**Appendix U: Four-Factor Analyses**

This appendix contains the Reasonable Progress Analysis and Determination (Four-Factor Analysis) for the following three units in Maine with the potential for 3.0 Mm-1 or greater visibility impacts at any MANE-VU Class 1 Area:

|  |  |  |  |
| --- | --- | --- | --- |
| Appendix Section | Facility | Unit | Location |
| U.1. | The Jackson Laboratory | Boiler #12 | Bar Harbor, Maine |
| U.2. | Woodland Pulp LLC | No. 9 Power Boiler | Baileyville, Maine |
| U.3. | FPL Energy Wyman, LLC | Boiler No. 4 | Yarmouth, Maine |

**Appendix U.1. Boiler #12, The Jackson Laboratory**

**Reasonable Progress Analysis and Determination**

**(Four-Factor Analysis)**

**The Jackson Laboratory**

**Bar Harbor, Maine**

**2019**

**Introduction**

In accordance with the *Regional Haze Program Requirements*, 40 C.F.R. Part 51.308, States must submit to EPA a long-term strategy that addresses regional haze visibility impairment. In developing its long-term strategy, selected sources must be evaluated, and the State must consider and analyze emission reduction measures based on four statutory factors. The four factors to be evaluated for each selected source are the following:

* Cost of compliance;
* Time necessary for compliance;
* Energy and non-air environmental impacts; and
* Remaining useful life of the source.

The “four-factor analysis,” also known as a Reasonable Progress Analysis and Determination, looks exclusively at pollutants that cause or contribute to regional haze; specifically particulate matter (PM), sulfur dioxide (SO2), and nitrogen oxides (NOX).

This section addresses the four-factor analysis for Boiler #12 operated by The Jackson Laboratory (JAX) at their facility located in Bar Harbor, Maine.

**Source Description**

JAX operates Boiler #12 for facility heating. The boiler is a Babcock & Wilcox package boiler which primarily fires pulverized wood pellets with a maximum moisture content of 10% by weight. It is also licensed to fire distillate fuel with a maximum sulfur content of 0.0015% by weight as well as natural gas and propane. Boiler #12 has a maximum heat input of 44.4 MMBtu/hr when firing wood and 49.9 MMBtu/hr when firing distillate fuel, natural gas, or propane.

Although Boiler #12 is licensed to fire multiple fuels, natural gas capability has not yet been installed, and propane is used only for ignition purposes. Distillate fuel is used infrequently and makes up less than 1% of the heat input to the boiler on an annual basis. Therefore, this analysis focuses only on emissions from wood combustion.

Emissions from Boiler #12 are controlled by a baghouse before exiting through a 60-foot stack. The boiler is subject to the following emission limits for PM, SO2, and NOX:

|  |  |  |  |
| --- | --- | --- | --- |
| **Emission Unit** | **Pollutant** | **lb/MMBtu** | **Origin and Authority** |
| Boiler #12(all fuels) | PM | 0.030 | 40 C.F.R. Part 60, Subpart Dc,40 C.F.R. Part 63, Subpart JJJJJJ,and 06-096 C.M.R. ch. 115, BPT |

| **Emission Unit** | **PM****(lb/hr)** | **SO2****(lb/hr)** | NOX**(lb/hr)** | **Origin and Authority** |
| --- | --- | --- | --- | --- |
| Boiler #12(wood) | 1.33 | 1.11 | 8.44 | 06-096 C.M.R. ch. 115, BPT |

**Evaluation**

The four-factor analysis is an assessment of the applicable control technologies capable of reducing emissions of specific pollutants that can potentially contribute to regional haze (i.e., PM, SO2, and NOX). It is conducted using a “top-down” approach, similar to a Best Available Control Technology (BACT) analysis, taking into account feasibility and cost effectiveness as well as economic, environmental, and energy impacts. The assessment is conducted on a case-by-case basis using site-specific information, as available. The following steps comprise the assessment process:

Step 1: Identify Available Control Technologies

Step 2: Eliminate Technically Infeasible Options

Step 3: Evaluate Each Control Based on the Four Statutory Factors

Step 4: Determine Control Technologies for Inclusion in State’s Long-Term Strategy

These steps are to be followed when performing the analysis. However, in the guidance document titled *Draft Guidance on Progress Tracking Metrics, Long-term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period* (July 2016), EPA encouraged States to reference the 2005 Best Available Retrofit Technology (BART) Guidelines as material that was still informative and useful. The 2005 BART Guidelines were included as Appendix D to the July 2016 document with section-by-section explanation of what material was still relevant to the reasonable progress determinations.

The 2005 BART Guidelines state that EPA believed many sources subject to Maximum Achievable Control Technology (MACT) Standards under Clean Air Act (CAA) Section 112 were well controlled for PM. Any source subject to MACT standards must meet a level that is as stringent as the best-controlled 12% of sources in the industry. It will be unlikely that States will identify emission controls more stringent that MACT standards without identifying control options that would be cost prohibitive. Therefore, unless they are able to identify new technologies subsequent to the MACT standards which would lead to a cost-effective increase in control, States may rely on the MACT standard for purposes of the determination. This rationale was reaffirmed as a recommendation for the development of the long-term strategy in the second implementation period.

Boiler #12 is subject to a MACT standard (40 C.F.R. Part 63, Subpart JJJJJJ) and has demonstrated compliance through performance testing with the required emission limitation of 0.030 lb/MMBtu for PM using a baghouse. There are no new PM control options for wood‑fired boilers which have been identified since the MACT standard was promulgated. Therefore, further analysis of PM controls for Boiler #12 have been determined to be unnecessary and have been excluded from the remainder of this analysis.

The following explains the steps of the four-factor analysis in more detail and applies them directly to emissions of NOX and SO2 from JAX’s Boiler #12.

Step 1: Identify Available Control Technologies

The first step of the evaluation is to identify “available” control options. Available control options are those air pollution control technologies or techniques that have the potential for practical application to the emissions unit and pollutant under evaluation, with a focus on technologies that have been demonstrated to achieve the highest levels of control for the pollutant in question, regardless of the source type in which the demonstration has occurred.

Nitrogen Oxides

NOX from combustion is generated through one of three mechanisms: fuel NOX, thermal NOX, and prompt NOX. Fuel NOX is produced by the oxidation of nitrogen in the fuel, with low nitrogen content fuels such as distillate fuel and natural gas producing less NOX than fuels with higher levels of fuel-bound nitrogen. Thermal NOX forms in the high temperature area of the combustor and increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel needed to consume all the available oxygen, also known as the equivalence ratio. The lower this ratio is, the lower the flame temperature; thus, by maintaining a low fuel ratio (lean combustion), the potential for NOX formation can be reduced. In most modern burner designs, the high temperature combustion gases are cooled with dilution air. The sooner this cooling occurs, the lower the formation of thermal NOX. Prompt NOX forms from the oxidation of hydrocarbon radicals near the combustion flame; this produces an insignificant amount of NOX.

Control of NOX emissions can be accomplished through one of three methods: the use of add-on controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR); the use of combustion control techniques, such as low NOX burners (LNBs), ultra-low NOX burners (ULNBs), and flue gas recirculation (FGR); and the combustion of clean fuel, such as wood, distillate fuel, or natural gas. Since Boiler #12 is already limited to the firing of clean fuels, only add‑on controls and combustion control techniques have been considered in this analysis.

1. Add-On Controls: SCR

SCR employs the reaction of NOX with ammonia in the presence of a catalyst to produce nitrogen and water. The reaction is considered “selective” because the catalyst selectively targets NOX reduction in the presence of ammonia within a temperature range of approximately 480 ºF to 800 ºF. One mole of ammonia is required to reduce one mole of NO, and two moles are required to reduce one mole of NO2, as shown in the following reactions:

4NO + 4NH3 + O2 → 4N2 + 6H2O

2NO2 + 4NH3 + O2 → 3N2 + 6H2O

SCR systems have typical control efficiencies between 70% and 90%.

1. Add-On Controls: SNCR

SNCR is a method of post-combustion control that selectively reduces NOX into nitrogen and water vapor by reacting the exhaust gas with a reagent such as ammonia or urea, similar to SCR. However, in SNCR, a catalyst is not used to lower the activation temperature of the NOX reduction reaction. Therefore, SNCR is used when flue gas temperatures are between 1,600 ºF and 2,100 ºF. The NOX reduction efficiency decreases rapidly at temperatures outside this optimum temperature window, which results in unreacted ammonia emissions (ammonia slip) and increased NOX emissions.

