels (such as kerosene, fuel gas distillate, and fuel oils), or lubricants; (2) Separating petroleum; or (3) Separating, cracking, reacting, or reforming an intermediate petroleum stream, or recovering a by-product(s) from the intermediate petroleum stream (e.g., sulfur recovery).

Because the fast pyrolysis biorefinery is expected to fall under SIC 286 (see Footnote 4 in this report), the petroleum NESHAP are not likely applicable to the fast pyrolysis biorefinery.

### 3.2.5 Summary of the NESHAPs that may Apply to the Biorefinery

Table 4 summarizes the specific NESHAP that may be applicable to the fast pyrolysis biorefinery. It is based on our review of the applicability of all NESHAP.

**Table 4. NESHAPs Potentially Applicable to the Fast Pyrolysis Biorefinery**

Design Plant Area	Affected Emission Release Points or Equipment	Federal Rule	Target Pollutants	Notes Regarding Applicability
Areas 100,200,300,500,600, and 700	<b>Emission Release Points:</b> Process vents, transfer operations, equipment leaks, storage tanks, wastewater treatment, heat exchange systems (including cooling towers)	Chemical manufacturing NESHAP, either CMAS (40 CFR 63, Subpart VVVVVV) or MON (40 CFR 63, Subpart FFFF)	HAP	If the fast pyrolysis biorefinery were a major source of HAP, MON would apply.  If the fast pyrolysis biorefinery were an area source of HAP, CMAS would apply.
Areas 200, 300, and 600	<b>Equipment:</b> Process heaters	Boiler and process heater NESHAP, 40 CFR 63, Subpart DDDDD	HAP	Only if the fast pyrolysis biorefinery were a major source of HAP would 40 CFR 63, Subpart DDDDD apply to the process heaters if they meet applicability criteria.
Area 700	<b>Equipment:</b> Emergency equipment (reciprocating internal combustion engines)	Internal combustion engine NESHAP, 40 CFR 63, Subpart ZZZZ	HAP	Depending on the size and design, the firewater pump and emergency diesel pump could be subject to an internal combustion engine NESHAP at 40 CFR 63, Subpart ZZZZ. The specific requirements in this rule depend on whether the facility is an area source or a major source of HAPs.

## 4 Estimation of Potential-to-Emit (PTE) of Regulated Air Pollutant Emissions for the Fast Pyrolysis Biorefinery

When preparing air permit applications and determining regulatory applicability for a planned source, the PTE of each regulated air pollutant from all activities at the source is considered. PTE is used to determine the applicability of many federal (and state) air emission regulations; it is also used during the construction and operating permitting requirements for a planned source. Other factors (e.g., physical and operational limitations, described below) play a role in determining applicability, but PTE must always be considered. PTE usually refers to the PTE of a specific regulated pollutant from the entire source. However, some rules may require PTE for a specific piece of equipment or process line to determine applicability; therefore, it is necessary to determine the PTE for each piece of equipment or process line. A bottom-up emission inventory is expected to be submitted with a permit application, along with documentation of how emissions are estimated.

### 4.1 Definition of PTE

Federal regulations (EPA 1996a)<sup>57</sup> define PTE as:

the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of fuel combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.

By definition, PTE refers to the *greatest* amount of a pollutant that a source can release into the atmosphere. PTE is always larger and is often much larger than a source's actual emissions. The PTE for each pollutant must be determined on a site-specific basis. The definition of PTE has several terms and phrases that can be interpreted in different ways; as a result, significant discussions, controversy, and court cases have led to clarifications of the language over the last several decades. Section 4 provides details on what is meant by maximum capacity to emit, physical or operational design, and enforceable limitations; it includes a discussion of fugitive emissions and how they are counted in PTE calculations.

In most cases, the phrase PTE refers to an annual rate and it is presented in units of tons per year (tpy). This convention is adopted in this analysis as well.

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<sup>57</sup> The term “federally enforceable” refers to all limitations and conditions that are enforceable by the administrator of the EPA including (1) requirements developed pursuant to any NSPS or NESHAP, (2) requirements within any applicable federally approved state implementation plan, and (3) any requirements contained in a permit issued pursuant to federal PSD regulations, or pursuant to PSD or operating permit provisions in a state implementation plan that have been federally approved.



### **4.1.1 Maximum Capacity to Emit**

For each pollutant, PTE estimates the highest possible emissions rate the specific source is capable of emitting. Generally, this means calculating the PTE based on:

1. The maximum capacity at which the equipment is capable of operating—in most cases, this is the equipment’s design capacity.
2. Continuous operations, i.e., 24 hours a day, 365 days a year (8,760 hours per year).
3. *Worst* case emission factor for a given pollutant used for the entire year—for example, if a source burns multiple types of fuel (e.g., biomass and coal) in the boiler, the fuel that emits the most for each pollutant is assumed to be burned year-round (i.e., 8,760 hours per year). If a source uses different raw materials, the PTE of a pollutant is calculated using the raw materials that would result in the greatest amount of emissions of that pollutant.

### **4.1.2 The Physical and Operational Design Factors**

The physical and operational design factors can be taken into account when calculating PTE. For a physical limitation to be taken into account in the calculation of PTE, it must be an unchanging and unavoidable physical constraint. For instance, a boiler may have low NO<sub>x</sub> burners. The burners are part of a boiler’s physical design and result in NO<sub>x</sub> emissions that are lower than would be emitted with conventional burners. Such an inherent physical limitation to pollutant emissions can be taken into account in calculating PTE. Operational factors can also affect the PTE. These factors could include the types of raw materials and fuels used during the operation, whether a unit operation is continuous, and the length of a batch cycle. For example, a source that only burns natural gas in its boiler has a lower PTE for SO<sub>2</sub> than one that also burns oil. A boiler might be physically able to burn oil and natural gas, but if the source has never burned oil and has no oil storage, its PTE likely would be based on just burning the natural gas.

Three general categories of physical and operational design factors are important to be aware of when calculating PTE. These factors are discussed in detail in Sections 4.1.2.1–4.1.2.3:

1. Process designs that have inherent physical limitations or bottlenecks;
2. Non-continuous operations;
3. Controls that are integral to the process.

#### **4.1.2.1 Inherent Physical Limitations or Rate Limiting Processes (“Bottlenecks”)**

Physical limitations on the source’s ability to operate at a maximum rate should be taken into account in PTE calculations. Bottlenecks in process lines are an obvious example of such limitations. For instance, if a fast pyrolysis biorefinery is producing hydrogen on-site to be used for hydrotreating of bio-oil, the biorefinery cannot hydrotreat bio-oil any faster than hydrogen can be produced. In calculating the PTE for hydrotreating, the capacity of the slower process (the on-site hydrogen production, which is a bottleneck in this example) should be taken into account.

#### 4.1.2.2 Non-Continuous Operations

Non-continuous operations present a dilemma in calculating PTE. As discussed above, the PTE is generally calculated based on the maximum design capacity for a facility operated 8,760 hours per year. For non-continuous operation, very high emissions rates could occur in certain hours whereas little or no pollutants are emitted during other hours. When present, non-continuous operations are a type of inherent design limitation. Depending on how a source operates, the source may carry out each step sequentially (i.e., not start the next step until the previous one is completed). This means that not all of a facility's process equipment is operated at all times and some may stand idle at times. The EPA has provided specific guidance on three types of non-continuous operations: emergency generators, grain elevators, and batch chemical production operations (Seitz 1995a, 1995b, and 1996).

#### 4.1.2.3 Controls that are Integral to the Process

A source's PTE is calculated without any consideration of the effect of air pollution control equipment, unless the controls are considered federally enforceable. However, certain operations can employ equipment that can function as an air pollution control device in another configuration. Under these circumstances, the air quality regulations are not the driving force for installing a specific piece of equipment; instead, the equipment is installed as part of the process and would be in place regardless of air pollution reduction concerns. For example, source facilities that have dry solid raw materials, by-products, or products often use pneumatic conveyance to move materials from one place to another. With a pneumatic conveyance system, air is used as a fluid stream to convey the materials. When the material reaches its destination in the plant (e.g., a storage hopper), a baghouse is often used to separate the solids from the air; the solids drop into a hopper or process equipment and the air is released to the atmosphere. If approved by a permitting authority, the baghouse, in this situation, is not considered a control device; rather, it is considered a piece of process equipment and the PTE is calculated based on the collection efficiency of the baghouse. The baghouse used as part of the process is referred to as a "control that is integral to the process." Controls that are integral to the process are considered part of the physical or operational design of the process and can be considered when calculating the source's PTE. However, whether control equipment can be considered an integral part of an emission unit's physical or operational design is determined on a case-by-case basis. It is the source's responsibility to (1) request that control equipment be considered part of the process and (2) submit sufficient information to prove that the control equipment is integral to the process. The criteria used to determine whether a control device is integral to the process is described in an EPA memorandum (Solomon 1995). The criteria include:

- The process cannot operate without the control equipment.
- The control equipment serves a primary purpose other than pollution control.
- The control equipment has an overwhelming positive net economic effect.

### 4.1.3 Enforceable Limitations

There are two main sources of federally enforceable limitations: permit limitations and regulatory provisions. For a permit limit to be federally enforceable and eligible to be treated as part of the process design and counted in PTE calculations, the limit must be included in a permit prepared under an EPA-approved permit program and the limit must be enforceable as a practical matter (Hunt and Seitz 1989; EPA 2014b). For limits to be enforceable as a practical matter, they must be based on a parameter that can be easily monitored or verified (e.g., a limit on operating hours or fuel use). A limit on emissions is generally not considered practically enforceable (unless continuous emission monitoring systems are used) because monitoring compliance is impossible. However, parameters on which emission rates are dependent (e.g., operating hours, type of fuel, amount of fuel, production rate) can often be monitored, and when adequately monitored, they are considered enforceable as a practical matter. Limits are included in a permit in order to make them enforceable. Limitations contained in permits can take many forms (e.g., production limits and operational limits).

NSPS, NESHAP, and state regulations<sup>58</sup> can provide other enforceable limitations that can be factored into PTE calculations, as long as the regulation (or permit) contains the necessary monitoring, recordkeeping, and reporting to ensure the limitations are achieved. These limitations would not be considered “permit limits” because the emission reduction authority would be derived from the NSPS, NESHAP, or state regulations and not from the permitting program itself; the regulatory limitations imposed by NSPS, NESHAP, and state regulations apply even if the source does not have a permit.

### 4.1.4 Fugitive Emissions

Because the fast pyrolysis biorefinery is a chemical process plant (refer to Footnote 9), which is one of the 28 listed source categories (see Appendix C), fugitive emissions from the biorefinery must be included in the PTE calculation. Fugitive emissions are “those emissions that could *not* reasonably pass through a stack, chimney, vent, or other functionally equivalent opening” as defined in federal regulations (40 CFR 70.2). The fugitive emissions definition does not depend on how the emissions are actually released to the environment; it depends on whether collecting the emissions and releasing them through a stack (or similar device) is feasible.

The determination of whether emissions are fugitive can be controversial. If emissions from a given activity can be collected and passed through a stack at another location even though the source in question does not collect the emissions, the emissions are unlikely ever to be considered fugitive. For example, NSPS requires that landfill gas be collected and controlled. Even if a landfill is not subject to the NSPS and does not collect landfill gas, the emissions of landfill gas would not be considered fugitive because collecting and venting the emissions is standard practice. Therefore, they do not meet the definition of fugitive. However, the emissions then would be considered uncontrolled and count toward the landfill’s PTE.

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<sup>58</sup> State regulations are only federally enforceable if they are part of the state’s approved implementation plan. A state regulation that is not in the approved state implementation plan can also become federally enforceable for a specific facility if it is included in a federally enforceable permit.

## 4.2 General Approach to Estimation of PTE

In calculating PTE, both technical and federally enforceable limitations must be considered. Technical factors include (1) using the best emissions data, which reflects the design of the process to estimate the maximum emissions as accurately as possible, and (2) evaluating physical and operational design factors and making proper judgments regarding whether the process has a bottleneck or controls that are integral to the process. Federally enforceable limitations include (1) any emission limitations specified in NSPS, NESHAP, or state regulations that can be considered federally enforceable and (2) permit limits, which are requested by a source and are established in a permit.

For example, the source can consider taking a limit based on the production rate or amount of fuel used, or it can decide to install a control device to meet the limit it will be requesting. Before a source requests federally enforceable avoidance limits, the source needs to make sure that it can operate within the avoidance limits at all times. For instance, a limit on the production rate would not be appropriate for a source that expects to operate at or near its maximum capacity year-round. A control device can be added, but the additional costs of installing a control device to avoid the applicability of a specific rule or a type of permit might not be economically justified. Also, based on how the source will be limited, the permitting authority will include monitoring, recordkeeping, and reporting requirements in the permit that ensure continuous compliance with the permit limits. In addition, the source must consider which emission units are best to be limited in its operation because likely not all emission units will need to have emissions limited for the source to avoid a regulation or permit type. The source must contemplate all of these issues when calculating its PTE and developing its permitting strategy.

Because the determination of PTE involves various policy and regulatory factors and decisions, as well as emission calculations, the source often presents two sets of values for PTE representing the different stages in the process of developing, reviewing, and refining PTE. Therefore, we mimic this process in this analysis. We first estimate “uncontrolled PTE” to represent the maximum capacity to emit, accounting for physical and operational limitations; then, we estimate “PTE” to refer to the value, as defined, to include federally enforceable limitations from NSPS, NESHAP, and any avoidance limitations the fast pyrolysis biorefinery may want to request be included in a permit.

## 4.3 Development of Preliminary Uncontrolled PTE for the Fast Pyrolysis Biorefinery

In this section, we estimate uncontrolled PTE for the regulated air pollutants identified in Table 2 for the fast pyrolysis biorefinery in Sections 4.3.1–4.3.14, where technical factors for calculating uncontrolled PTE are discussed in “Maximum Capacity to Emit and Physical/Operational Limitations” and regulatory and permit limits for calculating PTE values are discussed in “Federally Enforceable Limitations.” However, to complete the permitting strategy and the facility’s permitting plan, emissions from the entire source need to be considered. Therefore, federally enforceable limits and preliminary PTE values are discussed in detail in Section 5.

When a permitting authority reviews the emission calculations that a source presents in its permit application, the permitting authority tries to determine whether the best emission factors and emission estimation methodologies are being used, given the type of operation being permitted.

In general, results from stack testing from the same or very similar operation are the most preferred data to be used for calculating emissions factors. If such data are not available, emission factors from EPA's Compilation of Air Pollutant Emission Factors,<sup>59</sup> referred to as AP-42 (EPA 2015), are well accepted among permitting authorities. If emissions data are not available for a specific process, an engineering calculation, information based on a similar source, or a very conservative assumption can be used. The permitting authority wants to ensure the PTE is calculated for a worst-case scenario. If the permitting authority is uncertain about any of the methods used to calculate emissions, it may require a different method to be used and will likely require an emission stack test once the facility is constructed.

#### **4.3.1 Area 100 – Biomass Feedstock Transfer and Storage Operations, Dryer and Sand Heater, Ash and Sand Handling Operations**

##### *Maximum Capacity to Emit and Physical/Operational Limitations*

Emissions from the biomass feedstock transfer and storage operations, sand heater (R-124), ash and sand handling operations, and dryer (C-101) in Area 100 are added together when determining the uncontrolled PTE of the dryer because all of the emissions from these operations are released through the dryer (C-101) vent when control devices are not considered.

There is no detailed description about the biomass feedstock transfer and storage operations in the design report (Jones et al. 2013). Based on the process flow diagram for Area 100 in the design report (p.47), a conveyor is used to transfer the wet biomass from the storage area to the dryer. It is assumed that the biomass transfer and storage operations are completely enclosed such that the only vent to the atmosphere from these operations is through the dryer.

Per the design report (Jones et al. 2013, p.48), the exhaust from the sand heater contains SO<sub>2</sub>, NO<sub>x</sub>, and CO<sub>2</sub>, which are vented to the atmosphere through the dryer. We use the flow rates of SO<sub>2</sub>, NO<sub>x</sub>, and CO<sub>2</sub> in the design case to estimate SO<sub>2</sub>, NO<sub>x</sub>, and CO<sub>2</sub> emissions. Because no emission control is currently used in the design report to reduce SO<sub>2</sub>, NO<sub>x</sub>, and CO<sub>2</sub>, the estimated emissions reflect the uncontrolled PTE of these air pollutants. Refer to the worksheet titled, "Area 100 Dryer and Sand Heater" in Appendix I for calculations.

The design report (Jones et al. 2013) includes a baghouse to reduce sand and ash (considered PM) from the exhaust of the sand heater, which is then fed to the dryer. The spent ash and sand from the sand heater are collected by the baghouse and sent to an ash cooler, which uses quench water to reduce PM emissions. The ash is eventually disposed. To estimate uncontrolled PM from the sand heater, it is assumed that the baghouse is not used. Based on information in the design report (Jones et al. 2013, p.48), the flow rate of PM (i.e., sand and ash) entering the baghouse is estimated at 1,975 pounds per hour (lb/hr). Without using the baghouse filter, the same input flow rate of PM is expected into the dryer. PM<sub>10</sub> and PM<sub>2.5</sub> are estimated to be 50% and 14.6% of PM respectively, based on the methodology developed by the South Coast Air Quality Management District (2006a). Because we assumed the baghouse is not used when estimating uncontrolled PM from the sand heater, there are no ash and sand handling operations (i.e., all PM emissions from the sand heater would be routed to the dryer instead of going

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<sup>59</sup> "AP-42: Compilation of Air Emission Factors," EPA, last updated September 27, 2016, <https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emission-factors>.

through the baghouse). Refer to the worksheet titled, “Area 100 Dryer and Sand Heater” in Appendix I for calculations.

The dryer is used to reduce the moisture content of the incoming biomass feedstock from 30% (by weight, as received) to 10%. Based on the design report (Jones et al. 2013), the dryer does not burn any fuel, but it uses hot flue gas exhaust from the sand heater (R-124) in Area 100, which is fed to the dryer at 584°F to remove moisture from the feedstock. The feedstock drying process is expected to generate PM, VOC, and HAP emissions, which would be vented to the air from the dryer. We estimate PM, PM<sub>10</sub>, PM<sub>2.5</sub>, VOC, and HAP (formaldehyde and methanol) emissions based on annual woody biomass throughput in the design report (Jones et al. 2013) and the emissions factors (in lb/ovendried ton or lb/ODT) EPA developed for softwood drying in a rotary dryer commonly used in particleboard manufacturing facilities (EPA 2002, Chapter 10) (Eq. 1). Refer to the worksheet titled, “Area 100 Dryer and Sand Heater” in Appendix I for calculations.

$$Uncontrolled\ PTE\ (tpy) = Throughput\ \left(\frac{lb}{hr}\right) * \frac{1}{2000}\ \left(\frac{tons}{lb}\right) * EF\ \left(\frac{lb}{ODT}\right) * \frac{1}{2000}\ (tons/lb) * 8760\ \left(\frac{hrs}{yr}\right) \quad -\ Eq.\ 1$$

Where:

*Uncontrolled PTE* = the maximum capacity to emit, accounting for operational and design factors but without federally enforceable limitations included (tpy)

*Throughput* = wood throughput, mass flow rate of the wood material out from the dryer

*EF* = emission factor

*ODT* = oven-dried ton

Table 5 shows the uncontrolled PTE of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, SO<sub>2</sub>, VOC, HAP, and GHG emissions from the dryer and sand heater, which includes biomass feedstock transfer and storage operations, dryer and sand heater, and ash and sand handling operations in Area 100. Refer to the worksheet titled, “Area 100 Dryer and Sand Heater” in Appendix I for calculations.

**Table 5. Preliminary Estimates of Uncontrolled PTE of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, SO<sub>2</sub>, VOC, HAP, and GHGs from the Dryer and Sand Heater in Area 100**

Pollutant	Uncontrolled PTE (tpy)
PM	8,800
PM <sub>10</sub>	4,400
PM <sub>2.5</sub>	1,300
SO <sub>2</sub>	440
NO <sub>x</sub>	4.4
VOC	120

Pollutant	Uncontrolled PTE (tpy)
GHGs (CO <sub>2</sub> equivalent)	390,000
HAP (Total) <sup>a</sup>	30

<sup>a</sup> Refer to the worksheet titled, “Uncontrolled PTE Summary (HAP)” in Appendix I for PTE of individual HAP.

