APPENDIX H

Domtar Ashdown Mill Four-Factor Documentation

Division of Environmental Quality

Office of Air Quality

Contents

APPENDIX H-1

Domtar Ashdown Mill Information Collection Request

Division of Environmental Quality

Office of Air Quality

January 8, 2020

Kelley Crouch
Engineering Services Manager
Environmental Quality and Engineering
Domtar Ashdown Mill

Sent via Electronic Mail

RE: Regional Haze Four-Factor Analysis; Information Collection Request; AFIN 41-00002

Dear Ms. Crouch:

The Arkansas Department of Energy and Environment, Division of Environmental Quality (DEQ) hereby requests that Domtar submit the information described in Section II no later than 90 days from the date of this letter.

I. BACKGROUND

DEQ must develop a Regional Haze Program state implementation plan (SIP) that demonstrates reasonable progress toward achieving natural visibility conditions in Arkansas Class I areas during the period between 2018 and 2028, which is referred to as Planning Period II. The SIP must also address emissions from within the state that may impair visibility in Class I areas in other states. The Regional Haze Program uses an iterative planning process lead by the states with the ultimate goal of remedying existing and preventing future visibility impairment from anthropogenic sources of air pollution by 2064.

For the Planning Period II SIP, DEQ must develop a long-term strategy for reducing emissions of key pollutants and sources impacting visibility at Class I areas to make "reasonable" progress toward the goal of no anthropogenic visibility impairment by 2064. The Regional Haze Rule provides four factors by which a state must consider potential control measures for the long-term strategy. The factors are the cost of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of existing sources that contribute to visibility impairment.

The key pollutants from anthropogenic sources impairing visibility at Arkansas Class I areas are ammonium sulfate and ammonium nitrate.[1] Ammonium sulfate is formed by chemical reactions between ammonia and sulfur dioxide (SO_2) in the atmosphere. Ammonium nitrate is formed by chemical reactions between ammonia and nitrogen oxides (NOx) in the atmosphere. EPA modeling projects that these two pollutants will continue to be the key pollutants contributing to visibility impairment at Arkansas Class I areas in 2028.[2]

The states in the Central States Air Resources Agencies (CENSARA) organization, which includes Arkansas, contracted with Ramboll US Corporation (Ramboll) to produce a study examining the impact of stationary sources of NOx and SO_2 on each Class I area in the central region of the United States. For each Class I area, the study took into account light extinction-weighted wind trajectory residence times, 2016 sulfur dioxide and nitrogen oxides facility emissions, and distance from sources of nitrogen oxides and sulfur dioxide to Class I Areas. The study produced an area of influence (AOI) for each Class I area, which shows the geographic areas with a high probability of contributing to anthropogenic visibility impairment.

Based on the results of the AOI study, DEQ has identified Domtar Ashdown Mill as a source of visibility impacting pollutant emissions that DEQ should evaluate for potential emission reduction measures during Planning Period II.

II. INFORMATION REQUESTED FOR POTENTIAL EMISSION REDUCTION STRATEGIES

DEQ requests that Domtar provide information about potential emission reduction strategies for SO_2 and NOx emissions from the Domtar Ashdown Mill facility. At a minimum, Domtar should include the following potential strategies for the emission units that emit the majority of the SO_2 and NOx from Domtar Ashdown Mill, identified by DEQ as SN-01 (No. 3 Power Boiler), SN-05 (No. 2 Power Boiler), SN-06 (No. 2 Recovery Boiler), and SN-14 (No. 3 Recovery Boiler):

- SO_2 (ranked from highest control efficiency to lowest)[3]
    - For SN-05
        - Installation of new add-on scrubbers operating downstream of the existing scrubbers (typical control efficiency for industrial coal-fired boilers ≈ 90–95% control efficiency for industrial coal-fired boilers)
        - Increasing the SO_2 control efficiency of the existing scrubbers from current levels to 90% through the use of additional scrubbing reagent
        - Upgrades to the existing scrubbers
    - For SN-01

[1] http://vista.cira.colostate.edu/Improve/improve-data/
[2] https://www.epa.gov/visibility/visibility-guidance-documents
[3] EPA Menu of Control Measures https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

- Installation of a wet gas scrubber (typical control efficiency for industrial coal-fired boilers ≈ 90–99%)
- Installation of a spray dry absorber (typical control efficiency for industrial coal-fired boilers ≈ 90–95);

- NOx (ranked from highest control efficiency to lowest) for all units[4]
  - Selective Catalytic Reduction (typical control efficiency ≈ 80% for industrial boilers coal and 90% for industrial boilers wood/bark/waste)
  - Regenerative Selective Catalytic Reduction (typical control efficiency ≈ 75% for industrial boilers wood/bark/waste)
  - Selective Non-Catalytic Reduction (typical control efficiency ≈ 40% for industrial boilers coal)

The list above is not comprehensive. Domtar may provide information about strategies in addition to those listed above. In addition, Domtar may include updates to information provided in previous assessments during Planning Period 1.

For each emission reduction strategy, Domtar should assess whether the strategy is technically feasible.[5] If a strategy is not technically feasible, Domtar should provide a robust explanation about why the strategy is not technically feasible.

For each technically feasible emission reduction strategy, Domtar should provide the following information for SO_2 and/or NOx:

- Control effectiveness (Percentage NOx and/or SO_2 reduced) estimates specific to Domtar Ashdown Mill's emission units in terms of actual emissions
- Emission reductions that would be achieved by implementation of the strategy:
  - Baseline actual emission rate in lb/hr or lb/MMBTU (maximum monthly value in the period between 2017–2019)
  - Control rate in lb/hr or lb/MMBTU (units should match baseline actual emission rate)
  - Resulting annual emission reductions (tons/year)
- Time necessary to implement the strategy with an explanation justifying the time needed

[4] EPA Menu of Control Measures
https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

[5] From 40 CFR Appendix Y to Part 51 "Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: 'availability' and 'applicability.' As explained in more detail below, a technology is considered 'available' if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is 'applicable' if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible."

- A reasonable time period is one in which the source comes "into compliance in an efficient manner without unusual amounts of overtime, above-market wages and prices, or premium charges for expedited delivery of control equipment."[6]
- The time during which the source begins taking steps to come into compliance is assumed to begin upon EPA approval of the SIP, which is projected to be no later than January 31, 2023 based on deadlines for the SIP submission and EPA action on the SIP.[7]

- Remaining useful life
  - Remaining useful life of an emission unit should be based on an enforceable shutdown date. Otherwise, the remaining useful life should be the full period of the useful life for the control technology evaluated
  - The EPA Pollution Control Cost Manual[8] provides guidance on typical values for the useful life of various emission control systems
- Energy and non-air quality environmental impacts
  - Specify any energy and non-air environmental impacts, such as the generation of wastes for disposal, impacts on other environmental media, etc.
  - Factor any costs associated with energy and non-air environmental impacts into the cost of implementing the strategy, including without limitation:
    - Permitting costs if other regulatory requirements are triggered by the strategy
    - Costs associated with compliance with any other regulatory requirements triggered by the strategy
    - Cost of waste disposal for wastes generated by proposed control systems
- Cost of implementing the strategy
  - Use the EPA Pollution Control Cost Control Cost Manual[9] overnight methodology to quantify the following cost metrics:
    - Capital costs
    - Annual operating and maintenance costs
    - Annualized costs
  - The amortization period should be based on the time between when the strategy could reasonably be in place and the remaining useful life of the emission unit or emission control system, whichever is less.[10]

[6] https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period

[7] The deadline for submission of this state implementation plan is July 31, 2021. EPA's deadlines for timely action on a SIP submittal are as follows: six months for determining whether a SIP is complete and one year from determining that a SIP is complete to take final action on the SIP.

[8] https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[9] https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[10] Amortization start date is equal to the time necessary for compliance for the strategy added to January 31, 2023 (Deadline for timely EPA action on a SIP submitted on July 31, 2021).

III. CONCLUSION

Thank you for your timely response to this information request. This information is necessary for DEQ to prepare a technically and legally robust state implementation plan consistent with the Regional Haze Rule. Please respond with the requested information by April 7, 2020. If you have any questions, please contact Tricia Treece (treecep@adeq.state.ar.us) of my staff.

Sincerely,

William K. Montgomery
Interim Associate Director
Office of Air Quality
Division of Environmental Quality
Arkansas Department of Energy and Environment

APPENDIX H-2

Domtar Ashdown Mill ICR Response

Division of Environmental Quality

Office of Air Quality

Domtar
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VIA E-mail (*Montgomery@adeq.state.ar.us*)

April 6, 2020

Mr. William K. Montgomery
Interim Associate Director
Arkansas Department of Energy and Environment
Division of Environmental Quality, Office of Air Quality
5301 Northshore Drive
North Little Rock, AR 72118

Re: Response to January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request
Domtar A.W. LLC; Ashdown Mill; AFIN 41-00002; Air Operating Permit No. 287-AOP-R22

Dear Mr. Montgomery:

This letter is provided in response to your January 8, 2020 information collection request ("the ICR").

Please contact me at (870) 898-2711 ext. 26168 or kelley.crouch@domtar.com or Mr. Jeremy Jewell of Trinity Consultants at (918) 622-7111 ext. 1 or jjewell@trinityconsultants.com if you have any questions regarding this submittal.

DOMTAR A.W. LLC

Kelley R. Crouch

Kelley Crouch

Engineering Services Manager

ec: Tricia Treece, DEQ
Jeremy Jewell, Trinity Consultants

Domtar A.W. LLC > Ashdown Mill
AFIN 41-00002

Response to January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request

Prepared By:

Jeremy Jewell – Principal Consultant

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April 6, 2020

Project 203702.0003

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This report was prepared on behalf of Domtar A.W. LCC (Domtar) in response to the January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request ("the ICR") from the Arkansas Department of Energy and Environment, Division of Environmental Quality, Office of Air Quality ("the DEQ").

Per the ICR, this report provides information related to sulfur dioxide (SO_2) and/or nitrogen oxides (NO_X) emissions reduction options for the following sources/source numbers (SNs):

- No. 2 Power Boiler (SN-05)
- No. 3 Power Boiler (SN-01)
- No. 2 Recovery Boiler (SN-06)
- No. 3 Recovery Boiler (SN-14)

Each section of this report is related to a single source-pollutant combination, e.g., No. 2 Power Boiler – SO_2, and No. 3 Recovery Boiler – NO_X, resulting in eight (8) total sections. The following specific technical and economic information, where applicable, is provided in each section for each emissions reduction option considered, in accordance with instructions in the ICR:

- Technical feasibility
- Control effectiveness
- Emissions reductions
- Time necessary for implementation
- Remaining useful life
- Energy and non-air quality environmental impacts
- Costs

To the extent possible, information in this report is based on information prepared for the relevant Best Available Retrofit Technology (BART) assessment completed for the regional haze rule (RHR) first planning period (1PP) state implementation plan (SIP). The most recent 1PP SIP package was submitted to the U.S. Environmental Protection Agency (EPA) on August 13, 2019; it contains 594 pages. References in this report to the 1PP SIP package are to the version available on the DEQ's website as of April 6, 2020.[1]

[1] http://www.adeq.state.ar.us/air/planning/sip/pdfs/regional-haze/final-phase-III-sip-combined-files.pdf (accessed on April 6, 2020).

The ICR specifically listed the following three SO_2 emissions reduction options for consideration, and no other options have been identified:

- New scrubber downstream of existing scrubbers
- Increased reagent usage at existing scrubbers
- Upgrades to existing scrubbers

2.1. Technical Feasibility

Information about all three SO_2 emission reduction options listed above is presented in the 1PP SIP package. The relevant information (at 328-339 and 500-509) is included in Appendix A of this report for convenience. All three options were determined to be technically feasible.

2.2. Control Effectiveness

The appended (1PP SIP package pages 328-339) A.H. Lundberg Associates, Inc. (Lundberg) evaluation of the new scrubber option presented a 90 % control efficiency. Lundberg also evaluated possible upgrades to the existing scrubbers, including the elimination of bypass reheat, the installation of liquid distribution rings, the installation of perforated trays, improvements to the auxiliary system requirement, and a redesign of the spray header and nozzle configuration, and it was concluded that any control efficiency improvement to that already being achieved was unquantifiable (at 501).

Based on calculations presented in its February 2015 Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan (2015 FIP TSD), as presented in the 1PP SIP package (at 500-503), the EPA concluded that increased reagent usage at the existing scrubbers would achieve 90 % control efficiency and a controlled emission rate of 91.5 pounds per hour (lb/hr). This calculation was based on a 2009-2011 annual-average emission rate of approximately 280.9 lb/hr and a back-calculated control efficiency for the existing scrubbers of approximately 69 %.

Domtar asserted then, and maintains now, that the control efficiency and emission rate applied by the EPA to the increased reagent usage option has not been verified as sustainable over a long-term period in practice. A one-year or at least 30-day engineering study needs to be completed to confirm the EPA's assumptions. If the DEQ decides that increased reagent usage at the No. 2 Power Power Boiler is a reasonable part of its long-term strategy for the RHR, then Domtar requests time to conduct such a study and update the information provided in this report once that study is complete.

Additionally, Domtar has already commissioned an engineering firm to study the feasibility of operating No. 2 Power Boiler without coal as a fuel. If Domtar decides to remove coal as a fuel option, then the No. 2 Power Boiler emissions profile will likely change, and all assumptions in this report about control device efficiencies and costs will be subject to significant updates.

Table 2-1 summarizes and ranks (in descending order) the control effectiveness of the technically feasible SO_2 reduction options based on current assumptions and operation of the No. 2 Power Boiler.

Table 2-1. Control Effectiveness of SO_2 Emissions Reduction Options for No. 2 Power Boiler

SO_2 Reduction Option	Control Efficiency
New scrubber downstream of existing scrubbers	90 %
Increased reagent usage at existing scrubbers	90 %
Upgrades to existing scrubbers	0 %

2.3. Emissions Reductions

Table 2-2 presents the monthly average SO_2 emission rates from 2017 to 2019 for the No. 2 Power Boiler based on continuous emissions monitoring system (CEMS) records. Per the ICR, the baseline actual SO_2 emission rate used for this report is the maximum monthly value from 2017-2019, which is 279.3 lb/hr, equivalent to 1,223.1 tons per year (tpy).

Table 2-2. 2017-2019 Monthly SO_2 Emissions for No. 2 Power Boiler

	Monthly Average SO_2 Emission Rate (lb/hr)		
Month / Year	**2017**	**2018**	**2019**
1	250.63	250.54	279.25
2	223.92	230.75	270.93
3	134.35	212.36	163.72
4	195.53	198.91	173.68
5	205.25	170.94	196.26
6	205.22	109.46	221.19
7	206.03	141.34	199.35
8	212.67	123.15	183.45
9	141.45	92.17	214.62
10	237.61	166.26	187.33
11	256.48	224.19	130.71
12	273.59	213.20	169.52

Table 2-3 summarizes the controlled emission rates and emission reduction potentials based on the control efficiencies from Table 2-1 for the technically feasible SO_2 reduction options for the No. 2 Power Boiler.

The upgrades to existing scrubbers option is not carried forward in this report because it does not provide for any quantifiable decrease in SO_2 emissions (i.e., any cost of control greater than zero would result in an undefined or infinite cost effectiveness value).

Table 2-3. Emissions of SO_2 Emissions Reduction Options for No. 2 Power Boiler

SO_2 Reduction Option	Controlled Emission Rate (lb/hr)	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
New scrubber downstream of existing scrubbers	27.9	122.3	1,100.8
Increased reagent usage at existing scrubbers	27.9	122.3	1,100.8
Upgrades to existing scrubbers	279.3	1,223.1	0

2.4. Time Necessary for Implementation

Implementing the new scrubber option would take at least three (3) years. Domtar's capital projects approval process can take from six (6) to 18 months, and this would not begin until an enforceable requirement is effective. Depending on the timing of the effectiveness date and the project approval, it could be another 18 months before a window was available to complete construction on the No. 2 Power Boiler. According to the previously referenced Lundberg proposal, 34 weeks (8.5 months) is needed for shipment and construction of a new scrubber downstream of the existing scrubbers. This process can take place within the potential 18-month outage frequency. Domtar proposes three (3) years as an adequate time necessary to implement a new scrubber system on the No. 2 Power Boiler.

Increased reagent usage at the existing scrubbers can be implemented within approximately two (2) years of an enforcement requirement's effective date. The time is needed to procure and install two new pumps in conjunction with Domtar's outages schedule.

2.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 2 Power Boiler; it is needed in order to meet the steam demands of the Ashdown Mill processes. The useful life values found in EPA's Air Pollution Control Cost Manual (CCM)[2] are assumed to be applicable.

2.6. Energy and Non-air Quality Environmental Impacts

A new scrubber operating downstream of the existing scrubbers would incur an energy impact for the Ashdown Mill. This energy impact has been monetized. A new scrubber would also increase water usage and waste water generation. However, the increase would be small when compared to the existing quantities used and generated by the Ashdown Mill, and no further consideration is made for non-air quality environmental impacts of a new scrubber.

Energy impacts due to increased reagent usage are expected to be minimal. Non-air quality environmental impacts are also expected to be small when compared to existing storage and usage of caustic solutions at the Ashdown Mill.

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[2] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, available at https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf (accessed on January 31, 2020)

2.7. Costs

The total capital cost of the new scrubber option was estimated in the 1PP SIP package (at 504) to be $7,175,000, which was annualized to $578,207 per year based on 7 % interest and 30 years of operation. Further, the estimated total annual direct and indirect costs[3] (not including annualized capital) was $9,255,171 per year (at 504). Therefore, the total annual cost of the new scrubber option was estimated to $9,833,378 per year. These values are representative of 2014 and can be escalated to 2018 (the latest final information available as of January 28, 2020) using the Chemical Engineering Plant Cost Index (CEPCI) values (576.1 for 2014 and 603.1 for 2018). The result is a total annual cost estimate of $10,294,238 per year. Based on an SO_2 emission reduction of 1,100.8 tpy, the cost effectiveness of the new scrubber option is $9,351/ton. It is important to note that the cost values presented above are unrealistically small as they do not adequately account for the retrofit issues that would occur if a new scrubber were to be installed. Per the 1PP SIP package (at 504), "There is no existing property or adequate structure to support the add-on spray scrubber equipment…the installation of add-on spray scrubbers would require construction at the facility to accommodate the equipment, but an estimate of these costs was not available and therefore not factored into the cost estimates…"

The cost of increased reagent usage option was estimated in the 1PP SIP package (at 504) to be $200,000 in capital, annualized to $16,117 per year, and approximately $1,960,000 per year in direct annual operations and maintenance costs (i.e., additional reagent usage, waste water treatment, raw water treatment, and energy usage) for a total annual cost estimate of $1,976,117 per year. When escalated to 2018, this becomes $2,068,732 per year. Based on an SO_2 emission reduction of 1,100.8 tpy, the cost effectiveness of the increased reagent usage option is $1,879/ton. Table 2-4 summarizes the estimated costs, including the cost effectiveness estimates based on the emission reduction values from Table 2-3, for the technically feasible SO_2 reduction options for the No. 2 Power Boiler.

Table 2-4. Estimated Costs (2018 Basis) of SO_2 Emissions Reduction Options for No. 2 Power Boiler

SO_2 Reduction Option	Capital Costs ($)	Annualized Capital Costs ($/year)	Annual Direct and Indirect / Operations and Maintenance Costs ($/year)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
New scrubber downstream of existing scrubbers	7,511,70	605,306	9,688,932	10,294,238	9,351
Increased reagent usage at existing scrubbers	209,373	16,873	2,051,859	2,068,732	1,879

As mentioned above, Domtar has little confidence in the control efficiency assigned to the increased reagent option, therefore, it also has little confidence in the cost effectiveness value. If the DEQ decides that increased reagent usage at the No. 2 Power Power Boiler is a reasonable part of its long-term strategy for the RHR, then Domtar requests time to conduct such a study and update the information provided in this report once that study is complete.

[3] Annual direct costs include operations and maintenance labor, maintenance materials, and utilities. Annual indirect costs include property tax, insurance, and overhead/administration.

The ICR specifically listed for consideration the following three NO_X emissions reduction options, all of which involve the reaction of ammonia (NH_3) with NO_X, and no other options have been identified:

- Selective Catalytic Reduction (SCR)
- Regenerative Selective Catalytic Reduction (RSCR)
- Selective Non-Catalytic Reduction (SNCR)

3.1. Technical Feasibility

Two (SCR and SNCR) of the three NO_X emission reduction options listed above were examined in the BART assessment completed for the 1PP SIP. The relevant 1PP SIP packge information (at 127-133 and 510-512) is included in Appendix A of this report for convenience

For the 1PP, SCR was determined by Domtar, the DEQ, and the EPA to be technically infeasible for several reasons, all of which apply now as they did then.

RSCR, also known as tail-end SCR because it is placed downstream of the particulate matter (PM) control device, incorporates a regenerator, which pre-heats the cool gas stream from PM control device outlet before it enters the RSCR using the RSCR outlet gas that has been heated to within the optimal SCR temperature range. RSCR comes with many of the same technical challenges as traditional SCR. For example, space constraints often make retrofitting an SCR or RSCR impossible. This is true of the No. 2 Power Boiler, which is completely surrounded by existing equipment as shown in Figure 3-1 and Figure 3-2.

Additionally, the temperature of the No. 2 Power Boiler exhaust at the outlet of the scrubbers is too cold for SCR. Per the EPA's CCM, the desired minimum temperature for SCR application to achieve 70 % control efficiency is 575 degrees Fahrenheit (°F).[4] The No. 2 Power Boiler exhaust is, on average, approximately 125 °F. In an RSCR system, the regenerative heating reduces the required heat input; however, this reheating of the flue gas still represents a significant amount of auxiliary fuel that would be necessary for successful operation. Moreover, it is not considered available as RSCR has not been previously demonstrated on load-following industrial boilers. Such boilers, because of unstable and large exhaust temperature swings, make it particularly difficult to control reagent injection rates needed to ensure appropriate NO_X reductions while avoiding excessive ammonia slip.

The EPA's *Guidelines for BART Determinations Under the Regional Haze Rule* state that "[t]echnologies which have not yet been applied to (or permitted for) full scale operations need not be considered as available; we [EPA] do not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice."[5] While these "Guidelines" do not directly applicable to a four factor analysis, it is assumed that the EPA's view of availability with respect to control technologies/options is consistent within the broad regional haze rule. As such, because RSCR has not been successfully implemented on an emission unit comparable to the No. 2 Power Boiler, it is considered to be technically infeasible.

[4] EPA Air Pollution Control Cost Manual, Section 4.2, Chapter 2, Figure 2.2.

[5] 40 CFR part 51, Appendix Y.