The reagent solution (either ammonia or urea) is typically injected along the post-combustion section of the boiler. Injection sites must be optimized for reagent effectiveness and must balance residence time with flue gas stream temperature. The potential for unreacted ammonia slip emissions is greater with SNCR than with SCR, and the overall NOX reduction is less. SNCR systems have typical control efficiencies between 30% and 75%.

1. Combustion Control Techniques: LNBs/ULNBs

LNBs reduce NOX by accomplishing combustion in stages, which delays the combustion process and results in a cooler flame that suppresses thermal NOX formation. LNBs can achieve reductions in NOX of between 40% and 85% (relative to uncontrolled emission levels).

ULNBs employ staged combustion, like LNBs, while also allowing for the injection of flue gas at the burner. This allows the flue gas and fuel gas to mix prior to combustion, reducing flame temperature substantially and greatly suppressing thermal NOX. ULNBs can achieve reductions in NOX of between 60% and 90% (relative to uncontrolled emission levels).

1. Combustion Control Techniques: FGR

FGR is a system where a portion of the flue gas is recirculated back into the main combustion chamber; this helps to decrease the formation of thermal NOX by lowering the peak flame temperature and reducing the oxygen concentration surrounding the flame zone. The recycled flue gas consists of combustion products which act as inert heat sinks during combustion of the fuel/air mixture. This reduces NOX emissions by two mechanisms. Primarily, the recirculated gas acts as a diluent to reduce combustion temperatures, lowering peak flame temperatures, thus suppressing thermal NOX. In addition, the recirculated flue gas lowers the average oxygen concentration in the combustion zone, which lowers the oxygen available to react with nitrogen to form NOX. FGR systems are capable of control efficiencies up to 75%.

Sulfur Dioxide

Emissions of SO2 from Boiler #12 are attributable to the oxidation of sulfur compounds contained in the fuel. Pollution control options to reduce SO2 emissions include flue gas desulfurization by means of wet scrubbing and firing fuels with an inherently low sulfur content.

1. Flue Gas Desulfurization

Flue gas desulfurization by means of wet scrubbing works by injecting a caustic solution into the scrubber unit to react with SO2 in the flue gas to form a precipitate, along with either carbon dioxide or water. Flue gas desulfurization by means of wet scrubbing can have control efficiencies upwards of 90%.

1. Switching to Low Sulfur Fuels

Emissions of SO2 can be reduced by switching to fuels that have a lower sulfur content.

Step 2: Eliminate Technically Infeasible Options

Any applicable control technique listed in Step 1 may be eliminated from further consideration if it is not technically feasible for the specific source under review. A demonstration of technical infeasibility must show, based on physical, chemical, or engineering principles, that technical difficulty would preclude the successful use of the control option on the emissions unit under review. If a technology has been operated on the same type of emissions unit, it is presumed to be technically feasible.

Boiler #12 has a maximum heat input of 44 MMBtu/hr when firing wood. A search of EPA’s RACT/BACT/LAER Clearinghouse (RBLC) found no wood-fired boilers less than 99 MMBtu/hr using any add-on control technologies for NOX or SO2 or any of the other control technologies listed in this analysis. The only other similar boiler listed in the RBLC had no control technologies listed and a BACT emission limit for NOX higher than the limit Boiler #12 is already subject to.

However, an available technology cannot be eliminated as infeasible simply because it has not been used on the same type of source that is under review. If the technology has not been used on the same type of source, questions regarding “availability” and “applicability” to the particular source type under review should be considered.

A technology is considered “available” if it is commercially available. However, commercial availability by itself is not sufficient to consider a technology technically feasible. The control option must also be considered “applicable” to the source type under consideration. In general, a commercially available control option is presumed applicable if it has been used on the same or a similar source type. Absent this showing, technical feasibility can be evaluated by examining the physical and chemical characteristics of the pollutant-bearing gas stream and comparing them to the gas stream characteristics of the source type to which it has been previously applied.

1. Nitrogen Oxides
2. SCR

The installation of an SCR system in the exhaust stream ahead of Boiler #12’s baghouse is not technically feasible, because particulate matter in the exhaust would quickly poison and/or plug the catalyst.

Installing an SCR system after the baghouse would require the flue gas to be reheated to 480 ºF to 800 ºF. Since the actual exhaust temperature from Boiler #12 varies from 250 ºF to 350 ºF, an SCR system would require the installation of an exhaust reheat system. Such a system would require additional fuel to be combusted, and consequently increase overall NOX emissions to a level that would negate the control efficiency. Due to these technical limitations, the Department has determined that an SCR system for Boiler #12 is not technically feasible.

1. SNCR

Effective SNCR reactions take place at temperatures ranging between 1,600 ºF and 2,100 ºF. The NOX reduction efficiency decreases rapidly at temperatures outside this temperature window, which results in emissions of unreacted ammonia.

Due to the small size of Boiler #12, the space available for installation of SNCR equipment colocated with exhaust gases at temperatures within the required temperature range is very small. In addition to a targeted temperature range, SNCR requires sufficient volume and time for effective mixing of the reagent and exhaust gases to occur. The size limitations make a successful reaction highly unlikely. Due to these technical limitations, the Department has determined that an SNCR system for Boiler #12 is not technically feasible

1. LNBs/ULNBs

Low and ultra-low NOX burners that provide emission guarantees lower than those already achieved by Boiler #12 are not currently commercially available. Therefore, the Department has determined that retrofitting Boiler #12 with LNBs or ULNBs is not technically feasible.

1. FGR

FGR is commonly used on wood-fired boilers of this size and is determined to be technically feasible for control of NOX from Boiler #12.

Sulfur Dioxide

1. Flue Gas Desulfurization

No flue gas desulfurization systems are commercially available for small wood-fired boilers because wood is considered an inherently low sulfur fuel. Therefore, the Department has determined that flue gas desulfurization is not technically feasible for Boiler #12.

1. Switching to Low Sulfur Fuels

Wood is already considered an inherently low sulfur fuel. There are no other similar fuel sources with appreciably lower sulfur contents. Therefore, the Department has determined that switching to a lower sulfur fuel is not technically feasible.

Step 3: Evaluate Each Control Based on the Four Statutory Factors

For each remaining control option, the analysis must consider the four statutory factors: the cost of compliance; time necessary for compliance; energy and non-air quality environmental impacts; and the remaining useful life of source.

The only technically feasible control strategy remaining after Step 2 is FGR. However, the design of the burners in Boiler #12 already controls NOX to an emission rate of 0.19 lb/MMBtu or less. It is unlikely that FGR alone would be able to further reduce emissions of NOX by more than 1-2 tons per year. The annuitized installation and annual operational costs of an FGR system would therefore result in a cost of compliance exceeding $10,000 per ton of NOX controlled. This exceeds the amount traditionally considered by the Department to be appropriate for BACT. Also, additional energy resources would be required to operate the continuous fan and control system necessary for operation of an FGR system. Therefore, due to the cost of compliance and the additional energy impacts, the Department has determined that retrofitting Boiler #12 with FGR is not a reasonably available control technology for NOX.

Step 4: Determination of Controls Technologies for Inclusion in State’s Long-Term Strategy

As indicated by the results of the four-factor analysis for reasonable installation or upgrade to emission controls presented above, there are no additional control strategies for NOX or SO­2 that JAX could implement on Boiler #12 that are both technically and economically feasible. JAX already employs good combustion practices to minimize NOX emissions and combusts only clean, low-sulfur fuels. Therefore, current license requirements and emission levels will be retained.

**Appendix U.2. No. 9 Power Boiler, Woodland Pulp LLC**

**WOODLAND MILL**

**144 MAIN STREET**

**BAILEYVILLE, ME 04694**

**4-Factor Anaylsis**

**#9 Power Boiler**

**May 2019**

**Introduction**

Woodland Pulp LLC owns and operates a pulp mill in Baileyville, Maine, which utilizes the Kraft pulping process to produce market pulp.