### *Federally Enforceable Limitations*

In order to include the emission reductions from the use of the baghouse in calculating the PTE, the baghouse must be federally enforceable. As discussed previously, federally enforceable limitations either are from federal regulations or are established in air permits. Most states have PM regulations; however, they often do not include the monitoring or associated recordkeeping and reporting requirements to ensure continuous compliance with the regulation; therefore, these state PM regulations are not considered practicably enforceable. If a regulation is not practicably enforceable, it cannot be considered federally enforceable. In developing the air permit, the permitting authority will include the monitoring requirements necessary to ensure that the baghouse performs as expected (e.g., monitoring pressure drop hourly) and meets the state regulation, thereby making the regulations practicably enforceable and thus federally enforceable.

As shown in Table 4, one of the chemical manufacturing NESHAP would apply to the fast pyrolysis biorefinery, depending on whether the biorefinery is a major source or an area source of HAP. The NESHAP could have HAP emission reduction requirement for process vents (e.g., from the dryer) if the process vents meet the applicability criteria specified in the rule. The overall permitting strategy is discussed in detail in Section 5.

#### **4.3.2 Area 100 – Fast Pyrolysis Reactor**

##### *Maximum Capacity to Emit and Physical/Operational Limitations*

The design report indicates that most of the exhaust from the fast pyrolysis reactor (R-110) in Area 100 is recycled back to the pyrolysis reactor to assist fluidization (not for combustion) (Jones et al. 2013, p. 9). A portion of the exhaust (off-gas) is burned in the sand heater in Area 100 to heat the circulating sand. The remaining gas is sent to the methane reformer in Area 600 to be used for hydrogen production. The emissions from the pyrolysis reactor are the emissions after the gas is combusted in the sand heater and methane reformer. There is no emission vent stream from the fast pyrolysis reactor in the design case.

It is assumed that the use of the pyrolysis reactor gas as fuel in the sand heater and methane reformer is considered integral to the process. In other words, the sand heater and methane reformer would not be considered control devices for the fast pyrolysis reactor. This assumption is reasonably supported because the non-condensable off-gas from the pyrolysis reactor can provide an economic benefit (i.e., used as a fuel) to the facility. This configuration at the fast pyrolysis biorefinery is similar to a fuel gas system at chemical and refinery operations, where exhaust gas with meaningful heating value is collected and used by multiple combustion units onsite. In NESHAP that regulate chemical and refinery operations, the fuel gas system is considered a part of the process, which provides a precedent for considering the fuel gas system

an integral part of the process for the fast pyrolysis biorefinery. Refer to the worksheet titled, “Area 100 Pyrolysis Reactor” in Appendix I for details.

#### *Federally Enforceable Limitations*

Whether the permitting authorities consider this fuel gas system integral to the process or they view it as emission control with respect to pyrolysis reactor exhaust, the biorefinery can request that the final permit have conditions that specify that the pyrolysis reactor exhaust must be combusted in the sand heater, the methane reformer, or both, which would make it federally enforceable. The overall permitting strategy is discussed in detail in Section 5.

### **4.3.3 Area 200 – Hydrotreating Reactors**

#### *Maximum Capacity to Emit and Physical/Operational Limitations*

The design case indicates that exhaust (off-gas) from the first- and second-stage hydrotreating reactors (R-220 and R-225) in Area 200 is collected by the fuel gas system and is routed to the methane reformer in Area 600 (Jones et al. 2013). It is assumed that the methane reformer would not be considered a control device for the hydrotreating reactor exhaust because the hydrotreating reactor exhaust has meaningful heating value and can be used as a fuel, which provides an economic benefit to the facility.

Dimethyl sulfide is used to maintain the hydrotreating catalyst in a sulfide state (Jones et al. 2013). As a result, H<sub>2</sub>S is produced, and it ends up in the off-gases from the hydrotreating reactors. A part of the off-gas is reformed to produce hydrogen in the methane reformer. To avoid poisoning the catalyst in the methane reformer, H<sub>2</sub>S is removed from the off-gas using a zinc oxide bed. For the remaining off-gas used as a fuel for the methane reformer burners, H<sub>2</sub>S present in the off-gas is eventually released to the atmosphere through the methane reformer burner exhaust.

Emissions from the hydrotreating reactors are reflected in the emissions for the methane reformer (Area 600). Refer to the worksheet titled, “Area 200 Hydrotreating Reactors” in Appendix I for details.

#### *Federally Enforceable Limitations*

Whether the permitting authorities consider this fuel gas system integral to the process or view it as emission control with respect to hydrotreating reactor exhaust, the biorefinery can request that the final permit have conditions that specify that the hydrotreating reactor exhaust must be combusted in the methane reformer, which would make it federally enforceable. The overall permitting strategy is discussed in detail in Section 5.

### **4.3.4 Areas 200 and 300 – Distillation Columns**

#### *Maximum Capacity to Emit and Physical/Operational Limitations*

##### Area 200 - Distillation Column (T-290)

The design case indicates that the gas components from the distillation column (T-290) in Area 200 are collected by the fuel gas system and are sent to the fired reboiler (E-3200) in Area 300 and methane reformer (R-600) in Area 600 (Jones et al. 2013). It is assumed that the fired-



reboiler and the methane reformer would not be considered control devices for the distillation column because the exhaust from the distillation column has meaningful heating value and can be used as a fuel. Refer to the worksheet titled, “Area 200, 300 Distillation” in Appendix I for details.

#### Area 300 - Distillation Column (T-310, T-320)

The heavy fractions from the distillation column in Area 200 are fractionated into gasoline blendstock, diesel blendstock, and heavies by two distillation columns in Area 300, which are referred to as the naphtha splitter (T-310) and the diesel splitter (T-320) in the design case (Jones et al. 2013, p. 53). No exhaust is expected to be emitted from these two distillation columns based on the process flow diagram in the design case. The heavy fraction from the diesel splitter is sent to hydrocracking reactor (Area 500) to be catalytically cracked into additional fuels. Refer to worksheet titled, “Area 200, 300 Distillation” in Appendix I for details.

#### *Federally Enforceable Limitations*

Whether the permitting authorities consider this fuel gas system integral to the process or view it as emission control with respect to distillation column exhaust, the biorefinery can request that the final permit have conditions that specify that the exhaust from the distillation columns must be combusted in the fired reboiler, methane reformer, or both, which would make it federally enforceable. The overall permitting strategy is discussed in detail in Section 5.

#### **4.3.5 Area 200 – Fired Heater**

##### *Maximum Capacity to Emit and Physical/Operational Limitations*

As indicated by the process flow diagram in the design report (Jones et al. 2013, p.50), a fired heater (H-222) in Area 200 is used to heat the makeup sulfide agent, which is sent to the hydrotreating reactor. The fired heater has a heat capacity of 8.62 MMBtu/hr, and it uses the off-gas from the fuel gas system, which contains CH<sub>4</sub>, ethane, and propane among other compositions (refer to Stream 223 in Jones et al. 2013).

The fired heater is expected to emit products of combustion, including PM, PM<sub>10</sub>, PM<sub>2.5</sub>, SO<sub>2</sub>, NO<sub>x</sub>, CO, VOC, HAP, and GHG emissions (CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub>). Given that the compositions of the fuel used in the fired heater are similar to those of natural gas, the uncontrolled emission factors developed by EPA for natural gas combustion are used in this calculation (EPA 1998, Chapter 1.4). Uncontrolled PTE of air pollutants from the combustion is calculated using Eq. 2, and is summarized in Table 6. Refer to the worksheet titled, “Area 200 Fired Heater” in Appendix I for detailed calculations.

$$\text{Uncontrolled PTE (tpy)} = \text{HeatInput Capacity} \left( \frac{\text{MMBtu}}{\text{hr}} \right) * EF \left( \frac{\text{lb}}{\text{MMBtu}} \right) * \frac{1}{2000} \left( \frac{\text{tons}}{\text{lb}} \right) * 8760 \left( \frac{\text{hrs}}{\text{yr}} \right) \quad \text{- Eq. 2}$$

**Table 6. Preliminary Estimates of Uncontrolled PTE of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, SO<sub>2</sub>, CO, VOC, HAP, and GHGs from the Fired Heater in Area 200**

Pollutant	Uncontrolled PTE (tpy)
PM <sup>a</sup>	7.0×10 <sup>-2</sup>
PM <sub>10</sub> /PM <sub>2.5</sub> <sup>a</sup>	2.8×10 <sup>-1</sup>
SO <sub>2</sub>	2.0×10 <sup>-2</sup>
NO <sub>x</sub>	6.1
CO	3.1
VOC	2.0×10 <sup>-1</sup>
GHG (CO <sub>2</sub> equivalent)	4500
HAP (total) <sup>b</sup>	7.0×10 <sup>-2</sup>

<sup>a</sup> PM is regulated as filterable PM, while PM<sub>10</sub> and PM<sub>2.5</sub> are regulated as the total of filterable PM in the size fraction (i.e., PM<sub>10</sub> or PM<sub>2.5</sub>) and condensable PM. Specifically, PM is regulated as measured using EPA Method 5, which measures only filterable PM. PM<sub>10</sub> and PM<sub>2.5</sub> are regulated as measured using EPA Method 201A, which measures the filterable PM at the size fraction, and Method 202, which measures condensable PM. All condensable PM is included in the PM<sub>2.5</sub> and PM<sub>10</sub> size fractions.

<sup>b</sup> Refer to the worksheet titled, “Uncontrolled PTE Summary (HAP)” in Appendix I for PTE of individual HAP.

### Federally Enforceable Limitations

Only if the fast pyrolysis biorefinery is a major source of HAP and it meets the applicability criteria, the fired heater could be subject to NESHAP Subpart DDDDD. NESHAP Subpart DDDDD limits emissions of CO, filterable PM, hydrogen chloride, and mercury. On the other hand, if the fast pyrolysis is an area source of HAP, no specific regulation is expected to be applicable to the fired heater. The overall permitting strategy is discussed in detail in Section 5.

### 4.3.6 Area 300 – Fired Reboiler

#### Maximum Capacity to Emit and Physical/Operational Limitations

The design report indicates that a fired reboiler (E-3200) in Area 300 is used to heat the liquid effluent from the diesel splitter (T-320) distillation column (Jones et al. 2013). The heated liquid is then sent back to the distillation column to increase product yields. The fired reboiler uses off-gas from the fuel gas system as fuel. The fired reboiler is designed to have a heat capacity of 14 MMBtu/hr.

The fired reboiler is expected to emit products of combustion, including PM, PM<sub>10</sub>, PM<sub>2.5</sub>, SO<sub>2</sub>, NO<sub>x</sub>, CO, VOC, HAP, and GHG emissions (CO<sub>2</sub>, N<sub>2</sub>O, and CH<sub>4</sub>). Given that the fuel

compositions of the off-gas combusted in the fired reboiler are similar to those of natural gas, the uncontrolled emission factors developed by EPA for natural gas combustion are used in the calculation (EPA 1998, Chapter 1.4). Uncontrolled PTE of air pollutants from the combustion is calculated using Eq. 3 and is summarized in Table 7. Refer to the worksheet titled, “Area 300 Fired Reboiler” in Appendix I for detailed calculations.

$$\text{Uncontrolled PTE (tpy)} = \text{Heat Input Capacity} \left( \frac{\text{MMBtu}}{\text{hr}} \right) * EF \left( \frac{\text{lb}}{\text{MMBtu}} \right) * \frac{1}{2000} \left( \frac{\text{tons}}{\text{lb}} \right) * 8760 \left( \frac{\text{hrs}}{\text{yr}} \right) \quad \text{- Eq. 3}$$

**Table 7. Preliminary Estimates of Uncontrolled PTE of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, SO<sub>2</sub>, CO, VOC, HAP, and GHG Emissions from the Fired Reboiler in Area 300.**

Pollutant	Uncontrolled PTE (tpy)
PM <sup>a</sup>	1.1×10 <sup>-1</sup>
PM <sub>10</sub> /PM <sub>2.5</sub> <sup>a</sup>	4.6×10 <sup>-1</sup>
SO <sub>2</sub>	4.0×10 <sup>-2</sup>
NO <sub>x</sub>	6.0
CO	5.1
VOC	3.3×10 <sup>-1</sup>
GHGs (CO <sub>2</sub> equivalent)	7300
HAP (total) <sup>b</sup>	1.1×10 <sup>-1</sup>

<sup>a</sup> PM is regulated as filterable PM, while PM<sub>10</sub> and PM<sub>2.5</sub> are regulated as the total of filterable PM in the size fraction (i.e., PM<sub>10</sub> or PM<sub>2.5</sub>) and condensable PM. Specifically, PM is regulated as measured using EPA Method 5, which measures only filterable PM. PM<sub>10</sub> and PM<sub>2.5</sub> are regulated as measured using EPA Method 201A, which measures the filterable PM at the size fraction, and Method 202, which measures condensable PM. All condensable PM is included in the PM<sub>2.5</sub> and PM<sub>10</sub> size fractions.

<sup>b</sup> Refer to the worksheet titled, “Uncontrolled PTE Summary (HAP)” in Appendix I for PTE of individual HAP.

### Federally Enforceable Limitations

If the fast pyrolysis biorefinery is a major source of HAP, the fired reboiler could be subject to NESHAP Subpart DDDDD if it meets the applicability criteria. The NESHAP Subpart DDDDD limits emissions of CO, filterable PM, hydrogen chloride, and mercury. On the other hand, if the fast pyrolysis is an area source of HAP, no specific regulation is expected to be applicable to the fired reboiler. The overall permitting strategy is discussed in detail in Section 5.

### 4.3.7 Area 500 – Hydrocracking Reactor

#### Maximum Capacity to Emit and Physical/Operational Limitations

The heavy fraction from the diesel splitter (Area 300) is catalytically cracked into additional fuels by a hydrocracking reactor (R-510) in Area 500. The product from the hydrocracking reactor is a mixture of liquid spanning the gasoline and diesel range, along with some off-gas.

The off-gas from the hydrocracker is recovered and utilized in the methane reformer (Area 600) and fired reboiler (Area 300). It is assumed that the methane reformer and the fired reboiler would not be considered control devices for the hydrocracking reactor. As discussed earlier, this assumption is reasonably supported because the exhaust from the hydrocracking reactor has meaningful heating value and it can be used as a fuel, which provides an economic benefit to the facility. Refer to the worksheet titled, “Area 500 Hydrocracking Reactor” In Appendix I for details.

### *Federally Enforceable Limitations*

Whether the permitting authorities consider this fuel gas system integral to the process or view it as emission control with respect to distillation column exhaust, the source can request that the final permit have conditions that specify that the hydrocracking reactor exhaust must be combusted in the fired reboiler, methane reformer, or both, which would make it federally enforceable. The overall permitting strategy is discussed in detail in Section 5.

### **4.3.8 Area 600 – Methane Reformer**

#### *Maximum Capacity to Emit and Physical/Operational Limitations*

The fast pyrolysis biorefinery uses a methane reformer (R-600) in Area 600 to produce hydrogen required for hydrotreating and hydrocracking operations by steam reforming natural gas and off-gas generated from the fast pyrolysis reactor and hydrotreating reactors (Jones et al. 2013). Because steam reforming is endothermic, heat must be supplied to the process for the reaction to proceed. A combination of off-gases from several sources, including the second hydrotreating reactor in Area 200, a hydrocracker in Area 500, and a pyrolysis reactor in Area 100. Unreformed gas recycled back from the methane reformer is used as a fuel by the methane reformer burners. The methane reformer burners have a total combined heat capacity of 160.9 MMBtu/hr.

The burners in the methane reformer are expected to emit products of combustion, including PM, PM<sub>10</sub>, PM<sub>2.5</sub>, SO<sub>2</sub>, NO<sub>x</sub>, CO, VOC, HAP, and GHG. Given that the fuel compositions are similar to those of natural gas, the uncontrolled emission factors developed by EPA for natural gas combustion are used in the calculation (EPA 1998, Chapter 1.4). Uncontrolled PTE of air pollutants from the combustion is calculated using Eq. 4.

$$\text{Uncontrolled PTE (tpy)} = \text{Heat Input Capacity} \left( \frac{\text{MMBtu}}{\text{hr}} \right) * EF \left( \frac{\text{lb}}{\text{MMBtu}} \right) * \frac{1}{2000} \left( \frac{\text{tons}}{\text{lb}} \right) * 8760 \left( \frac{\text{hrs}}{\text{yr}} \right) \quad \text{- Eq. 4}$$

In addition to producing combustion emissions, steam reforming is expected to generate CO<sub>2</sub>. Based on the design case (Jones et al. 2013, p.57), the total CO<sub>2</sub> emissions (including combustion and non-combustion sources) are generated at a rate of 110,000 lb/hr from the methane reformer (Stream 630).

Table 8 summarizes the preliminary estimates of uncontrolled PTE of criteria air pollutant emissions, and GHG and HAP emissions from the methane reformer in Area 600. Refer to the worksheet titled, “Area 600 CH4Reformer” in Appendix I for detailed calculations.

**Table 8. Preliminary Estimates of Uncontrolled PTE of PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, SO<sub>2</sub>, CO, VOC, HAP, and GHGs from the Methane Reformer in Area 600**

Pollutant	Uncontrolled PTE (tpy)
PM <sup>a</sup>	1.3
PM <sub>10</sub> /PM <sub>2.5</sub> <sup>a</sup>	5.3
SO <sub>2</sub>	25
NO <sub>x</sub>	130
CO	58
VOC	3.8
GHG (CO <sub>2</sub> equivalent)	490,000
HAP (total) <sup>b</sup>	1.3

<sup>a</sup> PM is regulated as filterable PM, while PM<sub>10</sub> and PM<sub>2.5</sub> are regulated as the total of filterable PM in the size fraction (i.e., PM<sub>10</sub> or PM<sub>2.5</sub>) and condensable PM. Specifically, PM is regulated as measured using EPA Method 5, which measures only filterable PM. PM<sub>10</sub> and PM<sub>2.5</sub> are regulated as measured using EPA Method 201A, which measures the filterable PM at the size fraction, and Method 202, which measures condensable PM. All condensable PM is included in the PM<sub>2.5</sub> and PM<sub>10</sub> size fractions.

<sup>b</sup> Refer to the worksheet titled, “Uncontrolled PTE Summary (HAP)” in Appendix I for PTE of each individual HAP.

### *Federally Enforceable Limitations*

There are currently no known regulations that are applicable to the methane reformer. The design case (Jones et al. 2013) currently does not incorporate any emission controls to mitigate these emissions from the methane reformer burners. Thus, the PTE is expected to be identical to the uncontrolled PTE. Given the magnitude of the uncontrolled NO<sub>x</sub> PTE from the methane reformer, as shown in Table 8, further emission reductions may be necessary to meet BACT requirements under PSD. The overall permitting strategy is discussed in detail in Section 5.

### **4.3.9 Area 700 – Wastewater Treatment Plant**

#### *Maximum Capacity to Emit and Physical/Operational Limitations*

Wastewater from various parts of the facility is sent to the wastewater treatment plant (WWTP). A portion of the VOC and HAP produced in these areas would be expected to be in the wastewater sent to the WWTP and would likely have an opportunity to either (1) be released from the wastewater either as fugitive emissions (i.e., when wastewater is open to the atmosphere and/or wastewater vapors leak through sewers, drains, or other equipment in the WWTP) or (2) be vented from treatment process equipment. Other air pollutant emissions (e.g., NO<sub>x</sub>) could be emitted from the WWTP. However, sufficient information is not available in the design case (Jones et al. 2013) to determine exactly which air pollutants would be emitted.

Typically, a software program could be used to estimate air emissions from wastewater collection (e.g., INTERCEPTOR, TOXCHEM, or WATER9). These software programs use site-specific wastewater characteristics, contaminant properties, and the process design and operating information to estimate VOC and HAP emission rates.

The WWTP has an aerobic digester that releases CO<sub>2</sub>; however, information is not available in the design report to determine the amount of CO<sub>2</sub> that would be released to the atmosphere.

Based on limited information in the design case (Jones et al. 2013, p.50), Streams 281 and 282 are sent to the WWTP. Using the composition of these two streams, we assume 0.1% of VOC in the wastewater does not remain entrained in the wastewater and it is emitted to the air. Similarly, we assume 0.1% of HAP in Streams 281 and 282 would be emitted to air.

Table 9 summarizes the preliminary estimates of uncontrolled PTE for VOC and HAP emissions from the WWTP in Area 700. Refer to the worksheet titled, “Area 700 WWTP” in Appendix I for detailed calculations.

**Table 9. Preliminary Estimates of Uncontrolled PTE of VOC and HAP from WWTP in Area 700**

Pollutant	Uncontrolled PTE (tpy)
VOC	3.0×10 <sup>-1</sup>
HAP	1.2×10 <sup>-1</sup>

### *Federally Enforceable Limitations*

Depending on whether (1) the facility is a major or area source of HAP and (2) the wastewater streams meet applicability criteria, the emissions from the wastewater streams could be subject to one of two NESHAP, either the MON (40 CFR 63, Subpart FFFF) or the CMAS (40 CFR 63, Subpart VVVVVV). There could be enforceable requirements and/or limitations applicable to the WWTP, which will require the uncontrolled emissions to be reduced if the wastewater streams meet the applicability criteria specified in the rule. The overall permitting strategy is discussed in detail in Section 5.