Figure 3-1. Plot Plan Showing No. 2 Power Boiler and Surrounding Equipment

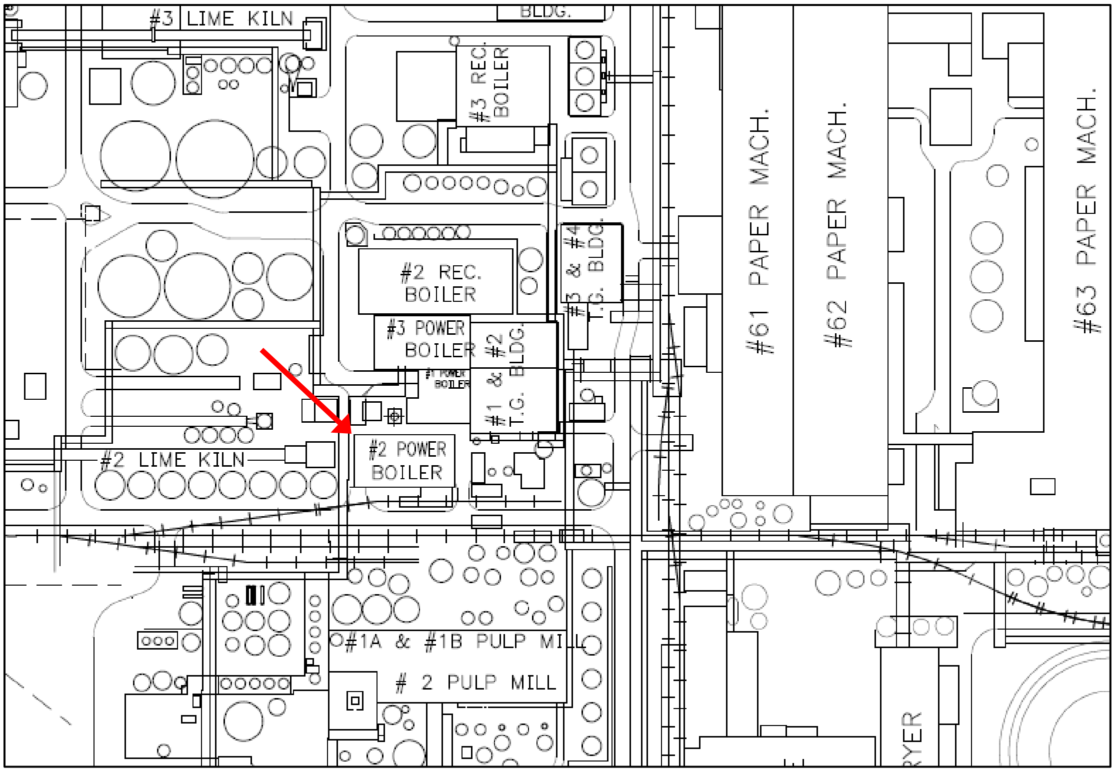

Figure 3-2. Aerial Showing No. 2 Power Boiler and Surrounding Equipment

SNCR was determined in the 1PP to be technically feasible although the effectiveness of SNCR on a boiler such as the No. 2 Power Boiler (multi-fuel, swing-load) is questionable. This issue is discussed in Section 3.2.

3.2. Control Effectiveness

As presented in the 1PP SIP package (at 511), EPA stated in its 2015 FIP TSD: "We [EPA] agree that because of the wide variability in steam demand and wide range in furnace temperature observed at Power Boiler No. 2, the NO_X control efficiency of SNCR at the boiler would not reach optimal control levels on a long-term basis. We also believe there is uncertainty as to the level of control efficiency that SNCR would be able to achieve on a longterm (sic) basis for Power Boiler No. 2." Additionally (at 510-511):

> *To demonstrate the wide range in temperature at Power Boiler No. 2 and its relationship to steam demand, Domtar obtained an analysis of furnace exit gas temperatures for Power Boiler No. 2 from an engineering consultant [International Applied Engineering, Inc. (IAE)]. The furnace exit gas temperatures were analyzed for a 12-day period that according to Domtar is representative of typical boiler operations. The consultant's report indicated that furnace exit gas temperatures are representative of temperatures in the upper portion of the furnace, which is the optimal location for installation of the SNCR injection nozzles. The consultant estimated that 1700 – 1800°F represents the temperature range at which SNCR can be expected to reach 40% control efficiency at the current boiler operating conditions. It was found that there is wide variability in the furnace exit gas temperatures for Power Boiler No. 2, with temperatures ranging from 1000 – 2000°F. The data also indicate that there is a direct positive relationship between boiler steam demand and furnace exit gas temperatures. It was also found that Power Boiler No. 2 operated in the optimal temperature zone at which SNCR can be expected to reach 40% control efficiency for only a total of 20 hours over the 12-day period analyzed (288 continuous hours), which is approximately 7% of the time.*

Based on the information published by the EPA in the 1PP, it is expected that for the No. 2 Power Boiler SNCR could achieve an overall control efficiency of approximately three (3) % based on operation at 40 % efficiency for seven (7) % of total boiler operating time.

Table 3-1 summarizes and ranks (in descending order) the control effectiveness of the technically feasible NO_X reduction options for the No. 2 Power Boiler.

Table 3-1. Control Effectiveness of NO_X Emissions Reduction Options for No. 2 Power Boiler

NO_X Reduction Option	Control Efficiency
SNCR	3 %

3.3. Emissions Reductions

Table 3-2 presents the monthly average NO_X emission rates from 2017 to 2019 for the No. 2 Power Boiler based on CEMS records. Per the ICR, the baseline actual NO_X emission rate used for this report is the maximum monthly value from 2017-2019, which is 176.7 lb/hr, equivalent to 774.1 tpy.

Table 3-2. 2017-2019 Monthly NO_X Emissions for No. 2 Power Boiler

Month / Year	Monthly Average NO_X Emission Rate (lb/hr)		
	2017	2018	2019
1	140.55	176.73	169.37
2	137.77	116.55	152.22
3	144.11	134.12	87.57
4	115.88	124.97	99.47
5	109.55	130.47	101.59
6	115.08	121.14	127.82
7	119.50	120.87	129.26
8	119.01	97.88	148.24
9	70.03	112.62	147.77
10	120.02	105.23	145.76
11	137.02	131.19	149.68
12	157.98	129.29	155.33

Table 3-3 summarizes the controlled emission rates and emission reduction potentials based on the control efficiencies from Table 3-1 for the technically feasible NO_X reduction options for the No. 2 Power Boiler.

Table 3-3. Emissions of NO_X Emissions Reduction Options for No. 2 Power Boiler

NO_X Reduction Option	Controlled Emission Rate (lb/hr)	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
SNCR	171.4	750.9	23.2

3.4. Time Necessary for Implementation

EPA has allowed for five (5) years for the implementation of add-on NO_X controls such as SNCR in at least two FIPs (e.g., for Utah and North Dakota). Domtar would request the same timeline if SNCR were required for either of its power boilers.

3.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 2 Power Boiler; it is needed in order to meet the steam demands of the Ashdown Mill processes. The useful life values found in EPA's CCM are assumed to be applicable.

3.6. Energy and Non-air Quality Environmental Impacts

The energy impacts (which are monetized) and non-air quality environmental impacts for SNCR, principally related to the storage and handling of ammonia/urea, are well known. They are expected to be no greater at the Ashdown Mill than any other industrial facility and are therefore not considered as a reason for rendering the control options infeasible in this context.

3.7. Costs

In the 1PP SIP package (at 512), the total capital cost of SNCR – for a 27.5 % control efficiency scenario, which, based on the above discussion, is unrealistic but is taken to be representative for the purposes of this ICR response – was estimated to be $2,681,678, which is annualized to $216,107 per year based on 7 % interest and 30 years of operation. Further, the estimated total annual direct costs[6] (not including annualized capital) was $627,469 per year. Therefore, the total annual cost of SNCR was estimated to $843,575 per year. These values are representative of 2012 and can be escalated to 2018 (the latest final information available as of January 28, 2020) using the CEPCI values (584.6 for 2012 and 603.1 for 2018). The result is a total annual cost estimate of $870,270 per year. Based on a NO_X emission reduction of 23.2 tpy, the cost effectiveness of SNCR is $37,475/ton.

Table 3-3 summarizes the estimated costs, including the cost effectiveness estimates based on the emission reduction values from Table 3-2, for the technically feasible NO_X reduction options for the No. 2 Power Boiler.

Table 3-4. Estimated Costs (2018 Basis) of NO_X Emissions Reduction Options for No. 2 Power Boiler

NO_X Reduction Option	Capital Costs ($)	Annualized Capital Costs ($/year)	Annual Direct and Indirect / Operations and Maintenance Costs ($/year)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
SNCR	2,766,541	222,946	647,326	870,271	37,475

[6] Annual direct costs include operations and maintenance labor, maintenance materials, reagent, and utilities.

The ICR specifically listed the following three SO_2 emissions reduction options for consideration:

- Wet gas scrubber (WGS)
- Spray dry absorber (SDA)

The above options are collectively referred to as flue gas desulfurization (FGD) technologies.

One other SO_2 emissions reduction options is discussed in this report:

- Inherent scrubbing by the ash created from combusting bark in the boiler ("ashes resulting from wood residue combustion typically contain significant fractions of oxides and carbonates of alkali metals such as calcium, potassium, and magnesium…wood residue ash can capture some of the sulfur dioxide released with the co-firing of sulfur-containing fossil fuels…"[7])

4.1. Technical Feasibility

All three SO_2 emission reduction options listed above are technically feasible for the No. 3 Power Boiler.

4.2. Control Effectiveness

Domtar has not commissioned site-specific studies of the FGD technologies, primarily because they are clearly economically infeasible considering the small emissions reduction potential available (i.e., small baseline emission rate). It is assumed for the purposes of this report that the FGD options can achieve 90 % control efficiency per EPA's Air Pollution Control Technology Fact Sheet.[8]

Inherent scrubbing is taken to be the base case. The baseline actual SO_2 emission rate presented below considers the inherent scrubbing that occurs in the No. 3 Power Boiler.

Table 4-1 summarizes and ranks (in descending order) the control effectiveness of the technically feasible SO_2 reduction options for the No. 3 Power Boiler.

Table 4-1. Control Effectiveness of SO_2 Emissions Reduction Options for No. 3 Power Boiler

SO_2 Reduction Option	Control Efficiency
WGS / Wet FGD	90 %
SDA / Dry FGD	90 %
Inherent Scrubbing	Base case

[7] Someshwar, Arun V. and Jain, Ashok K. (NCASI), "Sulfur capture in combination bark boilers", Tappi Journal Vol. 76, No. 7, July 1993.

[8] https://www3.epa.gov/ttn/catc/dir1/ffdg.pdf (accessed on January 30, 2020)

4.3. Emissions Reductions

Table 4-2 presents the monthly average SO_2 emission rates from 2017 to 2019 for the No. 3 Power Boiler based on records of the emissions calculations required by Specific Condition 6a of Air Operating Permit No. 287-AOP-R22.[9] Per the ICR, the baseline actual SO_2 emission rate used for this report is the maximum monthly value from 2017-2019, which is 12.1 tons per month (tpy) or 33.6 lb/hr (based on the 30-day month), equivalent to 147.1 tpy.

Table 4-2. 2017-2019 Monthly SO_2 Emissions for No. 3 Power Boiler

Month / Year	Monthly Average SO_2 Emission Rate (ton/month)		
	2017	2018	2019
1	3.48	0.42	0.00
2	3.91	7.95	5.26
3	2.13	5.09	7.87
4	2.64	6.86	4.54
5	7.59	2.37	0.26
6	4.05	12.09	1.27
7	4.20	7.41	5.09
8	0.00	4.40	0.03
9	0.00	2.63	4.28
10	0.02	0.89	4.07
11	3.18	0.00	6.11
12	3.30	0.00	11.06

Table 4-3 summarizes the controlled emission rates and emission reduction potentials based on the control efficiencies from Table 4-1 for the technically feasible SO_2 reduction options for the No. 3 Power Boiler.

Table 4-3. Emissions of SO_2 Emissions Reduction Options for No. 3 Power Boiler

SO_2 Reduction Option	Controlled Emission Rate (lb/hr)	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
WGS / Wet FGD	3.4	14.7	132.4
SDA / Dry FGD	3.4	14.7	132.4
Inherent Scrubbing	33.6	147.1	0

4.4. Time Necessary for Implementation

Domtar proposes five years as an appropriate timeline for implementing FGD systems based on numerous determinations for utilities in the 1PP.

[9] The issuance of the next version of the Air Operating Permit, No. 287-AOP-R23, is pending. Specific Condition 6a is not changed in draft version of this permit.

No time is needed to implement the inherent scrubbing option; it is already in place.

4.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 3 Power Boiler; it is needed in order to meet the steam demands of the Ashdown Mill processes. The useful life values found in EPA's CCM are assumed to be applicable.

4.6. Energy and Non-air Quality Environmental Impacts

An FGD system would incur an energy impact, which can be monetized, and it would increase water usage and waste water generation. However, the increase would be small when compared to the existing quantities used and generated by the Ashdown Mill, and no further consideration is made for non-air quality environmental impacts of an FGD system.

The inherent scrubbing option represents no new energy or non-air quality environmental impacts.

4.7. Costs

There is no new cost associated with the inherent scrubbing option as it is already in place.

For wet and dry FGD, EPA's Air Pollution Control Technology Fact Sheet provides ranges for capital and O&M costs, relative to heat input capacity, representative of 2001 (the CEPCI for 2001 is 394.3). The No. 3 Power Boiler heat input capacity is 790 MMBtu/hr. Table 4-4 summarizes the EPA Fact Sheet based cost ranges, including the cost effectiveness estimates based on the emission reduction values from Table 4-3, for the FGD options for the No. 3 Power Boiler.

Table 4-4. Estimated Costs (2018 Basis) of SO_2 Emissions Reduction Options for No. 3 Power Boiler

SO_2 Reduction Option	Capital Costs ($)	Annualized Capital Costs ($/year)	Annual Operations and Maintenance Costs ($/year)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
WGS / Wet FGD (low)	30,208,534	2,434,397	966,673	3,401,070	25,695
WGS / Wet FGD (high)	181,251,205	14,606,383	2,175,014	16,781,397	126,782
SDA / Dry FGD (low)	36,250,241	2,921,277	1,208,341	4,129,618	31,199
SDA / Dry FGD (high)	181,251,205	14,606,383	36,250,241	50,856,624	384,217

The ICR specifically listed for consideration the following three NO_X emissions reduction options, all of which involve the reaction of NH_3 with NO_X, and no other options have been identified:

- SCR
- RSCR
- SNCR

5.1. Technical Feasibility

The same problems with SCR and RSCR described above for No. 2 Power Boiler – principally space constraints, operation (load-swings), and cool exhaust – also apply to No. 3 Power Boiler, and these control options are deemed infeasible.

Because SNCR was determined in the 1PP to be technically feasible for the No. 2 Power Boiler it is also considered technically feasible for the purposes of this report for the No. 3 Power Boiler.

5.2. Control Effectiveness

The operation of the No. 3 Power Boiler is effectively identical to the No. 2 Power Boiler – both are swing-load boilers that operate as needed to meet demand. Therefore, a similar wide variability in exit gas temperature is expected. For the purposes of this report, the same SNCR control efficiency applied for No. 2 Power Boiler is also applied for No. 3 Power Boiler.

Table 5-1 summarizes and ranks (in descending order) the control effectiveness of the technically feasible NO_X reduction options for the No. 3 Power Boiler.

Table 5-1. Control Effectiveness of NO_X Emissions Reduction Options for No. 3 Power Boiler

NO_X Reduction Option	Control Efficiency
SNCR	3 %

5.3. Emissions Reductions

Table 5-2 presents the monthly average NO_X emission rates from 2017 to 2019 for the No. 3 Power Boiler based on CEMS records. Per the ICR, the baseline actual NO_X emission rate used for this report is the maximum monthly value from 2017-2019, which is is 134.4 lb/hr equivalent to 588.5 tpy.

Table 5-2. 2017-2019 Monthly NO_X Emissions for No. 3 Power Boiler

Month / Year	Monthly Average NO_X Emission Rate (lb/hr)		
	2017	**2018**	**2019**
1	29.16	97.83	134.35
2	52.95	75.69	78.70
3	52.67	98.05	88.44
4	62.47	70.03	52.61
5	62.23	84.95	55.50
6	34.93	56.92	40.01
7	40.80	66.46	50.45
8	94.55	70.82	38.04
9	62.59	43.22	32.01
10	72.65	47.66	46.32
11	84.94	118.12	87.28
12	53.90	71.45	75.41

Table 5-3 summarizes the controlled emission rates and emission reduction potentials based on the control efficiencies from Table 5-1 for the technically feasible NO_X reduction options for the No. 3 Power Boiler.

Table 5-3. Emissions of NO_X Emissions Reduction Options for No. 3 Power Boiler

NO_X Reduction Option	Controlled Emission Rate (lb/hr)	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
SNCR	130.3	570.8	17.65

5.4. Time Necessary for Implementation

EPA has allowed for five (5) years for the implementation of add-on NO_X controls such as SNCR in at least two FIPs (e.g., for Utah and North Dakota). Domtar would request the same timeline if SNCR were required for either of its power boilers.

5.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 3 Power Boiler; it is needed in order to meet the steam demands of the Ashdown Mill processes. The useful life values found in EPA's CCM are assumed to be applicable.

5.6. Energy and Non-air Quality Environmental Impacts

The energy impacts (which are monetized) and non-air quality environmental impacts for SNCR, principally related to the storage and handling of ammonia/urea, are well known. They are expected to be no greater at the Ashdown Mill than any other industrial facility and are therefore not considered as a reason for rendering the control options infeasible in this context.

5.7. Costs

The cost estimates used in the 1PP for the No. 2 Power Boiler (for the 27.5 % control efficiency scenario) are taken to be representative for the purposes of this ICR response. Table 5-4 summarizes these estimated costs, including the cost effectiveness estimates based on the emission reduction values from Table 5-3, for SNCR for the No. 3 Power Boiler.

Table 5-4. Estimated Costs (2018 Basis) of NO_X Emissions Reduction Options for No. 3 Power Boiler

NO_X Reduction Option	Capital Costs ($)	Annualized Capital Costs ($/year)	Annual Direct and Indirect / Operations and Maintenance Costs ($/year)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
SNCR	2,766,541	222,946	647,326	870,271	49,296

The ICR did not list any specific SO_2 emissions reduction options for consideration for the recovery boilers. Trinity queried the Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) and reviewed information from the National Council for Air and Stream Improvement (NCASI) and its own library of air pollution control assessments (e.g., from previous BACT determinations) to determine what SO_2 emissions reduction options may be feasible for recovery boilers. Two potential strategies emerge from this research:

- Good operating practices, i.e., optimizing liquor properties and combustion air firing patterns
- Flue gas desulfurization (FGD)

6.1. Technical Feasibility

NCASI states in its 2013 Handbook:

> *The combustion of black liquor in a kraft recovery furnace results in SO_2 emissions that are extremely variable. These emissions depend on a variety of factors, which include a) liquor properties such as sulfidity (or sulfur-to-sodium ratio), heat value, and solids content; b) combustion air and liquor firing patterns; c) furnace design; and d) other furnace operational parameters (NCASI 1991). Liquor sulfidity in most kraft mills today is low enough that it is no more considered a determining factor for SO_2 emissions (NCASI 1991). Optimizing liquor properties (such as solids content, Btu value) and combustion air firing patterns so as to yield maximum and uniform temperatures in the lower furnace are currently considered the best strategies for minimizing kraft recovery furnace SO_2 emissions. Flue gas desulfurization is capital- and energy-intensive and its efficacy is unproven, considering the generally low but rapidly fluctuating levels of SO_2 in kraft recovery furnace flue gases.*[10]

An RBLC query[11] confirms NCASI's statements about FGD being unproven on recovery boilers as no determinations for this technology on recovery boilers were found. Because FGD has not been applied to recovery boilers, it is considered unavailable and therefore infeasible for the No. 2 Recovery Boiler.

Domtar employs good operating practices, including those listed by NCASI, for the No. 2 Recovery Boiler.

6.2. Control Effectiveness

Good operating practices is taken to be the base case. The baseline actual SO_2 emission rate presented below considers the good operating practices in place for the No. 2 Recovery Boiler.

---

[10] NCASI Handbook of Environmental Regulations and Control, Volume 1: Pulp and Paper Manufacturing, April 2013, Section 6.8.3.3. (Copies of NCASI materials must be requested from NCASI directly).

[11] RBLC searches were completed on February 3, 2020 for Process Types 30.211, 30.219, 30.290, 11.190, 11.290, and 11.900 and for Process Names that contain the word "Recovery".

6.3. Emissions Reductions

Table 6-1 presents the monthly average SO_2 emission rates from 2017 to 2019 for the No. 2 Recovery Boiler based on CEMS records. Per the ICR, the baseline actual SO_2 emission rate used for this report is the maximum monthly value (presumably representative of normal operations) from 2017-2019, which is 8.52 lb/hr, equivalent to 37.3 tpy.

Table 6-1. 2017-2019 Monthly SO_2 Emissions for No. 2 Recovery Boiler

Month / Year	Monthly Average SO_2 Emission Rate (lb/hr)		
	2017	**2018**	**2019**
1	0.02	0.05	0.07
2	0.39	0.09	0.16
3	0.04	0.08	0.13
4	0.15	0.01	0.17
5	0.94	0.02	0.17
6	0.23	0.01	0.10
7	2.47	0.04	0.06
8	4.75	0.13	0.07
9	8.52	~~22.71~~ [12]	0.06
10	0.44	0.24	0.19
11	0.05	0.22	0.22
12	0.04	0.09	0.14

The continued employment of good operating practices will result in zero (0) emissions reduction.

6.4. Time necessary for Implementation

No time is needed to implement good operating practices.

6.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 2 Recovery Boiler; it is needed in order to meet the chemical recovery and steam demands of the Ashdown Mill processes.

6.6. Energy and Non-air Quality Environmental Impacts

Good operating practices result in no new energy or non-air quality environmental impacts.

6.7. Costs

There is no new cost associated with good operating practices already being used.

[12] The value for September 2018 (22.7 lb/hr) is excluded from consideration because it is dominated by startup and shutdown periods that occurred during a maintenance outage, i.e., it is not representative of normal operations.