The Mill’s No. 9 Power Boiler is considered a “BART-eligible source” under Section 169A of the Clean Air Act and implementing regulations at 40 CFR Part 51.300 et seq and Appendix Y. In addition to this previous BART evaluation, the Regional Haze Program requires a long-term strategy to address visibility impairments for each mandatory Class 1 Federal area within the state. In developing its long-term strategy, selected sources must be evaluated, and the State must consider and analyze emissions reduction measures based on four statutory factors. The four factors to be evaluated for each selected source are the following:

* Cost of compliance;
* Time necessary for compliance;
* Energy and non-air environmental impacts; and
* Remaining useful life of the source.

**Source Description**

The No. 9 Power Boiler is a mixed fuel boiler with a heat input capacity of 625 MMBtu/hr (24-hour average) and a steam production rating of approximately 440,000 lbs/hr. It was brought online in 1971. During its last analysis, the boiler was fueled primarily by biomass and No. 6 (residual) oil. On May 10, 2011, the Power Boiler was converted from No.6 oil to natural gas and ceased burning No. 6 oil. This boiler is also licensed to burn specification waste oil, mill yard waste, oily rags, stripper off-gas, propane, and high‑volume‑low‑concentration (HVLC) and low‑volume‑high-concentration (LVHC) gases from the Kraft pulping process. Emissions are controlled by low NOX burners (LNBs), good combustion control practices, and multiclones (mechanical dust collectors) upstream of an Airpol variable-throat venturi wet scrubber.

The wet scrubber was installed in 1979 and has had upgrades implemented to improve performance from its original design. In 2006, $1,200,000 was spent to improve the scrubber’s reliability by improving pumps, valves, piping, and associated instrumentation in order to comply with the then-pending Boiler MACT (40 CFR Part 63, Subpart DDDDD) rules. Also in 2006, the Emerson Boiler Combustion Air Control project was completed at a cost $587,000. This project allowed for advanced combustion control of the No. 9 Power Boiler to minimize emissions and to improve the thermal efficiency of the boiler. Additional scrubber improvements were made in 2008 at a cost of $207,000 to install an improved “state-of-the-art” mist eliminator (ME) wash system in the scrubber separator. Several other scrubber operational improvements were also implemented with this capital project. The goal of the ME improvement was to reduce particulate carry-over in the wash water by reducing the fouling of the MEs, and also to improve SO2 removal efficiency. In summation, the mill was successful in making nearly $2,000,000 worth of improvements to the Boiler and associated scrubber’s performance.

**Summary of Emission Control Technology**

Emissions from the No. 9 Power Boiler are controlled primarily by mechanical dust collectors (multiclones), a variable-throat wet venturi scrubber, and effective combustion controls. The scrubbing medium is slightly caustic, and in the past has included effluent from the wastewater treatment plant primary clarifier. If necessary, weak wash or sodium hydroxide (caustic) was added to supplement the available alkalinity. Mill water (fresh water) is used as the primary scrubbing media at the current time.

Emission controls and associated air license limits for the No. 9 Power Boiler include the following:

|  |  |  |
| --- | --- | --- |
| *Pollutant* | *Control Technology* | *License Emission Rates* |
| PM/PM10 | MulticlonesWet Scrubber | 0.22 1bs/MMBtu;84.4 lbs/hr |
| SO2 | Wet Scrubber | 0.30 lbs/MMBtu (24‑hr avg);186 lbs/hr (3-hr avg.) |
| NOX | Effective Operations | 0.40 lbs/MMBtu (24‑hr avg);186 1bs/24‑hr |

**Summary of #9 Power Boiler Emissions**

The #9 Power Boiler had a significant change in its operation in July 2011, when it was converted from firing #6 fuel oil to firing natural gas. The replacement of #6 oil with natural gas reduced total emissions, resulting in a net benefit to the environment and contributing to additional air pollutant emissions reduction achievements for the facility to meet progress goals for regional haze.

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| ***Year*** |  | ***NOx (tons)*** | ***SO2 (tons)*** | ***PM lb/hr*** | ***PM lb/MMBtu*** |
| 2011 |  | *474.8* | *418.8* | *70.0* | *0.19* |
| 2012 |  | *455.9* | *447.9* | *42.9* | *0.106* |
| 2013 |  | 369.3 | 190.9 | 41.2 | 0.086 |
| 2014 |  | 349.3 | 147.8 | 40.6 | 0.117 |
| 2015 |  | 279.5 | 42.2 | 45.2 | 0.114 |
| 2016 |  | 347.0 | 68.1 | 61.8 | 0.099 |
| 2017 |  | 419.5 | 70.9 | 50.9 | 0.089 |
| 2018 |  | 464.0 | 109.4 | Not Tested | Not Tested |

**Summary of Fuel Burned in the #9 Power Boiler**

|  |  |  |  |
| --- | --- | --- | --- |
| ***Year*** | ***Hog Fuel (Tons)*** | ***Natural Gas (MMBtu)*** | ***#6 Oil \*\* (Gallons)*** |
| 2011 | 154,561 | 454,371 | 1,191,546 |
| 2012 | 96,468 | 2,177,327 | - |
| 2013 | 102,731 | 1,884,343 | - |
| 2014 | 103,721 | 1,427,856 | - |
| 2015 | 93,835 | 1,120,022 | - |
| 2016 | 110,977 | 1,275,908 | - |
| 2017 | 113,168 | 1,106,973 | - |
| 2018 | 107,567 | 1,301,826 | - |

*\*\* #9 PB converted to Natural Gas on July 21, 2011 - no longer burns #6 oil.*

**Evaluation of Control Technology Analysis**

This evaluation will look at the first four steps of the top-down five-step BART analysis for the #9 Power Boiler based on data for the emissions that contribute to regional haze (SO2, PM, and NOX).

**SO2**

**Step 1:** Identification of available retrofit SO2 control technologies.

Wet scrubber and low sulfur fuel (if burning #6 oil)

**Step 2:** Eliminate technically infeasible SO2 control technologies.

Both technologies are technically feasible.

**Step 3:** Rank of technically feasible SO2 control options by effectiveness.

Wet scrubbers are the most effective SO2 add-on control technology for a power boiler, and as mentioned above, the No.9 Boiler already employs a wet scrubber. Low sulfur fuels would be less effective than wet scrubbing. In 2011, the No. 9 Power Boiler was converted to natural gas, in large part eliminating a sulfur contributor in its operation. Biomass, a low sulfur fuel, already comprises greater than 50% of the annual fuel mix for the No. 9 Boiler. Therefore, Woodland already employs both of the technically feasible and available SO2 control technologies.

**Step 4:** Evaluation of impacts for technically feasible alternative SO2 controls.

Woodland’s existing wet scrubber achieves approximately 95% SO2 control. There are no other feasible methods for further enhancing SO2 removal efficiency of the existing wet scrubber. The MANE-VU BART recommendation for SO2 from industrial boilers is 90% SO2 removal.[[1]](#footnote-1) Woodland meets this level of control with its existing control equipment.

**PM**

**Step 1:** Identification of available retrofit PM control technologies.

Fabric filter, wet electrostatic precipitator (WESP), dry electrostatic precipitator (DESP), and wet scrubber.

**Step 2:** Eliminate technically infeasible PM control technologies.

Fabric filters, sometimes referred to as baghouses, consist of a number of fabric bags, placed in parallel, that collect particulate matter on the surface of the filter bags as the exhaust stream passes through the fabric membrane. The collected particulate is periodically dislodged from the bags’ surface to collection hoppers via short blasts of high-pressure air, physical agitation of the bags, or by reversing the gas flow. Fabric filters are not typically used with biomass-fired boilers due to the possibility of fires caused by the carryover of combustible fly ash. For this reason, the Department has determined that fabric filters are not technically feasible for the No. 9 Power Boiler.

A DESP could not be used in conjunction with the existing wet scrubber due to the high level of moisture unless the DESP were to be located upstream of the existing scrubber.

WESPs on multi-fuel industrial boilers have proven to be extremely problematic from an operational and maintenance viewpoint. For this reason, if Woodland were required to install an ESP, Woodland would likely select a DESP as opposed to a WESP. According to MANE-VU, the costs and performance of DESP and WESP are comparable. For these reasons, this analysis will focus on DESPs only.