### **4.3.10 Area 700 – Storage Tanks**

#### *Maximum Capacity to Emit and Physical/Operational Limitations*

The design case (Jones et al. 2013) includes tanks for storing the gasoline and diesel blendstock products as well as process chemicals. The only tanks that would be expected to emit regulated pollutants (i.e., VOC and HAP) are the product tanks.

EPA’s TANKS emissions software (Version 4.09d) is used to estimate VOC emissions from the gasoline and diesel blendstock products storage tanks (EPA 2006a). TANKS uses chemical, meteorological, roof fitting, and rim seal data to generate emissions estimates for several types of storage tanks, including vertical and horizontal fixed roof tanks, internal and external floating roof tanks, domed external floating roof tanks and underground tanks (EPA 2006b). The emissions, referred to as standing losses, are estimated by TANKS are caused by diurnal temperature changes, which in turn result in changes in the vapor pressure of the liquid. These emissions would be released through rim seal losses, deck fitting losses, and deck seam losses. Emissions are also created because tanks are being filled with liquid. As new materials are added to a tank, saturated vapor from the headspace of the tank is forced out into the atmosphere. These emissions, estimated by TANKS, are referred to as working losses.

The capacity of the gasoline blendstock storage tank is about 580,000 gallons, and the capacity of the diesel blendstock storage tank is about 530,000 gallons. Based on the maximum throughput of the biorefinery and the storage tank capacities, the turnovers (i.e., estimated number of times per year the tank is emptied and refilled) are estimated to be about 50 and 60 per year for the gasoline and diesel blendstock tanks respectively. The emissions are a function of location-specific meteorological data, and we assume the biorefinery will be located in Dodge City, Kansas. We also assume the gasoline blendstock storage tank uses an internal floating roof tank with a diameter of 67 feet and a height of 30 feet. The true vapor pressure of gasoline and diesel is assumed to be the same as that of conventional gasoline (RVP 9) and No.2 diesel respectively (6.39 psia for gasoline and 0.011 psia for diesel, at 77°F based on the TANKS model [EPA 2006a]). The internal floating roof is considered a specific design feature of the gasoline blendstock tank (i.e., integral to the tank). We did not assume the diesel blendstock would have an internal floating roof because this design feature is typically not used for storing a liquid (such as the diesel blendstock) with such low vapor pressure.

The design case (Jones et al. 2013) does not provide detailed information on the fuel properties or compositions of gasoline and diesel blendstocks. To run the TANKS model, we assume the fuel properties of gasoline and diesel blendstocks produced in the fast pyrolysis biorefinery are the same as those of petroleum gasoline and diesel products. We also assume the HAP components in the gasoline and diesel blendstocks from the fast pyrolysis biorefinery are the same as those in conventional petroleum and diesel products (RTI International 2011).

Table 10 summarizes the preliminary estimates of uncontrolled PTE for VOC and HAP emissions from gasoline and diesel blendstock storage tanks in Area 700. Refer to the worksheet titled, “Area 700 Tanks” in Appendix I for detailed calculations.

**Table 10. Preliminary Estimates of Uncontrolled PTE of VOC and HAP from Storage Tanks in Area 700**

Pollutant	Uncontrolled PTE (tpy)
VOC	1.3
HAP	2.6×10 <sup>-1</sup>

### *Federally Enforceable Limitations*

The gasoline storage tank is expected to be subject to NSPS Subpart Kb (see Table 3). Depending on whether (1) the facility is a major or area source of HAP and (2) the storage tanks meet applicability criteria, the gasoline storage tank may also be subject to control under one of two NESHAP: the MON (40 CFR 63, Subpart FFFF) or CMAS (40 CFR 63, Subpart VVVVVV). Therefore, federally enforceable limitations and requirements likely could apply to the storage tanks. The overall permitting strategy is discussed in detail in Section 5.

The control requirements under the two NESHAP (Subparts FFFF and VVVVVV) are essentially the same; however, the NESHAP have somewhat more stringent requirements than NSPS Subpart Kb for fitting controls on floating roof tanks.

### 4.3.11 Area 700 – Loading Operations

#### Maximum Capacity to Emit and Physical/Operational Limitations

Although the design case (Jones et al. 2013) does not specify product loading operations, a fast pyrolysis biorefinery would need equipment for loading gasoline and diesel blendstocks into tank trucks or railcars, as other biofuel facilities do (e.g., refer to WLA Consulting 2011). Loading operations at the fast pyrolysis biorefinery are expected to emit VOC and HAP emissions.

We estimate a VOC emission factor for truck and railroad loading by using Eq. 5 (EPA 1995a, Chapter 5).

$$L = 12.46 * \frac{SPM}{T} \quad \text{- Eq. 5}$$

Where:

$L$  = emission factor for loading loss (pounds per thousand gallons [lb/kgal] of liquid loaded)

$S$  = a saturation factor (see AP-42, Table 5.2-1)

$P$  = true vapor pressure of the liquid loaded (psia)

$M$  = molecular weight of vapors

$T$  = temperature of the bulk liquid loaded (degree R = degree F+460).

The values for  $P$ ,  $M$ , and  $T$  are identical for a given liquid regardless of the type of loading operations. However, the value for  $S$  varies depending on (1) the type of operation used (termed as service) (e.g., dedicated normal service, dedicated vapor balance service, and clean cargo service) (EPA 1995a, Chapter 5) and (2) whether the loading operation uses a submerged or splash loading technique. The emission factor for loading loss is calculated for six possible combinations of service and loading technique:

1. Submerged loading of a clean cargo tank
2. Submerged loading of dedicated normal service
3. Submerged loading of dedicated vapor balance service
4. Splash loading of a clean cargo tank
5. Splash loading of dedicated normal service
6. Splash loading of dedicated vapor balance service).

The splash loading of a clean cargo tank and the splash loading of dedicated normal service have the highest VOC emission factors ( $4.8 \times 10^{-2}$  lb/kgal of diesel and 14.4 lb/kgal of gasoline). Given that the loading operations are not specified in the design case, we use the highest (i.e., worst-case) VOC emission factor in the uncontrolled PTE calculation for splash loading diesel. However, we apply the highest VOC emission factor for submerged loading of gasoline (9.93



lb/kgal of gasoline) to the uncontrolled PTE calculation (in lieu of splash loading) because state or local rules are unlikely to allow splash loading of gasoline (due to its properties and evaporation characteristics).

The HAP emissions from the loading operations are estimated by assuming the HAP components in the gasoline and diesel blendstocks from the fast pyrolysis biorefinery are the same as those in the conventional diesel and gasoline products. Table 11 summarizes the preliminary estimates of uncontrolled PTE for VOC and HAP emissions from loading operations in Area 700. Refer to the worksheet titled, “Area 700 Loading Operations” in Appendix I for detailed calculations.

**Table 11. Preliminary Estimates of Uncontrolled PTE of VOC, and HAP from Loading Operations in Area 700**

Pollutant	Uncontrolled PTE (tpy)
VOC	140
HAP	33

### *Federally Enforceable Limitations*

If the fast pyrolysis biorefinery is a major or area source of HAP, loading operations could be subject to emission control requirements under the MON (40 CFR 63, Subpart FFFF), depending on whether the loading operations meet applicability criteria. There are likely federally enforceable limitations in the MON applicable to the loading operations, which could require the uncontrolled emissions to be reduced. However, if the biorefinery is an area source of HAP, there is no specific emission reduction requirement in the CMAS (40 CFR 63, Subpart VVVVVV), which limits HAP emissions from the loading operations. The overall permitting strategy is discussed in detail in Section 5.

### **4.3.12 Area 700 – Emergency Generator, Emergency Fire Pump, and Cooling Tower**

#### *Maximum Capacity to Emit and Physical/Operational Limitations*

Utility equipment such as an emergency generator, emergency fire pump, and cooling tower are expected to emit regulated pollutants.

For the emergency generator, it is assumed that the engine is an internal combustion diesel engine rated at 300 horsepower. Combustion products, including PM, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, SO<sub>2</sub>, CO, CO<sub>2</sub>, and residual VOC and HAP not completely combusted are expected to be emitted. Based on EPA’s guidance (EPA 1995b), uncontrolled PTE of air pollutants is estimated based on an average usage rate of 500 hours per year, for which the emergency generator could be expected to operate under a worst-case scenario. Emission factors for criteria air pollutants, HAPs, and GHG emissions are derived from several sources, including Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (Title 40 Part 60,

Subpart III),<sup>60</sup> and AP-42 (EPA 1996b, Chapter 3). Refer to the worksheet titled, “Area 700 Emergency Generator” in Appendix I for detailed calculations.

It is assumed that the engine for the emergency fire pump will be identical to that for the emergency generator. Emissions factors used to calculate the uncontrolled PTE for criteria air pollutants, HAPs and GHG emissions are the same as those used for the emergency generator. See the worksheet titled, “Area 700-Emergency Fire Pump” in Appendix I for calculations.

A cooling tower is included in the design report (Jones et al. 2013) to handle chilled water and process water. The water that will be used in the biorefinery includes fresh water mixed with treated recycled water. Because the wet cooling tower provides direct contact of the cooling water with the air passing through the tower, some of the water may be entrained in the air stream and carried out of the tower as drift droplets (EPA 1995c). The PM constituent of the drift droplets may be classified as an air emission. Because the drift droplets generally contain the same chemical impurities as the water circulating through the tower, the purities can be converted to air emissions (EPA 1995c).

The cooling tower is capable of handling about 120,000 gallons of water per hour (Jones et al. 2013). We assume that the cooling tower is similar to the one used by Abengoa Bioenergy Biomass of Kansas (ABBK), which is equipped with a high efficiency drift eliminator. The drift loss of circulating water ( $\eta_{Drift}$ ) is 0.0005% (i.e., 0.0005% of water is lost in the form of mist carried out of the tower by an air drift). And, the concentration of total dissolved solids (TDS) in circulating water is 1,575 ppm (by weight). Both of these assumptions are based on ABBK’s air permit application (Kansas Department of Health and Environment 2011; WLA 2011). It should be noted that the TDS level for cooling tower water is highly variable and dependent on the specific site and the local quality of inlet water to the plant. The PM emission factor ( $EF_{PM}$ ) from the cooling tower is estimated using Eq. 6 (EPA 1995c, Chapter 13). Emissions factors for  $PM_{10}$  and  $PM_{2.5}$  are estimated to be 70% and 42% respectively of PM emissions, based on the methodology developed by South Coast Air Quality Management District (2006b).

$$EF_{PM} = \frac{TDS * \eta_{Drift} * \rho_{H2O}}{1000} \quad - \text{Eq. 6}$$

Where:

$EF_{PM}$  = emission factor for PM (lb/kgal of circulating water)

$TDS$  = concentration of total dissolved solids in circulating water (ppm by weight)

$\eta_{Drift}$  = drift loss of circulating water (%)

$\rho_{H2O}$  = water density (lb/gal)

Due to potential leaks in the process that can come in contact with the cooling water through cooling tower heat exchange systems, VOC and HAP are expected be emitted from the

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<sup>60</sup> Manufacturers of internal combustion engines must produce engines that meet the requirements of 40 CFR 60, Subpart III; therefore, the regulatory emission rate standards in the rule should reflect how newly purchased engines perform.

cooling tower. Although the fast pyrolysis biorefinery is not a petroleum refinery, the South Coast Air Quality Management District (2006b) provides guidance, which treats VOC emissions from cooling towers at chemical manufacturing facilities the same as those from petroleum refineries. For this reason, we use the default emission factor (6 pounds per millions gallons of cooling water) for uncontrolled VOC from cooling towers in petroleum refineries provided in AP-42 (EPA 1995a, Chapter 5) to estimate the PTE of VOC for the fast pyrolysis biorefinery. We assume 50% of VOC emissions are HAP. However, sufficient information is not available in the design case (Jones et al. 2013) to determine the speciated HAPs emitted from the cooling tower.

Table 12 summarizes the preliminary estimates of uncontrolled PTE of criteria air pollutants and HAP emissions from three sources in Area 700 (i.e., the emergency generator, emergency fire pump, and cooling tower). Detailed calculations of emissions from emergency generator, emergency fire pump, and cooling tower can be found in the worksheets titled, “Area 700 Emergency Generator,” “Area 700 Emergency Fire Pump, and “Area 700 Cooling Tower,” respectively in Appendix I.

**Table 12. Preliminary Estimates of Uncontrolled PTE of Criteria Air Pollutants, GHGs, and HAP emissions from Area 700**

Pollutant	Uncontrolled PTE (tpy)			
	Emergency Generator	Emergency Fire Pump	Cooling Tower	Subtotal for Area 700
PM	$2.5 \times 10^{-2}$	$2.5 \times 10^{-2}$	$4.0 \times 10^{-2}$	$8.4 \times 10^{-2}$
PM <sub>10</sub>	$2.5 \times 10^{-2}$	$2.5 \times 10^{-2}$	$2.0 \times 10^{-2}$	$7.4 \times 10^{-2}$
PM <sub>2.5</sub>	$2.5 \times 10^{-2}$	$2.5 \times 10^{-2}$	$1.0 \times 10^{-2}$	$6.4 \times 10^{-2}$
SO <sub>2</sub>	$8.2 \times 10^{-4}$	$8.2 \times 10^{-4}$	Not applicable	$1.6 \times 10^{-3}$
NO <sub>x</sub>	$5.0 \times 10^{-1}$	$5.0 \times 10^{-1}$	Not applicable	1.0
CO	$4.3 \times 10^{-1}$	$4.3 \times 10^{-1}$	Not applicable	$8.6 \times 10^{-1}$
VOC	$5.0 \times 10^{-1}$	$5.0 \times 10^{-1}$	3.2	4.2
GHGs (CO <sub>2</sub> equivalent)	87.0	87.0	Not applicable	170
HAP	$2.1 \times 10^{-3}$	$2.1 \times 10^{-3}$	1.6	1.6

### *Federally Enforceable Limitations*

Depending on whether (1) the biorefinery is a major or area source of HAP and (2) the cooling tower meets the applicability criteria, the cooling tower could be subject to one of two NESHAP, either the MON (40 CFR 63, Subpart FFFF) or CMAS (40 CFR 63, Subpart VVVVVV). Therefore, federally enforceable limitations or requirements likely could require the uncontrolled HAP emissions from the cooling tower to be reduced. The overall permitting strategy is discussed in detail in Section 5.

Depending on the size and type, the emergency generator and fire pump likely would be subject to the NSPS (40 CFR 60, Subpart IIII), the NESHAP (40 CFR 63, Subpart ZZZZ) for engines, or both. The emergency generator and fire pump in a new fast pyrolysis biorefinery are expected to meet the emission limits and/or work practice standards in the NSPS and/or NESHAP if they meet the applicability criteria specified in the rules.

### 4.3.13 Emissions from Leaking Equipment

#### Maximum Capacity to Emit and Physical/Operational Limitations

VOC and HAP could be released to the atmosphere as fugitive emissions through leaking equipment located in Areas 100, 200, 300, 400, 500, and 600 of the design plant. These VOC and HAP emissions are estimated using the Protocol for Leak Emission Estimates published by EPA (EPA 1995d). The EPA’s approach requires a count of equipment by type (e.g., valves, pumps, and connectors). Because the design case (Jones et al. 2013) is a feasibility-level analysis rather than an actual engineering design for a specific facility, we are unable to develop a detailed inventory of each type of equipment. Instead, the equipment count is based on numbers obtained from ABBK’s air permit application (Kansas Department of Health and Environment 2011; WLA 2011) and a scaling ratio of the fast pyrolysis biorefinery’s production capacity to the ABBK’s production capacity. For a preliminary, conservative estimate, we assume 50% of VOC emissions are emitted as HAP. This is a very high estimate, but given there are no details on speciation available, it was selected at a level that would not underestimate emissions. Table 13 summarizes preliminary estimates of uncontrolled PTE of VOC and HAP emissions from equipment leaks in Areas 200, 300, 400, 500, and 600. Detailed calculations of emissions for each type of equipment can be found in the worksheet titled, “Equipment Leaks” in Appendix I.

**Table 13. Preliminary Estimates of Uncontrolled PTE of VOC and HAP Emissions from Equipment Leaks in Areas 100, 200, 300, 400, 500, and 600**

Pollutant	Uncontrolled PTE (tpy)
VOC	30
HAP	15

#### Federally Enforceable Limitations

Depending on whether the biorefinery is a major or area source of HAP, equipment leaks could be subject to one of two NESHAP, either the MON (40 CFR 63, Subpart FFFF) or CMAS (40 CFR 63, Subpart VVVVVV). Therefore, there are likely federally enforceable limitations or requirements that could require the uncontrolled HAP emissions from the equipment leaks be reduced. The overall permitting strategy is discussed in detail in Section 5.

### 4.3.14 Emissions from Truck Traffic

#### Maximum Capacity to Emit and Physical/Operational Limitations

Truck traffic for the delivery of feedstock and other raw materials, and for the transfer of products and waste off-site is expected to generate fugitive PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from road dust. Emissions from the trucks' internal combustion engine exhaust are not regulated in stationary source regulations and permits, and therefore, are not included in the PTE estimation.

Without site-specific information, we assume that half of the throughput of biomass received, diesel and gasoline blendstock products, and chemicals and supplies are hauled on unpaved roads and the other half on paved roads. Emissions factors for PM, PM<sub>10</sub>, and PM<sub>2.5</sub> on paved and unpaved roads are calculated based on Eqs. 7 and 8 respectively, based on methodologies developed by EPA (2011a and 2006c).

$$E_{paved\_road} = k * (sL)^{0.91} * (W)^{1.02} * \left(1 - \frac{P}{(4*365)}\right) \quad - \text{Eq. 7}$$

Where:

$E_{paved\_road}$  = Annual emissions from paved roads per vehicle mile traveled (lb/vehicle mile traveled)

$k$  = Particle size multiplier for specific particle size range in lb/vehicle mile traveled (0.011 for PM, 0.0022 for PM<sub>10</sub> and 0.00054 for PM<sub>2.5</sub>)

$sL$  = Road surface silt loading (g/m<sup>2</sup>)

$W$  = Average weight of the vehicles traveling the roads (tons)

$P$  = Number of days with at least 0.01 inch of precipitation (days/yr) (default = 90)

$$E_{unpaved\_road} = k * \left(\frac{sC}{12}\right)^a * \left(\frac{W}{3}\right)^b * \left(1 - \frac{P}{365}\right) \quad - \text{Eq. 8}$$

Where:

$E_{unpaved\_road}$  = Annual emissions from unpaved roads per vehicle mile traveled (lb/vehicle mile traveled)

$k$ ,  $a$ ,  $b$  = constants (varying by specific particle size range, see Table 13.2.2-2 for Industrial Roads in EPA 2006c)

$sC$  = silt content of unpaved road surface (%)

$W$  = average weight of the vehicles traveling the roads (tons)

$P$  = Number of days with at least 0.01 inch of precipitation (days/yr) (default = 90)

The annual feedstock requirement is about 720,000 dry tons (or 1,040,000 tons including moisture) per year. It is assumed that on an annual basis, half of the biomass is hauled on paved roads and the other half on unpaved roads. Similarly, the maximum throughput of diesel blendstock is estimated to be 56,000 tons on paved and unpaved roads, each. The maximum throughput of gasoline blendstock is estimated to be 44,000 tons on paved and unpaved roads, each. The estimate of maximum throughput for chemicals and supplies is based on the consumption of various chemicals and supplies in the design case (Jones et al. 2013). The distance traveled (per year) is estimated based on maximum throughput and average truck capacity for biomass feedstock, the diesel and gasoline blendstock products, and chemicals and supplies. We also assume a round-trip length of 1,300 feet within the facility boundary for each truck delivery. Uncontrolled PTE of PM, PM<sub>10</sub>, and PM<sub>2.5</sub> generated from truck traffic is calculated by multiplying the emission factors (estimated from Eqs. 7 and 8) and distance traveled within the biorefinery. Table 14 summarizes the preliminary estimates of uncontrolled PTE for PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from truck traffic for the biorefinery. Detailed calculations for each pollutant can be found in the worksheets titled, “Truck Traffic” in Appendix I.