The ICR did not list any specific NO_X emissions reduction options for consideration for the recovery boilers. Trinity queried the RBLC and reviewed information from NCASI and its own library of air pollution control assessments (e.g., from previous BACT determinations) to determine what NO_X emissions reduction options may be feasible for recovery boilers. Three strategies emerge from this research:

- Good combustion practices, i.e., staged air combustion
- SNCR
- SCR

7.1. Technical Feasibility

NCASI states in its 2013 Handbook:

> *… NO_X emissions from black liquor combustion in kraft recovery furnaces are expected to result mainly from the "fuel NO_X" mechanism pathway. The highest temperatures measured in the recovery furnace, usually in the lower furnace region, range from about 1800°F to 2400°F. These are much lower than would be essential for appreciable NO_X formation by the thermal NO_X pathway (>2,800°F). Hence, factors that would aid in reducing peak gas temperatures in the lower furnace, such as the firing of lower solids content liquors, reducing combustion air temperature and pressure, changes in burner design and position, and reduced liquor feed temperature perhaps have only a limited role in controlling NO_X formation.*
>
> *A detailed investigation into the origins of kraft recovery furnace NO_X emissions and related parameters by NCASI concluded that black liquor N content was perhaps the most important factor affecting NO_X emissions from kraft recovery furnaces (NCASI 1992). Excess oxygen in the zone where the bulk of liquor combustion takes place was considered the second most important factor for NO_X formation. While very little can be done to affect the liquor nitrogen content, staged air combustion, which is already integral to the operation of most recovery furnaces, is perhaps the best strategy for minimizing NO_X formation. The precise distribution of combustion air between primary, secondary and, if relevant, tertiary or quaternary air levels is most likely quite furnace-specific…*
>
> *The above mentioned NCASI report on recovery furnace NO_X emissions (NCASI 1992) contained longterm continuous emissions monitoring data for NO_X emissions from several kraft recovery furnaces. These data showed the NO_X emissions fell within a fairly narrow range for each furnace, in spite of apparent, significant day-to-day changes in furnace operating behavior as suggested by the corresponding, widely fluctuating data for SO_2 and CO emissions. This lack of significant variability in a given recovery furnace's NO_X emissions would suggest most furnaces already utilize the concepts of staged combustion optimally, and the differences observed between one mill's furnace NO_X emissions and another's are mainly a result of the differences between their black liquor N contents…*
>
> *Relative to flue gas treatment as an (sic) NO_X control option, selective non-catalytic reduction (SNCR) is not considered technologically feasible for kraft recovery furnaces (Kravett and Hanson 1994). This conclusion was based on the fact that a recovery furnace is a complex chemical reaction system and any disruption of the delicate reaction chemistry could potentially damage the*

furnace, impact the quality of the product, or otherwise unacceptably affect the system. Also, like industrial boilers, kraft recovery furnaces operate at varying loads which makes it difficult to inject the SNCR reagent within the desired temperature window. Several technological limitations also come to bear when one considers the installation of a selected catalytic reduction (SCR) system on a recovery furnace: a) potential for plugging and fouling of the SCR catalyst, b) potential for fouling of the ESP, c) ammonia handling and ammonia slip emissions issues, d) potential for increased particulate emissions, e) creation of a new hazardous waste (spent catalyst), and f) potential significant energy penalty (Kravett and Hansen 1994).[13]

An RBLC query[14] confirms NCASI's statements about SCR and SNCR being infeasible on recovery boilers as no determinations for these technologies on recovery boilers were found.[15] For the technical reasons described above, and because SCR and SNCR have not been applied to recovery furnaces, these control options are infeasible for the No. 2 Recovery Boiler.

7.2. Control Effectiveness

Good combustion practices is taken to be the base case. The baseline actual NO_X emission rate presented below considers the good combustion practices in place for the No. 2 Recovery Boiler.

7.3. Emissions Reductions

Table 7-1 presents the monthly average NO_X emission rates from 2017 to 2019 for the No. 2 Recovery Boiler based on CEMS records. Per the ICR, the baseline actual NO_X emission rate used for this report is the maximum monthly value (presumably representative of normal operations) from 2017-2019, which is 124.0 lb/hr, equivalent to 543.2 tpy.

---

[13] NCASI Handbook of Environmental Regulations and Control, Volume 1: Pulp and Paper Manufacturing, April 2013, Section 6.8.3.4

[14] RBLC searches were completed on February 3, 2020 for Process Types 30.211, 30.219, 30.290, 11.190, 11.290, and 11.900 and for Process Names that contain the word "Recovery"

[15] There is one RBLC entry for SNCR on Recovery Boilers – for Apple Grove Pulp and Paper Company (RBLC ID WV-0016) – but according the RBLC's "Other Permitting Information" note for this entry, this facility was never built.

Table 7-1. 2017-2019 Monthly NO_X Emissions for No. 2 Recovery Boiler

Month / Year	Monthly Average NO_X Emission Rate (lb/hr)		
	2017	**2018**	**2019**
1	122.23	111.84	115.54
2	122.81	112.92	116.39
3	72.98	107.08	110.54
4	121.96	121.98	113.01
5	115.47	114.15	107.17
6	107.58	110.69	109.03
7	105.48	112.94	111.78
8	107.92	110.13	111.50
9	116.59	73.88	118.65
10	123.51	117.37	124.03
11	123.64	96.18	122.69
12	123.32	118.04	106.49

The continued employment of good combustion practices will result in zero (0) emissions reduction.

7.4. Time necessary for Implementation

No time is needed to implement good combustion practices.

7.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 2 Recovery Boiler; it is needed in order to meet the chemical recovery and steam demands of the Ashdown Mill processes.

7.6. Energy and Non-air Quality Environmental Impacts

Good combustion practices result in no new energy or non-air quality environmental impacts.

7.7. Costs

There is no new cost associated with good combustion practices already being used.

See Section 6. All statements that apply to the No. 2 Recovery Boiler also apply to the No. 3 Recovery Boiler except for the baseline actual emission rate, which is recorded below for the sake of completeness.

Table 8-1 presents the monthly average SO_2 emission rates from 2017 to 2019 for the No. 3 Recovery Boiler based on CEMS records. Per the ICR, the baseline actual SO_2 emission rate used for this report is the maximum monthly value (presumably representative of normal operations) from 2017-2019, which is 2.8 lb/hr, equivalent to 12.1 tpy.

Table 8-1. 2017-2019 Monthly SO_2 Emissions for No. 3 Recovery Boiler

Month / Year	Monthly Average SO_2 Emission Rate (lb/hr)		
	2017	**2018**	**2019**
1	0.00	0.54	1.52
2	0.03	0.61	2.13
3	~~11.35~~ [16]	0.46	1.81
4	0.52	0.39	0.39
5	0.54	0.17	1.97
6	0.53	0.29	1.09
7	0.45	0.46	0.44
8	0.51	0.77	0.00
9	0.49	1.45	0.66
10	0.44	2.46	0.39
11	0.54	2.76	0.63
12	0.48	1.36	0.43

[16] The value for March 2017 (11.35 lb/hr) is excluded from consideration because it is dominated by startup and shutdown periods that occurred during a maintenance outage, i.e., it is not representative of normal operations.

See Section 7. All statements that apply to the No. 2 Recovery Boiler also apply to the No. 3 Recovery Boiler except for the baseline actual emission rate, which is recorded below for the sake of completeness.

Table 9-1 presents the monthly average NO_X emission rates from 2017 to 2019 for the No. 3 Recovery Boiler based on CEMS records. Per the ICR, the baseline actual NO_X emission rate used for this report is the maximum monthly value (presumably representative of normal operations) from 2017-2019, which is 172.4 lb/hr, equivalent to 754.9 tpy.

Table 9-1. 2017-2019 Monthly NO_X Emissions for No. 2 Recovery Boiler

	Monthly Average NO_X Emission Rate (lb/hr)		
Month / Year	**2017**	**2018**	**2019**
1	153.40	136.56	163.90
2	125.76	148.07	166.39
3	130.64	143.52	162.10
4	162.37	134.24	162.08
5	151.70	137.64	150.97
6	146.06	124.24	141.21
7	136.33	142.66	132.86
8	133.74	137.69	115.11
9	131.49	56.72	139.28
10	144.44	152.41	143.58
11	153.14	153.07	152.20
12	146.88	172.36	140.65

APPENDIX A: 1PP SIP PACKAGE INFORMATION RELATED TO NO. 2 POWER BOILER SO_2 EMISSIONS REDUCTION OPTIONS

LUNDBERG

13201 Bel-Red Road
Bellevue, Washington 98005
tel: 425.283.5070
fax: 425.283.5081

April 17, 2014

Reference: P-125387, Rev.01

Attention: Ms. Kelley Crouch

Subject: SO_2 Scrubber for Power Boiler No. 2

Domtar Industries, Inc.
285 Highway 71 S
Ashdown, AR 71822-8356

Dear Ms. Crouch:

In response to your recent request, Lundberg is pleased to submit the following revised budget proposal for the supply of an SO_2 scrubbing system No. 2 power boiler at the Ashdown Mill. As you know, the original June, 2012 proposal included an SO_2 scrubbing system and a wet ESP for particulate control. In this revision the wet ESP has been eliminated.

As before, the proposal is to supply add-on spray scrubbers downstream of the existing venturi scrubbers. The spray scrubbers will utilize sodium hydroxide to absorb SO_2. The design efficiency for the scrubbers will continue to be 90% and all other process considerations addressed in the first proposal will remain the same.

The only significant change in the scrubber design is that we have changed to an upflow configuration. Without a downstream wet ESP operation in the upflow mode will save some cost because the gas can discharge directly out the top of the scrubber.

If you have any questions about the proposal, please feel free to me a call at 425/283-5070.

Thank you for the opportunity to present this proposal. We look forward to working with you on this project.

Sincerely,

Steven A. Jaasund, P.E.

Manager—Geoenergy Products
Lundberg

enc: Proposal

cc: Mr. Eric Gardner, Lundberg/ Monroe, LA
Mr. Rudi Miksa, Lundberg/Monroe, LA

P-125387, Rev.01

April 17, 2014

LUNDBERG

BUDGET PROPOSAL

SPRAY SCRUBBER

DOMTAR INDUSTRIES

ASHDOWN AR

Our representative in your area:

Mr. Eric Gardner
210 Pinehurst Drive
Monroe, LA 71201
Phone: 318/366-5909

Mr. Rudi Miksa
P.O. Box 7266
Monroe, LA 71211
Phone: 318/361-0165

PRESENTED BY: Steven A. Jaasund, P.E.

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INTRODUCTION

Lundberg proposes to supply an add-on spray scrubber for the control of SO_2 emissions from the No. 2 power boiler at the Domtar Industries Pulp Mill in Ashdown, Arkansas.

The proposal includes two identical gas cleaning trains each including a spray scrubber.

PROCESS DESCRIPTION

The spray scrubber/wet ESP trains will be installed downstream of the existing venturi scrubbers and will utilize the main boiler fan on a forced draft basis. We anticipate a maximum of 3 inches w.c. will be necessary to overcome the added resistance of the add-on equipment. If this additional pressure is not available from the existing fan, the capacity can be gained by reducing the pressure drop through your existing scrubber an appropriate amount. This pressure drop reduction will not have a significant effect on the size requirements of the new wet ESP.

The spray scrubbers will be an upflow design utilizing downward facing spray headers to maximize liquid to gas contact. The unit will operate at a liquid to gas ratio of 20 gal/1000 acf and will utilize a pH adjusted scrubbing solution to affect a minimum of 90% SO_2 absorption. Sodium hydroxide will be used to maintain pH at the required level.

After exiting the spray scrubbers, the gas streams will exit directly out of the top through a stub stack.

A process flow diagram and a general arrangement drawing for the system proposed are included in the appendix of this proposal.

DESIGN BASE

The following process information will be used for the design of the spray scrubber/wet ESP system.

NO. 2 POWER BOILER DESIGN CONDITIONS	
Fuel	Coal, bark, natural gas, TDF, (planning on fuel oil in future)
Boiler Type	Stoker
Volumetric Gas Flow (scfm dry)	142,737
Scrubber Exit Gas Temp. (°F)	136
Exit Moisture (% wt)	12.3
PM Loading (lb/hr)	44.6
SO2 Concentration (ppmv)	235.9

The spray scrubber/wet ESP equipment offered will be designed to reduce the SO_2 concentration by 90%.

ENERGY REQUIREMENTS

The following table shows the expected energy demands of the wet ESP system described in this proposal.

SPRAY SCRUBBER ENERGY REQUIREMENTS	
Scrubber pumps (kW)	108
Flange to flange pressure drop (in. w.c.)	3

Proposed Supply

The following list summarizes the major components of the systems offered to treat the emissions from the power boiler.

ITEM	QUANTITY	DESCRIPTION
1	One (1) lot	System Engineering, including process flow diagrams, process and instrument diagrams, general arrangement drawings, functional narrative of the logic, assembly drawings, instrument specifications, pump specifications, and operation and maintenance manual complete with spare parts lists
2	Two (2) only	Spray scrubbers; T-316L SS, upflow design with recycle pump, tank and piping
3	Two (2) only	Discharge stacks; T-316L SS
4	Two (2) lots	Support and access steel
5	Two (2) lots	Field instrumentation
6	One (1) lot	Commissioning, start-up and training
7	One (1) lot	Local wiring of all electrical elements
8	One (1) lot	Complete mechanical installation

Commercial terms and Conditions

Clarifications and Work by Others

1. Ducting from the existing scrubber to the inlet flange of the spray scrubbers is not included
2. The cost of a crane to lift the equipment offered to the top of the No. 2 boiler building is not included
3. Structural steel to the bottom of the spray scrubbers is not included. Structural and access steel above this level is included.
4. Civil work or improvements to existing structures is not included. Lundberg will provide foundation-loading information.
5. Performance testing is not included
6. Lundberg will require access to mill drawings and records required to design the proposed system.
7. The client is responsible for obtaining all necessary building/environmental permits, taxes and professional engineering fees.
8. The client is to provide a lay down area close to the work site, as well as field fabrication area for piping, etc.
9. The client is to supply steam and process water as required by the erection crew free of charge. Also parking area, trailer space(s), and access to phone lines. Phone line hookup will be by Lundberg. Lundberg is to supply electrical power for construction.
10. Construction crews may be union or non-union.
11. The client is responsible for the removal, handling, disposal, or replacement of all asbestos materials, lead paint, or contaminated soils that may be encountered.
12. The client is to provide an on-site location for construction debris.
13. Any required demolition work is not included in our bid.

Price

The budget price for the spray scrubber system, Items 1-7, is:

Two million fifty thousand dollars

$2,050,000.00

These prices are FOB mill site. Prices do not include applicable taxes. All prices are in U.S. dollars.

The purchaser assumes liability for payment to the state of any Sales or Use tax if he uses or consumes the property herein purchased in such a way as to render the sale subject to tax.

TERMS OF PAYMENT

The terms of payment shall be:

- 5% with purchase order.
- 10% with submittal of approval drawings (process flow sheets, equipment drawings and general arrangements.
- 25% with order placed for major equipment (WESP) .
- 10% on delivery of 10" diameter collection electrodes to the shop.
- 5% on construction mobilization.
- 15% on delivery of WESP to the mill; partial shipment allowed.
- 25% on monthly percent completion of construction.
- 5% on satisfaction of performance warranty on each unit, not to exceed six (6) months from shipment. This may be secured by a letter of credit at Lundberg's option, and due at shipment.

Payment will be due thirty (30) days after date of invoice.

ERECTION ADVISOR

If the Buyer elects to be responsible for the installation of the equipment the services of a qualified erection advisor can be made available at a rate of $1350.00 per man day (man day being ten (10) hours) plus expenses. Charges after ten (10) hours will be $170.00 per hour. Expenses are to include first class food and lodging, economy travel to and from plant site to lodging, and travel to and from project from the normal domicile of the engineer.

TRAINING SERVICES

Training is included as a part of the equipment package. The additional services of a trainer can be made available at a rate of $1,500.00 per man day (man day being eight (8) hours) plus expenses. Charges after eight (8) hours will be $210.00 per hour. Expenses are to include first class food and lodging, economy travel to and from plant site to lodging, and travel to and from project from the normal domicile of the engineer.

START-UP SERVICES

Start-up services are included as a part of the equipment package. The additional services of an engineer can be made available at a rate of $1350.00 per man day (man day being ten (10) hours), plus expenses. Charges after ten (10) hours will be $170.00 per hour. Expenses are to include first class food and lodging, economy travel to and from plant site to lodging, and travel to and from project from the normal domicile of the engineer.

SHIPMENT

Shipment will be made twenty-six (26) weeks after receipt of order. Shipment schedule requires that approval drawings, when submitted, will be returned within two (2) weeks. The time to complete erection is very dependent on site conditions. Normally equipment of this size can be installed in less than 8 weeks.

Cancellation

Should Purchaser place an order for the equipment proposed and later find it necessary to cancel, Purchaser shall pay the full amount for any equipment, portions thereof, or orders for which Vendor is liable, plus charges for engineering work completed at that time, plus fifteen (15) percent of the total costs incurred.

Performance Warranty

Lundberg will provide the equipment and process engineering as specified in this proposal for a complete and operable system and guarantee that the inlet SO_2 concentration will be reduced by 90% but no lower than 20 ppmv.

This guarantee is in effect when the system is operated in and supplied with the service conditions in general accordance with the Design Base of this proposal.

US EPA Method 1, 2, 3, 4, and 6 shall be used to quantify the SO_2 concentration at the outlet of the equipment.

Acceptance tests must be performed within three (3) months after initial start-up of the equipment, not to exceed six (6) months after final shipment. The testing shall be performed by an independent third party that is acceptable to both Buyer and Seller.

The warranty shall be fully satisfied and Lundberg discharged there from upon the earlier of: (a) obtaining guaranteed performance by the testing described above, (b) the expiration of three (3) months from initial start-up with no testing being made, (c) the expiration of six (6) months from final shipment without a test being made.

If the guaranteed performance is not obtained, then Lundberg shall have the right, and if required by the Owners, the obligation, to visit the installation to determine the cause of such failure. It is a condition of this guarantee that the Owner will cooperate with Lundberg in the making of further tests and make available necessary personnel, feed and operating conditions to enable Lundberg to conduct such tests. The tests will be paid for by the purchaser.

If failure to obtain guaranteed performance on the above is due to defect in Lundberg-supplied equipment, design, or engineering, then Lundberg will, at its expense, supply the equipment or process engineering it deems necessary until such performance is met, up to a limit of the contract price. Any remedy includes an equivalent scope of installation as outlined elsewhere in this proposal.

If failure to obtain guaranteed performance is due to the Purchaser's fault in operation, or in not providing proper feed or other specified operating conditions, the Owner shall pay the living and traveling expenses of Lundberg personnel visiting the installation. In addition, the Owner shall pay the sum of $1,300.00 per man-day or fraction thereof for such personnel. Nevertheless, such personnel will, on request, work with the Owner at the Owner's expense in making necessary corrections to accommodate the changed conditions.

MATERIAL AND WORKMANSHIP

We guarantee every part of the apparatus delivered in accordance with this proposal will be of proper material and workmanship, and agree to repair any part or parts which may prove defective in material or workmanship within twelve months from startup of equipment but not to exceed eighteen months from date of shipment on each unit, it being agreed that such replacement is the full extent of our liability in this connection. Scope of supply of such replacement shall be identical to the scope of supply of the original project. Corrosion or wear from abrasion shall not be considered as defective materials. The best engineering practice will always be followed and materials used will be clearly specified. We shall not be held liable or responsible for work done or expense incurred in connection with repairs, replacements, alterations, or additions made, except on our written authority.

VENDOR'S RESPONSIBILITY

In the course of design of processes and/or equipment where the Vendor provides process flow diagrams, layouts, and installation diagrams, it is anticipated that Vendor furnished design will be followed. Changes in design without written approval of the Vendor will relieve the Vendor of responsibility for performance of the supplied equipment.

DRAWINGS LIMITATION

All Vendor drawings supplied to the customer or his engineer under an order resulting from this proposal will remain the property of the Vendor and are conditionally loaned with the understanding that they will not be copied or used except as authorized by us. Reuse of the designs as shown on the drawings for another project is specifically prohibited.

CONFIDENTIALITY OF PROPOSAL INFORMATION

This proposal contains confidential information and remains the property of Lundberg and is conditionally loaned. The information contained herein is not to be shared with any party except those within the Buyer's company who are involved in its evaluation or outside consultants who are assisting the Buyer with this specific project. Specifically prohibited is the distribution of such information to any individual or business deemed to be a competitor by Lundberg.

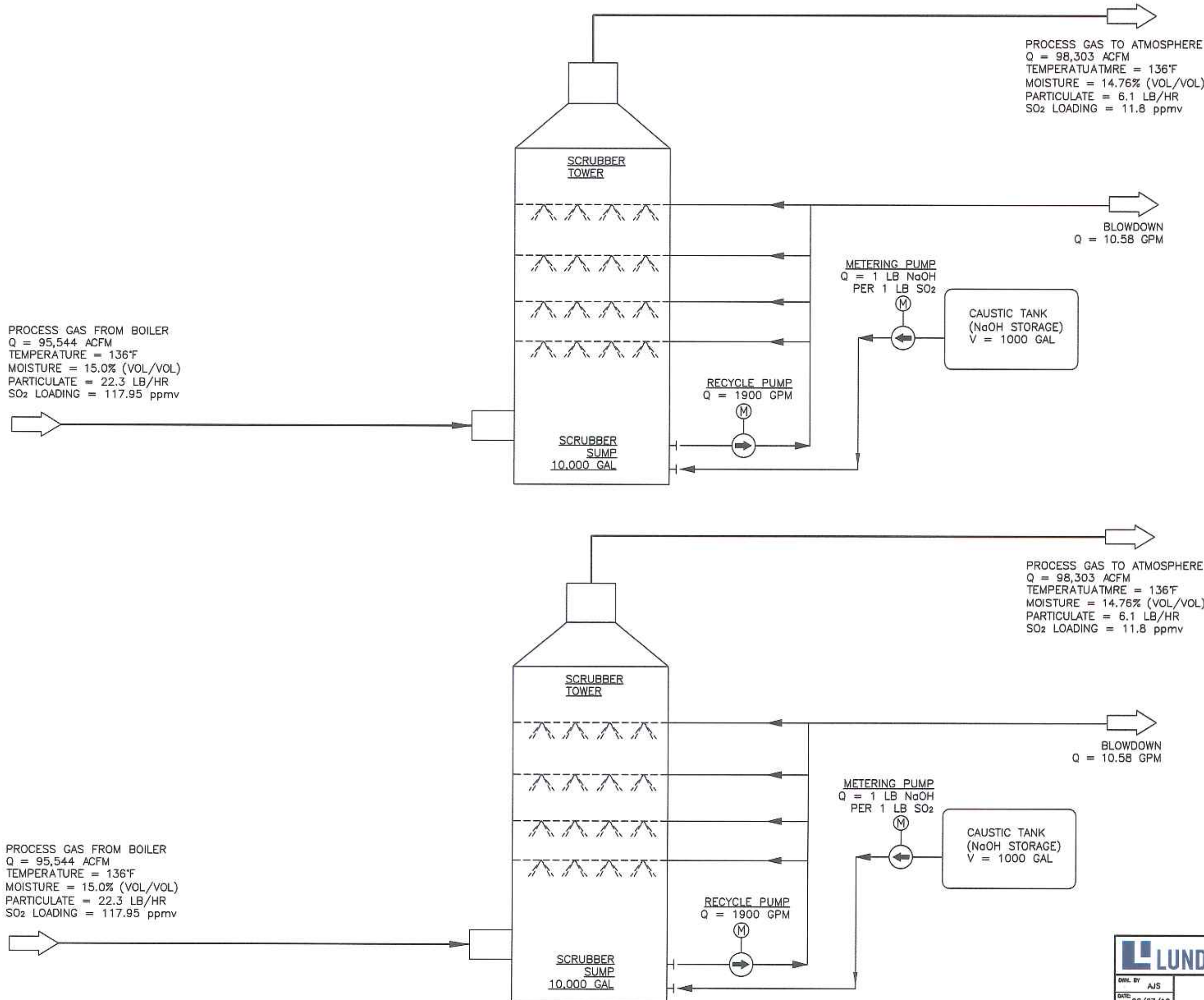
SECURITY INTEREST

Lundberg reserves the right to request a security interest in the materials provided as a part of this proposal, and Buyer agrees to provide information needed to assist Lundberg in obtaining a security interest and to execute such documents Lundberg reasonably requests to create a security interest. Security interest language is available on request.