**Step 3:** Rank of technically feasible PM control options by effectiveness.

* DESP = 98-99% control efficiency biomass; up to 90% for oil. See AP-42, 5th Edition, Sections 1.6.4 and 1.3.4.2.
* WESP = 98-99% control efficiency for biomass; up to 90% for oil.
* Wet scrubber = 85-98% control efficiency. The actual PM control efficiency of the No. 9 Power Boiler wet scrubber is estimated to be approximately 90%.

**Step 4:** Evaluation of impacts for technically feasible PM controls.

* **Costs**.

Woodland has estimated that the cost to install a DESP upstream of its existing wet scrubber would be toward the upper end of the cost ranges provided by NESCAUM.[[2]](#footnote-2) The physical limitations of the existing boiler and operational requirements of the wet scrubber controls would necessitate very large ID fans and other accommodations that would make installation and operation of a DESP at Woodland more expensive than would be the case for a typical uncontrolled boiler. Similarly, the need to operate unusually large ID fans would push annual O&M costs to the high end of the ranges normally incurred for operation of DESPs at typical boilers. Although Woodland’s costs would likely be at, or possibly above, the upper end of NESCAUM’s cost ranges, Woodland has used only 90% of the NESCAUM upper end costs for this analysis.

Installation of a DESP could potentially reduce current PM emissions by up to 90%. Given the variety of fuels fired in the boiler, operational load swings, and the high level of PM control already achieved by the wet scrubber, it is not reasonable to expect that incremental improvement in PM emissions from addition of a DESP to be higher than 90%. Thus, a DESP would be expected to reduce PM emissions by approximately 263 tons per year (90% of 292 tons/year), resulting in emissions of approximately 29 tons per year of PM.

Cost of DESP using 90% of the upper end of the capital and O&M cost ranges developed by NESCAUM:[[3]](#footnote-3)

* + - Capital cost: $7,020,000
		- Annual interest rate: 7%3
		- Capital recovery factor: 0.1424[[4]](#footnote-4)
		- Annual capital recovery costs: $999,648
		- O&M cost: $1.13/year-ACFM
		($1.13/yr-ACFM)(195,000 ACFM) = $220,350;
		- Annual Costs of control: $1,219,998
		- 90% reduction of 292 tons = 263 tons PM
		- **Cost effectiveness: $4,639/ton of PM removed**.

The cost per ton of PM removed for a DESP is significantly higher than the ranges ($100 to $1,500/ton for NOX and $400 to $2,000/ton for SO2) considered to be reasonable by EPA when it established its presumptive BART limits in Appendix Y. See 70 CFR pp 39133 – 39136 (July 6, 2005).

* **Energy impacts and non-air quality impacts.**

Installation of a DESP in lieu of the existing wet scrubber is not an option. Such an approach would lead to significant increases in SO2 emissions, and Woodland could not meet its existing SO2 emission limit without the wet scrubber. Addition of a DESP to supplement the wet scrubber would increase electricity usage at the Mill.

* **Conclusion.**

A DESP is not cost-effective for control of PM from the No. 9 Power Boiler. The dollars per ton of PM removed is well in excess of levels typically considered reasonable for BART by EPA and Maine DEP. In addition, the overall capital cost could jeopardize the economic viability of the Mill. Therefore, the Department has determined that the existing wet scrubber meets BART for PM control at the No. 9 Power Boiler.

**C. NOX**

**Step 1:** Identification of available retrofit NOX control technologies.

NOX tempering, flue gas recirculation (FGR), selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR), low NOX burners, and good combustion practices.

**Step 2:** Eliminate technically infeasible NOX control technologies.

NOX tempering involves injection of water as a high-pressure spray via injectors above the bed of fuel. The water spray reduces the temperature in the lower part of the combustion chamber, thereby reducing the formation of thermal NOX. However, this technology reduces the boiler’s combustion/thermal efficiency, increasing fuel consumption and causing a corresponding increase in overall emissions. Therefore, NOX tempering is not considered technically feasible for the No. 9 Power Boiler.

Selective Catalytic Reduction (SCR) is unproven technology for multi-fuel (biomass) fired industrial boilers with operating requirements similar to the No. 9 Power Boiler. SCR systems for wood-fired boilers are not technically feasible for reducing NOX emissions due to concerns that various contaminants in the flue gas exhaust stream could affect the performance of the SCR catalyst. Contaminants of concern include sodium, potassium, and toxic metals such as arsenic and lead found in the biomass fuel. While blowers could be used to prevent some of the contaminants from building up on the catalyst surface, they would not be able to remove all of the particulate that is present in the flue gas stream downstream of the boiler exhaust (upstream of the economizer and wet scrubber). For these reasons, the Department has determined that it is not technically feasible to use an SCR system to control NOX emissions from Woodland’s No. 9 Power Boiler.

Flue Gas Recirculation (FGR) has been evaluated for the No. 9 Power Boiler. The use of FGR on this boiler would limit the amount of oxygen available in the boiler to such an extent that the boiler could not achieve proper combustion, which would result in excess opacity of emissions. Woodland cannot utilize FGR and maintain compliance with applicable opacity limits. For this reason, the Department has determined that FGR is not technically feasible for this boiler.

**Step 3:** Rank of technically feasible NOX control options by effectiveness.

* SNCR is estimated to achieve 30%-40% NOX removal.[[5]](#footnote-5)
* Low NOX burners (in use on the No. 9 Boiler) achieve NOX reductions of approx.10%.

**Step 4:** Evaluation of impacts for technically feasible NOX controls.

* **Costs.**

Cost of SNCR using average of control efficiency and cost ranges developed by NESCAUM:[[6]](#footnote-6)

* + - Capital cost: $3,000 per MMBtu x 625 MMBtu/hr = $1,875,000
		- Annual interest rate: 7%[[7]](#footnote-7)
		- Capital recovery factor: 0.14246
		- Annual capital recovery costs: $267,000
		- Annual O&M cost: ($5,650/ton) (156.3 tons) = $883,095
		- Annual Costs of control: $1,150,095
		- 30% reduction of 521 tons = 156.3 tons NOX reduction
		- **Cost effectiveness: $7,358/ton of NOX removed.**

The cost per ton of NO**X** removed using SNCR is significantly higher than the ranges considered to be reasonable by EPA when it established its presumptive BART limits in Appendix Y ($100 to $1,500/ton for NOX and $400 to $2,000/ton for SO2). See 70 CFR pp 39133 – 39136 (July 6, 2005).

* **Energy impacts and non-air quality impacts.**

SNCR systems work by injecting ammonia or urea into the upper portion of the combustion chamber of the boiler, thereby converting NOX to elemental nitrogen, carbon dioxide, and water vapor. The reaction must take place between specific temperature ranges or more NOX will be formed instead of less NOX. The optimum temperature range for a system that uses ammonia is 1,600 - 2,000 oF, and for a system that uses urea, the optimum temperature range is 1,700 - 2,100 oF. Increasing the combustion chamber residence time available for mass transfer and chemical reactions generally increases NOX removal. Variations in boiler steam load, fuel consistency, or flue gas temperature make the design and operation of an SNCR system more difficult.

The effectiveness of SNCR on No. 9 Power Boiler would likely be at or even below the low end of the range of effectiveness cited by NESCAUM. First, rapid load swings of the No. 9 Boiler, the variety of fuels burned, and the need to incinerate LVHC and/or HVLC gases would render SNCR considerably less effective. Second, SNCR becomes less effective as the concentration of NOX in the exhaust stream diminishes. NOX levels from the No. 9 Boiler are already well below typical uncontrolled NOX levels due to the performance of the low NOX burners and proper operational control of the boiler.

An unwanted byproduct and inherent disadvantage of SNCR chemistry is ammonia slip. Ammonia slip occurs because significantly more reagent (ammonia or urea) must be injected into the combustion zone of the boiler than is required by the theoretical stoichiometric ratio. This leaves a large portion of the reagent unreacted. Most of the excess reagent is destroyed by other chemical reactions inside of the boiler, however a small portion of unreacted reagent remains in the flue gas as ammonia slip. Ammonia in the flue gas has several negative impacts. Ammonia has a detectable odor at 5 ppm or greater, and poses a health concern at levels of 25 ppm or greater. It can also cause a stack plume visibility problem by the formation of ammonia chlorides if there are any chlorine compounds present in the fuel. Ammonium salt can plug, foul, and corrode downstream boiler equipment such as the air pre-heater, ductwork, and fans. Limits on ammonia slip imposed by regulatory agencies place constraints on SNCR performance for NOX control.