**Table 14. Preliminary Estimates of Uncontrolled PTE of PM, PM<sub>10</sub>, and PM<sub>2.5</sub> from Truck Traffic**

Pollutant	Uncontrolled PTE (tpy)
PM	69
PM <sub>10</sub>	19
PM <sub>2.5</sub>	2.3

### *Federally Enforceable Limitations*

There are no currently known federal regulations that would apply to the fugitive dust emissions from the vehicle traffic. However, if reduction in emissions of PM, PM<sub>10</sub>, and PM<sub>2.5</sub> were desirable, dust suppression techniques could be used to reduce emissions, and federally enforceable limitations on these fugitive dust emissions could be requested be included in the permit. The request for federally enforceable limitations should be made after considering all emitting sources at the facility. The overall permitting strategy is discussed in detail in Section 5.

## **5 Results of Facility-Wide PTE of Regulated Air Pollutants and Discussion of Implications and Limitations**

### **5.1 Preliminary Estimates of Facility-Wide Uncontrolled PTE of Regulated Air Pollutant Emissions**

Table 15 summarizes preliminary estimates of facility-wide uncontrolled PTE for all regulated air pollutants potentially emitted from the fast pyrolysis biorefinery, including criteria air pollutants and their precursors, HAP emissions, and GHG emissions (in CO<sub>2</sub> equivalent). Detailed facility-wide uncontrolled PTE estimates on criteria air pollutants and GHG emissions can be found in the worksheet titled, “PTE Summary (Criteria and GHG)” and estimates on HAPs (including individual HAP when available) in the worksheet titled, “Uncontrolled PTE Summary (HAP)” in Appendix I.

Because the fast pyrolysis biorefinery (as described in Jones et al. 2013) is a chemical production facility, which is one of the 28 listed source categories (see Appendix C), fugitive emissions are included in the facility-wide uncontrolled PTE estimation (refer to Section 4.1.4). Efforts are made to estimate speciated HAP emissions for the fired-heater, fired reboiler, methane reformer, tanks, loading operations, emergency generator, and emergency fire pump when possible (e.g., default data are available from EPA’s guidelines). However, sufficient information is not readily available from the design case (Jones et al. 2013) to speciate HAPs for other HAP emitting sources, including WWTP, cooling tower, and equipment leaks.

**Table 15. Preliminary Estimates of Facility-Wide Uncontrolled PTE of Criteria Air Pollutants (and Precursors), HAPs, and GHG Emissions from the Design Biorefinery (tpy)**

	PM <sup>a</sup>	PM <sub>10</sub> <sup>a</sup>	PM <sub>2.5</sub> <sup>a</sup>	VOC	NO <sub>x</sub>	CO	Lead	SO <sub>2</sub>	HAP	GHGs (CO <sub>2</sub> eq)
Dryer and sand heater (Area 100) <sup>b</sup>	8,800	4,400	1,300	120	4.4			440	30	390,000
Fired heater (Area 200)	7.0x10 <sup>-2</sup>	2.8x10 <sup>-1</sup>	2.8x10 <sup>-1</sup>	2.0x10 <sup>-1</sup>	6.1	3.1	1.9x10 <sup>-5</sup>	2.0x10 <sup>-2</sup>	7.0x10 <sup>-2</sup>	4,500
Fired reboiler (Area 300)	1.1x10 <sup>-1</sup>	4.6x10 <sup>-1</sup>	4.6x10 <sup>-1</sup>	3.3x10 <sup>-1</sup>	6.0	5.1	3.0x10 <sup>-5</sup>	4.0x10 <sup>-2</sup>	1.1x10 <sup>-1</sup>	7,300
Methane reformer (Area 600) <sup>c</sup>	1.3	5.3	5.3	3.8	130	58	3.5x10 <sup>-4</sup>	25	1.3	490,000
WWTP (Area 700)				3.0x10 <sup>-1</sup>					1.2x10 <sup>-1</sup>	
Storage tanks (Area 700)				1.3					2.6x10 <sup>-1</sup>	
Loading operations (Area 700)				1.4x10 <sup>2</sup>					3.3x10 <sup>1</sup>	
Emergency generator (Area 700)	2.5x10 <sup>-2</sup>	2.5x10 <sup>-2</sup>	2.5x10 <sup>-2</sup>	5.0x10 <sup>-1</sup>	5.0x10 <sup>-1</sup>	4.3x10 <sup>-1</sup>		8.2x10 <sup>-4</sup>	2.1x10 <sup>-3</sup>	87
Emergency fire pump (Area 700)	2.5x10 <sup>-2</sup>	2.5x10 <sup>-2</sup>	2.5x10 <sup>-2</sup>	5.0x10 <sup>-1</sup>	5.0x10 <sup>-1</sup>	4.3x10 <sup>-1</sup>		8.2x10 <sup>-4</sup>	2.1x10 <sup>-3</sup>	87
Cooling tower (Area 700)	4.0x10 <sup>-2</sup>	2.0x10 <sup>-2</sup>	1.0x10 <sup>-2</sup>	3.2					1.6	
Equipment leaks (Areas 100, 200, 300, 400, 500, and 600)				30					15	



	PM <sup>a</sup>	PM <sub>10</sub> <sup>a</sup>	PM <sub>2.5</sub> <sup>a</sup>	VOC	NO <sub>x</sub>	CO	Lead	SO <sub>2</sub>	HAP	GHGs (CO <sub>2</sub> eq)
Truck traffic	69	19	2.3							
Facility-wide total <sup>d</sup>	8,900	4,500	1,400	300	150	67	3.9x10 <sup>-4</sup>	460	81 (All HAP) 19 (Single largest HAP – Formaldehyde)	890,000
Major source for NSR and Title V	100	100	100	100	100	100	100	100	25 <sup>e</sup> (All HAP) 10 (Any single HAP)	NA <sup>f</sup>
PSD Significance Emission Rate (SER)	25	15	10	40	40	100	0.6	40	NA <sup>e</sup>	Pending <sup>g</sup>

<sup>a</sup> PM is regulated as filterable PM, while PM10 and PM2.5 are regulated as the total of filterable PM in the size fraction (i.e., PM10 or PM2.5) and condensable PM. Specifically, PM is regulated as measured using EPA Method 5, which measures only filterable PM. PM10 and PM2.5 are regulated as measured using EPA Method 201A, which measures the filterable PM at the size fraction, and Method 202, which measures condensable PM. All condensable PM is included in the PM2.5 and PM10 size fractions.

<sup>b</sup> Includes emissions from the biomass feedstock transfer and storage operations, sand heater, ash and sand handling operations, and dryer

<sup>c</sup> Includes emissions from a hydrotreating reactor, hydrocracker, and pyrolysis reactor

<sup>d</sup> Numbers may not add up due to rounding and the use of two significant digits.

<sup>e</sup> Not subject to NSR, although HAPs that are also VOC are included in the VOC total and are considered when determining the applicability of PSD review for VOC

<sup>f</sup> GHGs alone do not determine the applicability of Title V or NSR.

<sup>g</sup> Currently, the PSD significance level for GHG is not defined. For pollutants with no significance level, any amount of emissions is considered significant. EPA is expected to publish a significance level in the future. In the meantime, some states are using 75,000 tpy of CO<sub>2</sub> equivalents as PSD significant level.

The uncontrolled PTE for several criteria air pollutants (i.e., NO<sub>x</sub>, PM, SO<sub>2</sub>, VOC [ozone precursor]), as currently estimated, suggest the biorefinery would exceed the 100-tpy NSR major source threshold if the biorefinery were located in an attainment area. (The NNSR major source thresholds could be lower, depending on the nonattainment classifications; see Appendix E.) If an actual fast pyrolysis biorefinery seeking an air permit had PTE of the regulated air pollutants at the same levels as the estimated uncontrolled PTE, the biorefinery would be required to conduct a PSD review for each pollutant that has PTE equal to or greater than the SER (see Table 15) for the pollutant. For example, the PSD significance threshold for NO<sub>x</sub> is 40 tpy. If a facility's PTE NO<sub>x</sub> exceeds 40 tpy, a PSD review would be required for NO<sub>x</sub>.

For the fast pyrolysis biorefinery, the uncontrolled PTE level suggests that PSD review would be required for NO<sub>x</sub>, CO, PM, PM<sub>10</sub>, PM<sub>2.5</sub>, SO<sub>2</sub>, VOC, and GHGs<sup>61</sup> (because at least one of the non-GHG pollutants exceeds 100 tpy and the other pollutants either exceed 100 tpy or exceed the SER). In addition, the biorefinery would be required to apply for a Title V operating permit if it were determined to be a major source under NSR. Furthermore, the estimated uncontrolled PTE suggests that the biorefinery exceeds the 25-tpy major source threshold for the sum of HAP and the 10-tpy major source threshold for several individual HAPs (e.g., toluene and formaldehyde). Refer to the worksheet titled, "Uncontrolled PTE Summary (HAP)" in Appendix I.

## 5.2 Development of Preliminary PTE

The types of permits required under the NSR and Title V programs are determined based on the PTE rather than the uncontrolled PTE. Federally enforceable limitations will apply to this source, and they can be accounted for when determining PTE and permitting requirements. As discussed in Sections 3 and 4, the fast pyrolysis biorefinery will likely be subject to several NESHAPs and NSPS. These regulations provide federally enforceable limitations that will reduce the uncontrolled PTE. Also, the biorefinery can request federally enforceable limits be included in the permit to reduce the uncontrolled PTE.

In developing the permitting strategy, a facility would prefer to be a minor source under the NSR and Title V. If it is not possible to be a minor source, the facility would likely prefer to reduce its PTE below the SER limit for as many pollutants as possible because the facility could then avoid conducting a PSD analysis (and installing best available control technology [BACT]) for a regulated pollutant if the PTE of the pollutant were lower than the SER.

Based on the discussion in Section 3, the federal air regulations that are likely to apply to the fast pyrolysis biorefinery are summarized in Table 16. The NSPS for storage tanks could provide emission control requirements that would reduce VOC from applicable equipment. The chemical manufacturing NESHAP (CMAS or MON) and the process heater NESHAP could reduce emissions of HAPs from several emission sources at the facility if the specific emission sources met certain applicability criteria. The NSPS and NESHAPs that could apply to the fire pump and

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<sup>61</sup> In July 2011, EPA deferred biogenic CO<sub>2</sub> emissions from permitting requirements for three years in order to develop an accounting framework for biogenic CO<sub>2</sub> emissions (EPA 2011b). The final rule on biogenic CO<sub>2</sub> accounting is still pending; it is unclear whether or how the CO<sub>2</sub> emissions from biogenic sources will be counted toward permit applicability in the future. However, the deferral expired July 21, 2014 pursuant to 40 CFR 65.166(b)(48)(ii)(a), and without the accounting framework, it must be assumed that biogenic CO<sub>2</sub> sources must be counted in the same way anthropogenic CO<sub>2</sub> is counted. This may change when an accounting framework is published.

emergency generator, depending on the size of these units may provide federally enforceable limitations that reduce the PM, VOC, NO<sub>x</sub>, and HAP emissions from the emergency equipment. It is assumed that the fire pump and emergency generator purchased by a new biorefinery will meet the NSPS and NESHAP if applicable.

**Table 16. Federal Air Regulations Potentially Applicable to the Fast Pyrolysis Biorefinery**

Plant Area	Affected Equipment/Operation	Federal Rule	Target Pollutant(s)
Areas 200, 300, and 600	Process heaters	Only if the fast pyrolysis biorefinery is a major source of HAPs, is the affected equipment/operation be subject to NESHAP – 40 CFR 63, Subpart DDDDD	HAPs
Area 700	Gasoline storage tank	NSPS for storage tanks – 40 CFR 60, Subpart Kb	VOCs
Areas 100, 200, 300, 500, 600, 700	Emission release points: Process vents, loading operations, equipment leaks, storage tanks, wastewater, heat exchange system (including cooling tower)	If the fast pyrolysis biorefinery is a major source of HAPs, the affected equipment/operation would be subject to NESHAP – 40 CFR 63, Subpart FFFF (MON). Or, if the fast pyrolysis biorefinery is an area source of HAPs, the affected equipment/operation would be subject to NESHAP – 40 CFR 63, Subpart VVVVVV (CMAS).	HAPs
Area 700	Fire pump and emergency generator	Depending on the size and design, the fire pump and emergency generator may be subject to NSPS – 40 CFR 60, Subpart IIII.	PM, VOCs, and NO <sub>x</sub>
Area 700	Fire pump and emergency generator	Depending on the size and design, the fire pump and emergency generator may be subject NESHAP – 40 CFR 63, Subpart ZZZZ.	HAPs

The following sections describe how the requirements of the potentially applicable regulations may impact the preliminary PTE calculation and provide some thoughts on potential controls to reduce the PTE to below major source levels. However, the preliminary PTE estimated in this section must undergo additional revisions to determine the final PTE, including:

- Incorporating the impact of any additional controls the source decides to install to lower the PTE to avoid NSR applicability
- Incorporating the impact of any additional controls the source is required to install to meet any applicable BACT or “lowest achievable emissions rate” control technology determinations.
- Implementing any emission estimation improvements identified based on new data or better estimates of assumptions.

In general, we do not speculate on what these additional revisions could be. Rather, we list these as additional considerations that must be made.

### **5.2.1 PTE of Hazardous Air Pollutants (HAPs)**

The uncontrolled PTE of HAPs is estimated to be 81 tpy from the entire fast pyrolysis biorefinery; the dryer and sand heater (Area 100), the loading operations (Area 700), and the equipment leaks (Areas 100–600) are the three largest emitting sources; together, they account for 96% of total uncontrolled HAPs. Each of the four individual HAPs (toluene, formaldehyde, xylene, and methanol) is estimated to have an uncontrolled PTE exceeding 10 tpy. When the PTE of total HAP is greater than 25 tpy or the PTE of any individual HAP is greater than 10 tpy, a source would be a major source of HAP and would be required to have a Title V permit. HAP emissions are not subject to NSR permitting requirements (unless the HAP is lead, which is also a criteria pollutant, or an organic HAP that is also a VOC). The estimated uncontrolled PTE for total HAP or individual HAP from the fast pyrolysis biorefinery indicates that the facility could be a major source of HAP. To make it an area source of HAP, the PTE of HAP would need to be reduced to below 25 tpy for total HAP and less than 10 tpy for any individual HAP.

The fast pyrolysis biorefinery will be subject to one of two chemical manufacturing NESHAP; CMAS (40 CFR 63, Subpart VVVVVV) applies to an area source of HAP and MON (40 CFR 63, Subpart FFFF) applies to major sources of HAP (refer to Table 4). It is in the best interest of the facility to be an area source of HAP because of the additional expenses and accountability associated with being a Title V source and with being subject to NESHAP for major sources of HAP.

Based on the uncontrolled PTE of HAP, the primary sources of HAP emissions are emissions from the drying and gasoline-loading operations. When the CMAS applies to the fast pyrolysis biorefinery, HAP emissions from the gasoline storage tank will need to be controlled because the gasoline tank meets the applicability criteria. The compliance requirement can be met by using a properly designed storage tank with a floating roof, following the specifications in the rule, or installing additional emission control devices. In our uncontrolled PTE HAP calculation, we assume the fast pyrolysis biorefinery will employ an internal floating roof to the gasoline storage tank that meets the specifications in CMAS. Because the internal floating roof is considered a specific design feature of the gasoline blendstock tank (i.e., integral to the tank), the PTE is identical to the uncontrolled PTE for HAP from the gasoline storage tank. The diesel blendstock storage tank is not subject to the control requirements of CMAS; only recordkeeping requirements apply.

CMAS has specific compliance requirements and emission limits for cooling towers if they meet the applicability criteria. The cooling tower in the fast pyrolysis biorefinery has a circulating water flow rate below the applicability criteria, and it is not expected to be subject to the emission limits. Therefore, the PTE is identical to the uncontrolled PTE for HAP from the cooling tower.

CMAS requires that inspection of equipment be conducted at least quarterly and any leaks detected be repaired within 15 days. These requirements in CMAS will reduce emissions based on the monitoring frequency and the type of equipment components (e.g., valves, connectors, and pumps) subject to monitoring. Based on the control effectiveness specified in EPA's

Protocol for leak emission estimates (EPA 1995d), it was estimated that the equipment leak HAP emissions are reduced from 15 tpy to 5.6 tpy in compliance with CMAS.

CMAS has compliance requirements for wastewater treatment (WWT) systems, depending on whether the wastewater stream meets applicability criteria (e.g., threshold on the concentration of partially soluble HAP). Without detailed information on wastewater streams generated at the fast pyrolysis biorefinery, it is unclear whether any emission controls for the wastewater streams are required. As a conservative estimate, we assume the PTE is identical to the uncontrolled PTE for HAP from the WWT system.

Without HAP reductions from gasoline-loading operations and the dryer, the fast pyrolysis biorefinery would be a major source of HAP and therefore be subject to the MON. The MON requires a facility to reduce HAP emissions by at least 98% from a continuous process vent. This requirement would apply to the HAP emissions from the dryer, which is a continuous process vent. The MON also requires a facility to reduce HAP emissions from gasoline-loading operation by at least 98% or to vent the emissions through a flue gas system that meets specific requirements. In our judgement, reducing HAP emissions from gasoline-loading operation and the dryer by 60% and 95% respectively is likely a preferred permitting strategy for the biorefinery to avoid being classified as a major source of HAP.

Several types of controls can easily meet these control levels, including catalytic and thermal oxidizers, carbon absorbers, and scrubbers. Any control used for the product loading operation would likely exceed 60% reduction.

Table 17 summarizes the uncontrolled PTE as well as preliminary PTE for HAP, assuming that the biorefinery elects to reduce HAP emissions from the gasoline-loading operation by 60% and those from the dryer vent by 95%. Adopting these emission controls along with HAP reduction from equipment leaks could reduce the facility-wide PTE to below 25 tpy for total HAP (shown in Table 17) and PTE of all individual HAP to below 10 tpy (refer to Appendix I).

When the fast pyrolysis biorefinery is an area source of HAP, Subpart DDDDD would *not* apply to the process heaters to limit HAP emissions (refer to Table 16). The PTE is expected to be identical to uncontrolled PTE for HAP from the process heaters.

**Table 17. Uncontrolled PTE and Preliminary PTE for HAP**

Process	Uncontrolled HAP PTE (tpy)	Preliminary HAP PTE (tpy)
Dryer and sand heater (Area 100)	30	1.5
Gasoline-loading operation (Area 700)	33	13
Equipment leaks (Areas 100–600)	15	5.6
Other emission sources: fired heater, fired reboiler, methane reformer, storage tanks, diesel loading operation, WWT, emergency generator and fire pump, and cooling tower	3.5	3.5
Total <sup>a</sup>	81	24

<sup>a</sup> The total may not add up due to rounding.

### 5.2.2 PTE of Particulate Matter (PM)

The uncontrolled PTE of PM, PM<sub>10</sub>, and PM<sub>2.5</sub> is greater than 100 tpy, as shown in Table 18. The emissions from the dryer and sand heater are much larger than other emission sources such as truck traffic and the methane reformer; however, the truck traffic generates emissions at levels higher than the respective SER (25 tpy for PM and 15 tpy for PM<sub>10</sub>) (refer to Table 15).

In calculating uncontrolled PM emissions, we assume that the baghouse that captures sand and ash from the hot exhaust of the sand heater is not used. If this baghouse is made federally enforceable in the permit, the PM from the sand heater exhaust, which is vented through the dryer, could be reduced (refer to Section 4.3.1). The design report does not specifically identify a level of control performance for the sand heater baghouse. Assuming a 99% PM reduction efficiency for the baghouse (EPA 2003), the PTE of PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the sand heater exhaust released through the dryer can be reduced to 87, 43, and 13 tpy respectively. As indicated in the design case (Jones et al. 2013), the baghouse is designed to capture emissions from the sand heater only; particulate emissions generated during the drying process are not reduced. The PTE of combined PM, PM<sub>10</sub>, and PM<sub>2.5</sub> emissions from the sand heater and dryer, which are released through the dryer, is estimated to be 250, 160, and 99 tpy respectively.

The ash and sand captured by the baghouse needs to be loaded out for disposal. The design case (Jones et al. 2013) incorporates an ash cooler that uses quench water to cool the ash unloaded from the baghouse. We assume using quench water reduces PM emissions from ash handling by 99%. The PTE of PM, PM<sub>10</sub>, and PM<sub>2.5</sub> from the ash handling operation is estimated to be 0.45, 0.22, and 0.07 tpy respectively. It should be noted that PM emissions from ash handling are not included in the uncontrolled PTE calculation because we assume the baghouse is not used and therefore no ash needs to be unloaded from the baghouse.