ENCLOSURES

General Arrangement Drawing

Process Flow Diagram



LUNDBERG

DWN. BY AJS
DATE: 08/27/12
CHK. BY
DATE:
APP. BY
DATE:

DOMTAR
ASHDOWN, ARKANSAS
BOILER #2 EMISSIONS

MODEL 1200 SPRAY TOWER SCRUBBER
PROCESS FLOW DIAGRAM

SCALE:	DRAWING NO.	SHT.	REV.
1/4"=1'-0"	AL-125387-P01	1/1	01

REV.	DESCRIPTION	BY	DATE	CHK	DATE	REV.	DESCRIPTION	BY	DATE	CHK	DATE
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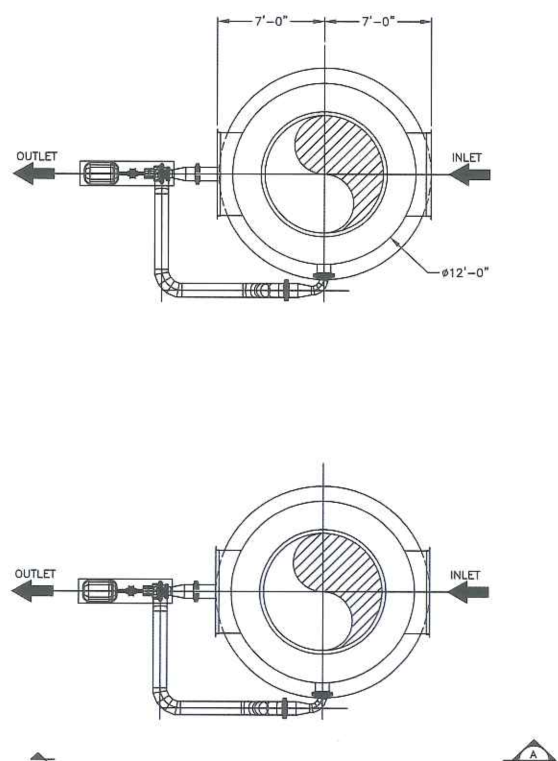
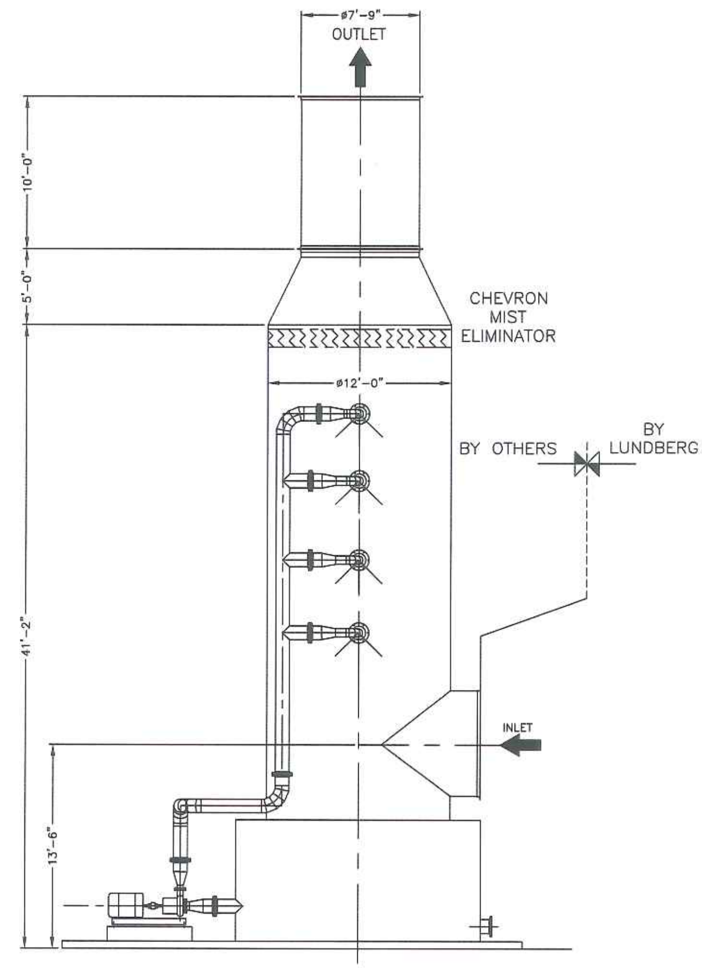
DESCRIPTION	DRAWING NO.
REFERENCE	

DWG. NO. AL-125387-P01 SHT. 1/1



MODEL 1200 SPRAY TOWER SCRUBBER
PLAN VIEW
BOILER # 2 EMISSIONS



MODEL 1200 SPRAY TOWER SCRUBBER
ELEVATION VIEW
BOILER # 2 EMISSIONS

LUNDBERG

DWN. BY: AJS	DOMTAR ASHDOWN, ARKANSAS BOILER #2 EMISSIONS
DATE: 06/27/12	
CHK. BY:	MODEL 1200 SPRAY TOWER SCRUBBER GENERAL ARRANGEMENT
DATE:	
APP. BY:	
DATE:	SCALE: 1/4"=1'-0" · DRAWING NO. AL-125387-P03 · SHT. 1/1 · REV. 01

REV.	DESCRIPTION	BY	DATE	CHK	DATE	REV.	DESCRIPTION	BY	DATE	CHK	DATE
	REVISIONS						REVISIONS				

DESCRIPTION	DRAWING NO.
REFERENCE	

DWG. NO. AL-125387-P03 SHT. 1/1

because it has not been fully demonstrated for this source type and incorporates FGR, which is technically infeasible for use at the boiler. The installation and operation of SNCR is projected to result in some visibility improvement at the Class I areas. As discussed in more detail above, we concur with Domtar's position that 20% removal efficiency is the most reasonable estimate of the level of NO_X control SNCR can achieve at Power Boiler No. 1. When operated at 20% removal efficiency, SNCR is projected to result in visibility improvement of up to 0.061 dv at any single Class I area and is estimated to cost $12,700/ton of NO_X removed. We do not believe this high cost justifies the modest visibility improvement projected from the installation and operation of SNCR at 20% removal efficiency. Although there is uncertainty as to whether SNCR can achieve a long term removal efficiency of 45% or even 32.5% at Power Boiler No. 1, we believe that the associated costs are also too high and not justified by the projected visibility benefits. Installation and operation of SNCR at a 45% removal efficiency is projected to result in a visibility improvement of up to 0.136 dv at any single Class I area and is estimated to cost $7,640/ton of NO_X removed. The operation of SNCR at a 32.5% removal efficiency is projected to result in visibility improvement of up to 0.098 dv at any single Class I area and is estimated to cost $7,996/ton of NO_X removed. Therefore, we are proposing to determine that NO_X BART for Power Boiler No. 1 is no additional control and are proposing that an emission limit of 207.4 lb/hr on a 30 boiler-operating-day rolling average satisfies NO_X BART. In this particular case, we are defining boiler-operating-day as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the Power Boiler. Power Boiler No. 1 is not currently equipped with a CEMS. To demonstrate compliance with this NO_X BART emission limit we are proposing to require annual stack testing. We are inviting public comment on the appropriateness of this method for demonstrating compliance with the NO_X BART emission limit for Power Boiler No. 1. Since this proposed BART determination does not require the installation of control equipment, we are proposing that this NO_X emission limit be complied with by the effective date of the final action.

d. SO_2 BART Evaluation for Power Boiler No. 2

Step 1- Identify All Available Retrofit Control Technologies

Power Boiler No. 2 is currently equipped with two venturi wet scrubbers in parallel for removal of particulates and SO_2. Domtar's 2014 BART analysis evaluated upgrades to the existing venturi wet scrubbers and new add-on scrubbers for Power Boiler No. 2.[96] Domtar contracted with a vendor to evaluate upgrades to the existing venturi scrubbers and to provide a quote for a new add-on spray scrubber system that would be installed downstream of the existing

[96] See "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis is found in the docket for our proposed rulemaking.

venturi scrubbers.[97] Domtar's analysis states that the existing venturi scrubbers achieve an SO_2 control efficiency of approximately 90% and notes that this is within the normal range for the highest efficiency achieved by SO_2 control technologies. Domtar's analysis also indicates that the upgrades considered for the existing venturi scrubbers include (1) the elimination of bypass reheat, (2) the installation of liquid distribution rings, (3) the installation of perforated trays, (4) improvements to the auxiliary system requirement, and (5) a redesign of spray header and nozzle configuration.

Another option not evaluated in Domtar's 2014 BART analysis is the operation of the existing venturi scrubbers to achieve a higher SO_2 control efficiency than what is currently being achieved through the use of additional scrubbing reagent. Following discussions between us and Domtar, the facility provided additional information regarding the existing venturi scrubbers, including a description of the internal structure of the scrubbers, whether any scrubber upgrades have taken place, the type of reagent used, how the facility determines how much reagent to use, and the SO_2 control efficiency.[98] Domtar confirmed that no upgrades to the scrubbers have ever been performed and stated that 100% of the flue gas is treated by the scrubber systems. The scrubbing solution used in the venturi scrubbers is made up of three components: 15% caustic solution (*i.e.*, NaOH), bleach plant EO filtrate (typical pH above 9.0), and demineralizer anion rinse water (approximately 2.5% NaOH). The bleach plant EO filtrate and demineralizer anion rinse water are both waste byproducts from the processes at the plant. The 15% caustic solution is added to adjust the pH of the scrubbing solution and maintain it within the required range to ensure that sufficient SO_2 is removed from the flue gas in the scrubber to meet the permitted SO_2 emission limit of 1.20 lb/MMBtu on a three hour average. Each venturi scrubber has a recirculation tank that is equipped with level control systems to ensure that an adequate supply of the scrubbing solution is maintained. There are pH controllers in place that provide signals for the 15% caustic flow controllers to adjust the flow of the caustic solution to bring the pH into the desired set point range. The pH controllers are overridden in the event that SO_2 levels measured at the stack by the CEMS are above the operator set point of 0.86 lb/MMBtu on a two hour average (the SO_2 permit limit is 1.20 lb/MMBtu on a three hour average). This allows additional caustic feed to the scrubber solution to increase the pH and reduce the SO_2 measured at the stack. According to Domtar, the scrubber systems operate in this manner to maintain continuous compliance with permitted emission limits.

Domtar provided monthly average data for 2011, 2012, and 2013 on monitored SO_2 emissions from Power Boiler No. 2, mass of the fuel burned for each fuel type, and the percent

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[97] The information provided by the vendor to Domtar is found in Appendix D to the analysis titled "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC.

[98] See the following: Letters dated July 9, 2014; July 21, 2014; August 15, 2014; August 29, 2014; and September 12, 2014, from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. Copies of these letters and all attachments are found in the docket for our proposed rulemaking.

sulfur content of each fuel type burned.[99] According to the data provided by Domtar, the monthly average SO_2 control efficiency of the existing scrubbers for the 2011-2013 period ranged from 57% to 90%. The data indicate that the monthly average control efficiency of the scrubbers is usually below 90%. The information provided also indicates that the facility could add more scrubbing solution to achieve greater SO_2 removal than what is necessary to meet permit limits.

Based on our discussions with Domtar and the additional information provided to us, we believe it is technically feasible to increase the current SO_2 control efficiency of the existing scrubbers from current levels to 90% on a monthly average basis through the use of additional scrubbing reagent.

Step 2- Eliminate Technically Infeasible Options

Domtar's analysis discusses that the vendor determined that any upgrades to the existing venturi scrubbers for purposes of achieving additional SO_2 control would involve efforts to increase pressure drop. Additionally, it determined that any additional control that could potentially be achieved from implementation of such upgrades would be marginal, but Domtar was unable to quantify the potential additional control. Therefore, Domtar determined that the installation of new add-on scrubbers to operate downstream of the existing scrubbers was more feasible than any upgrade option. The remainder of Domtar's analysis focused on the add-on scrubber option only.

Additionally, as discussed above, based on our discussions with Domtar and the additional information Domtar provided to us, we determined it would be technically feasible to increase the current control efficiency of the existing scrubbers through the use of additional scrubbing reagent. We evaluate this control option in this TSD.

Step 3- Evaluate Control Effectiveness of Remaining Control Technologies:

Based on the information provided to Domtar by the vendor, new add-on spray scrubbers were estimated to achieve 90% control efficiency on top of the SO_2 removal currently achieved by the existing venturi scrubbers. In Domtar's analysis, it was estimated that a controlled SO_2 emission rate of 78.8 lb/hr would be achieved by the operation of add-on spray scrubbers installed downstream of the existing venturi scrubbers.

To estimate the current control efficiency of the existing venturi scrubbers, we asked Domtar to provide monthly average data for 2011, 2012, and 2013 on monitored SO_2 emissions from Power Boiler No. 2, mass of the fuel burned for each fuel type, and the percent sulfur

[99] August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. A copy of this letter and an Excel file attachment titled "Domtar 2PB Monthly SO2 Data," are found in the docket for our proposed rulemaking.

content of each fuel type burned.[100] Based on the information provided by Domtar, the monthly average SO_2 control efficiency of the existing scrubbers for the 2011-2013 period ranged from 57% to 90%. The data indicate that the monthly average control efficiency of the scrubbers is usually below 90%. Based on the monthly average SO_2 control efficiency data for the 2011-2013 period, we estimated the annual average SO_2 control efficiency for the three-year period to be approximately 69%.[101]

To determine the controlled emission rate that corresponds to the operation of the existing venturi scrubbers at a 90% removal efficiency, we first determined the SO_2 emission rate that corresponds to the operation of the scrubbers at the current control efficiency of 69%. Based on emissions data we obtained from Domtar, we determined that the No. 2 Power Boiler's annual average SO_2 emission rate for the years 2009-2011 was 280.9 lb/hr.[102] This annual average SO_2 emission rate corresponds to the operation of the scrubbers at a 69% removal efficiency. We also estimated that 100% uncontrolled emissions would correspond to an emission rate of approximately 915 lb/hr. Application of 90% control efficiency to this results in a controlled emission rate of 91.5 lb/hr, or 0.11 lb/MMBtu based on the boiler's maximum heat input of 820 MMBtu.[103]

Step 4- Evaluate Impacts and Document the Results

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

Domtar's estimates of the capital and operating and maintenance costs of add-on spray scrubbers for Power Boiler No. 2 were based on the equipment vendor's budget proposal and on calculation methods from our Control Cost Manual. Domtar annualized the capital cost of the add-on spray scrubbers over a 30-year amortization period and then added these to the annual

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[100] August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. A copy of this letter and an Excel file attachment titled "Domtar 2PB Monthly SO2 Data," are found in the docket for our proposed rulemaking.

[101] See the spreadsheet titled "Domtar 2PB Monthly SO2 Data." This spreadsheet was included as an attachment to the August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "Domtar PB No2- Cost Effectiveness calculations." Copies of these documents can be found in the docket for this proposed rulemaking.

[102] See the spreadsheet titled "Domtar 2PB Monthly SO2 Data." This spreadsheet was included as an attachment to the August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "No2 Boiler_Monthly Avg SO2 emission rate and calculations." Copies of these documents can be found in the docket for this proposed rulemaking.

[103] See the spreadsheet titled "No2 Boiler_Monthly Avg SO2 emission rate and calculations." A copy of this spreadsheet can be found in the docket for this proposed rulemaking.

operating costs to obtain the total annualized cost.[104] The average cost-effectiveness in dollars per ton removed was calculated by dividing the total annualized cost by the annual SO_2 emissions reductions. The average cost-effectiveness of the add-on spray scrubbers for Power Boiler No. 2 was estimated to be $5,258/ton of SO_2 removed (see table below). Domtar's analysis notes that because of constricted space, there is no existing property or adequate structure to support the add-on spray scrubber equipment. In our discussions with Domtar, the facility indicated that the installation of add-on spray scrubbers would require construction at the facility to accommodate the equipment, but an estimate of these costs was not available and therefore not factored into the cost estimates presented in Domtar's analysis.

Table 69. Summary of Costs for Add-On Spray Scrubber for Power Boiler No. 2

Control Technology	Baseline Emission Rate (SO_2 tpy)	Controlled Emission Level (lb/hr)	Controlled Emission Rate (tpy)	Annual Emissions Reductions (SO_2 tpy)	Capital Cost* ($)	Annual Direct O&M Cost ($/yr)	Annual Indirect O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost Effectiveness ($/ton)
Add-on Spray Scrubber	2,078	78.8	208	1,870	7,175,000	8,833,382	421,789	9,833,378	5,258

* Capital cost does not include new construction to accommodate equipment.

Based on the cost information provided by the facility, increasing the monthly average SO_2 control efficiency of the existing venturi scrubbers from current levels to 90% control efficiency would require replacing two scrubber pumps, which involves capital costs of $200,000.[105] It would also require additional scrubbing reagent, treatment of additional wastewater, treatment of additional raw water, and additional energy usage, which involves annual operation and maintenance costs of approximately $1.96 million. We annualized the capital cost of the two scrubber pumps over a 30-year amortization period, assuming a 7% interest rate. We calculated the annualized capital cost to be $16,120, and added this to the annual operating costs to obtain a total annual costs of $1,976,554.[106]

[104] See Appendices B and D to the "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC.

[105] September 30, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "Domtar PB No2- Cost of Using Additional Scrubbing Reagent. Copies of these documents can be found in the docket for this proposed rulemaking.

[106] See the Excel spreadsheet titled "Domtar PB No2- Cost of Using Additional Scrubbing Reagent" for line items of the capital and operation and maintenance costs associated with the use additional scrubbing reagent, and for calculation of the total annual cost. This spreadsheet can be found in the docket for this proposed rulemaking.

We calculated the average cost-effectiveness in dollars per ton removed by dividing the total annual cost by the estimated annual SO_2 emissions reductions. To estimate the SO_2 annual emissions reductions expected from increasing the control efficiency of the scrubbers through the use of additional scrubbing solution, we calculated the annual average SO_2 control efficiency of the existing scrubbers. As discussed above, based on data provided by Domtar for the 2011-2013 period, we estimated the annual average SO_2 control efficiency for the three-year period to be approximately 69%.[107] Considering the baseline annual emissions for Power Boiler No. 2 are 2,078 SO_2 tpy, and assuming that the scrubbers currently operate at an annual average control efficiency of 69%, we have estimated that the uncontrolled annual emissions would be 6,769 SO_2 tpy and that operating the scrubbers at 90% control efficiency would result in controlled annual emissions of 677 SO_2 tpy.[108] By subtracting the controlled annual emission rate of 677 SO_2 tpy from the baseline annual emission rate of 2,078 SO_2 tpy, we estimate that increasing the control efficiency of the existing venturi scrubbers from the current level of 69% to 90% control efficiency would result in annual emissions reductions of 1,401 SO_2 tpy.[109] We estimate the average cost-effectiveness of using additional scrubbing reagent to increase the SO_2 control efficiency of the existing venturi scrubbers from the current control efficiency (estimated to be 69%) to 90% is $1,411/ton of SO_2 removed. The cost information is presented in the table below.

Table 70. Summary of Cost of Using Additional Scrubbing Reagent to Increase Control Efficiency of Existing Venturi Scrubbers at Domtar Ashdown Mill Power Boiler No. 2

Control Option	Baseline Emission Rate (SO_2 tpy)	Controlled Emission Rate (tpy)	Annual Emissions Reductions (SO_2 tpy)	Capital Costs[110] ($)	Annual Operation & Maintenance Cost[111] ($/yr)	Total Annual Cost ($/yr)	Average Cost Effectiveness ($/ton)
Use of Additional Scrubbing Reagent	2,078	677	1,401	200,000	1,960,434	1,976,554	1,411

[107] See the spreadsheet titled "Domtar 2PB Monthly SO2 Data." This spreadsheet was included as an attachment to the August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "Domtar PB No2- Cost Effectiveness calculations." Copies of these documents can be found in the docket for this proposed rulemaking.

[108] See the spreadsheet titled "Domtar PB No2- Cost Effectiveness calculations." A copy of this spreadsheet can be found in the docket for this proposed rulemaking.

[109] *Id.*

[110] The capital costs consist of two new pumps for the existing scrubber system.

[111] The operation and maintenance costs consist of the following costs: additional scrubbing reagent, treatment of additional wastewater, treatment of additional raw water, and additional energy usage.

Domtar's 2014 BART analysis did not identify any energy or non-air quality environmental impacts associated with the use of add-on spray scrubbers. We are not aware of any unusual circumstances at the facility that create energy or non-air quality environmental impacts associated with the use of add-on spray scrubbers greater than experienced elsewhere that may therefore provide a basis for the elimination of this control option as BART (40 CFR Part 51, Appendix Y, section IV.D.4.i.2.). We are also not aware of any unusual circumstances at the facility that create energy or non-air quality environmental impacts associated with the use of additional scrubbing reagent to increase the control efficiency of the existing venturi scrubbers greater than experienced elsewhere that may therefore provide a basis for the elimination of this control option as BART. Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with these control options at Power Boiler No. 2 that would affect our proposed BART determination.

Consideration of the presence of existing pollution control technology at the source is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. Power Boiler No. 2 is equipped with multiclones for particulate removal and two venturi scrubbers in parallel for control of SO_2 emissions. It is also equipped with a combustion air system including overfire air to optimize boiler combustion efficiency, which also helps control emissions. The baseline emission rate used in the cost calculations and visibility modeling reflects the use of these existing controls. As discussed above, Domtar's analysis also evaluated upgrades to the existing venturi scrubbers to potentially achieve greater SO_2 control efficiency. Another option we have identified and are evaluating in this TSD is to use additional scrubbing reagent to achieve greater SO_2 control efficiency of the existing venturi scrubbers,

We are not aware of any enforceable shutdown date for the Domtar Ashdown Mill Power Boiler No. 2, nor did Domtar's 2014 BART analysis indicate any enforceable future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of the add-on spray scrubbers. Therefore, a 30-year amortization period was assumed in the evaluation of the add-on spray scrubbers as the remaining useful life of the boiler. A 30-year amortization period was also assumed for the scrubber pump replacements required for using additional scrubbing reagent.

Step 5- Evaluate Visibility Impacts

In the 2014 BART analysis, Domtar assessed the visibility improvement associated with the add-on spray scrubbers by modeling the controlled SO_2 emission rate using CALPUFF, and then comparing the visibility impairment associated with the controlled emission rate to that of the baseline emission rate as measured by the 98th percentile modeled visibility impact. The tables below show the emission rates modeled and a comparison of the baseline (*i.e.*, existing) visibility impacts and the visibility impacts associated with the add-on spray scrubbers. The

installation and operation of add-on spray scrubbers is projected to result in visibility improvement of 0.146 dv at Caney Creek. The visibility improvement is projected to range from 0.026 to 0.053 dv at each of the other Class I areas.