Decomposition of urea or ammonia in the furnace results in the formation of CO, which is normally fully oxidized to CO2 in the furnace, resulting in greenhouse gas consequences. Ammonia sulfates can contribute to visibility impacts, thus offsetting, to some degree, the benefits of NOX reduction with respect to reducing visibility impacts. Ammonia must also be treated as a hazardous material that poses risks to the public and mill personnel if an accidental spill should occur.

For fuels with sulfur, such as No. 6 fuel oil, ammonia slip will cause the formation of sticky, corrosive ammonium bisulfate and ammonium sulfate downstream of the injection grid in amounts that may create operational problems. This material would add to the particulate load leaving the boiler and can be deposited on the surfaces of the air heater, ID fan, and other downstream systems. Additional particulate emissions may jeopardize the boiler’s ability to comply with its existing BACT particulate emissions limit of 0.15 lbs/MMBtu.

* **Conclusion.**

The No. 9 Power Boiler is already equipped with low NOX burners that control NOX to the licensed limit of 0.40 lbs/MMBtu. This limit is within the range of the MANE-VU draft recommendations for BART for NOX from industrial boilers of 0.1 lbs/MMBtu to 0.40 lbs/MMBtu.[[8]](#footnote-8) Furthermore, the No. 9 Boiler is also controlled to the NOX New Source Performance Standards (NSPS) limit in 40 CFR Part 60, Subpart Db for comparable units constructed prior to 1997 (i.e., 0.40 lbs/MMBtu). The only technically feasible alternative to low NOX burners is SNCR. However, at $7,358/ton of NOX removed, SNCR is clearly not within the range typically considered cost-effective for NOX controls by EPA or Maine DEP. The potential operational difficulties that can be caused by SNCR in a multi-fuel fired boiler and the negative impacts on visibility that could be caused by ammonia slip are additional reasons supporting the conclusion that SNCR is not a feasible control technology for purposes of BART. The No. 9 Boiler will continue to meet BART by operation of low NOX burners and meeting a NOX emission limit of 0.40 lbs/MMBtu.

**IV. 4-Factor Analysis Conclusions**

This analysis demonstrates that the current SO2, PM, and NOX emissions control equipment and air license limits for the No. 9 Power Boiler as set forth in The Maine DEP’s BART Determination, dated February 2, 2008, #A-215-77-1-A, continue to constitute BART for this unit.

**Appendix U.3: Boiler No. 4, FPL Energy Wyman, LLC**

FOUR-FACTOR ANALYSIS FOR BOILER NO. 4

*FPL Energy Wyman Station*

**FPL Energy Wyman, LLC**

677 Cousins Street

Yarmouth, ME 04096-5314

# Table of Contents

1.0 INTRODUCTION

2.0 DESCRIPTION OF APPLICABLE EMISSIONS UNITS

* 1. FOUR-FACTOR ANALYSIS
	2. Overall Strategy
	3. Four-Factor Analysis for SO2
		1. Step 1 - Available Retrofit Control Technologies
		2. Step 2 - Control Technology Feasibility
		3. Step 3 - Control Effectiveness of Options
		4. Step 4 - Impacts of Control Technology Options
		5. Selection of Control Technology for SO2
	4. Four-Factor Analysis for NOX
	5. Four-Factor Analysis for PM

4.0 REFERENCES

TABLES

Table 3-1 Summary of SO2 BACT Determinations for Liquid Fuel Fired Large Industrial Boilers Table 3-2 SO2 Control Technology Feasibility Analysis – Boiler No. 4

Table 3-3 FPL Energy Wyman Station Actual Fuel Usage, 2012 to 2017

Table 3-4 Cost Effectiveness for Fuel Switching for FPL Energy Wyman Unit 4

Table 3-5 Cost Effectiveness of NOX Control Alternatives, Wyman Unit

**1.0 INTRODUCTION**

FPL Energy Wyman, LLC (FPL Energy Wyman) operates an 850-megawatt (MW) electric power generating facility on Cousins Island in Yarmouth, Maine. The power plant consists of four generation units, all of which fire No. 6 residual fuel oil. A fifth unit at the site is a smaller oil-fired auxiliary boiler, which provides building heat and auxiliary steam. There is also a sixth unit at the facility, which is an emergency backup diesel generator that provides electricity for use on site. The facility is currently operating under Part 70 Air Emission License No. A-388-70-G-R, issued May 14, 2020.

Maine is part of the Mid-Atlantic/Northeast Visibility Union (MANE-VU), which coordinates regional haze planning activities for the region. The intent of the regional haze program is the achievement of natural visibility conditions in Prevention of Significant Deterioration (PSD) Class 1 areas by the year 2064. MANE-VU has adopted the “cumulative assessment of all BART-eligible sources contribution” approach for sources subject to BART. Northeast States for Coordinated Air Use Management (NESCAUM), an association of eight northeastern states, conducted a visibility impact contribution assessment using 2002 emissions and concluded that every MANE-VU state with BART-eligible sources contributes to visibility impairment at the PSD Class 1 areas to a significant degree. Based on this assessment, MANE-VU decided that the entire region is subject to BART, and therefore each BART-eligible unit in the region is subject to a BART determination.

In 2009, FPL Energy Wyman submitted a simplified five-step BART determination analysis for Boiler No. 3 to the Maine Department of Environmental Protection (Maine DEP), with the intent of potentially reducing emissions of SO2, which is a dominant contributor to visibility impact. The analysis focused on the options of reducing sulfur content of the fuel from 2 percent to 1.0-, 0.7-, 0.5-, and 0.3 percent. Although Maine DEP did not request an analysis for Boiler No. 4, the 2009 report also included evaluation of reducing sulfur content from 0.7 percent to 0.5- and 0.3 percent for Boiler No. 4. The five basic steps of a case-by-case BART analysis are: identify all available retrofit control technologies; eliminate technically infeasible options; evaluate control effectiveness of remaining control technologies; evaluate impacts and document the results; and evaluate visibility impacts. Maine DEP has now requested a four-factor analysis to update the effectiveness of pollution control options for Boiler No. 4, which is the subject of this report. Note that Boiler No. 4 is currently limited to using 0.5 percent sulfur fuel oil. As a result, the four-factor analysis contains evaluation of reducing fuel sulfur content from 0.5 percent to 0.3 percent. The analysis has used the latest cost information for fuels with different sulfur content, and control technology cost information from the 2009 report that has been updated to current dollars.

A description of the applicable emissions units at the FPL Energy Wyman Station is presented in Section 2.0. The four-factor analysis is presented in Section 3.0.

#### 2.0 DESCRIPTION OF APPLICABLE EMISSIONS UNITS

The FPL Energy Wyman Station is located on Cousins Island in Yarmouth, Maine at 43°45′6.4″ north and 70°9′21.9″ west. The PSD Class 1 areas within 300 kilometers of the FPL Energy Wyman Station are as follows:

* Acadia National Park (NP)
* Great Gulf National Wilderness Area (NWA)
* Lye Brook NWA
* Moosehorn NWA
* Presidential Range - Dry River NWA
* Roosevelt Campobello IP

The 2009 BART report included the 5-step BART determination for emissions units Boiler No. 3 and Boiler No. 4. This report includes the four-factor analysis to update the effectiveness of pollution control options for Boiler No. 4 only.

Boiler No. 4 has a maximum design heat input of 6,290 MMBtu/hr and fires both No. 6 and No. 2 fuel oil. This unit was installed in 1975 and is capable of firing 41,333 gal/hr of fuel. Sulfur content of the fuel was limited to 0.7 percent by weight until December 31, 2017. As of January 1, 2018, the sulfur content is limited to 0.5 percent by weight. Boiler No. 4 was modified in 2002 and 2003 for low NOX firing to conform with Maine’s Chapter 145 requirements. Modifications included installation of low NOX fuel atomizers, improved swirler design, and overfire and interstage air ports.. In addition, fuel and air were balanced for optimal NOX performance. NOX emissions from the unit are limited to 0.170 lb/MMBtu, or 0.165 lb/MMBtu if Units 3 and 4 are combined. PM/PM10 emissions are limited to 0.1 lb/MMBtu. SO2 emissions from Boiler No. 4 are limited to 0.8 lb/MMBtu. The unit has a flue gas recirculation system primarily to control boiler steam temperature and, to a limited degree, NOX emissions, and an electrostatic precipitator to control PM/PM10 emissions.