The engine NSPS (40 CFR 60, Subpart IIII) provides emission limits for PM emissions from stationary compression ignition internal combustion engines, depending on the type and size of the engines (see Table 16). The fast pyrolysis biorefinery is expected to purchase an emergency generator and fire pump equipped with engines that already comply with the engine NSPS. Therefore, the uncontrolled PTE and PTE of PM, PM<sub>10</sub>, and PM<sub>2.5</sub> from the emergency generator and fire pump is estimated based on the emission limits specified in the engine NSPS. The emergency generator and fire pump combined are estimated to emit less than 1 tpy of PM.

Table 18 shows uncontrolled PTE and the preliminary PTE for PM assuming that federally enforceable limits are taken in a permit to make the baghouse performance on the sand handling exhaust federally enforceable. The PTE of PM and PM<sub>10</sub> is still above the major source level (i.e., 100 tpy under the NSR program) and the PTE of PM<sub>2.5</sub> exceeds the SER. The source could consider other emission reduction options to reduce emissions such as including a baghouse on the dryer exhaust to reduce particulate emissions from feedstock drying, and watering the roads to reduce truck traffic emissions. In addition, it is possible the source would install a more efficient baghouse on the sand heater exhaust that achieves as much as 99.99% PM reduction (as opposed to the 99% PM reduction efficiency assumed in the calculation); this would further reduce PM emissions.

**Table 18. Uncontrolled PTE and Preliminary PTE for PM, PM<sub>10</sub>, and PM<sub>2.5</sub>**

Process	Uncontrolled PM PTE (tpy)			Preliminary PM PTE (tpy)		
	PM	PM <sub>10</sub>	PM <sub>2.5</sub>	PM	PM <sub>10</sub>	PM <sub>2.5</sub>
Dryer and sand heater (Area 100)	8,800	4,400	1,300	250	160	99
Ash and sand handling (Area 100)	-	-	-	4.5x10 <sup>-1</sup>	2.2x10 <sup>-1</sup>	7.0x10 <sup>-2</sup>
Fired heater (Area 200)	7.0x10 <sup>-2</sup>	2.8x10 <sup>-1</sup>	2.8x10 <sup>-1</sup>	7.0x10 <sup>-2</sup>	2.8x10 <sup>-1</sup>	2.8x10 <sup>-1</sup>
Fired reboiler (Area 300)	1.1x10 <sup>-1</sup>	4.6x10 <sup>-1</sup>	4.6x10 <sup>-1</sup>	1.1x10 <sup>-1</sup>	4.6x10 <sup>-1</sup>	4.6x10 <sup>-1</sup>
Methane reformer (Area 600)	1.3	5.3	5.3	1.3	5.3	5.3
Truck traffic	69	19	2.3	69	19	2.3
Other emission sources: cooling tower, emergency fire pump, and emergency generator	8.4x10 <sup>-2</sup>	7.4x10 <sup>-2</sup>	6.4x10 <sup>-2</sup>	8.4x10 <sup>-2</sup>	7.4x10 <sup>-2</sup>	6.4x10 <sup>-2</sup>
Total <sup>a</sup>	8,900	4,500	1,400	330	190	110

<sup>a</sup> Total may not add up due to rounding.

### 5.2.3 PTE of Carbon Monoxide (CO)

Table 15 indicates the methane reformer is the only significant emitting source of CO. There are currently no known federal regulations that apply to CO emissions from the methane reformer, and no emission control is presently incorporated in the design case (Jones et al. 2013) to reduce CO emissions from any emission sources. Thus, the PTE is identical to uncontrolled PTE for CO (67 tpy) from the methane reformer. The PTE of CO is below the major source threshold under the NSR program.

### 5.2.4 PTE of Volatile Organic Compounds (VOCs)

Table 15 indicates the loading operation is the single largest emitter of VOC, followed by the dryer and sand heater and equipment leaks; these three emission sources combined are estimated to have an uncontrolled PTE of 294 tpy for VOC. All other VOC emission sources combined emit about 10 tpy of VOC.

As discussed in Section 5.2.1, the fast pyrolysis biorefinery can avoid being a major source of HAP and therefore be subject to the NESHAP, 40 CFR 63, Subpart VVVVVV (i.e., CMAS). We assume the biorefinery chooses to adopt the likely preferable permitting strategy to make the biorefinery an area source of HAP by reducing HAP emissions from gasoline-loading operation by 60% and reducing HAP emissions from the dryer by 95%, as required by CMAS. Because many organic HAPs are also VOCs, emission controls used to reduce HAP emissions are generally expected to achieve similar efficiency in reducing VOC emissions. For the PTE calculations, we assume the VOC emissions from the gasoline-loading operations and the dryer vent are reduced by 60% and 95% respectively because of the use of emission controls to reduce HAPs (Section 5.2.1).

Several types of controls that can easily meet these control levels, including catalytic and thermal oxidizers, carbon absorbers, and scrubbers. Any control used for the product loading operation would likely exceed 60% reduction.

Furthermore, CMAS requires that inspection of equipment be conducted at least quarterly and any leaks detected be repaired within 15 days. These requirements in CMAS will reduce emissions based on the monitoring frequency and the type of equipment components (e.g., valves, connectors, and pumps) subject to monitoring. Based on the control effectiveness specified in EPA's protocol for leak emission estimates (EPA 1995d), it was estimated that the equipment leak VOC emissions are reduced from 30 tpy to 11 tpy, assuming the biorefinery is in compliance with an leak detection and repair program based on the EPA's best practices guide (EPA 2014c).

VOC emissions from the gasoline storage tank are required to be controlled by the storage vessel NSPS (40 CFR 60, Subpart Kb) (refer to Table 16). A properly designed internal floating roof tank is one option in the rule that can be used to meet this compliance requirement. In our uncontrolled PTE VOC calculation, we assume the fast pyrolysis biorefinery will employ an internal floating roof to the gasoline storage tank that meets the specifications in the storage vessel NSPS. Because the internal floating roof is considered a specific design feature of the gasoline blendstock tank (i.e., integral to the tank), the PTE is identical to the uncontrolled PTE for VOC from the gasoline storage tank. The diesel blendstock storage tank is not subject to the



storage vessel NSPS because it does not meet the applicability criteria in the storage vessel NSPS (40 CFR 60, Subpart Kb).

As discussed in Section 5.2.1, the cooling tower at the fast pyrolysis facility is not subject to the compliance requirements in CMAS. The PTE is identical to the uncontrolled PTE for VOC from the cooling tower. Similarly, the PTE is identical to the uncontrolled PTE for VOC from WWT.

The engine NSPS (40 CFR 60, Subpart IIII) provides emission limits for VOC emissions from stationary compression ignition internal combustion engines, depending on the type and size of the engines. The fast pyrolysis biorefinery is expected to purchase an emergency generator and a fire pump equipped with engines that already comply with the engine NSPS. Therefore, the uncontrolled PTE and PTE of VOC from the emergency generator and fire pump are identical.

Table 19 summarizes the uncontrolled PTE as well as the preliminary PTE for VOC after the VOC emissions from the gasoline-loading operation and the dryer vent are reduced by 60% and 95% respectively, and the VOC emission reduction from equipment leaks because of complying with the monitoring and repair requirements in CMAS. The estimated facility-wide PTE for VOC is below the major source threshold (100 tpy) under the NSR program.

**Table 19. Uncontrolled PTE and Preliminary PTE for VOCs**

<b>Process</b>	<b>Uncontrolled VOC PTE (tpy)</b>	<b>Preliminary VOC PTE (tpy)</b>
Dryer and sand heater (Area 100)	120	6
Gasoline-loading operation (Area 700)	140	60
Equipment leaks (Areas 100–600)	30	11
Other emission sources: fired heater, fired reboiler, methane reformer, storage tanks, diesel loading operation, WWT, emergency generator and fire pump, and cooling tower	11	11
<b>Total</b>	<b>300</b>	<b>90</b>

### 5.2.5 PTE of Nitrogen Oxides (NO<sub>x</sub>)

Table 15 indicates the methane reformer is the only significant emitting source of NO<sub>x</sub>. There are currently no known federal regulations that apply to NO<sub>x</sub> emissions from the methane reformer, and no emission control is presently incorporated in the design case (Jones et al. 2013) to reduce NO<sub>x</sub> emissions from any emission sources. Thus, the PTE is identical to uncontrolled PTE for NO<sub>x</sub> (130 tpy) from the methane reformer.

Because the PTE of NO<sub>x</sub> exceeds the major source threshold (100 tpy) under the NSR program, the biorefinery is considered a major source of NO<sub>x</sub>. The biorefinery could consider using low NO<sub>x</sub> burners or installing emission controls such as a selective catalytic reduction (SCR) unit to reduce emissions of NO<sub>x</sub>. The biorefinery can request federally enforceable limits be included in the permit to reduce the PTE of NO<sub>x</sub> if emission controls are implemented.

### 5.2.6 PTE of Lead

The uncontrolled PTE is above neither the major source level nor the SER for lead. No emission control is currently planned to reduce lead in the design case (Jones et al. 2013). There are currently no known regulations that require lead emissions from the three emission sources (fired heater, fired reboiler and methane reformer) at the fast pyrolysis biorefinery to be controlled. Thus, the PTE is identical to uncontrolled PTE for lead from the fired heater, fired reboiler and methane reformer.

### 5.2.7 PTE of Sulfur Dioxide (SO<sub>2</sub>)

Estimates of uncontrolled PTE for all SO<sub>2</sub>-emitting sources at the biorefinery (Table 15) suggest that the dryer and sand heater (Area 100) is the only significant emitting sources of SO<sub>2</sub>. There are currently no known federal regulations that apply to SO<sub>2</sub> emissions from the dryer, and no emission control is presently incorporated in the design case (Jones et al. 2013) to reduce SO<sub>2</sub> emissions from any emission sources. Thus, the PTE is identical to uncontrolled PTE for SO<sub>2</sub> (440 tpy) from the dryer.

Because the PTE of SO<sub>2</sub> exceeds the major source threshold (100 tpy) under the NSR program, the biorefinery is considered a major source of SO<sub>2</sub>. The biorefinery could consider installing emission controls such as flue gas desulfurization to reduce SO<sub>2</sub> emissions, and it could request federally enforceable limits be included in the permit to reduce the PTE of SO<sub>2</sub> if emission controls were implemented. Incorporating SO<sub>2</sub> reduction technologies could reduce the PTE to below major source levels or below the SER if desired.

### **5.2.8 PTE of Greenhouse Gases (GHGs)**

EPA recently announced it would be revising the PSD rules to include an exemption of PSD requirements for GHGs from waste-derived feedstocks and feedstocks from sustainable forest or agricultural practices (EPA 2014a). The vast majority of GHG emissions from the fast pyrolysis biorefinery likely will fit this exemption and, therefore, would not need to be counted to determine the applicability of PSD to GHG emissions. Also, a source is not required to obtain a PSD or Title V permit on the sole basis of its PTE of GHG emissions per a recent U.S. Supreme Court ruling (U.S. Supreme Court 2014). Other pollutants must be subject to PSD or Title V before the GHG emissions are considered.

The type of the feedstocks will need to be considered to determine which emissions must be counted for GHG emissions. As a conservative assumption, the current uncontrolled PTE estimate for GHG emissions includes all GHG emissions. Without further control, the PTE is expected to be identical to the uncontrolled PTE for GHG emissions. However, the PTE for GHG emissions will need to be revised once the EPA finalizes the rule for biogenic carbon accounting.

### **5.2.9 Facility-Wide PTE**

Table 20 shows the preliminary PTE for the entire fast pyrolysis biorefinery, accounting for the potential federally enforceable limitations (in a permit or federal air regulations) discussed in this section, which are summarized in Table 21. Table 21 also notes where (1) further emission reduction could be considered and (2) emission calculations should be refined when specific design parameters are available. The preliminary PTE indicates that the biorefinery could be (1) major sources for NSR and Title V, and (2) an area source of HAP if no additional emissions controls (other than those currently planned) are implemented.

**Table 20. Preliminary Estimates of Facility-Wide PTE of Criteria Air Pollutants (and polycyclic aromatic hydrocarbons), HAPs, and GHG Emissions from the Design Biorefinery (tpy)**

Process	PM <sup>a</sup>	PM <sub>10</sub> <sup>a</sup>	PM <sub>2.5</sub> <sup>a</sup>	VOC	NOx	CO	Lead	SO <sub>2</sub>	HAP	GHGs (CO <sub>2</sub> eq)
Dryer and sand heater (Area 100) <sup>b</sup>	250	160	99	6.0	4.4			440	1.5	390,000
Ash and sand handling operations (Area 100)	4.5x10 <sup>-1</sup>	2.2x10 <sup>-1</sup>	7.0 x10 <sup>-2</sup>							
Fired heater (Area 200)	7.0x10 <sup>-2</sup>	2.8x10 <sup>-1</sup>	2.8 x10 <sup>-1</sup>	2.0x10 <sup>-1</sup>	6.1	3.1	1.9x10 <sup>-5</sup>	2.0x10 <sup>-2</sup>	7.0x10 <sup>-2</sup>	4,500
Fired reboiler (Area 300)	1.1x10 <sup>-1</sup>	4.6x10 <sup>-1</sup>	4.6 x10 <sup>-1</sup>	3.3x10 <sup>-1</sup>	6.0	5.1	3.0x10 <sup>-5</sup>	4.0x10 <sup>-2</sup>	1.1x10 <sup>-1</sup>	7,300
Methane reformer (Area 600) <sup>c</sup>	1.3	5.3	5.3	3.8	130	58	3.5x10 <sup>-4</sup>	25	1.3	490,000
WWTP (Area 700)				3.0x10 <sup>-1</sup>					1.2x10 <sup>-1</sup>	
Storage tanks (Area 700)				1.3					2.6x10 <sup>-1</sup>	
Loading operations (Area 700)				58					13	
Emergency generator (Area 700)	2.5x10 <sup>-2</sup>	2.5x10 <sup>-2</sup>	2.5 x10 <sup>-2</sup>	5.0x10 <sup>-1</sup>	5.0x10 <sup>-1</sup>	4.3x10 <sup>-1</sup>		8.2x10 <sup>-4</sup>	2.1x10 <sup>-3</sup>	87
Emergency fire pump (Area 700)	2.5x10 <sup>-2</sup>	2.5x10 <sup>-2</sup>	2.5 x10 <sup>-2</sup>	5.0x10 <sup>-1</sup>	5.0x10 <sup>-1</sup>	4.3x10 <sup>-1</sup>		8.2x10 <sup>-4</sup>	2.1x10 <sup>-3</sup>	87
Cooling tower (Area 700)	4.0x10 <sup>-2</sup>	2.0x10 <sup>-2</sup>	1.0 x10 <sup>-2</sup>	3.2					1.6	
Equipment leaks (Areas 100, 200, 300, 400, 500, and 600)				11.1					5.6	
Truck traffic	69	19	2.3							

Process	PM <sup>a</sup>	PM <sub>10</sub> <sup>a</sup>	PM <sub>2.5</sub> <sup>a</sup>	VOC	NOx	CO	Lead	SO <sub>2</sub>	HAP	GHGs (CO <sub>2</sub> eq)
Facility-wide total <sup>d</sup>	330	190	110	85	150	67	3.9x10 <sup>-4</sup>	460	24 (All HAP)	890,000
									4.6 (Single largest HAP – Toluene)	
Major Source for NSR and Title V	100	100	100	100	100	100	100	100	25 <sup>e</sup> (All HAP)	NA <sup>f</sup>
									10 (Any single HAP)	
PSD SER	25	15	10	40	40	100	0.6	40	NA <sup>e</sup>	Pending <sup>g</sup>

<sup>a</sup> PM is regulated as filterable PM, while PM<sub>10</sub> and PM<sub>2.5</sub> are regulated as the total of filterable PM in the size fraction (i.e., PM<sub>10</sub> or PM<sub>2.5</sub>) and condensable PM. Specifically, PM is regulated as measured using EPA Method 5, which measures only filterable PM. PM<sub>10</sub> and PM<sub>2.5</sub> are regulated as measured using EPA Method 201A, which measures the filterable PM at the size fraction and Method 202, which measures condensable PM. All condensable PM is included in the PM<sub>2.5</sub> and PM<sub>10</sub> size fractions.

<sup>b</sup> Includes emissions from the biomass feedstock transfer and storage operations, sand heater, and dryer

<sup>c</sup> Includes emissions from a hydrotreating reactor, hydrocracker, and pyrolysis reactor

<sup>d</sup> Numbers may not add up due to rounding and the use of two significant digits.

<sup>e</sup> Not subject to NSR; however, HAPs that are also VOCs are included in the VOC total and are considered when determining the applicability of PSD review for VOC.

<sup>f</sup> GHGs alone do not determine applicability of Title V or NSR.

<sup>g</sup> Currently, the PSD significance level for GHG is not defined. For pollutants with no significance level, any amount of emissions is considered significant. EPA is expected to publish a significance level in the future. In the meantime, some states are using 75,000 tpy of CO<sub>2</sub> equivalents as a PSD significant level.

**Table 21. Factors Considered for PTE Estimation and Preliminary Determination of Status**

Pollutant	Factors considered in PTE calculations in Table 20	Status	Additional Consideration and Refinements to PTE Calculation
PM, PM <sub>10</sub> , and PM <sub>2.5</sub>	<ol style="list-style-type: none"> <li>1. Planned baghouse on sand heater per the design case (Jones et al. 2013)</li> <li>2. Permit limits will be needed to make the PTE federally enforceable.</li> </ol>	Major for NSR	Further emission controls to reduce the PTE of PM, PM <sub>10</sub> , and PM <sub>2.5</sub> to below the major source level for NSR and PSD SER; or controls that would be considered BACT.
VOC	<ol style="list-style-type: none"> <li>1. Assumed VOC emission reduction (60%) for gasoline-loading operation as a preferred strategy to reduce HAP emissions for CMAS (40 CFR 63, Subpart VVVVVV) to apply; emission control devices will need to be installed.</li> <li>2. Assumed VOC emission reduction (95%) for the dryer vent as a preferred strategy to reduce HAP emissions for CMAS (40 CFR 63, Subpart VVVVVV) to apply; emission control devices will need to be installed.</li> <li>3. Use of a properly designed internal floating roof tank that meets the specifications in storage tank NSPS (Subpart Kb) for gasoline blendstock storage.</li> <li>4. Assumed emission reduction for equipment leaks (Areas 100–600) due to compliance with a leak detection and repair program required by CMAS (40 CFR 63, Subpart VVVVVV).</li> <li>5. Permit limits will be needed to make the PTE federally enforceable.</li> </ol>	Below major source level, but above SER for NSR	<ol style="list-style-type: none"> <li>1) Conservative assumptions are used for estimating PTE due to lack of information in the design case (Jones et al. 2013). Assumptions need to be revisited and refined when design specifics (e.g., true vapor pressure of gasoline and diesel blendstock) are available.</li> <li>2) Further emission controls to reduce the PTE to below SER for VOC; or controls that would be considered BACT.</li> </ol>
NO <sub>x</sub>	<ol style="list-style-type: none"> <li>1. No currently applicable regulatory limitation</li> <li>2. No planned emission control in the design case (Jones et al. 2013)</li> </ol>	Major for NSR	Further emission controls to reduce the PTE to below the major source level for NSR or PSD SER; or controls that would be considered BACT.
CO	<ol style="list-style-type: none"> <li>1. No currently applicable regulatory limitation</li> <li>2. No planned emission control in the design case (Jones et al. 2013)</li> </ol>	Below major source level and SER for NSR	Further refinement of emissions calculations

Pollutant	Factors considered in PTE calculations in Table 20	Status	Additional Consideration and Refinements to PTE Calculation
SO <sub>2</sub>	<ol style="list-style-type: none"> <li>1. No currently applicable regulatory limitation</li> <li>2. No planned emission control in the design case (Jones et al. 2013)</li> </ol>	Major for NSR	Further emission controls to reduce the PTE to below the major source level for NSR or PSD SER; or controls that would be considered BACT.
GHGs	<ol style="list-style-type: none"> <li>1. No currently applicable regulatory limitation</li> <li>2. No planned emission control in the design case (Jones et al. 2013)</li> </ol>	Pending	Refine PTE by determining what portion of the biogenic GHG emissions are exempt from being counted once regulation is finalized.
HAP (including lead)	<ol style="list-style-type: none"> <li>1. Assumed HAP emission reduction (60%) for gasoline-loading operation as a preferred strategy to reduce HAP emissions for CMAS (40 CFR 63, Subpart VVVVVV) to apply; emission control devices will need to be installed.</li> <li>2. Assumed HAP emission reduction (95%) for the dryer vent as a preferred strategy to reduce HAP emissions for CMAS (40 CFR 63, Subpart VVVVVV) to apply; emission control devices will need to be installed.</li> <li>3. Use of a properly designed internal floating roof tank that meets the specifications in CMAS for gasoline blendstock storage</li> <li>4. Assumed emission reduction for equipment leaks (Areas 100–600) due to compliance with a leak detection and repair program required by CMAS (40 CFR 63, Subpart VVVVVV).</li> <li>5. Permit limits will be needed to make the PTE federally enforceable.</li> </ol>	Area Source of HAP (i.e., below major source level of HAP for Title V)	Conservative assumptions are used for estimating PTE; assumptions should be revisited and refined when design specifics (e.g., HAP compositions in the gasoline and diesel blendstocks) are available.