Table 71. Summary of Emission Rates Modeled for SO_2 Controls for Domtar Power Boiler No.2

Scenario	NO_X Emissions (lb/hr)	SO_2 Emissions (lb/hr)	PM_{10}/PMF Emissions (lb/hr)
Baseline	526.8	788.2	81.6
Add-on Spray Scrubber	526.8	78.8	81.6

Table 72. Domtar Ashdown Mill Power Boiler No. 2: Summary of the 98th Percentile Visibility Impacts and Improvement due to Add-on Spray Scrubbers

Class I area	Baseline Visibility Impact[112] (dv)	Add-on Spray Scrubbers	
		Visibility Impact (Δdv)	Visibility Improvement from Baseline (Δdv)
Caney Creek	0.844	0.698	0.146
Upper Buffalo	0.146	0.093	0.053
Hercules-Glades	0.105	0.054	0.051
Mingo	0.065	0.039	0.026
Cumulative Visibility Improvement (Δdv)	--	--	0.276

Using the visibility modeling analysis of the baseline visibility impacts from Power Boiler No. 2 and the visibility improvement projected from the installation and operation of new add-on spray scrubbers, we have extrapolated the visibility improvement projected as a result of using additional scrubbing reagent to increase the SO_2 control efficiency of the existing venturi

[112] The baseline visibility impacts reflect the operation of the existing venturi scrubbers.

scrubbers from the current control efficiency (estimated to be 69%) to 90%, or an outlet emission rate of 0.11 lb/MMBtu. We have assumed that the maximum 24-hour baseline emission rate used in the visibility modeling represents the operation of the existing venturi scrubbers at a 69% control efficiency. We estimate that the visibility improvement of using additional scrubbing reagent to increase the SO_2 control efficiency of the existing venturi scrubbers to 90% control efficiency is 0.139 dv at Caney Creek and 0.05 dv or less at each of the other Class I areas (see table below).

Table 73. Domtar Ashdown Mill Power Boiler No. 2: Summary of the 98th Percentile Visibility Impacts and Improvement from Use of Additional Scrubbing Reagent

Class I area	Baseline Visibility Impact (dv)	Add-on Spray Scrubber Impacts (dv)		Estimated Impacts from Use of Additional Reagent (dv)	
		Visibility Impact (dv)	Visibility Improvement from Baseline (dv)	Visibility Impact (dv)	Visibility Improvement from Baseline (dv)
Caney Creek	0.844	0.698	0.146	0.705	0.139
Upper Buffalo	0.146	0.093	0.053	0.096	0.05
Hercules-Glades	0.105	0.054	0.051	0.057	0.048
Mingo	0.065	0.039	0.026	0.04	0.025
Cumulative Visibility Improvement (dv)	--	--	0.276	--	0.262

Our Proposed SO_2 BART determination Power Boiler No. 2:

Taking into consideration the five factors, we propose to determine that SO_2 BART for Power Boiler No. 2 is an emission limit of 0.11 lb/MMBtu on a 30 boiler-operating-day rolling average, which we estimate is representative of operating the existing scrubbers at 90% control efficiency. In this particular case, we define boiler-operating-day as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the Power Boiler. We are inviting public comment specifically on the appropriateness of this proposed SO_2 emission limit. We believe that this emission limit can be achieved by using additional scrubbing reagent in the operation of the existing venturi scrubbers. We estimate that operating the existing scrubbers to achieve this level of control would result in visibility improvement of 0.139 dv at Caney Creek and 0.05 dv or lower at each of the other Class I areas.

We estimate the cumulative visibility improvement at the four Class I areas to be 0.262 dv. Based on the cost information provided by the facility, we have estimated that the use of additional scrubbing reagent to increase the control efficiency of the existing venturi scrubbers is estimated to cost $1,411/ton of SO_2 removed. Based on Domtar's BART analysis, new add-on spray scrubbers that would be operated downstream of the existing venturi scrubbers are projected to result in visibility improvement of 0.146 dv at Caney Creek and 0.053 dv or lower at each of the other Class I areas. The cumulative visibility improvement at the four Class I areas is projected to be 0.276 dv. The cost of add-on spray scrubbers is estimated to be $5,258/ton of SO_2 removed, not including additional construction costs that would likely be incurred to make space to house the new scrubbers. We do not believe that the amount of visibility improvement that is projected from the installation and operation of new add-on spray scrubbers would justify their high average cost-effectiveness. The incremental visibility improvement of new add-on spray scrubbers compared to using additional scrubbing reagent to increase the control efficiency of the existing venturi scrubbers ranges from 0.001 to 0.007 dv at each Class I area, yet the incremental cost-effectiveness is estimated to be $16,752. We do not believe the incremental visibility benefit warrants the higher cost associated with new add-on spray scrubbers. Therefore, we are proposing to determine that SO_2 BART for Power Boiler No. 2 is an emission limit of 0.11 lb/MMBtu on a 30 boiler-operating-day rolling averaging basis, and are inviting comment on the appropriateness of this emission limit. We propose to require the facility to demonstrate compliance with this emission limit using the existing CEMS. Since the SO_2 emission limit we are proposing can be achieved with the use of the existing venturi scrubbers but will require scrubber pump upgrades and the use of additional scrubbing reagent, we propose to require compliance with this BART emission limit no later than 3 years from the effective date of the final action, but are inviting public comment on the appropriateness of a compliance date anywhere from 1 – 5 years.

NO_X BART Evaluation for Power Boiler No. 2

Step 1- Identify All Available Retrofit Control Technologies

For NO_X BART, Domtar's 2014 BART analysis evaluated LNB, SNCR, and Methane de-NO_X (MdN). In the 2006/2007 Domtar BART analysis, which was submitted in the 2008 Arkansas RH SIP, other NO_X controls were also evaluated but found by the State to be either already in use or not technically feasible for use at Power Boiler No. 2. Fuel blending, boiler operational modifications, and boiler tuning/optimization are already in use at the source, while FGR, OFA, and SCR were found to be technically infeasible for use at Power Boiler No. 2. Domtar did not further evaluate these NO_X controls, and instead focused on LNB, SNCR, and MdN in its 2014 BART analysis for Power Boiler No. 2.

APPENDIX B: 1PP SIP PACKAGE INFORMATION RELATED TO NO. 2 POWER BOILER NO_X EMISSIONS REDUCTION OPTIONS

The problems with typical SNCR systems (e.g., ammonia slippage and heat transfer surface fouling with byproduct formation) also exist with the NO_XOUT process.

4.4.1.8 SELECTIVE CATALYTIC REDUCTION

SCR is a post-combustion gas treatment process in which NH_3 is injected into the exhaust gas in the presence of a catalyst bed usually located between the boiler and air preheater. The catalyst lowers the activation energy required for NO_X decomposition.[47] On the catalyst surface, NH_3 and nitric oxide (NO) react to form diatomic nitrogen and water. The overall chemical reaction can be expressed as:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

When operated within the optimum temperature range of approximately 575 to 750 °F, the reaction can result in removal efficiencies between 70 and 90 percent. For coal-fired industrial boilers, SCR can achieve approximately 80 percent NO_X control.[48] The specific temperature ranges are 600 to 750 °F for conventional (vanadium or titanium) catalysts, 470 to 510 °F for platinum catalysts, and 600 to 1000 °F for high-temperature zeolite catalysts.[49] SCR units have the ability to function effectively under fluctuating temperature conditions (usually ± 50 °F), although fluctuation in exhaust gas temperature reduces removal efficiency by disturbing the chemical kinetics (speed) of the NO_X-removal reaction.

According to the U.S. EPA, the performance of an SCR system is affected by six factors.

> *These are a) NO_X level at SCR inlet, b) flue gas temperature, c) NH_3-to-NO_x ratio, d) fuel sulfur content, e) gas flow rate, and f) catalyst condition. For SCR, when inlet NO_X concentrations fall below 150 ppm, the reduction efficiencies decrease with decreasing NO_X concentrations. Each type of catalyst has an optimum operating temperature range. Temperatures below this range result in ammonia emissions (slip), and temperatures above the desired range result in NH_3 being oxidized to NO_X. For up to about 80 percent NO_X reduction efficiencies, a 1:1 NH_3:NO_X ratio is sufficient. For higher efficiencies, higher reagent to NO_X ratios are required which may result in higher NH_3 slip. In the case of high sulfur fuels, excess NH_3 can react with sulfur trioxide to form ammonium sulfate salt compounds that deposit and foul downstream equipment. SCR application experience in the case of*

[47] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.
[48] MRPO, *Interim White Paper – Midwest RPO Candidate Control Measures*, March 29, 2005.
[49] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

medium-to-high sulfur fuels is limited. For a given flue gas flow rate, the catalyst structural design should be chosen so that the residence time needed for the reduction reactions to take place on the catalyst surface is achievable.[50]

4.4.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Per the BART Guidelines, documentation of infeasibility should "explain, based on physical, chemical, or engineering principles, why technical difficulties would preclude the successful use of the control option under review." The BART Guidelines use the two key concepts of "availability" and "applicability" to determine if a control option is technically feasible. These concepts are defined in Section IV.D.2:

…a technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration.

The typical stages for bringing a control technology concept to reality as a commercial product are:

- *concept stage;*
- *research and patenting;*
- *bench scale or laboratory testing;*
- *pilot scale testing;*
- *licensing and commercial demonstration; and*
- *commercial sales.*

A control technique is considered available, within the context presented above, if it has reached the stage of licensing and commercial availability. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as "available" for purposes of BART review.

In general, a commercially available control option will be presumed applicable if it has been used on the same or a similar source type. Absent a showing of this type, you evaluate technical feasibility by examining the physical and chemical characteristics of the pollutant-bearing gas stream, and comparing them to the gas stream characteristics of the source types to which the technology had been applied previously.

COMBUSTION MODIFICATIONS

[50] U.S. EPA, *New source performance standards, subpart Db – technical support for proposed revisions to NO_X*, EPA-453-/R-95-012 (republished in NCASI's Special Report 03-04).

4.4.2.1 FLUE GAS RECIRCULATION

FGR is used to reduce thermal NO_X formation. Emissions due to fuel-bound NO_X, which are significant for coal-fired boilers, are not meaningfully affected by FGR. Therefore, FGR is not technically feasible to control NO_X emissions from coal-fired boilers.[51] Similarly, FGR would not be effective in wood combustion since most of the NO_X generated during wood combustion is also from the fuel NO_X pathway.[52] Recent refusals by vendors (e.g., Entropy Technology & Environmental Consultants LP[53]) to provide budgetary estimates for installing FGR are further evidence that FGR is not applicable for the Ashdown Mill's No. 1 and No. 2 Power Boilers.

4.4.2.2 REBURNING / METHANE DE-NO_X

Generally, Domtar considers MdN not feasible because (1) it is not fully demonstrated and (2) it incorporates FGR, which is clearly technically infeasible (see Section 4.4.2.1). However, Domtar was able to obtain equipment cost estimates from vendors of MdN. Therefore, MdN is considered further in this analysis.

POST-COMBUSTION MODIFICATIONS

NCASI points out the following issues of concern for post-combustion NO_X controls (i.e., SNCR and SCR) for pulp and paper mill power boilers:[54]

> **Load Swings** - Pulp mill combination and power boilers frequently exhibit wide and rapid load swings that are not consistent with the steady conditions required for effective use of either SNCR or SCR NO_X control technologies. The load swings produce variable temperature conditions in the boiler, causing the temperature zone for NO_X reduction to fluctuate, making it more difficult to know where to inject the reactants.
>
> **Temperature Incompatibility** - Combination and power boilers are affected by temperature profile incompatibility. To obtain the required temperature window, the only location to install this technology is upstream of the particulate matter control device, yet this is where flue gases are dirty and can foul the catalyst rapidly.

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[51] U.S. EPA. *Alternative Control Technologies Document: NO_X Emissions from Utility Boilers.* (EPA-453/R-94-023).

[52] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[53] Steve Wood (ETEC), e-mail to Joel Martin (Domtar), September 20, 2006: "Based on the design and operational data provided regarding #2 Coal Boiler, ETEC would decline to bid the application Induced Flue Gas Recirculation for Boiler #2 NO_X control. Flue gas recirculation technology is very effective in reducing natural gas and light oil fuel NO_X emissions, but is not for No.6 fuel oil, coal, bark and other solid fuels. To the best of our knowledge, flue gas recirculation for NO_X control has never been installed on a coal fired boiler."

[54] Ibid.

Downstream of the PM control device, the temperature is too low for the catalyst to be effective.

Unproven – SCR or SNCR controls, technologies which, for the most part, are untested and infeasible for pulp and paper mill boilers. These technologies must be operated on a continuous basis within a specified temperature range in order to be effective. The type of fuel burned influences the design of the technology, and FPI facilities' frequent fuel changes and co-firing of multiple fuels would result in design and operational problems.

Lack of Guarantee for FPI Boilers – Boiler owners are finding that vendors of SCR and SNCR technologies are unwilling to provide performance guarantees that the controls will meet the level of reduction called for in [NSPS Subpart Db (promulgated on September 16, 1998)].

4.4.2.3 SELECTIVE NON-CATALYTIC REDUCTION

Most boilers in the pulp and paper industry operate in the swing load mode, a consequence of supplying steam as required to the various components of the process. The problem with control of the required flue gas temperature window is an inherent difficulty with use of SNCR for load-following boilers, whether wood or fossil fuel.[55]

Controlling flue gas temperatures over the entire range of operating loads that the boiler is expected to experience will be very difficult to achieve. Boilers in the pulp and paper industry rarely operate under base loaded conditions. Consequently, the location of the desired temperature window is expected to change constantly. Accurate, instantaneous temperature measurement, as well as the ability to accurately adjust the location of the injection nozzle, would be necessary. Ammonia slip would be a recurring problem associated with the application of the SNCR process to industrial boilers with fluctuating loads.[56]

Inadequate reagent dispersion in the region of reagent injection in wood-fired boilers is also a factor mitigating against the use of SNCR technology.[57] Good dispersion of the reagent in the flue gas is needed to get good utilization of the reagent and to avoid excessive ammonia slip from the process. The need for a

[55] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for* NO_X*,* SO_2 *and PM Emissions*, Corporate Correspondence Memo 06-014.
[56] NCASI, NO_X *Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.
[57] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for* NO_X*,* SO_2 *and PM Emissions*, Corporate Correspondence Memo 06-014.

sufficient volume in the boiler at the right temperature window precludes the application of SNCR in all types of industrial boilers.[58]

Additional issues with SNCR include the potential for formation of ammonium sulfate salts (if sulfur oxides are present in the gas stream where they can react with excess ammonia from the SNCR process to form ammonium salts), which cause plugging problems. Ammonia also poses potential water quality issues - ammonia slip released to the atmosphere could contaminate surface waters by deposition.

SNCR has been applied to a few base-loaded wood and combination wood-fired boilers, mainly in the electric generating industry. However, its efficacy on wood-fired boilers with changing loads has not been demonstrated, except when used as a polishing step. Early use of ammonia injection in the case of one pulp mill wood-fired boiler met with significant problems and had to be abandoned (significant ammonia slip, caused by inefficient dispersion of the reagent within the boiler, was to blame). The boiler was unable to meet the manufacturer guarantee unless operated at less than half load. Even then, reducing NO_X to near permitted limits consumed considerably more ammonia than anticipated, leading to the formation of a visible ammonium chloride plume. A similar problem was encountered at a second FPI mill where nearly half the urea (on a molar basis) injected was being emitted as ammonia.[59]

The use of SNCR on stoker type wood-fired boilers that have significant load swings has not been demonstrated. Excessive ammonia slip is a primary concern when adequate dispersion of the SNCR chemical is not achieved in the boiler ductwork within the range of residence times available and temperatures needed for the NO_X reduction reactions to go to completion. Additional concerns include the impact of interference from higher CO levels present in many wood-fired boilers, the possibility of appreciable SNCR chemical being absorbed onto the ash matrix in a wood-fired boiler, and the extent and fate of ammonia in scrubber purge streams.[60]

The MRPO concludes, "if combustion zone temperatures within the boiler do not fall into [the ideal temperature range], then SNCR would be infeasible."[61]

4.4.2.4 SELECTIVE CATALYTIC REDUCTION

The use of SCR on boilers operating in the FPI has also never been successfully demonstrated for wood boilers, and would face the same inherent problem of requiring it to be post PM-control to protect the catalyst, and

[58] NESCAUM and MANE-VU, *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plant and Paper and Pulp Facilities*, March 2005.
[59] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.
[60] Ibid.
[61] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

achieving and maintaining the required temperature window for effective NO_X control.[62] There are numerous other issues with using SCR including catalyst plugging and soluble alkali poisoning as well as increased energy consumption.[63]

The use of SCR technology would be considered technically infeasible based upon the fact that post-particulate removal flue gas temperatures are typically significantly lower than those desired for this application. Many boilers are equipped with wet scrubbers for particulate emission (PM) control. Reheating the scrubbed flue gases from these boilers to bring them within the desired temperature window would involve a significant energy penalty. For pre-particulate removal flue gas application, catalyst deactivation from high particulate loading would be a serious concern, in addition to the impact of fluctuating loads on flue gas temperatures. Deactivation and/or poisoning could result from the size and density of fly ash particulate, and from their unique chemical and physical nature. Water-soluble alkali (such as Mg or Na) in particulate-laden gas streams has been known to poison SCR catalysts. Space considerations for installing a catalyst section in an existing boiler's ductwork are also important. Also note the use of solid fuels can result in catalyst contamination even with efficient PM control system and high moisture levels in exhaust air would result in inefficient SCR operation.[64]

Most boilers feature a flue gas temperature at the economizer exit that is below the ammonium sulfate/bisulfate dew point. Air heater surfaces must withstand corrosion from ammonium sulfates and bisulfates, be easily cleaned with conventional soot blowing, and survive corrosion-inducing water washing. SO_3 produced by the catalyst may condense on cooler surfaces, depending on the temperature, during both steady-state and non-steady-state operation. Higher levels of SO_2 to SO_3 conversion could cause accelerated corrosion or higher SO_3-induced plume opacity. Minimizing ammonia levels in the stack (typically <2 to 3 ppm) is required to avoid problems with disposal of scrubber byproduct contaminated by ammonia. The use of a particular catalyst puts restrictions on the fuel flexibility for a boiler. For example, purchasing coal with fly ash containing calcium oxide and arsenic outside the defined range absolves the catalyst supplier from responsibility for arsenic poisoning.[65]

The only "wood-fired" boiler SCR application in service in the U.S. was located at a woodworking facility in Ohio. This SCR was located downstream of a mechanical collector and electrostatic precipitator, operating in flue gas temperatures ranging from 550 to 650 °F. The only problem reported at this

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[62] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, Corporate Correspondence Memo 06-014.

[63] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[64] Ibid.

[65] Ibid.

installation was minor catalyst blinding due to the deposition of fine particulate that escaped the PM collection devices. It was learned the operating temperature for this SCR system allowed the use of conventional catalysts designed to accommodate high dust applications. For these catalysts, the catalyst openings through which the flue gas flows are sized to provide proper surface area contact and sufficient flue gas velocity to minimize fouling. Low temperature catalyst designs are considerably different and would not be recommended for use on any high dust application. Based on this description of the air pollution control system configuration and the operating conditions for this particular wood-fired boiler, it is important to identify several specific differences between this installation and those that operate in the FPI. First, due to the requirement to provide hot air to burn all but the driest of wood fuels, wood-fired boilers are usually equipped with air preheaters. Thus, even when dry particulate control devices like an ESP are utilized, the installation of an SCR catalyst section after a PM control device is not amenable for adaptation to such boilers without, of course, incurring a severe energy penalty. Second, a significant portion of the FPI's wood-fired boilers is controlled for PM emissions by multiclones and wet scrubbers. Therefore the PM emissions from these would be higher than the example situation. Third, it is unclear how the Ohio facility's SCR system would have worked under the fluctuating boiler load characteristics common to many FPI boilers. Finally, sawdust, which was the fuel fired in the Ohio facility's boiler, is a low moisture fuel and the particulate matter present in the flue gases from its combustion is likely to be of different composition than when bark or hog fuel (typically much higher moisture) is burned.[66]

Hence the use of SCR technology has clearly not been demonstrated for industrial wood, biomass or combination fuel-fired boilers in the FPI.[67]

4.4.3 Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Table 4-2 presents a ranking of the technically feasible control strategies in order of their effectiveness (i.e., potential control efficiency). For controls with a range of performance levels, the BART Guidelines note:

> *It is not [the U.S. EPA's] intent to require analysis of each possible level of efficiency for a control technique as such an analysis would result in a large number of options. It is important, however, that in analyzing the technology you take into account the most stringent emission control level that the technology is capable of achieving.*

[66] Ibid.
[67] Ibid.

Step 2- Eliminate Technically Infeasible Options

MdN utilizes the injection of natural gas together with recirculated flue gases to create an oxygen-rich zone above the combustion grate. Air is then injected at a higher furnace elevation to burn the combustibles. In response to comments provided by us regarding Domtar's 2014 BART analysis, Domtar stated that discussions regarding the technical infeasibility of MdN in the 2006/2007 Domtar BART analysis, submitted as part of the 2008 Arkansas RH SIP, remain correct.[113] The 2006/2007 Domtar BART analysis submitted in the 2008 Arkansas RH SIP discussed that MdN has not been fully demonstrated for this type of boiler and incorporates FGR, which is considered technically infeasible for use at Power Boiler No. 2. Domtar also stated it recently completed additional research and found that since the 2006/2007 Domtar BART analysis, MdN has not been placed into operation in power boilers at paper mills or any comparable source types. We are also not aware of any power boilers at paper mills that operate MdN for NO_X control, and agree that this control can be considered technically infeasible for use at Power Boiler No. 2 and do not further consider it in this evaluation. Domtar also questioned the technical feasibility of SNCR for boilers with high load swing such as Power Boiler No. 2, but in response to comments from us, SNCR was evaluated in Domtar's 2014 BART analysis.

Step 3- Evaluate Control Effectiveness of Remaining Control Technologies:

Based on vendor estimates, the 2006/2007 Domtar BART analysis estimated the potential control efficiency of LNB to be 30%. In Domtar's 2014 BART analysis, SNCR was evaluated at a control efficiency of 27.5% and 35% for Power Boiler No. 2. These values were based on SNCR control efficiency estimates that came from the equipment vendor's proposal,[114] which according to the facility, is not an appropriations request level quote and therefore requires further refinement.[115] For example, Domtar's 2014 BART analysis discusses that for a base loaded coal boiler with steady flue gas flow patterns and temperature distribution across the flue gas pathway, SNCR is typically capable of achieving 50% NO_X reduction. However, Power Boiler No. 2 is not a base loaded boiler and does not have steady flue gas flow patterns or steady temperature distribution across the flue gas pathway.

To demonstrate the wide range in temperature at Power Boiler No. 2 and its relationship to steam demand, Domtar obtained an analysis of furnace exit gas temperatures for Power Boiler

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[113] See the document titled "Domtar Responses to ADEQ Regarding Region 6 Comments on Domtar BART Analysis," p. 10. A copy of this document can be found in the docket for our proposed rulemaking.