#### FOUR-FACTOR ANALYSIS

* 1. **Overall Strategy**

The overall strategy followed in the 2009 BART report for controlling emissions from the FPL Energy Wyman Station BART-eligible source (combination of all BART-eligible emissions units at the facility) was to follow the BART determination guidelines contained in Appendix Y of 40 CFR 51 in a way that makes the most practical sense, with the overall goal of improving visibility.

The following overall steps were followed in the 2009 BART determination analysis for the FPL Energy Wyman Boiler No. 4:

* Estimate visibility contribution assessment modeling results for each BART-eligible emissions unit and focus on the clearly dominant pollutant(s)
* Identify existing and in-use control technologies
* For the clearly dominant pollutant(s), conduct full scale top-down 5-step BART analysis(es)
* Select BART and propose emission rates

Since sulfates are the most dominant contributor to visibility impairment, the 2009 BART determination analysis focused on the reduction in SO2 emissions.

In this report, the first four steps of the top-down 5-step BART analysis for Boiler No. 4 have been updated based on latest information.

#### Four-Factor Analysis for SO2

The four factors of the analysis are described below.

##### Step 1 - Available Retrofit Control Technologies

A review was performed of previous SO2 BACT determinations for boilers listed in the RACT/BACT/LAER Clearinghouse (RBLC) on EPA’s webpage. A summary of BACT determinations for industrial boilers from this review is presented in Table 3-1. Determinations issued during the last 10 years are included in the table. Only four determinations were found for large industrial boilers burning fuel oil, and from the review of these BACT determinations, it is evident that SO2 BACT determinations for large industrial boilers and boilers firing fuel oil have been based solely on the use of low-sulfur fuels.

##### Step 2 - Control Technology Feasibility

The technically feasible SO2 controls for Boiler No. 4 are shown in Table 3-2. A technology that is available and applicable is technically feasible. As shown, there are three technically feasible approaches for SO2 abatement: low sulfur No. 2 fuel oil, reduced sulfur No. 6 fuel oil, and wet or dry scrubbers. Each abatement method is described below.

###### Low Sulfur No. 2 Fuel Oil

Emissions of SO2 are directly proportional to fuel oil sulfur content. Boiler No. 4 is permitted to fire No. 2 fuel oil. Use of lower sulfur No. 2 fuel oil is considered a technically feasible means of reducing SO2 emissions and, therefore, is being evaluated for this boiler.

###### Reduced Sulfur No. 6 Fuel Oil

Reducing the sulfur content of the No. 6 fuel oil combusted in the Boiler No. 4 would reduce SO2 emissions proportional to the magnitude of the sulfur reduction. Based on information from the Energy Information Administration, low sulfur No. 6 fuel oil is defined as having sulfur content of 1.0 percent or less. While there is a cost premium for low sulfur No. 6 fuel oil, Boiler No. 4 is already limited to burning fuel oil with a maximum sulfur content of 0.5 percent, and therefore it is considered a technically feasible control technology.

###### Post-Combustion Controls

Post-combustion SO2 controls consist primarily of flue gas desulfurization systems, or scrubbers. In a wet scrubber, the SO2-containing flue gas passes through a vessel or tower where it contacts alkaline slurry, usually in a counter-flow arrangement. The intensive contact between the gas and the liquid droplets ensures rapid and effective reactions that can yield greater than 90-percent SO2 capture. Conversely, a configuration where the reaction between SO2 and the sorbent takes place in a dedicated reactor is referred to as a “dry scrubber”.

Several configurations are possible based on the temperature window desired, including furnace (~2,200°F), economizer (800 to 900°F), or duct (~250°F) temperatures. Dry processes are more compatible with low to medium sulfur coals due to limitations in reaction rates and sorbent handling (MANE-VU, March 2005).

From review of the RBLC data, post-combustion controls are typically applied to coal-fired boilers. The application of scrubbing systems to primarily fuel oil-fired boilers is considered cost prohibitive. Boiler No. 4 primarily burns fuel oil.

Boiler No. 4 is currently permitted to burn up to 0.5-percent sulfur content fuel oil, which results in inherently lower SO2 levels in the exhaust gas stream. This further reduces the feasibility of add-on scrubbers as a potential technology. Therefore, post-combustion controls are rejected as an option for Boiler No. 4.

##### Step 3 - Control Effectiveness of Options

Each of the above available control techniques is listed in Table 4-2 with its associated control efficiency estimate and is ranked based on control efficiency. Since Boiler No. 4 already burns low sulfur No. 6 fuel oil, switching to an even lower sulfur content fuel oil is the best option for the unit. This control method is ranked the highest based on suitability to the unit because of the higher sulfur content associated with the fuel compared to No. 2 fuel oil. Based on actual fuel usage data, more than 99% of the annual heat input for the unit is produced by firing No. 6 fuel oil. Using low- to ultra-low-sulfur No. 2 fuel oil is ranked second. Wet or dry scrubbers are ranked the lowest as they are typically used for coal fired boilers and have not been determined as BACT for large fuel oil- fired boilers in the last 10 years.

##### Step 4 - Impacts of Control Technology Options

###### Cost of Compliance

To achieve SO2 emissions below currently permitted levels, Boiler No. 4 would require the use of a lower sulfur content fuel oil. Since Boiler No. 4 is currently permitted to burn 0.5-percent sulfur oil, a lower sulfur content of 0.3 percent was analyzed for this unit.

To calculate the emissions reduction due to the control options, baseline emissions were calculated based on the maximum 2-year average actual fuel usage from the period 2012 to 2017, which is 3 million million British thermal units (3 x 106 MMBtu) per year or 20.3 million gallons per year. Baseline fuel usage data are presented in Table 3-3. The controlled emissions were calculated based on the same usage in the future with the proposed lower sulfur content in the fuel oil.

The current cost for 0.5-percent sulfur No. 6 fuel oil of $66.58 per barrel is based on actual fuel purchase data for 2018 obtained from FPL Energy. The cost of 0.3-percent sulfur content fuel oil is obtained from an online publication named “Oil Price Daily” dated August 8, 2018 for No. 6 oil 0.3% bio-blend, which is $86.06 per barrel.

The cost analyses were prepared following EPA’s Control Cost Manual. Table 3-4 presents cost analyses for Boiler No. 4. The 0.3-percent sulfur fuel oil has much less viscosity than 0.5-percent sulfur fuel oil, and modifications are needed for the unit to accept the lower viscosity fuel. Wyman has only one fuel tank and therefore, Unit 3 would need to be modified in addition to Unit 4 to accept the lower viscosity 0.3-percent sulfur fuel oil. FPL estimates that the modification would cost approximately $1,000,000 per unit, which includes inspection of burner and booster pumps, burner tuning/optimization, replacement of instrumentation, and test burns to determine ESP performance. A new fuel oil tank would not be needed since the facility already burns No. 6 fuel oil and the existing fuel tank would be used to hold the 0.3-percent sulfur fuel oil. No operation or maintenance costs were used in the cost analysis because no change is expected to these costs. The only direct operating cost involved with using lower sulfur fuel oil is the annual differential fuel cost.

As shown in Table 3-4, the estimated total annual cost of switching Boiler No. 4 from 0.5-percent sulfur fuel oil to 0.3-percent sulfur content fuel oil is $10.3 million, most of which is the differential fuel cost. The cost effectiveness is estimated to be $20,226 per ton of SO2 removed.

###### Energy Impacts

No energy impacts are associated with using lower sulfur fuel oil since the heating value of No. 6 fuel oil is expected to remain the same with lower sulfur content.

###### Non-Air Quality Environmental Impacts

Use of low or reduced sulfur fuel oils do not result in any non-air quality environmental impacts.

###### Remaining Useful Life

FPL Energy Wyman has no plans to shut down the facility or Boiler No. 4 in the near future.