## 6 Concluding Notes

As the fast pyrolysis design report (Jones et al. 2013) indicates, the design case is meant to quantify the economic impacts of the fast pyrolysis conversion process to allow evaluation of possible cost reductions. Per se, the design case is not intended to optimize the process to minimize air pollutant emissions. It is reasonable to expect that emissions from the biorefinery likely will be reduced as the technology matures and the entire process continues to be optimized (Jones 2010).

Caution is advised in using the preliminary estimates of PTE for decision making, as there are significant uncertainties inherent in the analysis. These are due to a lack of many specific design parameters required for PTE estimates and the subsequent use of general procedures for estimating emissions (e.g., the EPA's AP-42 approaches to estimating emissions from analogous unit operations in existing air permits).

The preliminary estimates of PTE reported here represent the maximum capacity of the biorefinery to emit pollutants after accounting for potentially federally enforceable limits. Therefore, the estimates may not reflect the actual emissions from the biorefinery. Because of the nascent stage of the design conversion technology, no emission data exist for the facilities, which use the same or similar technology. The estimates from this analysis should be considered preliminary and need to be verified once test results are available from facilities or unit operations using similar technology being built or in full operation. Some emission data from first-generation cellulosic biofuel facilities are expected to be available in the near future, as source performance tests are generally required by most permits within the first year of startup (see for example, ABBK's permit [Kansas Department of Health and Environment 2011]). These data can (1) help improve the fidelity of the PTE estimates to the designed unit processes of the fast pyrolysis biorefinery and (2) validate estimated emissions.

Finally yet importantly, this PTE analysis is for a standalone biorefinery based on the design case documented in Jones et al. (2013), with feedstock delivered to the biorefinery in trucks or by railcar. It is likely the biomass feedstock will be conveyed within a minimal distance from a biomass preprocessing facility to the cellulosic biorefinery through conveyors as envisioned in Kenney et al. (2013). Choosing one design scenario over the other has implications. If the preprocessing design plant is not co-located with the biorefinery, air permitting for the biorefinery and the preprocessing design plant could be completed separately. However, if the two facilities were considered a single source, the air permitting analyses would be conducted as if the two facilities were only one facility. For example, if the facilities were on adjacent properties, under common control of the same persons, and in the same industrial group per standard industrial classification codes, the emissions from each facility would be added together and only one air permit would be issued. Given that the biorefinery likely would be a major source for NSR and Title V without implementing emission controls other than those already planned, permitting the biomass preprocessing facility and biorefinery as one facility (i.e., co-located) increases the possibility that both operations would be considered a major source for NSR and Title V.



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## Appendix A. PSD Significant Emission Rates

For any PSD regulated pollutant not listed in Table A-1, any emissions are considered significant.

**Table A-1. PSD Significant Emission Rates (SERs)**

Pollutant	PSD Significant Emission Rate (tpy)
CO	100
NO <sub>x</sub>	40
SO <sub>2</sub>	40
PM	25
PM <sub>10</sub>	15
PM <sub>2.5</sub>	10
VOC	40
Lead	0.6
Fluorides	3
Sulfuric acid mist	7
Hydrogen sulfide	10
Total reduced sulfur (including hydrogen sulfide)	10
Reduced sulfur compounds (including hydrogen sulfide)	10
GHG	75,000 (CO <sub>2</sub> equivalents)
Municipal waste combustor organics <sup>a</sup>	$3.5 \times 10^6$
Municipal waste combustor metals <sup>b</sup>	15
Municipal waste combustor acid gases <sup>c</sup>	40
Municipal solid waste landfill emissions <sup>d</sup>	50

<sup>a</sup> Measured as total tetra-through octachlorinated dibenzo-p-dioxins and dibenzofurans.

<sup>b</sup> Measured as PM.

<sup>c</sup> Measured as SO<sub>2</sub> and HCl.

<sup>d</sup> Measured as nonmethane organic compounds.

## Appendix B. Regulated Pollutants

Disclaimer: This list of regulated pollutants in Table B-1 may not be up-to-date or may not be complete. Please refer to the EPA, Air Toxics website at [www.epa.gov/ttn/atw/](http://www.epa.gov/ttn/atw/) for current information.

**Table B-1. Regulated Pollutants**

Pollutant	CAS Number <sup>a</sup>	Type of Regulated Pollutant <sup>b</sup>
Acenaphthene <sup>c</sup>	83329	HAP
Acenaphthylene <sup>c</sup>	203968	HAP
Acetaldehyde [Ethanal]	75070	HAP, 112(r)
Acetamide [Ethanamide]	60355	HAP
Acetonitrile [Methyl cyanide]	75058	HAP
Acetophenone [1-Phenyl-ethanone]	98862	HAP
2-Acetylaminofluorene [N-9H-Fluoren-2-yl-acetamide]	53963	HAP
Acetylene [Ethyne; Ethine]	74862	112(r)
Acetylene tetrachloride [1,1,2,2-Tetrachloroethane]	79345	HAP
Acrolein [2-Propenal]	107028	HAP, 112(r)
Acrylamide [2-Propenamide]	79061	HAP
Acrylic acid [Propenoic acid]	79107	HAP
Acrylonitrile [2-Propenenitrile]	107131	HAP, 112(r)
Acrylyl chloride [2-Propenoyl chloride]	814686	112(r)
Allyl alcohol [2-Propen-1-ol; Propenyl alcohol]	107186	112(r)
Allylamine [2-Propen-1-amine]	107119	112(r)
Allyl chloride [3-Chloro-1-propene]	107051	HAP
p-Aminobiphenyl [4-Aminobiphenyl; p-Biphenyl amine]	92671	HAP
Ammonia (anhydrous)	7664417	112(r)
Ammonia (conc 20% or greater)	7664417	112(r)
Aniline [Amino benzene; Phenyl amine; Cyanol]	62533	HAP
o-Anisidine [2-Methoxy-benzenamine]	90040	HAP
Anthracene <sup>c</sup>	120127	HAP
Antimony compounds	NA	HAP
Arsenic compounds (inorganic including arsine)	NA	HAP
Arsenic pentoxide	1303282	HAP
Arsenous trichloride	7784341	HAP, 112(r)
Arsine	7784421	HAP, 112(r)
Asbestos	1332214	HAP, NSPS

Pollutant	CAS Number <sup>a</sup>	Type of Regulated Pollutant <sup>b</sup>
Benz(a)anthracene <sup>c</sup>	56553	HAP
Benzene (including benzene from gasoline) [Benzol;Phynyl hydride; Cyclohexatriene <sup>c</sup>	71432	HAP
Benzidine [(1,1'-Biphenyl)-4,4'-diamine]	92875	HAP
Benzo(a)pyrene <sup>c</sup>	50328	HAP
Benzo(b)fluoranthene <sup>c</sup>	205992	HAP
Benzo(g,h,i)perylene <sup>c</sup>	191242	HAP
Benzo(k)fluoranthene <sup>c</sup>	207089	HAP
Benzotrichloride [Phenyl chloroform]	98077	HAP
Benzyl chloride [w-Chlorotoluene]	100447	HAP
Beryllium compounds	NA	HAP
Beryllium oxide [Bromollite]	1304569	HAP
Beryllium sulfate	13510491	HAP
Biphenyl [1,1'-Biphenyl; Diphenyl]	92524	HAP
Bis (chloromethyl) ether [BCME; Chloromethyl ether; Oxybis (chloromethane)]	542881	HAP
Bis (2-ethylhexyl) phthalate [DEHP; 1,2-Benzenedicarboxylic acid; bis (2-thylhexyl) ester	117817	HAP
Boron trichloride [Trichloroborane]	10294345	112(r)
Boron trifluoride [Trifluoroborane]	7637072	112(r)
Boron trifluoride compound with methyl ether (1:1)	353424	112(r)
Bromine	7726956	112(r)
Bromoform [Tribromomethane]	75252	HAP
Bromotrifluoroethylene [Bromotrifluoroethene]	598732	112(r)
1,3-Butadiene [Erythrene]	106990	HAP, 112(r)
Butane [n-Butane; Diethyl]	106978	112(r)
Butene	25167673	112(r)
1-Butene [1-Butylene]	106989	112(r)
2-Butene [2-Butylene]	107017	112(r)
cis-2-Butene [(Z)-2-Butene]	590181	112(r)
trans-2-Butene [(E)-2-Butene]	624646	112(r)
Cadmium compounds	NA	HAP
Cadmium oxide	1306190	HAP
Cadmium sulfate [Soluble anhydrite]	10124364	HAP
Calcium cyanamide	156627	HAP

Pollutant	CAS Number <sup>a</sup>	Type of Regulated Pollutant <sup>b</sup>
Captan [3a,4,7,7a-Tetrahydro-2-((trichloromethyl)thio)-1H-isoindole-1,3(2H)-dione]	133062	HAP
Carbaryl [Methylcarbamate 1-naphthalenol]	63252	HAP
Carbon disulfide [Carbon bisulfide]	75150	HAP, 112(r)
Carbon monoxide [Carbon oxide]	630080	Criteria, NSPS
Carbon oxysulfide [Carbonyl sulfide; Carbon oxide sulfide]	463581	HAP, 112(r)
Carbon tetrachloride [Tetrachloromethane]	56235	HAP, Ozone-depleting
Catechol [1,2-Benzenediol; Pyrocatechol]	120809	HAP
Chloramben [3-Amino-2,5-dichloro-benzoic acid]	133904	HAP
Chlordane [1,2,4,5,6,7,8,8-Octachloro-2,3,3a,4,7,7a-hexahydro-4,7-mehano-1H-indene]	57749	HAP
Chlorine	7782505	HAP, 112(r)
Chlorine dioxide	10049044	112(r)
Chlorine monoxide [Chlorine oxide]	7791211	112(r)
Chloroacetic acid [b-Chloroacetic acid]	79118	HAP
2-Chloroacetophenone [w-Chloroacetophenone;2-chloro-1-pheyl-ethanone]	532274	HAP
Chlorobenzene	108907	HAP
Chlorobenzilate [Chlorobenzylate]	510156	HAP
Chlorofluorocarbon-I I (CFC-I I)	75694	Ozone-depleting
Chlorofluorocarbon-12 (CFC-12)	75718	Ozone-depleting
Chlorofluorocarbon-13 (CFC-13)	75729	Ozone-depleting
Chlorofluorocarbon-I I I (CFC-I I I)	354563	Ozone-depleting
Chlorofluorocarbon-112 (CFC-112)	76120	Ozone-depleting
Chlorofluorocarbon-113 (CFC-113)	76131	Ozone-depleting
Chlorofluorocarbon-114 (CFC-114)	76142	Ozone-depleting
Chlorofluorocarbon-115 (CFC-115)	76153	Ozone-depleting
Chlorofluorocarbon-211 (CFC-211)	422786	Ozone-depleting
Chlorofluorocarbon-212 (CFC-212)	3182261	Ozone-depleting
Chlorofluorocarbon-213 (CFC-213)	2354065	Ozone-depleting
Chlorofluorocarbon-214 (CFC-214)	29255310	Ozone-depleting
Chlorofluorocarbon-215 (CFC-215)	4259432	Ozone-depleting
Chlorofluorocarbon-216 (CFC-216)	661972	Ozone-depleting
Chlorofluorocarbon-217 (CFC-217)	422866	Ozone-depleting



Pollutant	CAS Number <sup>a</sup>	Type of Regulated Pollutant <sup>b</sup>
Chloroform [Trichloromethane]	67663	HAP, 112(r)
Chloromethyl ether	542881	112(r)
Chloromethyl methyl ether [Chloromethoxymethane]	107302	HAP, 112(r)
Chloroprene [2-Chloro-1,3-butadiene]	126998	HAP
1-Chloropropylene [1-Chloro-1-propene]	590216	112(r)
2-Chloropropylene [2-Chloro-1-propene]	557982	112(r)
Chromium compounds	NA	HAP
Chromium (+6) compounds	NA	HAP
Chrysene <sup>c</sup>	218019	HAP
Cobalt compounds	NA	HAP
Coke oven emissions	NA	HAP
Cresols/Cresylic acid (isomers and mixture)	1319773	HAP
m-Cresol [3-Methyl-phenol]	108394	HAP
o-Cresol [2-Methyl phenol]	95487	HAP
p-Cresol [4-Methyl phenol]	106445	HAP
Crotonaldehyde [2-Butenal]	4170303	112(r)
(E)-Crotonaldehyde [trans-Crotonaldehyde; (E)-2-Butenal]	123739	112(r)
Cumene [1-Methylethyl benzene, Isopropylbenzene]	98828	HAP
Cyanamide [Cyanogenamide]	420042	HAP
Cyanic acid [Hydrogen cyanate]	420053	HAP
Cyanide compounds [1]	NA	HAP
Cyanoacetamide [2-Cyanoacetamide]	107915	HAP
Cyanogen [Ethanedinitrile]	460195	HAP, 112(r)
Cyanogen chloride [Chlorine cyanide]	506774	HAP, 112(r)
Cyclohexylamine [Cyclohexanamine]	108918	112(r)
Cyclopropane [Trimethylene]	75194	112(r)
2,4- D [(2,4-Dichlorophenoxy)acetic acid], (including salts and esters)	94757	HAP
DDE [1,1'-Ethylidenebis(4-chloro-benzene); 1,1-Bis(4-chlorophenyl)ethane]	3547044	HAP
Diazomethane	334883	HAP
Dibenzo(a,h)anthracene <sup>c</sup>	53703	HAP
Dibenzofurans [2,2'-Biphenylene oxide]	132649	HAP, NSPS
Diborane	19287457	112(r)
1,2-Dibromo-3-chloropropane [Dibromochloropropane]	96128	HAP

Pollutant	CAS Number <sup>a</sup>	Type of Regulated Pollutant <sup>b</sup>
Dibutylphthalate [Dibutyl ester 1,2-benzenedicarboxylic acid]	84742	HAP
Dichlorobenzene <sup>c</sup>	25321226	HAP
1,4-Dichlorobenzene [p-Dichlorobenzene]	106467	HAP
3,3-Dichlorobenzidene	91941	HAP
Dichloroethyl ether [bis(2-chloroethyl)ether; 1,1'-oxybis{2-chloroethane}]	111444	HAP
Dichloromethane [Methylene chloride]	75092	HAP
1,3-Dichloropropene	542756	HAP
Dichlorosilane	4109960	112(r)
Dichlorvos [2,2-Dichloroethenyl dimethyl ester phosphoric acid]	62737	HAP
Diethanolamine [2,2'-Iminobisethanol]	111422	HAP
N,N-Diethylaniline [N,N-Dimethylbenzenamine]	121697	HAP
Diethyl sulfate [Diethyl ester sulfuric acid]	64675	HAP
Difluoroethane [1,1-Difluoroethane; Ethylidenedichloride]	75376	112(r)
3,3'-Dimethoxybenzidine [3,3'-Dimethoxy-(1,1'-biphenyl)-4,4'-diamine; o-Dianisidine]	119904	HAP
Dimethylamine [N-Methylmethanamine]	124403	112(r)
Dimethyl aminoazobenzene [N,N-Dimethyl-4-(phenylazo)-benzenamine; 4-(Dimethylamino)azobenzene]	60117	HAP
7,12-Dimethylbenz(a)anthracene <sup>c</sup>		HAP
3,3'-Dimethyl benzidine [3,3'-Dimethyl-(1,1'-biphenyl)- 4,4'-diamine; O-Tolidine]	119937	HAP
Dimethyl carbamoyl chloride [Dimethylcarbamic chloride]	79447	HAP
Dimethyldichlorosilane [Dichlorodimethylsilane]	75785	112(r)
Dimethyl formamide [N,N-Dimethyl formamide]	68122	HAP
1,1-Dimethyl hydrazine	57147	HAP, 112(r)
Dimethyl phthalate [Dimethyl ester 1,2-benzenedicarboxylic acid]	131113	HAP
2,2-Dimethylpropane	463821	112(r)
Dimethyl sulfate [Dimethyl ester sulfuric acid]	77781	HAP
4,6-Dinitro-o-cresol, and salts	534521	HAP
2,4-Dinitrophenol	51285	HAP
2,4-Dinitrotoluene [1-Methyl-2,4-dinitrobenzene]	121142	HAP
1,4-Dioxane [Dioxane; 1,4-Dioxacyclohexane]	123911	HAP
Dioxins and furans (total tetra through octachlorinated dibenzo-p-dioxins)	NA	NSPS, HAP
1,2-Diphenylhydrazine [N,N'-Diphenylhydrazine]	122667	HAP

Pollutant	CAS Number <sup>a</sup>	Type of Regulated Pollutant <sup>b</sup>
Epichlorohydrin [Chloromethyloxirane; 1-Chloro-2,3-epoxypropane]	106898	HAP, 112(r)
1,2-Epoxybutane [Ethyloxirane]	106887	HAP
Ethane	74840	112(r)
Ethyl acetylene [1-Butyne]	107006	112(r)
Ethyl acrylate [Ethyl ester 2-propenoic acid]	140885	HAP
Ethylamine [Ethanamine]	75047	112(r)
Ethylbenzene	100414	HAP
Ethyl carbamate [Urethane; Ethyl ester carbamic acid]	51796	HAP
Ethyl chloride [Chloroethane]	75003	HAP, 112(r)
Ethyl ether [1,1'-Oxybis-ethane]	60297	112(r)
Ethyl mercaptan [Ethanethiol]	75081	112(r)
Ethyl nitrite [Ethyl ester nitrous acid]	109955	112(r)
Ethylene [Ethene]	74851	112(r)
Ethylene dibromide [Dibromoethane]	106934	HAP
Ethylene dichloride [1,2-Dichloroethane]	107062	HAP
Ethylene glycol [1,2-Ethanediol]	107211	HAP
Ethyleneimine [Aziridine]	151564	HAP, 112(r)
Ethylene oxide [Oxirane]	75218	HAP, 112(r)
Ethylene thiourea [2-Imidazolidinethione]	96457	HAP
Ethylenediamine [1,2-Ethanediamine]	107153	112(r)
Ethylidene dichloride [1,2-Dichloroethane]	75343	HAP
Fine mineral fibers [3]	NA	HAP
Fluoranthene <sup>c</sup>	206440	HAP
Fluorene <sup>c</sup>	86737	HAP
Fluorides	NA	NSPS
Fluorine	7782414	112(r)
Formaldehyde [Methanal] <sup>c</sup>	50000	HAP, 112(r)
Furans (total tetra through octachlorinated dibenzofurans)	110009	112(r), NSPS, HAP
Glycol ethers [2](excludes surfactant alcohol ethoxylates)	NA	HAP
Greenhouse Gases <sup>d</sup>	NA	GHG
Halon-1211	353593	Ozone-depleting
Halon-1301	75638	Ozone-depleting
Halon-2402	124732	Ozone-depleting