[114] Fuel Tech Proposal titled "Domtar Paper Ashdown, Arkansas- NO_X Control Options, Power Boilers 1 and 2," dated June 29, 2012. A copy of the vendor proposal is included under Appendix D to the "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis and its appendices is found in the docket for our proposed rulemaking.

[115] See the document titled "Domtar Responses to ADEQ Regarding Region 6 Comments on Domtar BART Analysis," p. 9. A copy of this document can be found in the docket for our proposed rulemaking.

No. 2 from an engineering consultant.[116] The furnace exit gas temperatures were analyzed for a 12-day period that according to Domtar is representative of typical boiler operations. The consultant's report indicated that furnace exit gas temperatures are representative of temperatures in the upper portion of the furnace, which is the optimal location for installation of the SNCR injection nozzles. The consultant estimated that 1700 – 1800°F represents the temperature range at which SNCR can be expected to reach 40% control efficiency at the current boiler operating conditions. It was found that there is wide variability in the furnace exit gas temperatures for Power Boiler No. 2, with temperatures ranging from 1000 – 2000°F. The data also indicate that there is a direct positive relationship between boiler steam demand and furnace exit gas temperatures. It was also found that Power Boiler No. 2 operated in the optimal temperature zone at which SNCR can be expected to reach 40% control efficiency for only a total of 20 hours over the 12-day period analyzed (288 continuous hours), which is approximately 7% of the time.

According to Domtar, the significant temperature swings, which are due to load following and steam demand variability, create a scenario where urea injection will either be too high or too low. When not enough urea is injected, NO_X removal will be less than projected and when too much urea is injected, excess ammonia slip will occur. Domtar stated that the observed significant temperature swings demonstrate that it will be difficult to maintain stable, optimal furnace temperatures at which urea can be injected to effectively reduce NO_X with minimal ammonia slip. We agree that because of the wide variability in steam demand and wide range in furnace temperature observed at Power Boiler No. 2, the NO_X control efficiency of SNCR at the boiler would not reach optimal control levels on a long-term basis. We also believe there is uncertainty as to the level of control efficiency that SNCR would be able to achieve on a long-term basis for Power Boiler No. 2. However, we further consider SNCR in the remainder of the analysis.

Step 4- Evaluate Impacts and Document the Results

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

In the 2006/2007 Domtar BART analysis, the capital cost, operating cost, and cost-effectiveness of LNB were estimated based on vendor estimates.[117] The analysis was based on a 10-year amortization period, based on the equipment's life expectancy. However, since we believe a 30-year equipment life is a more appropriate estimate for LNB, we have we have

[116] September 12, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. A copy of this letter and its attachments are found in the docket for our proposed rulemaking

[117] See "Best Available Retrofit Technology Determination Domtar Industries Inc., Ashdown Mill (AFIN 41-00002)," originally dated October 31, 2006 and revised on March 26, 2007, prepared by Trinity Consultants Inc. This BART analysis is part of the 2008 Arkansas RH SIP, upon which EPA took final action on March 12, 2012 (77 FR 14604). A copy of this BART analysis is found in the docket for this proposed rulemaking.

adjusted Domtar's cost estimate for LNB.[118] The annual emissions reductions used in the cost-effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. We have also adjusted the average cost-effectiveness calculations presented in the 2006/2007 Domtar BART analysis for LNB by using the boiler's actual annual uncontrolled NO_X emissions rather than the maximum 24-hour emission rate as the baseline annual emissions. The table below summarizes the estimated cost of LNB for Power Boiler No. 2, based on our adjustments to the cost estimates in the 2006/2007 Domtar BART analysis as discussed above.

In Domtar's 2014 BART analysis, the capital costs, operating costs, and cost-effectiveness of SNCR were calculated based on methods and assumptions found in our Control Cost Manual, and supplemented with mill-specific cost information for water, fuels, and ash disposal and urea solution usage estimates from the equipment vendor.[119] The two SNCR control scenarios evaluated were 27.5% and 35% control efficiencies. Domtar annualized the capital cost over a 30-year period and then added to the annual operating cost to obtain the total annualized costs. The annual emissions reductions associated with each NO_X control option were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emissions used in the calculations are the uncontrolled actual emissions from the 2001-2003 baseline period. The average cost-effectiveness was calculated by dividing the total annual cost by the estimated annual NO_X emissions reductions. The table below summarizes Domtar's estimate of the cost of SNCR for Power Boiler No. 2.

Table 74. Summary of Cost of NO_X Controls for Power Boiler No. 2

NO_X Control Scenario	Baseline Emission Rate (NO_X tpy)	NO_X Removal Efficiency of Controls (%)	Annual Emissions Reduction (NO_X tpy)	Capital Cost ($)	Total Annual Cost ($/yr)	Average Cost Effectiveness ($/ton)	Incremental Cost-Effectiveness ($/ton)
SNCR- 27.5%	1,536	27.5%	422	2,681,678	843,575	1,998	-
LNB	1,536	30%	461	6,131,745	899,605	1,951	1,437
SNCR- 35%	1,536	35%	537	2,877,523	1,026,214	1,909	1,666

118 See the spreadsheet titled "Domtar PB No2 LNB_cost revisions." A copy of this spreadsheet is found in the docket for this proposed rulemaking.

119 See "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis is found in the docket for our proposed rulemaking.

APPENDIX H-3

Domtar Ashdown Mill ICR Response,

Revised

Division of Environmental Quality

Office of Air Quality

Domtar A.W. LLC > Ashdown Mill
AFIN 41-00002

Response to January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request

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April 6, 2020
Revised May 7, 2020

Project 203702.0003

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1. Introduction

This report was prepared on behalf of Domtar A.W. LCC (Domtar) in response to the January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request ("the ICR") from the Arkansas Department of Energy and Environment, Division of Environmental Quality, Office of Air Quality ("the DEQ").

Per the ICR, this report provides information related to sulfur dioxide (SO_2) and/or nitrogen oxides (NO_X) emissions reduction options for the following sources/source numbers (SNs):

- No. 2 Power Boiler (SN-05)
- No. 3 Power Boiler (SN-01)
- No. 2 Recovery Boiler (SN-06)
- No. 3 Recovery Boiler (SN-14)

Each section of this report is related to a single source-pollutant combination, e.g., No. 2 Power Boiler – SO_2, and No. 3 Recovery Boiler – NO_X, resulting in eight (8) total sections. The following specific technical and economic information, where applicable, is provided in each section for each emissions reduction option considered, in accordance with instructions in the ICR:

- Technical feasibility
- Control effectiveness
- Emissions reductions
- Time necessary for implementation
- Remaining useful life
- Energy and non-air quality environmental impacts
- Costs

To the extent possible, information in this report is based on information prepared for the relevant Best Available Retrofit Technology (BART) assessment completed for the regional haze rule (RHR) first planning period (1PP) state implementation plan (SIP). The most recent 1PP SIP package was submitted to the U.S. Environmental Protection Agency (EPA) on August 13, 2019; it contains 594 pages. References in this report to the 1PP SIP package are to the version available on the DEQ's website as of April 6, 2020.[1]

[1] http://www.adeq.state.ar.us/air/planning/sip/pdfs/regional-haze/final-phase-III-sip-combined-files.pdf (accessed on April 6, 2020).

The ICR specifically listed the following three SO_2 emissions reduction options for consideration, and no other options have been identified:

- New scrubber downstream of existing scrubbers
- Increased reagent usage at existing scrubbers
- Upgrades to existing scrubbers

2.1. Technical Feasibility

Information about all three SO_2 emission reduction options listed above is presented in the 1PP SIP package. The relevant information (at 328-339 and 500-509) is included in Appendix A of this report for convenience. All three options were determined to be technically feasible.

2.2. Control Effectiveness

The appended (1PP SIP package pages 328-339) A.H. Lundberg Associates, Inc. (Lundberg) evaluation of the new scrubber option presented a 90 % control efficiency. Lundberg also evaluated possible upgrades to the existing scrubbers, including the elimination of bypass reheat, the installation of liquid distribution rings, the installation of perforated trays, improvements to the auxiliary system requirement, and a redesign of the spray header and nozzle configuration, and it was concluded that any control efficiency improvement to that already being achieved was unquantifiable (at 501).

Based on calculations presented in its February 2015 Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan (2015 FIP TSD), as presented in the 1PP SIP package (at 500-503), the EPA concluded that increased reagent usage at the existing scrubbers would achieve 90 % control efficiency and a controlled emission rate of 91.5 pounds per hour (lb/hr). This calculation was based on a 2009-2011 annual-average emission rate of approximately 280.9 lb/hr and a back-calculated control efficiency for the existing scrubbers of approximately 69 %.

Domtar asserted then, and maintains now, that the control efficiency and emission rate applied by the EPA to the increased reagent usage option has not been verified as sustainable over a long-term period in practice. A one-year or at least 30-day engineering study needs to be completed to confirm the EPA's assumptions. If the DEQ decides that increased reagent usage at the No. 2 Power Power Boiler is a reasonable part of its long-term strategy for the RHR, then Domtar requests time to conduct such a study and update the information provided in this report once that study is complete.

Additionally, Domtar has already commissioned an engineering firm to study the feasibility of operating No. 2 Power Boiler without coal as a fuel. If Domtar decides to remove coal as a fuel option, then the No. 2 Power Boiler emissions profile will likely change, and all assumptions in this report about control device efficiencies and costs will be subject to significant updates.

Table 2-1 summarizes and ranks (in descending order) the control effectiveness of the technically feasible SO_2 reduction options based on current assumptions and operation of the No. 2 Power Boiler.

Table 2-1. Control Effectiveness of SO_2 Emissions Reduction Options for No. 2 Power Boiler

SO_2 Reduction Option	Control Efficiency
New scrubber downstream of existing scrubbers	90 %
Increased reagent usage at existing scrubbers	90 %
Upgrades to existing scrubbers	0 %

2.3. Emissions Reductions

Table 2-2 presents SO_2 emission rates from 2017 to 2019 for the No. 2 Power Boiler based on continuous emissions monitoring system (CEMS) records. Per the ICR, the baseline actual SO_2 emission rate is the maximum monthly value from 2017-2019, which is 103.8 tons/month, which is equivalent to 1,246.1 tons per year (tpy). Additionally, because it serves as a more appropriate basis for annual control cost calculations, the average of the three (2017, 2018, and 2019) annual total emission rates is calculated as 858.9 tpy. Both the "Max Month Basis" emission rate and "Avg Year Basis" emission rate are used for the emissions reductions estimates and control cost calculations presented in the remainder of this section.

Table 2-2. 2017-2019 Monthly SO_2 Emissions for No. 2 Power Boiler

Month / Year	Monthly Total SO_2 Emission Rate (ton/month)	Annual Total SO_2 Emission Rate (tpy)
1/2017	93.27	928.32
2/2017	75.28	
3/2017	50.00	
4/2017	70.29	
5/2017	76.32	
6/2017	74.02	
7/2017	76.45	
8/2017	79.20	
9/2017	50.92	
10/2017	88.35	
11/2017	92.44	
12/2017	101.77	
1/2018	93.18	777.85
2/2018	77.71	
3/2018	78.81	
4/2018	71.60	
5/2018	63.65	
6/2018	39.37	
7/2018	52.47	
8/2018	45.98	
9/2018	33.14	
10/2018	61.82	
11/2018	80.72	

Month / Year	Monthly Total SO_2 Emission Rate (ton/month)	Annual Total SO_2 Emission Rate (tpy)
12/2018	79.39	
1/2019	103.84	870.52
2/2019	91.05	
3/2019	60.94	
4/2019	62.40	
5/2019	73.02	
6/2019	79.57	
7/2019	74.31	
8/2019	68.13	
9/2019	77.25	
10/2019	69.71	
11/2019	47.23	
12/2019	63.05	

Table 2-3 summarizes the controlled emission rates and emission reduction potentials based on the control efficiencies from Table 2-1 for the technically feasible SO_2 reduction options for the No. 2 Power Boiler.

The upgrades to existing scrubbers option is not carried forward in this report because it does not provide for any quantifiable decrease in SO_2 emissions (i.e., any cost of control greater than zero would result in an undefined or infinite cost effectiveness value).

Table 2-3. Emissions of SO_2 Emissions Reduction Options for No. 2 Power Boiler

SO_2 Reduction Option	Max Month Basis		Avg Year Basis	
	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
New scrubber downstream of existing scrubbers	124.6	1,121.5	85.9	773.0
Increased reagent usage at existing scrubbers	124.6	1,121.5	85.9	773.0
Upgrades to existing scrubbers	1,246.1	0.00	858.9	0.00

2.4. Time Necessary for Implementation

Implementing the new scrubber option would take at least three (3) years. Domtar's capital projects approval process can take from six (6) to 18 months, and this would not begin until an enforceable requirement is effective. Depending on the timing of the effectiveness date and the project approval, it could be another 18 months before a window was available to complete construction on the No. 2 Power Boiler. According to the previously referenced Lundberg proposal, 34 weeks (8.5 months) is needed for shipment and construction of a new scrubber downstream of the existing scrubbers. This process can take place within the potential 18-month outage frequency. Domtar proposes three (3) years as an adequate time necessary to implement a new scrubber system on the No. 2 Power Boiler.

Increased reagent usage at the existing scrubbers can be implemented within approximately two (2) years of an enforcement requirement's effective date. The time is needed to procure and install two new pumps in conjunction with Domtar's outages schedule.

2.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 2 Power Boiler; it is needed in order to meet the steam demands of the Ashdown Mill processes. The useful life values found in EPA's Air Pollution Control Cost Manual (CCM)[2] are assumed to be applicable.

2.6. Energy and Non-air Quality Environmental Impacts

A new scrubber operating downstream of the existing scrubbers would incur an energy impact for the Ashdown Mill. This energy impact has been monetized. A new scrubber would also increase water usage and waste water generation. However, the increase would be small when compared to the existing quantities used and generated by the Ashdown Mill, and no further consideration is made for non-air quality environmental impacts of a new scrubber.

Energy impacts due to increased reagent usage are expected to be minimal. Non-air quality environmental impacts are also expected to be small when compared to existing storage and usage of caustic solutions at the Ashdown Mill.

2.7. Costs

The total capital cost of the new scrubber option was estimated in the 1PP SIP package (at 504) to be $7,175,000, which was annualized to $578,207 per year based on 7 % interest and 30 years of operation. Further, the estimated total annual direct and indirect costs[3] (not including annualized capital) was $9,255,171 per year (at 504). Therefore, the total annual cost of the new scrubber option was estimated to $9,833,378 per year. These values are representative of 2014 and can be escalated to 2018 (the latest final information available as of January 28, 2020) using the Chemical Engineering Plant Cost Index (CEPCI) values (576.1 for 2014 and 603.1 for 2018). The result is a total annual cost estimate of $10,294,238 per year. Based on the max month basis SO_2 emission reduction of 1,121.5 tpy, the cost effectiveness of the new scrubber option is $9,179/ton, and it is $13,317/ton using the more appropriate avg year basis emission reduction of 773.0 tpy. It is important to note that the cost values presented above are unrealistically small as they do not adequately account for the retrofit issues that would occur if a new scrubber were to be installed. Per the 1PP SIP package (at 504), "There is no existing property or adequate structure to support the add-on spray scrubber equipment…the installation of add-on spray scrubbers would require construction at the facility to accommodate the equipment, but an estimate of these costs was not available and therefore not factored into the cost estimates…"

The cost of increased reagent usage option was estimated in the 1PP SIP package (at 504) to be $200,000 in capital, annualized to $16,117 per year, and approximately $1,960,000 per year in direct annual operations and maintenance costs (i.e., additional reagent usage, waste water treatment, raw water treatment, and energy usage) for a total annual cost estimate of $1,976,117 per year. When escalated to 2018, this becomes $2,068,732 per year. Based on the max month basis SO_2 emission reduction of 1,121.5 tpy, the cost effectiveness of the

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[2] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, available at https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf (accessed on January 31, 2020)

[3] Annual direct costs include operations and maintenance labor, maintenance materials, and utilities. Annual indirect costs include property tax, insurance, and overhead/administration.

increased reagent usage option is $1,845/ton, and it is $2,676/ton using the more appropriate avg year basis emission reduction of 773.0 tpy. Table 2-4 summarizes the estimated costs, including the cost effectiveness estimates based on the emission reduction values from Table 2-3, for the technically feasible SO_2 reduction options for the No. 2 Power Boiler.

Table 2-4. Estimated Costs (2018 Basis) of SO_2 Emissions Reduction Options for No. 2 Power Boiler

SO_2 Reduction Option	Capital Costs ($)	Annualized Capital Costs ($/year)	Annual Direct and Indirect / Operations and Maintenance Costs ($/year)	Total Annual Costs ($/year)	Max Month Basis Cost Effectiveness ($/ton)	Avg Year Basis Cost Effectiveness ($/ton)
New scrubber downstream of existing scrubbers	7,511,270	605,306	9,688,932	10,294,238	9,179	13,317
Increased reagent usage at existing scrubbers	209,373	16,873	2,051,859	2,068,732	1,845	2,676

As mentioned above, Domtar has little confidence in the control efficiency assigned to the increased reagent option, therefore, it also has little confidence in the cost effectiveness value. If the DEQ decides that increased reagent usage at the No. 2 Power Power Boiler is a reasonable part of its long-term strategy for the RHR, then Domtar requests time to conduct such a study and update the information provided in this report once that study is complete.

The ICR specifically listed for consideration the following three NO_X emissions reduction options, all of which involve the reaction of ammonia (NH_3) with NO_X, and no other options have been identified:

- Selective Catalytic Reduction (SCR)
- Regenerative Selective Catalytic Reduction (RSCR)
- Selective Non-Catalytic Reduction (SNCR)

3.1. Technical Feasibility

Two (SCR and SNCR) of the three NO_X emission reduction options listed above were examined in the BART assessment completed for the 1PP SIP. The relevant 1PP SIP packge information (at 127-133 and 510-512) is included in Appendix A of this report for convenience

For the 1PP, SCR was determined by Domtar, the DEQ, and the EPA to be technically infeasible for several reasons, all of which apply now as they did then.

RSCR, also known as tail-end SCR because it is placed downstream of the particulate matter (PM) control device, incorporates a regenerator, which pre-heats the cool gas stream from PM control device outlet before it enters the RSCR using the RSCR outlet gas that has been heated to within the optimal SCR temperature range. RSCR comes with many of the same technical challenges as traditional SCR. For example, space constraints often make retrofitting an SCR or RSCR impossible. This is true of the No. 2 Power Boiler, which is completely surrounded by existing equipment as shown in Figure 3-1 and Figure 3-2.

Additionally, the temperature of the No. 2 Power Boiler exhaust at the outlet of the scrubbers is too cold for SCR. Per the EPA's CCM, the desired minimum temperature for SCR application to achieve 70 % control efficiency is 575 degrees Fahrenheit (°F).[4] The No. 2 Power Boiler exhaust is, on average, approximately 125 °F. In an RSCR system, the regenerative heating reduces the required heat input; however, this reheating of the flue gas still represents a significant amount of auxiliary fuel that would be necessary for successful operation. Moreover, it is not considered available as RSCR has not been previously demonstrated on load-following industrial boilers. Such boilers, because of unstable and large exhaust temperature swings, make it particularly difficult to control reagent injection rates needed to ensure appropriate NO_X reductions while avoiding excessive ammonia slip.

The EPA's *Guidelines for BART Determinations Under the Regional Haze Rule* state that "[t]echnologies which have not yet been applied to (or permitted for) full scale operations need not be considered as available; we [EPA] do not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice."[5] While these "Guidelines" do not directly applicable to a four factor analysis, it is assumed that the EPA's view of availability with respect to control technologies/options is consistent within the broad regional haze rule. As such, because RSCR has not been successfully implemented on an emission unit comparable to the No. 2 Power Boiler, it is considered to be technically infeasible.

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[4] EPA Air Pollution Control Cost Manual, Section 4.2, Chapter 2, Figure 2.2.

[5] 40 CFR part 51, Appendix Y.

Figure 3-1. Plot Plan Showing No. 2 Power Boiler and Surrounding Equipment

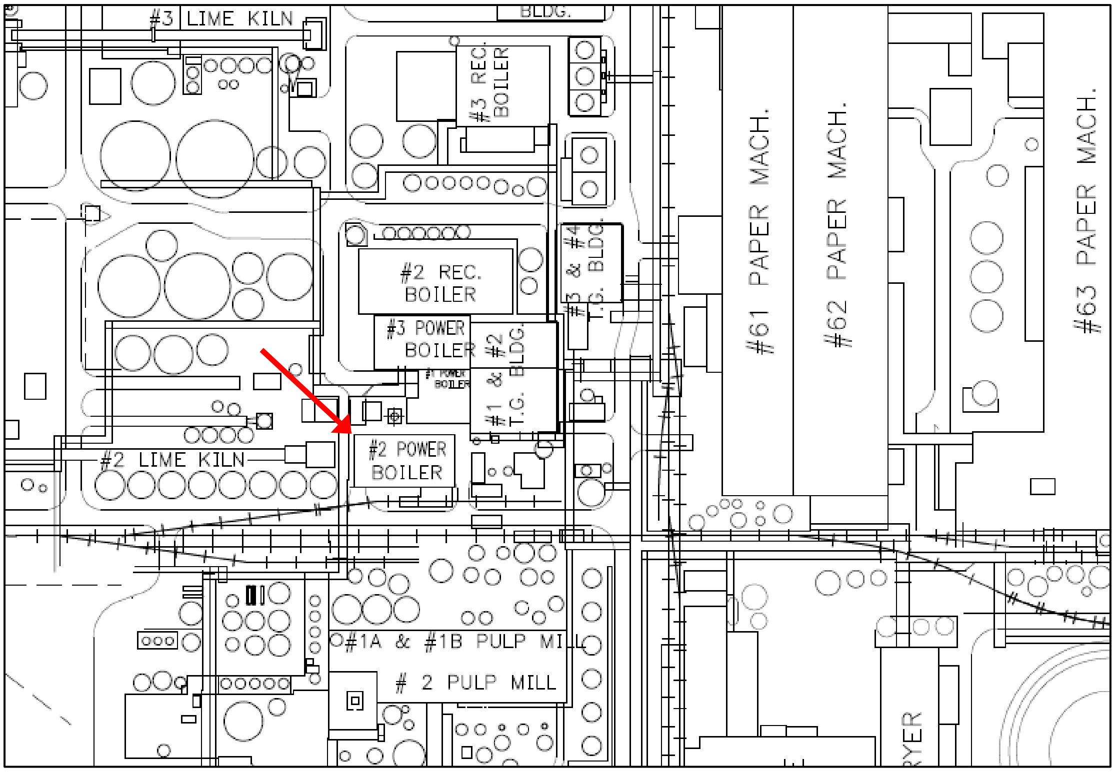

Figure 3-2. Aerial Showing No. 2 Power Boiler and Surrounding Equipment

SNCR was determined in the 1PP to be technically feasible although the effectiveness of SNCR on a boiler such as the No. 2 Power Boiler (multi-fuel, swing-load) is questionable. This issue is discussed in Section 3.2.