###### 3.2.5 Selection of Control Technology for SO2

As the cost effectiveness value indicates, the cost of further improvement is extremely high. As of July 1, 2018 Boiler No. 4 is limited to 0.5-percent sulfur oil. Switching from the current 0.5 percent sulfur oil to 0.3-percent sulfur oil would cost $20,226 for each ton of additional SO2 reduction, which is considered to be very high and not cost effective.

#### Four-Factor Analysis for NOX

Wyman Unit 4 has installed very effective combustion control technologies to lower the NOX emissions in compliance with Maine’s Chapter 145 Rule. The plant spent more than $4.2 million in 2003 to install NOX control measures including the installation of low NOX fuel atomizers, improved swirler design, and overfire and interstage air ports. The burners were optimized and fuel/air flows were balanced to the burners.

Wyman Unit 4 is currently limited to the following NOX standards:

* 0.170 lb/MMBtu rolling 90-day average (Unit 4 alone)
* 0.165 lb/MMBtu rolling 90-day average (Unit and Unit 4 average)

The emissions limits were determined as BART limits and also under Chapter 145 Rule. Based on the emissions limit of 0.17 lb/MMBtu and a capacity factor of 7% (maximum actual annual capacity factor in the period 2012 – 2017), Unit 4 will emit approximately 328 TPY of NOX emissions per year. The 2009 BART report analyzed the cost effectiveness of further 25% reduction in NOX emissions for the addition of a regenerative selective catalytic reduction (RSCR) system in addition to the Chapter 145 emissions control efforts. This cost analysis has been updated based on equipment cost adjusted to 2018 dollars using producer price index (for dust collection & other air purification equipment for industrial gas cleaning systems) and is presented in Table 3-5. As shown, the cost effectiveness of adding a RSCR system is $135,249 per ton of NOX, which is excessive.

#### Four-Factor Analysis for PM

Wyman Unit 4 has an ESP to control PM emissions. As described in the 2009 BART report, PM represents a very small contribution to visibility impairment (typically <4 percent) at the MANE-VU Class 1 areas. Based on these facts, the 2009 report determined BART for PM emissions from Unit 4 to be the already existing ESP and an emission limit of 0.10 lb/MMBtu. The four-factor analysis was not performed based on the assumption that the existing ESP is the best control option for PM from Unit No. 4.

4.0 REFERENCES

AECOM, April 2009. Updated CALMET Modeling Procedures for BART Visibility Improvement Assessments in the MANE-VU RPO.

Clean Air Task Force, April 2003. Deciview scale and Clear Skies, Bruce Hill, Ph.D.

Combustion Components Associates, December 22, 2004. Letter to Maine DEP from R. Gifford Broderick, President

FPL Energy, December 2004. Application for the establishment of an alternative NOX emission limit for Wyman Station Units 3 & 4

Guidelines for Best Available Retrofit Technology. Federal Register, Volume 70, pages 39104-39172. August 1, 2005.

MANE-VU, March 2005. Assessment of Control Technology Options for BART-Eligible Sources; Northeast States for Coordinated Air Use Management, in partnership with the Mid-Atlantic/Northeast Visibility Union.

MANE-VU, August 2006. Contributions to Regional Haze in the Northeast and Mid-Atlantic United States, Mid- Atlantic/Northeast Visibility Union (MANE-VU) Contribution Assessment, August 2006, Tools and Techniques for Apportioning Fine Particle/Visibility Impairment in MANE-VU.

U.S. Environmental Protection Agency (EPA). Cost Control Manual, Fifth Edition, EPA-4531B-96-001. February 1996.

U.S. Environmental Protection Agency (EPA). 40 CFR Part 51, July 2005. Regional Haze Regulations and Guidelines for Best Available Retrofit (BART) Determinations.

U.S. Forest Service (USFS), National Park Service (NPS), US Fish and Wildlife Service (USFWS), 2008. Air Quality Related Values Workgroup (FLAG) Phase I Report, Draft

Visibility Improvement State and Tribal Association of the Southeast (VISTAS), 2006. Protocol for the Application of the CALPUFF Model for Analyses of Best Available Retrofit Technology (BART). Revision 3.2, August 31, 2006.

**Tables**

Table 3-1: Summary of SO2 BACT Determinations for Liquid Fuel Fired Large Industrial boilers (>250 MMBtu/hr) (1999 to 2009)

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Facility Name** | **State** | **Permit Date** | **Process Info** | **Fuel** | **Heat Input** | **Control Method** | **SO2 Li** | **Basis - Mitigation** |
| Longview Fibre Paper And Packaging, Inc. | WA | 11/01/2006 | Power Boilers Nos. 12 and 13 |  | 444 MMBtu/hr, ea |  | 100.00 PPMDV @ 7% O2 | Other - Case-by-Case |
| Longview Fibre Paper And Packaging, Inc. | WA | 11/01/2006 | Power Boiler No. 16 | Fuel Oil | 525 MMBtu/hr |  | 250.00 PPMDV @ 7% O2 | Other - Case-by-Case |
| Longview Fibre Paper And Packaging, Inc. | WA | 11/01/2006 | Power Boiler No. 17 | Fuel Oil | 591 MMBtu/hr | Low Sulfur Fuel | 250.00 PPMDV @ 7% O2 | Other - Case-by-Case |
| Longview Fibre Paper And Packaging, Inc. | WA | 11/01/2006 | Power Boiler No. 20 | Fuel Oil | 900 MMBtu/hr | Low Sulfur Fuel | 100.00 PPMDV @ 7% O2 | Other - Case-by-Case |
| Columbia Energy Center | SC | 07/03/2003 | Boiler, Fuel Oil | No.2 Oil | 550 MMBtu/hr | Low Sulfur Fuel | 0.06 lb/MMBtu | BACT-PSD |
| International Paper - Mansfield Mill | LA | 08/14/2001 | Power Boiler No. 1, Oil | Fuel Oil | 645 MMBtu/hr | Max S Content 0.7% | 21.00 lb/hr | BACT-PSD |
| International Paper - Mansfield Mill | LA | 08/14/2001 | Power Boiler No. 2, Oil | Combined Fuel | 760 MMBtu/hr | Limit S Content | 21.00 lb/hr | BACT-PSD |

Source: EPA 2018 (RBLC database).

Boilers more than 250 MMBtu/hr have been working with natural gas from 2019 to the present. This is the reason the summary above remains the same.

Table 3-2: SO2 Control Technology Feasibility Analysis - Boiler No. 4

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  |  |  |  |  |
|  |  |  |  |  |

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **SO2 Abatement Method** | **Estimated Efficiency** | **Technically Feasible and Demonstrated?** | **Rank Based on Control Efficiency** | **Rank Based on Project Suitability** |
| Low-sulfur (0.05, 0.0015%) No. 2 Fuel Oil 98% Yes 1 2Reduced sulfur (0.5%) No. 6 Fuel Oil 30-50% Yes 4 1Wet Scrubbers >90% No 2 3Dry Scrubbers 60-95% No 3 4 |

**Table 3-3: FPL Energy Wyman Station Actual Fuel Usage, 2012 to 2017**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  |  |  |  |  |



**Table 3-4: Cost Effectiveness of Fuel Switching for FPL Energy Wyman Unit 4**

|  |  |  |  |
| --- | --- | --- | --- |
| **Cost Items** | **Cost Factors** | **Baseline 0.5% S Fuel Cost ($)** | **Projected Future 0.3% S Fuel Cost ($)** |
| DIRECT CAPITAL COSTS (DCC):1. Equipment Cost
	1. New Fuel Oil Storage tank
	2. Pumps, piping, etc.
	3. New oil guns/atomizer sprayer plates
2. Sales Tax

Subtotal: Total Equipment Cost (TEC)1. Direct Installation Costs Total DCC:

INDIRECT CAPITAL COSTS (ICC): a1. Indirect Installation Costs
	1. Engineering
	2. Construction & Field Expenses
	3. Construction Contractor Fee
	4. Contingencies
	5. Modifications to Unit 3 b

(e) Modifications to Unit 4 b1. Other Indirect Costs
	1. Startup
	2. Performance Test Total ICC:

PROJECT CONTINGENCYTOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI): DIRECT OPERATING COSTS (DOC):1. Variable Operation & Maintenance Cost
2. Fuels (FPL Data) c