Pollutant	CAS Number <sup>a</sup>	Type of Regulated Pollutant <sup>b</sup>
Heptachlor [1,4,5,6,7,8,8-Heptachlor-3a,4,7,7a-tetrahydro-4,7-methano-1H-indene]	76448	HAP
Hexachlorobenzene [HCB]	118741	HAP
Hexachlorobutadiene	87683	HAP
Hexachlorocyclopentadiene [Perchlorocyclopentadiene]	77474	HAP
Hexachloroethane	67721	HAP
Hexamethylene-1,6-diisocyanate [1,6-Diisocyanatohexane]	822060	HAP
Hexamethylphosphoramide [Tris(dimethylamino)phosphine oxide]	680319	HAP
Hexane <sup>c</sup>	110543	HAP
Hydrazine	302012	HAP, 112(r)
Hydrobromofluorocarbons	NA	Ozone-depleting
Hydrochloric acid [Hydrogen chloride]	7647010	HAP, 112(r), NSPS
Hydrochloric acid [Hydrogen chloride](con. 37% or greater)	7647010	112(r)
Hydrochlorofluorocarbon-21 (HCFC-21)	75434	Ozone-depleting
Hydrochlorofluorocarbon-22 (HCFC-22)	75456	Ozone-depleting
Hydrochlorofluorocarbon-31 (HCFC-31)	593704	Ozone-depleting
Hydrochlorofluorocarbon-121 (HCFC-121)	354143	Ozone-depleting
Hydrochlorofluorocarbon-122 (HCFC-122)	354212	Ozone-depleting
Hydrochlorofluorocarbon-123 (HCFC-123)	306832	Ozone-depleting
Hydrochlorofluorocarbon-124 (HCFC-124)	2837890	Ozone-depleting
Hydrochlorofluorocarbon-131 (HCFC-131)	359284	Ozone-depleting
Hydrochlorofluorocarbon-132-b (HCFC-132-b)	1649087	Ozone-depleting
Hydrochlorofluorocarbon-133-a (HCFC-133-a)	75887	Ozone-depleting
Hydrochlorofluorocarbon-141-b (HCFC-141-b)	1717006	Ozone-depleting
Hydrochlorofluorocarbon-142-b (HCFC-142-b)	75683	Ozone-depleting
Hydrochlorofluorocarbon-221 (HCFC-221)	422264	Ozone-depleting
Hydrochlorofluorocarbon-222 (HCFC-222)	422491	Ozone-depleting
Hydrochlorofluorocarbon-223 (HCFC-223)	422526	Ozone-depleting
Hydrochlorofluorocarbon-224 (HCFC-224)	422548	Ozone-depleting
Hydrochlorofluorocarbon-225-ca (HCFC-225-ca)	422560	Ozone-depleting
Hydrochlorofluorocarbon-225-cb (HCFC-225-cb)	507551	Ozone-depleting
Hydrochlorofluorocarbon-226 (HCFC-226)	431878	Ozone-depleting
Hydrochlorofluorocarbon-231 (HCFC-231)	421943	Ozone-depleting
Hydrochlorofluorocarbon-232 (HCFC-232)	460899	Ozone-depleting

Pollutant	CAS Number <sup>a</sup>	Type of Regulated Pollutant <sup>b</sup>
Hydrochlorofluorocarbon-233 (HCFC-233)	7125840	Ozone-depleting
Hydrochlorofluorocarbon-234 (HCFC-234)	425945	Ozone-depleting
Hydrochlorofluorocarbon-235 (HCFC-235)	460924	Ozone-depleting
Hydrochlorofluorocarbon-241 (HCFC-241)	666273	Ozone-depleting
Hydrochlorofluorocarbon-242 (HCFC-242)	460639	Ozone-depleting
Hydrochlorofluorocarbon-243 (HCFC-243)	460695	Ozone-depleting
Hydrochlorofluorocarbon-244 (HCFC-244)	NA	Ozone-depleting
Hydrochlorofluorocarbon-251 (HCFC-251)	421410	Ozone-depleting
Hydrochlorofluorocarbon-252 (HCFC-252)	819001	Ozone-depleting
Hydrochlorofluorocarbon-253 (HCFC-253)	460355	Ozone-depleting
Hydrochlorofluorocarbon-261 (HCFC-261)	420973	Ozone-depleting
Hydrochlorofluorocarbon-262 (HCFC-262)	4210203	Ozone-depleting
Hydrochlorofluorocarbon-271 (HCFC-271)	430557	Ozone-depleting
Hydrogen	1333740	112(r)
Hydrogen cyanide [Hydrocyanic acid]	74908	HAP, 112(r)
Hydrogen fluoride [Hydrofluoric acid]	7664393	HAP
Hydrogen fluoride [Hydrofluoric acid] (con. 50% or greater)	7664393	112(r)
Hydrogen selenide	7783075	112(r)
Hydrogen sulfide	7783064	112(r), NSPS
Hydroquinone [p-Hydroquinone; 1,4-Benzenediol]	123319	HAP
Indeno(1,2,3-cd)pyrene <sup>c</sup>	193395	HAP
Iron,pentacarbonyl-(Iron carbonyl)	13463406	112(r)
Isobutane (2-Methyl propane)	75285	112(r)
Isobutyronitrile (2-Methyl-propanenitrile)	78820	112(r)
Isopentane (2-Methyl-butane)	78784	112(r)
Isophorone (3,5,5-Trimethyl-2-cyclohexane-1-one)	78591	HAP
Isoprene (2-Methyl-1,3-butadiene)	78795	112(r)
Isopropylamine (2-Propamine)	75310	112(r)
Isopropyl chloride (2-chloro-propane)	75296	112(r)
Isopropyl chloroformate (1-Methylethyl ester carbonochloridic acid )	108236	112(r),
Lead	7439921	Criteria, NSPS
Lead arsenate	7645252	HAP
Lead (+2) arsenate	7784409	HAP
Lead Compounds	NA	HAP

Pollutant	CAS Number <sup>a</sup>	Type of Regulated Pollutant <sup>b</sup>
Lindane (All isomers)	58899	HAP
Maleic anhydride [2,5-Furandione]	108316	HAP
Manganese compounds	NA	HAP
Mercury compounds	NA	HAP
Methacrylonitrile [2-Methyl-2-propenenitrile]	126987	112(r)
Methane <sup>d</sup>	74828	112(r)
Methanol [Methyl alcohol]	67561	HAP
Methoxychlor [1,1'-(2,2,2-Trichloroethylidene)bis(4-methoxy benzene)]	72435	HAP
Methylamine [Methanamine]	74895	112(r)
Methyl bromide [Bromomethane]	74839	HAP, Ozone-depleting
3-Methylchloranthrene <sup>c</sup>	56495	HAP
Methyl chloride [Chloromethane]	74873	HAP, 112(r)
Methyl chloroform [1,1,1-Trichloroethane]	71556	HAP, Ozone-depleting
Methyl chloroformate [Methyl ester carbonochloridic acid]	79221	112(r)
Methyl ether [Oxybismethane]	115106	112(r)
Methyl formate [Methyl ester formic acid]	107313	112(r),
Methyl hydrazine	60344	HAP, 112(r)
Methyl iodide [Iodomethane]	74884	HAP
Methyl isobutyl ketone [Hexone][MIBK]	108101	HAP
Methyl isocyanate [Isocyanato-methane]	624839	HAP, 112(r)
2-Methyl-1-butene	563462	112(r)
3-Methyl-1-butene	563451	112(r)
2-Methylnaphthalene <sup>c</sup>	91576	HAP
Methyl mercaptan [Methanethiol]	74931	112(r)
Methyl methacrylate [Methyl ester 2-methyl-2-propenoic acid]	80626	HAP
2-Methylpropene [2-Methyl-1-propene]	115117	112(r)
Methyl tert-butyl ether [2-Methoxy-2-methyl propane]	1634044	HAP
Methyl thiocyanate [Methyl ester thiocyanic acid]	556649	112(r)
4,4'-Methylene bis(2-chloroaniline)	101144	HAP
Methylene chloride [Dichloromethane]	75092	HAP
4,4'-Methylenedianiline [4,4'-Methylenebis(2-chloro-benzenamine)]	101779	HAP
4,4'-Methylenediphenyl diisocyanate [MDI; Methylene bi-phenyl isocyanate]	101688	HAP

Pollutant	CAS Number <sup>a</sup>	Type of Regulated Pollutant <sup>b</sup>
Methyltrichlorosilane [Trichloromethylsilane]	75796	112(r)
Municipal waste combustor organics (measured as total tetra- thru octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	NA	NSPS
Municipal waste combustor metals (measured as particulate matter)	NA	NSPS
Municipal waste combustor acid gases (measured as sulfur dioxide and hydrogen chloride)	NA	NSPS
Municipal solid waste landfill emissions (measured as non-methane organic compounds)	NA	NSPS
Naphthalene <sup>c</sup>	91203	HAP
Nickel Compounds	NA	HAP
Nickel carbonyl	13463393	HAP, 112(r)
Nickel oxide [Nickel mono-oxide; Bunsenite]	1313991	HAP
Nickel sulfate	7786814	HAP
Nitric acid (conc. 80% or greater)	7697372	112(r)
Nitric oxide [Nitrogen oxide (NO)]	10102439	112(r)
Nitrobenzene	98953	HAP
4-Nitrobiphenyl [4-Nitro-1,1'-biphenyl]	92933	HAP
Nitrogen dioxide	10102440	Criteria, NSPS
Nitrogen oxides (NO; NO <sub>2</sub> ; NO <sub>3</sub> ; N <sub>2</sub> O; N <sub>2</sub> O <sub>3</sub> ; N <sub>2</sub> O <sub>4</sub> ; N <sub>2</sub> O <sub>5</sub> )	NA	NSPS
4-Nitrophenol [p-Nitrophenol]	100027	HAP
2-Nitropropane	79469	HAP
N-Nitrosodimethylamine [N-Methyl-N-nitrosomethanamine]	62759	HAP
N-Nitroso-N-methylurea [Methylnitrosourea]	684935	HAP
N-Nitrosomorpholine	59892	HAP
Oleum (Fuming Sulfuric acid) [Sulfuric acid, mixture with sulfur trioxide]	8014957	112(r)
Ozone	NA	Criteria
Parathion [O,O-diethyl O-(4-nitrophenyl) ester phosphoro-thioic acid]	56382	HAP
Particulate matter [PM]	NA	NSPS
Particulate matter with an aerodynamic diameter less than 10 microns [PM <sub>10</sub> ]	NA	Criteria
Particulate matter with an aerodynamic diameter less than 2.5 microns [PM <sub>2.5</sub> ]	NA	Criteria
Pentachloronitrobenzene [PCNB; Quintobenzene]	82688	HAP
Pentachlorophenol	87865	HAP
1,3-Pentadinene	504609	112(r)
Pentane	109660	112(r)

Pollutant	CAS Number <sup>a</sup>	Type of Regulated Pollutant <sup>b</sup>
1-Pentene [a-Amylene]	109671	112(r)
trans-2-Pentene[(E)-2-Pentene]	646048	112(r)
sis-2-Pentene [(Z)-2-Pentene]	627203	112(r)
Peracetic acid [Ethaneperoxoic acid]	79210	112(r)
Perchloroethylene [Tetrachloroethylene]	127184	HAP
Perchloromethylmercaptan [Trichloromethanesulfenyl chloride]	594423	112(r)
Phenanathrene <sup>c</sup>	85018	HAP
Phenol [Hydroxybenzene]	108952	HAP
p-Phenylenediamine [1,4-Benzenediamine]	106503	HAP
Phosgene [Carbonyl chloride; Carbonic dichloride]	75445	HAP, 112(r)
Phosphine	7803512	HAP, 112(r)
Phosphorus	7723140	HAP
Phosphorus oxychloride [Phosphoryl chloride]	10025873	112(r)
Phosphorus trichloride [Phosphorous trichloride]	7719122	112(r)
Phthalic anhydride [1,3-Isobenzofurandione]	85449	HAP
Piperidine [Azacyclohexane]	110894	112(r)
Polychlorinated biphenyls [PCB's, Aroclors]	1336363	HAP
Polycyclic organic matter [4]	NA	HAP
Propadiene [1,2-Propadiene]	463490	112(r)
Propane	74986	112(r)
1,3-Propane sultone [Propane sultone; 2,2-Dioxide 1,2- oxathiolane]	1120714	HAP
b-Propiolactone [2-Oxetanone]	57578	HAP
Propionaldehyde [Propanal]	123386	HAP
Propionitrile [Propanenitrile]	107120	112(r)
Propoxur [Baygon]	114261	HAP
Propyl chloroformate [Propyl ester carbonochloridic acid]	109615	112(r)
Propylene [1-Propene]	115071	112(r)
Propylene dichloride [1,2-Dichloropropane]	78875	HAP
Propylene oxide [Methyl oxirane]	75569	HAP, 112(r)
1,2-Propylenimine [2-Methylaziridine; Propyleneimine]	75558	HAP, 112(r)
Propyne [1-Propyne]	74997	112(r)
Pyrene <sup>c</sup>	129000	HAP
Quinoline [1-Azanaphthalene]	91225	HAP
Quinone [p-Benzoquinone; 2,5-Cyclohexadiene-1,4-dione]	106514	HAP



Pollutant	CAS Number <sup>a</sup>	Type of Regulated Pollutant <sup>b</sup>
Radionuclides (including radon) [5]	NA	HAP
Selenium compounds	NA	HAP
Silane	7803625	112(r)
Styrene [Ethenylbenzene]	100425	HAP
Styrene oxide [Phenyloxirane; Phenylethylene oxide]	96093	HAP
Sulfur dioxide	7446095	Criteria, NSPS
Sulfur dioxide (anhydrous)	7446095	112(r)
Sulfur tetrafluoride [T4-Sulfur fluoride]	7783600	112(r)
Sulfur trioxide	7446119	112(r)
Sulfuric acid mist	7664939	NSPS
2,3,7,8-Tetrachlorodibenzo-p-dioxin [Tetrachlorinated Dibenzo-p-dioxins]	1746016	HAP, NSPS
Tetrachloroethylene (Perchloroethylene)	127184	HAP
1,1,2,2-Tetrachloroethane [Acetylene tetrachloride]	79345	HAP
Tetrafluoroethylene [Tetrafluoroethene]	116143	112(r)
Tetramethyllead [Tetramethyl plumbane]	75741	112(r)
Tetramethylsilane	75763	112(r)
Tetranitromethane	509148	112(r)
Titanium tetrachloride (TiCl <sub>4</sub> ) [T4- Titanium chloride]	7550450	HAP, 112(r)
Toluene [Methylbenzene] <sup>c</sup>	108883	HAP
2,4-Toluenediamine [4-Methyl-1,3-benzenediamine; Toluene-2,4-diamine]	95807	HAP
Toluene diisocyanate (unspecified isomer) [1,3-Diisocyanatomethylbenzene]	26471625	112(r)
2,4-Toluene diisocyanate [TDI, 2,4-diisocyanato-1-methylbenzend]	584849	HAP, 112(r)
Toluene 2,6-diisocyanate [1,3-diisocyanato-2-methylbenzene]	91087	112(r)
o-Toluidine [2-Methylbenzenamine]	95534	HAP
Total fluorides	NA	NSPS
Total organic compounds (TOC)	NA	NSPS
Total suspended particulate matter (TSP) [Particulate Matter]	NA	NSPS
Total reduced sulfur (TRS) and reduced sulfur compounds	NA	NSPS
Toxaphene [Chlorinated camphene]	8001352	HAP
1,2,4-Trichlorobenzene	120821	HAP
1, 1, 1-Trichloroethane [Methyl chloroform]	71556	HAP, Ozone-depleting
1,1,2-Trichloroethane	79005	HAP

Pollutant	CAS Number <sup>a</sup>	Type of Regulated Pollutant <sup>b</sup>
Trichloroethylene	79016	HAP
Trichloromethane [Chloroform]	67663	HAP, 112(r)
2,4,5-Trichlorophenol	95954	HAP
2,4,6-Trichlorophenol	88062	HAP
Trichlorosilane	10025782	112(r)
Triethylamine [N,N-Diethylethanamine]	121448	HAP
Trifluorochloroethylene [Chlorotrifluoroethene]	79389	112(r)
Trifluralin	1582098	HAP
Trimethylamine [N,N dimethylmethanamine]	75503	112(r)
Trimethylchlorosilane [Chlorotrimethylsilane]	75774	112(r)
2,2,4-Trimethylpentane [Isooctane]	540841	HAP
Urethane (Carbamic acid ethyl ester)	51796	HAP
Vinyl acetate [Acetic acid ethenyl ester]	108054	HAP, 112(r)
Vinylacetylene [1-Buten-3-yne]	689974	112(r)
Vinyl bromide [Bromoethene]	593602	HAP
Vinyl chloride [Chloroethene]	75014	HAP, 112(r)
Vinyl ethyl ether [Ethyl vinyl ether, Ethoxyethene, EVE]	109922	112(r)
Vinyl fluoride [Fluoroethene]	75025	112(r)
Vinylidene chloride [1,1-Dichloroethylene]	75354	HAP, 112(r)
Vinylidene fluoride [1,1-Difluoroethylene]	75387	112(r)
Vinyl methyl ether [Methyl vinyl ether, Methoxyethene, MVE]	107255	112(r)
Volatile organic compounds [VOC's] <sup>d</sup>	NA	Criteria, NSPS
Xylenes (isomers and mixtures)	1330207	HAP
m-Xylene [1,3-Dimethylbenzene]	108383	HAP
o-Xylene [1,2-Dimethylbenzene]	95476	HAP
p-Xylene [1,4-Dimethylbenzene]	106423	HAP

<sup>a</sup> The CAS number is the numerical identifier assigned by the Chemical Abstracts Service (CAS).

<sup>b</sup> There is no significance to the order of the types of pollutants listed in the table.

<sup>c</sup> These pollutants are also considered polycyclic organic matter.

<sup>d</sup> One of the pollutants listed in the table (i.e., methane) is a specific GHG; however, it is not identified as such in the table because it is not intended to be an exhaustive list of *all* GHGs.

<sup>d</sup> Some of the pollutants listed in the table are specific VOC; however, they are not identified as such in the table because it is not intended to be an exhaustive list of *all* VOCs. Refer to Section 3 for a definition of VOC.

## Appendix C. Source Categories for Fugitives Counted in PTE (and for which 100 tpy PSD Major Source Threshold is Applicable)

For complete rule context, refer to 40 CFR 51.165(a)(1)(iv)(C).

1. Fossil fuel-fired steam electric plants of more than 250 million Btu/hr of heat input
2. Coal cleaning plants (with thermal dryers)
3. Kraft pulp mills
4. Portland cement plants
5. Primary zinc smelters
6. Iron and steel mill plants
7. Primary aluminum ore reduction plants
8. Primary copper smelters
9. Municipal incinerators capable of charging more than 250 tons of refuse per day
10. Hydrofluoric acid plants
11. Sulfuric acid plants
12. Nitric acid plants
13. Petroleum refineries
14. Lime plants
15. Phosphate rock processing plants
16. Coke oven batteries
17. Sulfur recovery plants
18. Carbon black plants (furnace plants)
19. Primary lead smelters
20. Fuel conversion plants
21. Sintering plants
22. Secondary metal production plants
23. Chemical process plants (“The term chemical processing plant shall not include ethanol production facilities that produce ethanol by natural fermentation included in NAICS codes 325193 or 312140,” per XYZ)
24. Fossil fuel boilers (or combinations thereof) totaling more than 250 million Btu/hr of heat input
25. Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels

26. Taconite ore processing plants
27. Glass fiber processing plants
28. Charcoal production plants
29. Any other stationary source category that is being regulated under Section 111 or 112 of the Clean Air Act as of August 7, 1980.

## Appendix D. Major Source Thresholds for Title V Operating Permits

A “major” source, for the purposes of Title V of the Clean Air Act, is a source that meets any one or more of the following:<sup>62</sup>

- Has the PTE a regulated pollutant at 100 tpy or more
- Has the PTE of an individual HAP of 10 tpy or more or the PTE of 25 tpy or more for the sum of HAP
- Has the PTE of GHGs of 100,000 tons of CO<sub>2</sub> equivalent per year or more (CO<sub>2</sub> emissions from biogenic sources have been deferred from permitting and are pending).
- Is located in a serious, severe, or extreme nonattainment area and has the PTE of NO<sub>x</sub> or VOC of greater than or equal to 50, 25, or 10 tpy respectively
- Is located in a serious CO nonattainment area, and the EPA Administrator has determined that stationary sources contribute significantly to the CO ambient levels in the area, and has the PTE of CO of 50 tpy or more
- Is located in a serious particulate matter (PM<sub>10</sub>) nonattainment area that has the PTE of PM<sub>10</sub> of 70 tpy or more
- Is located within an ozone transport region and has (1) the PTE of VOC of greater than or equal to 50 tpy or (2) a PTE of NO<sub>x</sub> of greater than or equal to 100 tpy.

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<sup>62</sup> For complete rule context, refer to 40 CFR 70.2 and the definition of a “major source.”

## Appendix E. Major NSR Thresholds for Nonattainment Areas (NNSR)

For complete rule context, refer to 40 CFR 51.165(a)(1)(iv)(A).

**Table E-1. Insert Caption Here**

Pollutant	Nonattainment Classification	Major Source Threshold (tpy)
Ozone	Marginal ( $\geq 0.085 < 0.092$ ppm)	100 of VOC or NOx
	Moderate ( $\geq 0.092 < 0.107$ ppm)	100 of VOC or NOx
	Serious ( $\geq 0.107 < 0.120$ ppm)	50 of VOC or NOx
	Severe ( $\geq 0.120 < 0.187$ ppm)	25 of VOC or NOx
	Extreme ( $= 0.187$ ppm and up)	10 of VOC or NOx
Particulate Matter (10 $\mu$ m)	Moderate	100
	Serious	70
Carbon Monoxide	Moderate (9.1–16.4 ppm)	100
	Serious ( $\geq 16.5$ ppm)	50
Sulfur Dioxide, Nitrogen Oxides and Lead	No nonattainment classifications exist.	100

Current attainment status for each state can be found in EPA's "Green Book" (<http://www3.epa.gov/airquality/greenbook/astate.html>).