3.2. Control Effectiveness

As presented in the 1PP SIP package (at 511), EPA stated in its 2015 FIP TSD: "We [EPA] agree that because of the wide variability in steam demand and wide range in furnace temperature observed at Power Boiler No. 2, the NO_X control efficiency of SNCR at the boiler would not reach optimal control levels on a long-term basis. We also believe there is uncertainty as to the level of control efficiency that SNCR would be able to achieve on a longterm (sic) basis for Power Boiler No. 2." Additionally (at 510-511):

> *To demonstrate the wide range in temperature at Power Boiler No. 2 and its relationship to steam demand, Domtar obtained an analysis of furnace exit gas temperatures for Power Boiler No. 2 from an engineering consultant [International Applied Engineering, Inc. (IAE)]. The furnace exit gas temperatures were analyzed for a 12-day period that according to Domtar is representative of typical boiler operations. The consultant's report indicated that furnace exit gas temperatures are representative of temperatures in the upper portion of the furnace, which is the optimal location for installation of the SNCR injection nozzles. The consultant estimated that 1700 – 1800°F represents the temperature range at which SNCR can be expected to reach 40% control efficiency at the current boiler operating conditions. It was found that there is wide variability in the furnace exit gas temperatures for Power Boiler No. 2, with temperatures ranging from 1000 – 2000°F. The data also indicate that there is a direct positive relationship between boiler steam demand and furnace exit gas temperatures. It was also found that Power Boiler No. 2 operated in the optimal temperature zone at which SNCR can be expected to reach 40% control efficiency for only a total of 20 hours over the 12-day period analyzed (288 continuous hours), which is approximately 7% of the time.*

Based on the information published by the EPA in the 1PP, it is expected that for the No. 2 Power Boiler SNCR could achieve an overall control efficiency of approximately three (3) % based on operation at 40 % efficiency for seven (7) % of total boiler operating time.

Table 3-1 summarizes and ranks (in descending order) the control effectiveness of the technically feasible NO_X reduction options for the No. 2 Power Boiler.

Table 3-1. Control Effectiveness of NO_X Emissions Reduction Options for No. 2 Power Boiler

NO_X Reduction Option	Control Efficiency
SNCR	3 %

3.3. Emissions Reductions

Table 3-2Table 2-2 presents NO_X emission rates from 2017 to 2019 for the No. 2 Power Boiler based on CEMS records. Per the ICR, the baseline actual SO_2 emission rate is the maximum monthly value from 2017-2019, which is 65.8 tons/month, which is equivalent to 789.1 tons per year (tpy). Additionally, because it serves as a more appropriate basis for annual control cost calculations, the average of the three (2017, 2018, and 2019) annual total emission rates is calculated as 559.9 tpy. Both the "Max Month Basis" emission rate and "Avg Year Basis" emission rate are used for the emissions reductions estimates and control cost calculations presented in the remainder of this section.

Table 3-2. 2017-2019 Monthly NO_X Emissions for No. 2 Power Boiler

Month / Year	Monthly Total NO_X Emission Rate (ton/month)	Annual Total NO_X Emission Rate (tpy)
1/2017	52.31	542.74
2/2017	46.28	
3/2017	53.55	
4/2017	41.72	
5/2017	40.74	
6/2017	41.43	
7/2017	44.43	
8/2017	44.30	
9/2017	25.21	
10/2017	44.62	
11/2017	49.42	
12/2017	58.73	
1/2018	65.76	548.33
2/2018	39.18	
3/2018	49.83	
4/2018	44.98	
5/2018	48.49	
6/2018	43.67	
7/2018	44.96	
8/2018	36.41	
9/2018	40.53	
10/2018	39.17	
11/2018	47.27	
12/2018	48.08	
1/2019	62.99	588.68
2/2019	51.19	
3/2019	32.58	
4/2019	35.76	
5/2019	37.78	
6/2019	46.00	
7/2019	48.09	
8/2019	55.15	
9/2019	53.19	
10/2019	54.19	
11/2019	54.04	
12/2019	57.72	

Table 3-3 summarizes the controlled emission rates and emission reduction potentials based on the control efficiencies from Table 3-1 for the technically feasible NO_X reduction options for the No. 2 Power Boiler.

Table 3-3. Emissions of NO_X Emissions Reduction Options for No. 2 Power Boiler

NO_X Reduction Option	Max Month Basis		Avg Year Basis	
	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
SNCR	765.4	23.67	543.1	16.80

3.4. Time Necessary for Implementation

EPA has allowed for five (5) years for the implementation of add-on NO_X controls such as SNCR in at least two FIPs (e.g., for Utah and North Dakota). Domtar would request the same timeline if SNCR were required for either of its power boilers.

3.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 2 Power Boiler; it is needed in order to meet the steam demands of the Ashdown Mill processes. The useful life values found in EPA's CCM are assumed to be applicable.

3.6. Energy and Non-air Quality Environmental Impacts

The energy impacts (which are monetized) and non-air quality environmental impacts for SNCR, principally related to the storage and handling of ammonia/urea, are well known. They are expected to be no greater at the Ashdown Mill than any other industrial facility and are therefore not considered as a reason for rendering the control options infeasible in this context.

3.7. Costs

In the 1PP SIP package (at 512), the total capital cost of SNCR – for a 27.5 % control efficiency scenario, which, based on the above discussion, is unrealistic but is taken to be representative for the purposes of this ICR response – was estimated to be $2,681,678, which is annualized to $216,107 per year based on 7 % interest and 30 years of operation. Further, the estimated total annual direct costs[6] (not including annualized capital) was $627,469 per year. Therefore, the total annual cost of SNCR was estimated to $843,575 per year. These values are representative of 2012 and can be escalated to 2018 (the latest final information available as of January 28, 2020) using the CEPCI values (584.6 for 2012 and 603.1 for 2018). The result is a total annual cost estimate of $870,270 per year. Based on the max month basis NO_X emission reduction of 23.7 tpy, the cost effectiveness of SNCR is $36,762/ton, and it is $51,809/ton using the more appropriate avg year basis emission reduction of 16.8 tpy.

Table 3-4 summarizes the estimated costs, including the cost effectiveness estimates based on the emission reduction values from Table 3-3, for the technically feasible NO_X reduction options for the No. 2 Power Boiler.

[6] Annual direct costs include operations and maintenance labor, maintenance materials, reagent, and utilities.

Table 3-4. Estimated Costs (2018 Basis) of NO_X Emissions Reduction Options for No. 2 Power Boiler

NO_X Reduction Option	Capital Costs ($)	Annualized Capital Costs ($/year)	Annual Direct and Indirect / Operations and Maintenance Costs ($/year)	Total Annual Costs ($/year)	Max Month Basis Cost Effectiveness ($/ton)	Avg Year Basis Cost Effectiveness ($/ton)
SNCR	2,766,541	222,946	647,326	870,271	36,762	51,809

The ICR specifically listed the following three SO_2 emissions reduction options for consideration:

- Wet gas scrubber (WGS)
- Spray dry absorber (SDA)

The above options are collectively referred to as flue gas desulfurization (FGD) technologies.

One other SO_2 emissions reduction options is discussed in this report:

- Inherent scrubbing by the ash created from combusting bark in the boiler ("ashes resulting from wood residue combustion typically contain significant fractions of oxides and carbonates of alkali metals such as calcium, potassium, and magnesium…wood residue ash can capture some of the sulfur dioxide released with the co-firing of sulfur-containing fossil fuels…"[7])

4.1. Technical Feasibility

All three SO_2 emission reduction options listed above are technically feasible for the No. 3 Power Boiler.

4.2. Control Effectiveness

Domtar has not commissioned site-specific studies of the FGD technologies, primarily because they are clearly economically infeasible considering the small emissions reduction potential available (i.e., small baseline emission rate). It is assumed for the purposes of this report that the FGD options can achieve 90 % control efficiency per EPA's Air Pollution Control Technology Fact Sheet.[8]

Inherent scrubbing is taken to be the base case. The baseline actual SO_2 emission rate presented below considers the inherent scrubbing that occurs in the No. 3 Power Boiler.

Table 4-1 summarizes and ranks (in descending order) the control effectiveness of the technically feasible SO_2 reduction options for the No. 3 Power Boiler.

Table 4-1. Control Effectiveness of SO_2 Emissions Reduction Options for No. 3 Power Boiler

SO_2 Reduction Option	Control Efficiency
WGS / Wet FGD	90 %
SDA / Dry FGD	90 %
Inherent Scrubbing	Base case

[7] Someshwar, Arun V. and Jain, Ashok K. (NCASI), "Sulfur capture in combination bark boilers", Tappi Journal Vol. 76, No. 7, July 1993.

[8] https://www3.epa.gov/ttn/catc/dir1/ffdg.pdf (accessed on January 30, 2020)

4.3. Emissions Reductions

Table 4-2Table 2-2 presents SO_2 emission rates from 2017 to 2019 for the No. 3 Power Boiler based on records of the emissions calculations required by Specific Condition 6a of Air Operating Permit No. 287-AOP-R22.[9] Per the ICR, the baseline actual SO_2 emission rate used for this report is the maximum monthly value from 2017-2019, which is 12.1 ton/month, which is equivalent to 144.8 tpy. Additionally, because it serves as a more appropriate basis for annual control cost calculations, the average of the three (2017, 2018, and 2019) annual total emission rates is calculated as 46.9 tpy. Both the "Max Month Basis" emission rate and "Avg Year Basis" emission rate are used for the emissions reductions estimates and control cost calculations presented in the remainder of this section.

Table 4-2. 2017-2019 Monthly SO_2 Emissions for No. 3 Power Boiler

Month / Year	Monthly Total SO_2 Emission Rate (ton/month)	Annual Total SO_2 Emission Rate (tpy)
1/2017	4.10	40.70
2/2017	4.59	
3/2017	2.50	
4/2017	3.15	
5/2017	8.87	
6/2017	4.76	
7/2017	4.94	
8/2017	0.00	
9/2017	0.00	
10/2017	0.11	
11/2017	3.78	
12/2017	3.90	
1/2018	0.46	50.20
2/2018	7.94	
3/2018	5.09	
4/2018	6.86	
5/2018	2.39	
6/2018	12.07	
7/2018	7.40	
8/2018	4.41	
9/2018	2.64	
10/2018	0.94	
11/2018	0.00	
12/2018	0.00	
1/2019	0.00	49.84
2/2019	5.26	
3/2019	7.87	
4/2019	4.54	
5/2019	0.26	
6/2019	1.27	

[9] The issuance of the next version of the Air Operating Permit, No. 287-AOP-R23, is pending. Specific Condition 6a is not changed in draft version of this permit.

Month / Year	Monthly Total SO_2 Emission Rate (ton/month)	Annual Total SO_2 Emission Rate (tpy)
7/2019	5.09	
8/2019	0.03	
9/2019	4.28	
10/2019	4.06	
11/2019	6.11	
12/2019	11.06	

Table 4-3 summarizes the controlled emission rates and emission reduction potentials based on the control efficiencies from Table 4-1 for the technically feasible SO_2 reduction options for the No. 3 Power Boiler.

Table 4-3. Emissions of SO_2 Emissions Reduction Options for No. 3 Power Boiler

	Max Month Basis		Avg Year Basis	
SO_2 Reduction Option	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
WGS / Wet FGD	14.5	130.4	4.7	42.2
SDA / Dry FGD	14.5	130.4	4.7	42.2
Inherent Scrubbing	144.8	0	46.9	0

4.4. Time Necessary for Implementation

Domtar proposes five years as an appropriate timeline for implementing FGD systems based on numerous determinations for utilities in the 1PP.

No time is needed to implement the inherent scrubbing option; it is already in place.

4.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 3 Power Boiler; it is needed in order to meet the steam demands of the Ashdown Mill processes. The useful life values found in EPA's CCM are assumed to be applicable.

4.6. Energy and Non-air Quality Environmental Impacts

An FGD system would incur an energy impact, which can be monetized, and it would increase water usage and waste water generation. However, the increase would be small when compared to the existing quantities used and generated by the Ashdown Mill, and no further consideration is made for non-air quality environmental impacts of an FGD system.

The inherent scrubbing option represents no new energy or non-air quality environmental impacts.

4.7. Costs

There is no new cost associated with the inherent scrubbing option as it is already in place.

For wet and dry FGD, EPA's Air Pollution Control Technology Fact Sheet provides ranges for capital and O&M costs, relative to heat input capacity, representative of 2001 (the CEPCI for 2001 is 394.3). The No. 3 Power Boiler heat input capacity is 790 MMBtu/hr. Table 4-4 summarizes the EPA Fact Sheet based cost ranges, including the cost effectiveness estimates based on the emission reduction values from Table 4-3, for the FGD options for the No. 3 Power Boiler.

Table 4-4. Estimated Costs (2018 Basis) of SO_2 Emissions Reduction Options for No. 3 Power Boiler

SO_2 Reduction Option	Capital Costs ($)	Annualized Capital Costs ($/year)	Annual Operations and Maintenance Costs ($/year)	Total Annual Costs ($/year)	Max Month Basis Cost Effectiveness ($/ton)	Avg Year Basis Cost Effectiveness ($/ton)
WGS / Wet FGD (low)	30,208,534	2,434,397	966,673	3,401,070	26,091	80,555
WGS / Wet FGD (high)	181,251,205	14,606,383	2,175,014	16,781,397	128,737	397,470
SDA / Dry FGD (low)	36,250,241	2,921,277	1,208,341	4,129,618	31,680	97,811
SDA / Dry FGD (high)	181,251,205	14,606,383	36,250,241	50,856,624	390,141	1,204,548

The ICR specifically listed for consideration the following three NO_X emissions reduction options, all of which involve the reaction of NH_3 with NO_X, and no other options have been identified:

- SCR
- RSCR
- SNCR

5.1. Technical Feasibility

The same problems with SCR and RSCR described above for No. 2 Power Boiler – principally space constraints, operation (load-swings), and cool exhaust – also apply to No. 3 Power Boiler, and these control options are deemed infeasible.

Because SNCR was determined in the 1PP to be technically feasible for the No. 2 Power Boiler it is also considered technically feasible for the purposes of this report for the No. 3 Power Boiler.

5.2. Control Effectiveness

The operation of the No. 3 Power Boiler is effectively identical to the No. 2 Power Boiler – both are swing-load boilers that operate as needed to meet demand. Therefore, a similar wide variability in exit gas temperature is expected. For the purposes of this report, the same SNCR control efficiency applied for No. 2 Power Boiler is also applied for No. 3 Power Boiler.

Table 5-1 summarizes and ranks (in descending order) the control effectiveness of the technically feasible NO_X reduction options for the No. 3 Power Boiler.

Table 5-1. Control Effectiveness of NO_X Emissions Reduction Options for No. 3 Power Boiler

NO_X Reduction Option	Control Efficiency
SNCR	3 %

5.3. Emissions Reductions

Table 5-2 presents NO_X emission rates from 2017 to 2019 for the No. 3 Power Boiler based on CEMS records. Per the ICR, the baseline actual NO_X emission rate used for this report is the maximum monthly value from 2017-2019, which is is 49.7 tons/month, which is equivalent to 596.7 tpy. Additionally, because it serves as a more appropriate basis for annual control cost calculations, the average of the three (2017, 2018, and 2019) annual total emission rates is calculated as 290.1 tpy. Both the "Max Month Basis" emission rate and "Avg Year Basis" emission rate are used for the emissions reductions estimates and control cost calculations presented in the remainder of this section.

Table 5-2. 2017-2019 Monthly NO_X Emissions for No. 3 Power Boiler

Month / Year	Monthly Total NO_X Emission Rate (ton/month)	Annual Total NO_X Emission Rate (tpy)
1/2017	10.85	256.96
2/2017	17.77	
3/2017	19.57	
4/2017	22.48	
5/2017	23.16	
6/2017	12.58	
7/2017	15.19	
8/2017	35.15	
9/2017	22.52	
10/2017	27.03	
11/2017	30.61	
12/2017	20.04	
1/2018	36.46	329.39
2/2018	25.51	
3/2018	36.02	
4/2018	25.56	
5/2018	31.60	
6/2018	20.48	
7/2018	24.75	
8/2018	26.42	
9/2018	15.54	
10/2018	17.76	
11/2018	42.35	
12/2018	26.93	
1/2019	49.73	284.07
2/2019	26.37	
3/2019	32.84	
4/2019	19.18	
5/2019	20.53	
6/2019	14.51	
7/2019	18.62	
8/2019	14.29	
9/2019	11.47	
10/2019	17.18	
11/2019	31.32	
12/2019	28.03	

Table 5-3 summarizes the controlled emission rates and emission reduction potentials based on the control efficiencies from Table 5-1 for the technically feasible NO_X reduction options for the No. 3 Power Boiler.

Table 5-3. Emissions of NO_X Emissions Reduction Options for No. 3 Power Boiler

NO_X Reduction Option	Max Month Basis		Avg Year Basis	
	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
SNCR	578.8	17.90	281.4	8.70

5.4. Time Necessary for Implementation

EPA has allowed for five (5) years for the implementation of add-on NO_X controls such as SNCR in at least two FIPs (e.g., for Utah and North Dakota). Domtar would request the same timeline if SNCR were required for either of its power boilers.

5.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 3 Power Boiler; it is needed in order to meet the steam demands of the Ashdown Mill processes. The useful life values found in EPA's CCM are assumed to be applicable.

5.6. Energy and Non-air Quality Environmental Impacts

The energy impacts (which are monetized) and non-air quality environmental impacts for SNCR, principally related to the storage and handling of ammonia/urea, are well known. They are expected to be no greater at the Ashdown Mill than any other industrial facility and are therefore not considered as a reason for rendering the control options infeasible in this context.

5.7. Costs

The cost estimates used in the 1PP for the No. 2 Power Boiler (for the 27.5 % control efficiency scenario) are taken to be representative for the purposes of this ICR response. Table 5-4 summarizes these estimated costs, including the cost effectiveness estimates based on the emission reduction values from Table 5-3, for SNCR for the No. 3 Power Boiler.

Table 5-4. Estimated Costs (2018 Basis) of NO_X Emissions Reduction Options for No. 3 Power Boiler

NO_X Reduction Option	Capital Costs ($)	Annualized Capital Costs ($/year)	Annual Direct and Indirect / Operations and Maintenance Costs ($/year)	Total Annual Costs ($/year)	Max Mont Basis Cost Effectiveness ($/ton)	Avg Year Basis Cost Effectiveness ($/ton)
SNCR	2,766,541	222,946	647,326	870,271	48,614	99,983

The ICR did not list any specific SO_2 emissions reduction options for consideration for the recovery boilers. Trinity queried the Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) and reviewed information from the National Council for Air and Stream Improvement (NCASI) and its own library of air pollution control assessments (e.g., from previous BACT determinations) to determine what SO_2 emissions reduction options may be feasible for recovery boilers. Two potential strategies emerge from this research:

- Good operating practices, i.e., optimizing liquor properties and combustion air firing patterns
- Flue gas desulfurization (FGD)

6.1. Technical Feasibility

NCASI states in its 2013 Handbook:

> *The combustion of black liquor in a kraft recovery furnace results in SO_2 emissions that are extremely variable. These emissions depend on a variety of factors, which include a) liquor properties such as sulfidity (or sulfur-to-sodium ratio), heat value, and solids content; b) combustion air and liquor firing patterns; c) furnace design; and d) other furnace operational parameters (NCASI 1991). Liquor sulfidity in most kraft mills today is low enough that it is no more considered a determining factor for SO_2 emissions (NCASI 1991). Optimizing liquor properties (such as solids content, Btu value) and combustion air firing patterns so as to yield maximum and uniform temperatures in the lower furnace are currently considered the best strategies for minimizing kraft recovery furnace SO_2 emissions. Flue gas desulfurization is capital- and energy-intensive and its efficacy is unproven, considering the generally low but rapidly fluctuating levels of SO_2 in kraft recovery furnace flue gases.*[10]

An RBLC query[11] confirms NCASI's statements about FGD being unproven on recovery boilers as no determinations for this technology on recovery boilers were found. Because FGD has not been applied to recovery boilers, it is considered unavailable and therefore infeasible for the No. 2 Recovery Boiler.

Domtar employs good operating practices, including those listed by NCASI, for the No. 2 Recovery Boiler.

6.2. Control Effectiveness

Good operating practices is taken to be the base case. The baseline actual SO_2 emission rate presented below considers the good operating practices in place for the No. 2 Recovery Boiler.

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[10] NCASI Handbook of Environmental Regulations and Control, Volume 1: Pulp and Paper Manufacturing, April 2013, Section 6.8.3.3. (Copies of NCASI materials must be requested from NCASI directly).

[11] RBLC searches were completed on February 3, 2020 for Process Types 30.211, 30.219, 30.290, 11.190, 11.290, and 11.900 and for Process Names that contain the word "Recovery".

6.3. Emissions Reductions

Per the ICR, the baseline actual SO_2 emission rate is the maximum monthly value from 2017 to 2019, which, based on CEMS records, is 3.1 tons/month, which equivalent to 36.8 tpy. Additionally, because it serves as a more appropriate basis for annual control cost calculations, the average of the three (2017, 2018, and 2019) annual total emission rates, 2.6 tpy, is also noted.

The continued employment of good operating practices will result in zero (0) emissions reduction.

6.4. Time necessary for Implementation

No time is needed to implement good operating practices.

6.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 2 Recovery Boiler; it is needed in order to meet the chemical recovery and steam demands of the Ashdown Mill processes.

6.6. Energy and Non-air Quality Environmental Impacts

Good operating practices result in no new energy or non-air quality environmental impacts.

6.7. Costs

There is no new cost associated with good operating practices already being used.