Existing Fuel Cost (No. 6 fuel oil with 0.5%S) Proposed Fuel Cost (No. 6 fuel oil with 0.3%S) Differential Fuel Cost (Proposed - Existing)Total DOC:INDIRECT OPERATING COSTS (IOC): a1. Overhead
2. Property Taxes
3. Insurance
4. Administration Total IOC:

CAPITAL RECOVERY COSTS (CRC): ANNUALIZED COSTS (AC):Baseline Emissions: Projected Future Emissions:Emissions Reduction (TPY)(AC):Average Cost Effectiveness ($/ton): | New tank will not be needed NANA NANA10% of TEC10% of TEC10% of TEC3% of TECUnit 3 modifications to accept 0.3% S fuel, FPL Data Unit 4 modifications to accept 0.3% S fuel, FPL Data1% of TEC1% of TEC15% of (DCC+ICC)DCC + ICC+Project Contingency$11.01 /MMBtu and 3.1x106 MMBtu$14.23 /MMBtu and 3.1x106 MMBtu Proposed fuel cost - existing fuel cost60% of oper. labor & maintenance, CCM Chapter 2 1% of total capital investment, CCM Chapter 21% of total capital investment, CCM Chapter 2 2% of total capital investment, CCM Chapter 2 (1) + (2) + (3) + (4)CRF of 0.0944 times TCI (20 yrs @ 7%) DOC + IOC + CRFMax. 2-year average last 5 years, 20,311.0 x103 gal/yr (TPY) d20,311.0 x103 gal/yr, Future S content (TPY)Baseline - Future Projected (TPY) AC/Emissions Reduction | $0 | $0 |
| $0 | $0 |
| $0 | $0 |
| $0 | $0 |
| $0 | $0 |
| $0 | $0 |
| $0 | $0 |
| $0 | $0 |
| $0 | $0 |
| $0 | $0 |
| $0 | $0 |
| $0 | $1,000,000 |
| $0 | $1,000,000 |
| $0 | $0 |
| $0 | $0 |
| $0 | $2,000,000 |
| $0 | $300,000 |
| $0 | $2,300,000 |
| $0 | $0 |
| $34,126,653 | -- |
| -- | $44,111,442 |
| -- | $9,984,788 |
|  | $9,984,788 |
| $0 | $0 |
| $0 | $23,000 |
| $0 | $23,000 |
| $0 | $46,000 |
| $0 | $92,000 |
| $0 | $217,120 |
| $0 | $10,293,908 |
| 1,014.7 | 1,014.7 |
| -- | 506 |
| 0 | 509 |
| -- | $20,226 |

Notes:

a Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002.

b Since Wyman only has 1 fuel tank, Unit 3 will need to be modified in addition to Unit 4 to accept the 0.3% S fuel.

c Based on information provided by FPL and Oil Price Information Services (August 8, 2018)

d Maximum 2-year average actual SO2 emissions for the period 2014-2015. Note that up to 0.7%S content fuel oil was permitted until December 31, 2017.

### **Table 3-5: Cost Effectiveness of NOX Control Alternatives, Wyman Unit 4**

|  |  |  |
| --- | --- | --- |
| Cost Items | Cost Factors | Boiler Unit 4 RSCR System Cost ($) |
| DIRECT CAPITAL COSTS (DCC):1. RSCR Equipment and Materials Emission Monitoring

Ammonia Storage System Flue Gas Booster FanTransition Ducts to and from SCR Duct InsulationWater wash system1. Sales Tax

Subtotal: Total Equipment Cost (TEC)1. Installation Costs
	1. Direct SCR Installation
	2. Tank Foundation and Structural Support
	3. Piping and Wiring
	4. Electrical and Controls

(h) Reagent Supply - First Fill Total DCC:INDIRECT CAPITAL COSTS (ICC): (b)1. Indirect Installation Costs
	1. General Facilities
	2. Engineering and Home Office Fees
	3. Process Contingency
2. Other Indirect Costs
	1. Emissions Monitoring
	2. Performance Testing
	3. Spare Parts
	4. Contractor Fees Total ICC:

PROJECT CONTINGENCYTOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI): DIRECT OPERATING COSTS (DOC): (b)1. Operating Labor Operator Supervisor
2. Maintenance (labor and material)
3. Aqueous Ammonia (19%) Cost
4. RSCR Energy Requirement
5. Auxiliary Power Requirement
6. Auxiliary Fuel Heat Input
7. Compressed Air
8. Catalyst Replacement and disposal Total DOC:

INDIRECT OPERATING COSTS (IOC): (b)1. Overhead
2. Property Taxes
3. Insurance
4. Administration Total IOC:

CAPITAL RECOVERY COSTS (CRC): ANNUALIZED COSTS (AC):Unit 4 - Baseline NOx Emissions (TPY) :Unit 4 - Controlled NOx Emissions (TPY), RSCR : Reduction in NOx Emissions (TPY):Average Cost Effectiveness ($/ton): | Vendor Quote(a) | 26,720,867 |
| 5% of RSCR equipment cost | 1,336,043 |
| Assumed included | included |
| Assumed included | included |
| Assumed included | included |
| Assumed included | included |
| Assumed included | included |
| Assumed 6% | 1,603,252 |
|  | 29,660,163 |
| 60% of Vendor Quote | 16,032,520 |
| 8% of TEC (Control Cost Manual (CCM) 5th Edition, 2/1996) | 2,372,813 |
| 2% of TEC (CCM 5th Edition, 2/1996) | 593,203 |
| 4% of TEC (CCM 5th Edition, 2/1996) | 1,186,407 |
| Assumed included | included |
|  | 49,845,106 |
| 5% of TEC | 1,483,008 |
| 10% of TEC | 2,966,016 |
| 5% of TEC | 1,483,008 |
| Assumed included | included |
| 1% of TEC (Table 3.16, CCM) | 296,602 |
| Vendor Estimate - 5% of TEC | 1,483,008 |
| 10% of TEC (Table 3.16, CCM) | 2,966,016 |
|  | 10,677,659 |
| 15% of (DCC+ICC) | 9,078,415 |
| DCC + ICC+Project Contingency | 69,601,179 |
| 1.0 hr/shift, $30/hr, 8760 hrs/yr | 32,850 |
| 15% of operator cost | 4,928 |
| 1.5% of TCI | 1,044,018 |
| No data, not included | no data |
| No data, not included | no data |
| No data, not included | no data |
| No data, not included | no data |
| No data, not included | no data |
| No data, not included | no data |
|  | 1,081,795 |
| 60% of oper. labor & maintenance | 649,077 |
| 1% of total capital investment | 696,012 |
| 1% of total capital investment | 696,012 |
| 2% of total capital investment | 1,392,024 |
| (1) + (2) + (3) + (4) | 3,433,124 |
| CRF of 0.0944 times TCI (20 yrs @ 7%) | 6,570,351 |
| DOC + IOC + CRF | 11,085,271 |
| Current permit - 6290 MMBtu/hr x 0.17 lb/MMBtu x 8760 hr/yr, 7% CF (c) | 327.8 |
| Reduced emission for RSCR - further 25% reduction | 245.9 |
| Baseline - Controlled | 82.0 |
| $ per ton of NOx Removed | 135,249 |

(a) Equipment cost used in the 2009 BART report was updated to 2018 dollars using producer price index for Dust collection & other air purification equipment for

 industrial gas cleaning systems.

(b) Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002.

(c) Current permit limit and maximum annual capacity factor for the period 2012 - 2017.

1. *See* “Five-Factor Analysis of BART-Eligible Sources, prepared by NESCAUM for MANE-VU, June 1, 2007 (hereinafter “MANE-VU BART Analysis”), Appendix C. [↑](#footnote-ref-1)
2. Assessment of Control Technology Options for BART-Eligible Sources, Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities, March 2005, NESCAUM (“NESCAUM BART Assessment”). [↑](#footnote-ref-2)
3. Id at p. 3-13. [↑](#footnote-ref-3)
4. EPA Cost Control Manual (6th Edition – Jan. 2002). [↑](#footnote-ref-4)
5. NESCAUM BART Assessment at p. 3-9. [↑](#footnote-ref-5)
6. NESCAUM BART Assessment at p. 3-13. [↑](#footnote-ref-6)
7. EPA Cost Control Manual (6th Edition – Jan. 2002). [↑](#footnote-ref-7)
8. MANE-VU BART Assessment, Appendix C. [↑](#footnote-ref-8)