## Appendix F. Specific NSPSs that are Applicable to Equipment at the Design Plant

**Table F-1. Standards of Performance for Volatile Organic Liquid Storage Vessels (NSPS Subpart Kb)**

NSPS Subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels
Applicability	<ul style="list-style-type: none"> <li>• Storage vessels with a capacity greater than or equal to 19,813 gallons that are used to store volatile organic liquids (VOL) [60.110b(a)]</li> <li>• Does <i>not</i> apply to storage vessels with a capacity greater than or equal to 39,890 gallons storing a liquid with a maximum true vapor pressure less than 3.5 kPa or with a capacity greater than or equal to 19,813 gallons but less than 39,890 gallons storing a liquid with a maximum true vapor pressure less than 15.0 kPa [60.110b(b)]</li> <li>• Does <i>not</i> apply to process tanks [60.111b]</li> <li>• There are other specific exemptions to this rule [60.110b(d)].</li> </ul>
Assumptions	<ul style="list-style-type: none"> <li>• The design report (Jones et al. 2013) mentions two product storage tanks, each with a capacity greater than 500,000 gallons; presumably, these tanks are to hold the liquid blendstock products that are similar to gasoline and diesel.               <ul style="list-style-type: none"> <li>○ Even though the product storage tank holding diesel is over 500,000 gallons, it does not meet the maximum true vapor pressure thresholds of the rule applicability.</li> <li>○ The product storage tank holding gasoline will meet the capacity and maximum true vapor pressure thresholds of the rule applicability; therefore, it is subject to this rule.</li> </ul> </li> <li>• The design report does not specify any other tanks meeting size or liquid rule applicability thresholds. It states that there are an ammonia storage tank and a hydrazine storage tank, but ammonia and hydrazine are not organic liquids; therefore, they are not subject to this NSPS. The design report also mentions that the design plant will have a “tank farm”; however, the design report does not provide the size or contents of each tank that will be located at the “tank farm.”</li> </ul>
VOC Standards	<ul style="list-style-type: none"> <li>• Work practice standards to minimize VOC emissions apply (see compliance)</li> </ul>
Compliance	<ul style="list-style-type: none"> <li>• Certain tanks applicable to the rule may install a fixed roof in combination with an internal floating roof [60.112b(a)(1)].</li> <li>• Certain tanks applicable to the rule may install an external floating roof [60.112b(a)(2)].</li> <li>• Any tanks applicable to the rule may use a closed vent system and control device [60.112b(a)(3) or 60.112b(b)(1)].</li> <li>• Any tanks applicable to the rule may use a system equivalent to those described above [60.112b(a)(4) or 60.112b(b)(2)].</li> </ul>
Design Plant Area	<ul style="list-style-type: none"> <li>• Area 700: Storage tanks</li> </ul>
Specific Design Plant Equipment	<ul style="list-style-type: none"> <li>• Gasoline product storage tank<sup>a</sup></li> </ul>

<sup>a</sup> See page 63 of Appendix A in the design report (Jones et al. 2013).

**Table F-2. Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE) (NSPS Subpart III)**

NSPS Subpart III	Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE)
Applicability	<ul style="list-style-type: none"> <li>Stationary compression ignition internal combustion engines [60.4200(a)]</li> </ul>
Assumptions	<ul style="list-style-type: none"> <li>Although the design report mentions a firewater pump and diesel pump, it does not include the size or design of this emergency equipment. Therefore, assume the design plant uses a 300-hp firewater pump engine with a displacement of less than 30 liters per cylinder.</li> </ul>
PM Standards	<ul style="list-style-type: none"> <li>0.15 g/hp-hr [60.4205(c)]</li> </ul>
NMHC + NO <sub>x</sub> Standards	<ul style="list-style-type: none"> <li>3.0 g/hp-hr [60.4205(c)]</li> </ul>
Compliance	<ul style="list-style-type: none"> <li>The sulfur content of the diesel fuel combusted in the emergency fire water-pump engine shall not exceed 15 ppm [60.4207(b)].</li> <li>The diesel fuel combusted in the emergency fire water-pump engine shall have a minimum centane index of 40 or a maximum aromatic content of 35 volume percent [60.4207(b)].</li> </ul>
Design Plant Area	<ul style="list-style-type: none"> <li>Area 700: emergency engines</li> </ul>
Specific Design Plant Equipment	<ul style="list-style-type: none"> <li>Firewater pump<sup>a</sup></li> <li>Diesel pump<sup>a</sup></li> </ul>

<sup>a</sup> See page 63 of Appendix A in the design report (Jones et al. 2013).



## Appendix G. Clean Air Act HAPs Used to Determine Applicability of Chemical Manufacturing Operations to Chemical Manufacturing Area Sources NESHAP (40 CFR 63, Subpart VVVVVV)

**Table G-1. List of HAPs used to Determine Applicability of CMAS (NESHAP Subpart VVVVVV)<sup>a</sup>**

Type of HAP	Chemical Name	CAS #
Metal compounds	Arsenic compounds	NA
	Cadmium compounds	NA
	Chromium compounds	NA
	Lead compounds	NA
	Manganese compounds	NA
	Nickel compounds	NA
Organic compounds	Chloroform	67-66-3
	Acetaldehyde	75-07-0
	Methylene chloride (Dichloromethane)	75-09-2
	Quinoline	91-22-5
	1,3-Butadiene	106-99-0
	Ethylene dichloride (1,2-Dichloroethane)	107-06-2
	Hexachlorobenzene	118-74-1
	1,3-Dichloropropene	542-75-6
Others	Hydrazine	302-01-2

<sup>a</sup> The following web page provides an updated HAP list that can be used to determine the applicability of this rule: <http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr;rgn=div6;view=text;node=40%3A15.0.1.1.1.35;idno=40;sid=fd3b12eb6d0178cbf50139f96d7e9fad;cc=ecfr>.

## Appendix H. Specific NESHAPs that are Applicable to the Design Plant

Table H-1. Standards of Performance for Chemical Manufacturing Area Sources (NESHAP Subpart VVVVVV)

NESHAP Subpart VVVVVV	National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources
Applicability	<ul style="list-style-type: none"> <li>• In order to be subject to Subpart VVVVVV a facility must meet the following three conditions [63.11193]:               <ol style="list-style-type: none"> <li>1. The facility is an area (minor) source of HAPs [63.11494(a)(1)].</li> <li>2. The facility uses a feedstock or produce a product or byproduct containing any HAP listed in Table 1 of the regulation and [63.11494(a)(2)] (refer to Appendix F for list of chemicals).</li> <li>3. One of the following is met:                   <ul style="list-style-type: none"> <li>○ The HAP(s) in feedstock have levels greater than 1.0% (for quinoline, manganese, and/or trivalent chromium), or 0.1% for any other HAP listed in Table 1 of the regulation.</li> <li>○ Quinoline is generated as byproduct and is present in the CMPU in any liquid stream (process or waste) at a concentration greater than 1.0% by weight.</li> <li>○ Hydrazine and/or Table 1 organic HAP other than quinoline are generated as byproduct and are present in the CMPU in any liquid stream (process or waste), continuous process vent, or batch process vent at an individual concentration greater than 0.1% by weight.</li> <li>○ Hydrazine or any HAP listed in Table 1 of the regulation is produced as a product of the CMPU [63.11494(a)(2)].</li> </ul> </li> </ol> </li> </ul>
Assumptions	<ul style="list-style-type: none"> <li>• Design plant is an area source of HAP (i.e., it has the potential to emit any single HAP at a rate &lt;10 tpy, and any combination of HAP at a rate &lt;25 tpy).</li> <li>• Design plant uses hydrazine (or another HAP listed in Table 1 of the regulation) in the hydrogen production process (Area 600).</li> <li>• No metal HAPs</li> <li>• No halogenated streams</li> </ul>
<b>A. Batch Process Vents</b>	
Assumptions	<ul style="list-style-type: none"> <li>• Assume that the design plant does not have batch process vents; however, if it did and the total organic HAP emissions from all of the batch process vents are equal to or greater than 10,000 lb/yr (which is a worst-case scenario for batch process vent rule requirements), the following HAP standards would apply to the batch process vents.</li> </ul>
HAP Standards	<ul style="list-style-type: none"> <li>• Reduce collective uncontrolled total organic HAP emissions from the sum of all batch process vents by ≥90% by weight or to ≤20 parts per million by volume by routing emissions from a sufficient number of the batch process vents through a closed vent system to any combination of control devices (except a flare) in accordance</li> </ul>

NESHAP Subpart VVVVV	National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources
	<p>with the requirements of §63.982(c) [63.11496(a)]</p> <ul style="list-style-type: none"> <li>• Route emissions from batch process vents containing at least 90% of the uncontrolled total organic HAP through a closed-vent system to a flare in accordance with the requirements of §63.982(b) [63.11496(a)]</li> <li>• Comply with the alternative standard specified in §63.2505 [63.11496(a)]</li> </ul>
Design Plant Area	<ul style="list-style-type: none"> <li>• None</li> </ul>
Specific Design Plant Equipment	<ul style="list-style-type: none"> <li>• None</li> </ul>
B. Continuous Process Vents	
Assumptions	<ul style="list-style-type: none"> <li>• Data to allow TRE<sup>a</sup> calculations do not exist for design plant; therefore, assume <math>TRE \leq 1.0</math>, which designates continuous process vents as Group 1 (which is a worst-case scenario for process vent rule requirements). <ul style="list-style-type: none"> <li>• Assume that in the worst case, HAP is emitted in large enough quantities to require control</li> </ul> </li> </ul>
HAP Standards	<ul style="list-style-type: none"> <li>• Reduce emissions of total organic HAP by <math>\geq 95\%</math> by weight (<math>\geq 85\%</math> by weight for periods of startup or shutdown) or to <math>\leq 20</math> parts per million by volume by routing emissions through a closed vent system to any combination of control devices (except a flare) in accordance with §63.982(c) [63.11496(b)]</li> <li>• Reduce emissions of total organic by HAP by routing all emissions through a closed-vent system to a flare in accordance with §63.982(b) [63.11496(b)]</li> <li>• Comply with the alternative standard specified in §63.2505 [63.11496(b)]</li> </ul>
Design Plant Area	<ul style="list-style-type: none"> <li>• Area 100: Fast pyrolysis</li> <li>• Area 200: Hydrotreating to hydrocarbons</li> <li>• Area 300: Product recovery</li> <li>• Area 500: Hydrocracking</li> <li>• Area 600: Hydrogen production</li> </ul>
Specific Design Plant Equipment	<ul style="list-style-type: none"> <li>• R-110 pyrolysis reactor</li> <li>• R-220 and R-225 hydrotreating reactors</li> <li>• T-290 lights column</li> <li>• T-310 naphtha splitter</li> <li>• T-320 diesel splitter</li> <li>• R-510 hydrocracking process unit</li> <li>• R-600 methane reformer</li> </ul>

NESHAP Subpart VVVVV	National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources
C. Storage Tanks	
Assumptions	<ul style="list-style-type: none"> <li>• Design plant will have at least two storage tanks with capacity greater than or equal to 40,000 gallons, that stores liquid containing organic HAP listed in Table 1 of the regulation, and that has a maximum true vapor pressure of total HAP at the storage temperature greater than or equal to 5.2 kilopascals.</li> <li>• The design report (Jones et al. 2013) mentions a hydrazine storage tank, but its capacity is unknown; assume capacity of this tank is greater than or equal to 40,000 gallons and therefore subject to this rule.</li> <li>• The design report mentions two product storage tanks each of which has a capacity greater than 500,000 gallons; presumably, these tanks are to hold the liquid blendstock products that are similar to gasoline and diesel. <ul style="list-style-type: none"> <li>○ Even though the product storage tank holding diesel has a capacity greater than 500,000 gallons, it does not meet the maximum true vapor pressure thresholds of the rule applicability.</li> <li>○ The product storage tank holding gasoline will meet the capacity and maximum true vapor pressure thresholds of the rule applicability; therefore, it is subject to this rule.</li> </ul> </li> <li>• The design report mentions that the design plant will have a “tank farm”; however, the design report does not provide the size or contents of each tank that will be located at the “tank farm.”</li> </ul>
HAP Standards	<ul style="list-style-type: none"> <li>• Certain tanks applicable to rule may comply with the requirements of 40 CFR 63, Subpart WW [63.11497(a)].</li> <li>• Certain tanks applicable to rule may reduce total organic HAP emissions by ≥95% by weight by operating and maintaining a closed-vent system and control device [63.11497(a)].</li> <li>• Certain tanks applicable to rule may reduce total HAP emissions by operating and maintaining a closed-vent system and a flare [63.11497(a)].</li> </ul>
	<ul style="list-style-type: none"> <li>• Certain tanks applicable to rule may use vapor balance [63.11497(a)].</li> <li>• Certain tanks applicable to rule may route emissions to a fuel gas system or process [63.11497(a)].</li> </ul>
Design Plant Area	<ul style="list-style-type: none"> <li>• Area 700: Storage tanks</li> </ul>
Specific Design Plant Equipment	<ul style="list-style-type: none"> <li>• Gasoline product storage tank<sup>b</sup></li> <li>• Hydrazine storage tank<sup>b</sup></li> </ul>

<b>NESHAP Subpart VVVVVV National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources</b>	
<b>D. Wastewater</b>	
Assumptions	<ul style="list-style-type: none"> <li>The design plant will have wastewater that (1) contains at least 5 parts per million by weight of any HAP listed in Table 9 to 40 CFR part 63, Subpart G and (2) has an annual average flow rate of 0.02 liters per minute. Note: more requirements (not shown here) apply if (1) the partially soluble HAP (listed in Table 7 of NESHAP Subpart VVVVVV) concentration in a wastewater stream is equal to or greater than 10,000 parts per million by weight and (2) the wastewater stream contains a separate organic phase. However, this is impossible to determine with the information provided in the design report.</li> </ul>
HAP Standards	<ul style="list-style-type: none"> <li>Discharge to onsite or offsite wastewater treatment or hazardous waste treatment [63.11498(a)]</li> <li>Maintain records identifying each wastewater stream and documenting the type of treatment that it receives; multiple wastewater streams with similar characteristics and from the same type of activity in a CMPU may be grouped together for recordkeeping purposes [63.11498(a)].</li> </ul>
Design Plant Area	<ul style="list-style-type: none"> <li>Area 700: Wastewater treatment</li> </ul>
Specific Design Plant Equipment	<ul style="list-style-type: none"> <li>Any wastewater stream that meets applicability thresholds from any areas of the design plant</li> </ul>
<b>E. Heat Exchange System</b>	
Assumptions	<ul style="list-style-type: none"> <li>Design plant will have a cooling tower system (capable of handling 44,200 gallons per minute) that does not meet any of the criteria specified in 63.104(a)(1) through (6). Note: it is possible that the cooling tower system would meet 63.104(a)(2) (which says if the intervening cooling fluid between the process and the cooling water contains &lt;5% by weight of total HAPs listed in Table 4 of 40 CFR 63, Subpart F, the cooling tower system is excluded from any requirements under this rule. However, this is impossible to determine with the information provided in the design report.</li> </ul>
HAP Standards	<ul style="list-style-type: none"> <li>Work practice standards to minimize HAP emissions apply.</li> <li>Monitor using a surrogate indicator of heat exchange system leaks; prepare and implement a monitoring plan that documents the procedures that will be used to detect leaks of process fluids into cooling water; the plan shall require monitoring of one or more surrogate indicators or monitoring of one or more process parameters or other conditions that indicate a leak. Surrogate indicators that could be used to develop an acceptable monitoring program include ion specific</li> </ul>

NESHAP Subpart VVVVV	National Emission Standards for Hazardous Air Pollutants for Chemical Manufacturing Area Sources
	<p>electrode monitoring, pH, conductivity, and other representative indicators [63.11499(a) and 63.104(c)].</p> <ul style="list-style-type: none"> <li>Leak repair requirements in §63.104(d) and (e), and the recordkeeping and reporting requirements in §63.104(f); a leak shall be (1) repaired as soon as practical but not later than 45 calendar days and (2) confirmed to not be leaking after repair or startup [63.11499(a)].</li> </ul>
Design Plant Area	<ul style="list-style-type: none"> <li>Area 700: Cooling tower</li> </ul>
Specific Design Plant Equipment	<ul style="list-style-type: none"> <li>Cooling tower system</li> </ul>

<sup>a</sup> TRE means total resource effectiveness. It is a measure of the supplemental total resource requirement per unit reduction of organic HAP associated with a process vent stream, based on vent stream flow rate, emission rate of organic HAP, net heating value, and corrosion properties (whether the vent stream contains halogenated compounds), as quantified by an equation (see 63.11496(b)(1)), which was developed from current characteristics of process vents. TRE was developed by the EPA as a cost cut-off concept that when equal to or higher than a given number of a federal rule, the facility is not required to install control.

<sup>b</sup> See page 63 of Appendix A in the design report (Jones et al. 2013).

**Table H-2a. Standards of Performance for Stationary Reciprocating Internal Combustion Engines (RICE) (NESHAP Subpart ZZZZ)**

NESHAP Subpart ZZZZ	National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)
Applicability	<ul style="list-style-type: none"> <li>Stationary reciprocating internal combustion engines at a major or area source of HAP emissions</li> </ul>
Assumptions	<ul style="list-style-type: none"> <li>Although the design report mentions a firewater pump and diesel pump, it does not include the size or design of this emergency equipment. Therefore, assume the design plant uses an emergency stationary compression ignition (CI) RICE that is black start stationary and 300HP. Black start engine means an engine whose only purpose is to start up a combustion turbine.</li> <li>Design plant has the potential to emit any single HAP at a rate &lt;10 tpy, and any combination of HAP at a rate &lt;25 tpy.</li> </ul>
Work Practice Standards	<ul style="list-style-type: none"> <li>Work practice standards to minimize HAP emissions apply. (see compliance)</li> </ul>
Compliance	<ul style="list-style-type: none"> <li>Change oil and filter every 500 hours of operation or annually, whichever comes first [63.6603(a)]</li> <li>Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary [63.6603(a)]</li> <li>Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary [63.6603(a)]</li> </ul>
Design Plant Area	<ul style="list-style-type: none"> <li>Area 700: Emergency engines</li> </ul>
Specific Design Plant Equipment	<ul style="list-style-type: none"> <li>Firewater pump<sup>a</sup></li> <li>Diesel pump<sup>b</sup></li> </ul>

<sup>a</sup> See page 63 of Appendix A in the design report (Jones et al. 2013).

**Table H-2b. Standards of Performance for Stationary Reciprocating Internal Combustion Engines (RICE) (Subpart ZZZZ)**

<b>NESHAP Subpart ZZZZ</b>	<b>National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE)</b>
Applicability	<ul style="list-style-type: none"> <li>Stationary reciprocating internal combustion engines at a major or area source of HAP emissions</li> </ul>
Assumptions	<ul style="list-style-type: none"> <li>Although the design report mentions a firewater pump and diesel pump, it does not include the size or design of this emergency equipment. Therefore, assume the design plant will have an emergency stationary compression ignition (CI) RICE that is black start stationary and 300HP. Black start engine means an engine whose only purpose is to start up a combustion turbine.</li> <li>Design plant has the potential to emit any single HAP at a rate &gt;10 tpy, and/or any combination of HAP at a rate &gt;25 tpy.</li> </ul>
Work Practice Standards	<ul style="list-style-type: none"> <li>Work practice standards to minimize HAP emissions apply. (see compliance)</li> </ul>
Compliance	<ul style="list-style-type: none"> <li>Change oil and filter every 500 hours of operation or annually, whichever comes first [63.6602]</li> <li>Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary [63.6602]</li> <li>Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary [63.6602]</li> <li>During periods of startup, you must minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply [63.6602].</li> </ul>
Design Plant Area	<ul style="list-style-type: none"> <li>Area 700: Emergency engines</li> </ul>
Specific Design Plant Equipment	<ul style="list-style-type: none"> <li>Firewater pump<sup>a</sup></li> <li>Diesel pump<sup>a</sup></li> </ul>

<sup>a</sup> See page 63 of Appendix A in the design report (Jones et al. 2013).



# Appendix I. Preliminary Estimates of Uncontrolled PTE and PTE of Regulated Air Pollutants from Fast Pyrolysis Biorefinery

[Link to Appendix I Excel worksheet](#)