The ICR did not list any specific NO_X emissions reduction options for consideration for the recovery boilers. Trinity queried the RBLC and reviewed information from NCASI and its own library of air pollution control assessments (e.g., from previous BACT determinations) to determine what NO_X emissions reduction options may be feasible for recovery boilers. Three strategies emerge from this research:

- Good combustion practices, i.e., staged air combustion
- SNCR
- SCR

7.1. Technical Feasibility

NCASI states in its 2013 Handbook:

> *… NO_X emissions from black liquor combustion in kraft recovery furnaces are expected to result mainly from the "fuel NO_X" mechanism pathway. The highest temperatures measured in the recovery furnace, usually in the lower furnace region, range from about 1800°F to 2400°F. These are much lower than would be essential for appreciable NO_X formation by the thermal NO_X pathway (>2,800°F). Hence, factors that would aid in reducing peak gas temperatures in the lower furnace, such as the firing of lower solids content liquors, reducing combustion air temperature and pressure, changes in burner design and position, and reduced liquor feed temperature perhaps have only a limited role in controlling NO_X formation.*
>
> *A detailed investigation into the origins of kraft recovery furnace NO_X emissions and related parameters by NCASI concluded that black liquor N content was perhaps the most important factor affecting NO_X emissions from kraft recovery furnaces (NCASI 1992). Excess oxygen in the zone where the bulk of liquor combustion takes place was considered the second most important factor for NO_X formation. While very little can be done to affect the liquor nitrogen content, staged air combustion, which is already integral to the operation of most recovery furnaces, is perhaps the best strategy for minimizing NO_X formation. The precise distribution of combustion air between primary, secondary and, if relevant, tertiary or quaternary air levels is most likely quite furnace-specific…*
>
> *The above mentioned NCASI report on recovery furnace NO_X emissions (NCASI 1992) contained longterm continuous emissions monitoring data for NO_X emissions from several kraft recovery furnaces. These data showed the NO_X emissions fell within a fairly narrow range for each furnace, in spite of apparent, significant day-to-day changes in furnace operating behavior as suggested by the corresponding, widely fluctuating data for SO_2 and CO emissions. This lack of significant variability in a given recovery furnace's NO_X emissions would suggest most furnaces already utilize the concepts of staged combustion optimally, and the differences observed between one mill's furnace NO_X emissions and another's are mainly a result of the differences between their black liquor N contents…*
>
> *Relative to flue gas treatment as an (sic) NO_X control option, selective non-catalytic reduction (SNCR) is not considered technologically feasible for kraft recovery furnaces (Kravett and Hanson 1994). This conclusion was based on the fact that a recovery furnace is a complex chemical reaction system and any disruption of the delicate reaction chemistry could potentially damage the*

> *furnace, impact the quality of the product, or otherwise unacceptably affect the system. Also, like industrial boilers, kraft recovery furnaces operate at varying loads which makes it difficult to inject the SNCR reagent within the desired temperature window. Several technological limitations also come to bear when one considers the installation of a selected catalytic reduction (SCR) system on a recovery furnace: a) potential for plugging and fouling of the SCR catalyst, b) potential for fouling of the ESP, c) ammonia handling and ammonia slip emissions issues, d) potential for increased particulate emissions, e) creation of a new hazardous waste (spent catalyst), and f) potential significant energy penalty (Kravett and Hansen 1994).*[12]

An RBLC query[13] confirms NCASI's statements about SCR and SNCR being infeasible on recovery boilers as no determinations for these technologies on recovery boilers were found.[14] For the technical reasons described above, and because SCR and SNCR have not been applied to recovery furnaces, these control options are infeasible for the No. 2 Recovery Boiler.

7.2. Control Effectiveness

Good combustion practices is taken to be the base case. The baseline actual NO_X emission rate presented below considers the good combustion practices in place for the No. 2 Recovery Boiler.

7.3. Emissions Reductions

Per the ICR, the baseline actual NO_X emission rate is the maximum monthly value from 2017 to 2019, which, based on CEMS records, is 46.1 tons/month, which equivalent to 553.7 tpy. Additionally, because it serves as a more appropriate basis for annual control cost calculations, the average of the three (2017, 2018, and 2019) annual total emission rates, 491.1 tpy, is also noted.

The continued employment of good combustion practices will result in zero (0) emissions reduction.

7.4. Time necessary for Implementation

No time is needed to implement good combustion practices.

7.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 2 Recovery Boiler; it is needed in order to meet the chemical recovery and steam demands of the Ashdown Mill processes.

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[12] NCASI Handbook of Environmental Regulations and Control, Volume 1: Pulp and Paper Manufacturing, April 2013, Section 6.8.3.4

[13] RBLC searches were completed on February 3, 2020 for Process Types 30.211, 30.219, 30.290, 11.190, 11.290, and 11.900 and for Process Names that contain the word "Recovery"

[14] There is one RBLC entry for SNCR on Recovery Boilers – for Apple Grove Pulp and Paper Company (RBLC ID WV-0016) – but according the RBLC's "Other Permitting Information" note for this entry, this facility was never built.

7.6. Energy and Non-air Quality Environmental Impacts

Good combustion practices result in no new energy or non-air quality environmental impacts.

7.7. Costs

There is no new cost associated with good combustion practices already being used.

8. No. 3 Recovery Boiler – SO_2

See Section 6. All statements that apply to the No. 2 Recovery Boiler also apply to the No. 3 Recovery Boiler except for the baseline actual emission rate, which is recorded below for the sake of completeness.

Per the ICR, the baseline actual SO_2 emission rate is the maximum monthly value from 2017 to 2019, which, based on CEMS records, is 1.0 tons/month, which equivalent to 12.0 tpy. Additionally, because it serves as a more appropriate basis for annual control cost calculations, the average of the three (2017, 2018, and 2019) annual total emission rates, 3.2 tpy, is also noted.

9. No. 3 Recovery Boiler - NO_X

See Section 7. All statements that apply to the No. 2 Recovery Boiler also apply to the No. 3 Recovery Boiler except for the baseline actual emission rate, which is recorded below for the sake of completeness.

Per the ICR, the baseline actual NO_X emission rate is the maximum monthly value from 2017 to 2019, which, based on CEMS records, is 64.1 tons/month, which equivalent to 769.5 tpy. Additionally, because it serves as a more appropriate basis for annual control cost calculations, the average of the three (2017, 2018, and 2019) annual total emission rates, 623.7 tpy, is also noted.

APPENDIX A: 1PP SIP PACKAGE INFORMATION RELATED TO NO. 2 POWER BOILER SO_2 EMISSIONS REDUCTION OPTIONS

LUNDBERG

13201 Bel-Red Road
Bellevue, Washington 98005
tel: 425.283.5070
fax: 425.283.5081

April 17, 2014

Reference: P-125387, Rev.01

Attention: Ms. Kelley Crouch

Subject: SO_2 Scrubber for Power Boiler No. 2

Domtar Industries, Inc.
285 Highway 71 S
Ashdown, AR 71822-8356

Dear Ms. Crouch:

In response to your recent request, Lundberg is pleased to submit the following revised budget proposal for the supply of an SO_2 scrubbing system No. 2 power boiler at the Ashdown Mill. As you know, the original June, 2012 proposal included an SO_2 scrubbing system and a wet ESP for particulate control. In this revision the wet ESP has been eliminated.

As before, the proposal is to supply add-on spray scrubbers downstream of the existing venturi scrubbers. The spray scrubbers will utilize sodium hydroxide to absorb $SO_{2.}$ The design efficiency for the scrubbers will continue to be 90% and all other process considerations addressed in the first proposal will remain the same.

The only significant change in the scrubber design is that we have changed to an upflow configuration. Without a downstream wet ESP operation in the upflow mode will save some cost because the gas can discharge directly out the top of the scrubber.

If you have any questions about the proposal, please feel free to me a call at 425/283-5070.

Thank you for the opportunity to present this proposal. We look forward to working with you on this project.

Sincerely,

Steven A. Jaasund, P.E.

Manager—Geoenergy Products
Lundberg

enc: Proposal

cc: Mr. Eric Gardner, Lundberg/ Monroe, LA
Mr. Rudi Miksa, Lundberg/Monroe, LA

P-125387, Rev.01

April 17, 2014

LUNDBERG

BUDGET PROPOSAL

SPRAY SCRUBBER

DOMTAR INDUSTRIES

ASHDOWN AR

Our representative in your area:

Mr. Eric Gardner
210 Pinehurst Drive
Monroe, LA 71201
Phone: 318/366-5909

Mr. Rudi Miksa
P.O. Box 7266
Monroe, LA 71211
Phone: 318/361-0165

PRESENTED BY: Steven A. Jaasund, P.E.

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INTRODUCTION

Lundberg proposes to supply an add-on spray scrubber for the control of SO_2 emissions from the No. 2 power boiler at the Domtar Industries Pulp Mill in Ashdown, Arkansas.

The proposal includes two identical gas cleaning trains each including a spray scrubber.

PROCESS DESCRIPTION

The spray scrubber/wet ESP trains will be installed downstream of the existing venturi scrubbers and will utilize the main boiler fan on a forced draft basis. We anticipate a maximum of 3 inches w.c. will be necessary to overcome the added resistance of the add-on equipment. If this additional pressure is not available from the existing fan, the capacity can be gained by reducing the pressure drop through your existing scrubber an appropriate amount. This pressure drop reduction will not have a significant effect on the size requirements of the new wet ESP.

The spray scrubbers will be an upflow design utilizing downward facing spray headers to maximize liquid to gas contact. The unit will operate at a liquid to gas ratio of 20 gal/1000 acf and will utilize a pH adjusted scrubbing solution to affect a minimum of 90% SO_2 absorption. Sodium hydroxide will be used to maintain pH at the required level.

After exiting the spray scrubbers, the gas streams will exit directly out of the top through a stub stack.

A process flow diagram and a general arrangement drawing for the system proposed are included in the appendix of this proposal.

DESIGN BASE

The following process information will be used for the design of the spray scrubber/wet ESP system.

NO. 2 POWER BOILER DESIGN CONDITIONS	
Fuel	Coal, bark, natural gas, TDF, (planning on fuel oil in future)
Boiler Type	Stoker
Volumetric Gas Flow (scfm dry)	142,737
Scrubber Exit Gas Temp. (°F)	136
Exit Moisture (% wt)	12.3
PM Loading (lb/hr)	44.6
SO2 Concentration (ppmv)	235.9

The spray scrubber/wet ESP equipment offered will be designed to reduce the SO_2 concentration by 90%.

ENERGY REQUIREMENTS

The following table shows the expected energy demands of the wet ESP system described in this proposal.

SPRAY SCRUBBER ENERGY REQUIREMENTS	
Scrubber pumps (kW)	108
Flange to flange pressure drop (in. w.c.)	3

Proposed Supply

The following list summarizes the major components of the systems offered to treat the emissions from the power boiler.

ITEM	QUANTITY	DESCRIPTION
1	One (1) lot	System Engineering, including process flow diagrams, process and instrument diagrams, general arrangement drawings, functional narrative of the logic, assembly drawings, instrument specifications, pump specifications, and operation and maintenance manual complete with spare parts lists
2	Two (2) only	Spray scrubbers; T-316L SS, upflow design with recycle pump, tank and piping
3	Two (2) only	Discharge stacks; T-316L SS
4	Two (2) lots	Support and access steel
5	Two (2) lots	Field instrumentation
6	One (1) lot	Commissioning, start-up and training
7	One (1) lot	Local wiring of all electrical elements
8	One (1) lot	Complete mechanical installation

Commercial terms and Conditions

Clarifications and Work by Others

1. Ducting from the existing scrubber to the inlet flange of the spray scrubbers is not included
2. The cost of a crane to lift the equipment offered to the top of the No. 2 boiler building is not included
3. Structural steel to the bottom of the spray scrubbers is not included. Structural and access steel above this level is included.
4. Civil work or improvements to existing structures is not included. Lundberg will provide foundation-loading information.
5. Performance testing is not included
6. Lundberg will require access to mill drawings and records required to design the proposed system.
7. The client is responsible for obtaining all necessary building/environmental permits, taxes and professional engineering fees.
8. The client is to provide a lay down area close to the work site, as well as field fabrication area for piping, etc.
9. The client is to supply steam and process water as required by the erection crew free of charge. Also parking area, trailer space(s), and access to phone lines. Phone line hookup will be by Lundberg. Lundberg is to supply electrical power for construction.
10. Construction crews may be union or non-union.
11. The client is responsible for the removal, handling, disposal, or replacement of all asbestos materials, lead paint, or contaminated soils that may be encountered.
12. The client is to provide an on-site location for construction debris.
13. Any required demolition work is not included in our bid.

Price

The budget price for the spray scrubber system, Items 1-7, is:

Two million fifty thousand dollars

$2,050,000.00

These prices are FOB mill site. Prices do not include applicable taxes. All prices are in U.S. dollars.

The purchaser assumes liability for payment to the state of any Sales or Use tax if he uses or consumes the property herein purchased in such a way as to render the sale subject to tax.

Terms of Payment

The terms of payment shall be:

- 5% with purchase order.
- 10% with submittal of approval drawings (process flow sheets, equipment drawings and general arrangements.
- 25% with order placed for major equipment (WESP) .
- 10% on delivery of 10" diameter collection electrodes to the shop.
- 5% on construction mobilization.
- 15% on delivery of WESP to the mill; partial shipment allowed.
- 25% on monthly percent completion of construction.
- 5% on satisfaction of performance warranty on each unit, not to exceed six (6) months from shipment. This may be secured by a letter of credit at Lundberg's option, and due at shipment.

Payment will be due thirty (30) days after date of invoice.

Erection Advisor

If the Buyer elects to be responsible for the installation of the equipment the services of a qualified erection advisor can be made available at a rate of $1350.00 per man day (man day being ten (10) hours) plus expenses. Charges after ten (10) hours will be $170.00 per hour. Expenses are to include first class food and lodging, economy travel to and from plant site to lodging, and travel to and from project from the normal domicile of the engineer.

Training Services

Training is included as a part of the equipment package. The additional services of a trainer can be made available at a rate of $1,500.00 per man day (man day being eight (8) hours) plus expenses. Charges after eight (8) hours will be $210.00 per hour. Expenses are to include first class food and lodging, economy travel to and from plant site to lodging, and travel to and from project from the normal domicile of the engineer.

Start-Up Services

Start-up services are included as a part of the equipment package. The additional services of an engineer can be made available at a rate of $1350.00 per man day (man day being ten (10) hours), plus expenses. Charges after ten (10) hours will be $170.00 per hour. Expenses are to include first class food and lodging, economy travel to and from plant site to lodging, and travel to and from project from the normal domicile of the engineer.

Shipment

Shipment will be made twenty-six (26) weeks after receipt of order. Shipment schedule requires that approval drawings, when submitted, will be returned within two (2) weeks. The time to complete erection is very dependent on site conditions. Normally equipment of this size can be installed in less than 8 weeks.

Cancellation

Should Purchaser place an order for the equipment proposed and later find it necessary to cancel, Purchaser shall pay the full amount for any equipment, portions thereof, or orders for which Vendor is liable, plus charges for engineering work completed at that time, plus fifteen (15) percent of the total costs incurred.

Performance Warranty

Lundberg will provide the equipment and process engineering as specified in this proposal for a complete and operable system and guarantee that the inlet SO_2 concentration will be reduced by 90% but no lower than 20 ppmv.

This guarantee is in effect when the system is operated in and supplied with the service conditions in general accordance with the Design Base of this proposal.

US EPA Method 1, 2, 3, 4, and 6 shall be used to quantify the SO_2 concentration at the outlet of the equipment.

Acceptance tests must be performed within three (3) months after initial start-up of the equipment, not to exceed six (6) months after final shipment. The testing shall be performed by an independent third party that is acceptable to both Buyer and Seller.

The warranty shall be fully satisfied and Lundberg discharged there from upon the earlier of: (a) obtaining guaranteed performance by the testing described above, (b) the expiration of three (3) months from initial start-up with no testing being made, (c) the expiration of six (6) months from final shipment without a test being made.

If the guaranteed performance is not obtained, then Lundberg shall have the right, and if required by the Owners, the obligation, to visit the installation to determine the cause of such failure. It is a condition of this guarantee that the Owner will cooperate with Lundberg in the making of further tests and make available necessary personnel, feed and operating conditions to enable Lundberg to conduct such tests. The tests will be paid for by the purchaser.

If failure to obtain guaranteed performance on the above is due to defect in Lundberg-supplied equipment, design, or engineering, then Lundberg will, at its expense, supply the equipment or process engineering it deems necessary until such performance is met, up to a limit of the contract price. Any remedy includes an equivalent scope of installation as outlined elsewhere in this proposal.

If failure to obtain guaranteed performance is due to the Purchaser's fault in operation, or in not providing proper feed or other specified operating conditions, the Owner shall pay the living and traveling expenses of Lundberg personnel visiting the installation. In addition, the Owner shall pay the sum of $1,300.00 per man-day or fraction thereof for such personnel. Nevertheless, such personnel will, on request, work with the Owner at the Owner's expense in making necessary corrections to accommodate the changed conditions.

Material and Workmanship

We guarantee every part of the apparatus delivered in accordance with this proposal will be of proper material and workmanship, and agree to repair any part or parts which may prove defective in material or workmanship within twelve months from startup of equipment but not to exceed eighteen months from date of shipment on each unit, it being agreed that such replacement is the full extent of our liability in this connection. Scope of supply of such replacement shall be identical to the scope of supply of the original project. Corrosion or wear from abrasion shall not be considered as defective materials. The best engineering practice will always be followed and materials used will be clearly specified. We shall not be held liable or responsible for work done or expense incurred in connection with repairs, replacements, alterations, or additions made, except on our written authority.

Vendor's Responsibility

In the course of design of processes and/or equipment where the Vendor provides process flow diagrams, layouts, and installation diagrams, it is anticipated that Vendor furnished design will be followed. Changes in design without written approval of the Vendor will relieve the Vendor of responsibility for performance of the supplied equipment.

Drawings Limitation

All Vendor drawings supplied to the customer or his engineer under an order resulting from this proposal will remain the property of the Vendor and are conditionally loaned with the understanding that they will not be copied or used except as authorized by us. Reuse of the designs as shown on the drawings for another project is specifically prohibited.

Confidentiality of Proposal Information

This proposal contains confidential information and remains the property of Lundberg and is conditionally loaned. The information contained herein is not to be shared with any party except those within the Buyer's company who are involved in its evaluation or outside consultants who are assisting the Buyer with this specific project. Specifically prohibited is the distribution of such information to any individual or business deemed to be a competitor by Lundberg.

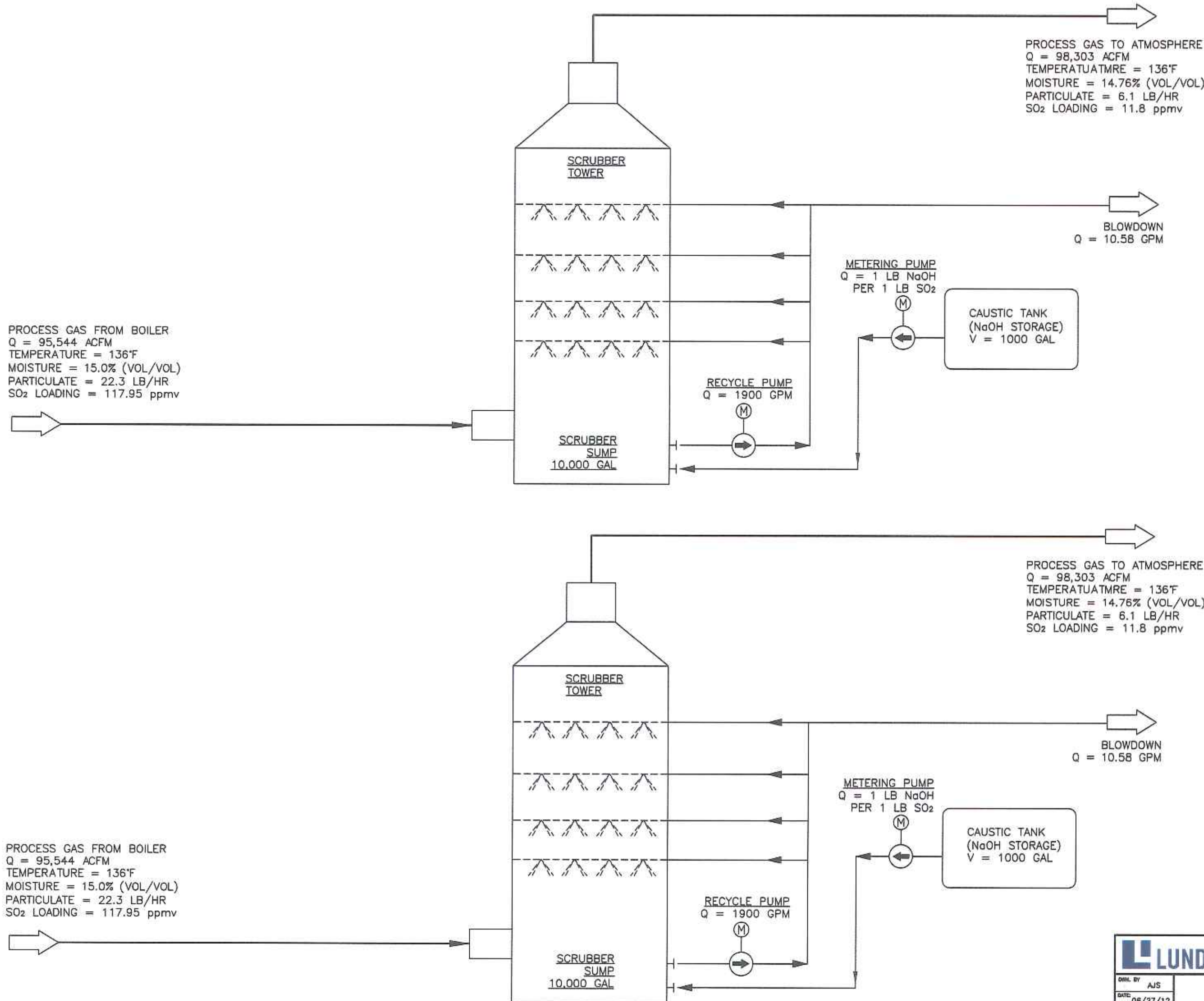
Security Interest

Lundberg reserves the right to request a security interest in the materials provided as a part of this proposal, and Buyer agrees to provide information needed to assist Lundberg in obtaining a security interest and to execute such documents Lundberg reasonably requests to create a security interest. Security interest language is available on request.

Enclosures

General Arrangement Drawing

Process Flow Diagram



DESCRIPTION	DRAWING NO.
REFERENCE	

REV.	DESCRIPTION	BY	DATE	CHK	DATE	REV.	DESCRIPTION	BY	DATE	CHK	DATE
	REVISIONS						REVISIONS				

LUNDBERG

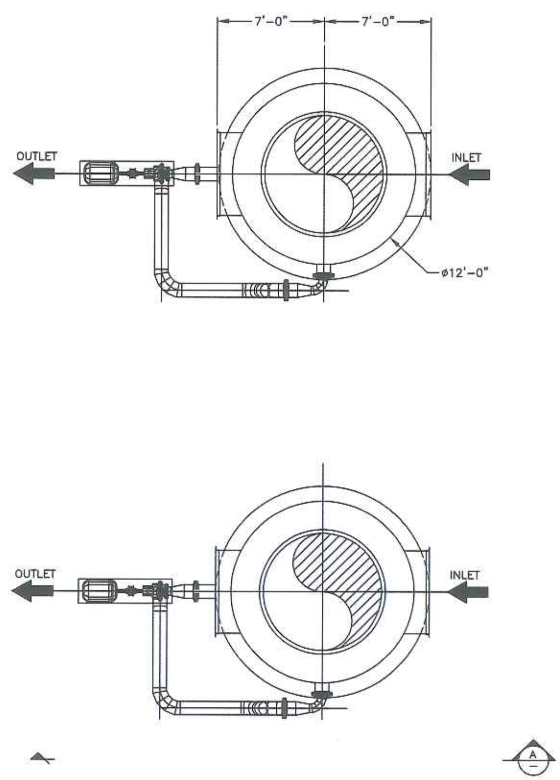
DRN. BY AJS
DATE: 08/27/12
CHK. BY
DATE:
APP. BY
DATE:

DOMTAR
ASHDOWN, ARKANSAS
BOILER #2 EMISSIONS

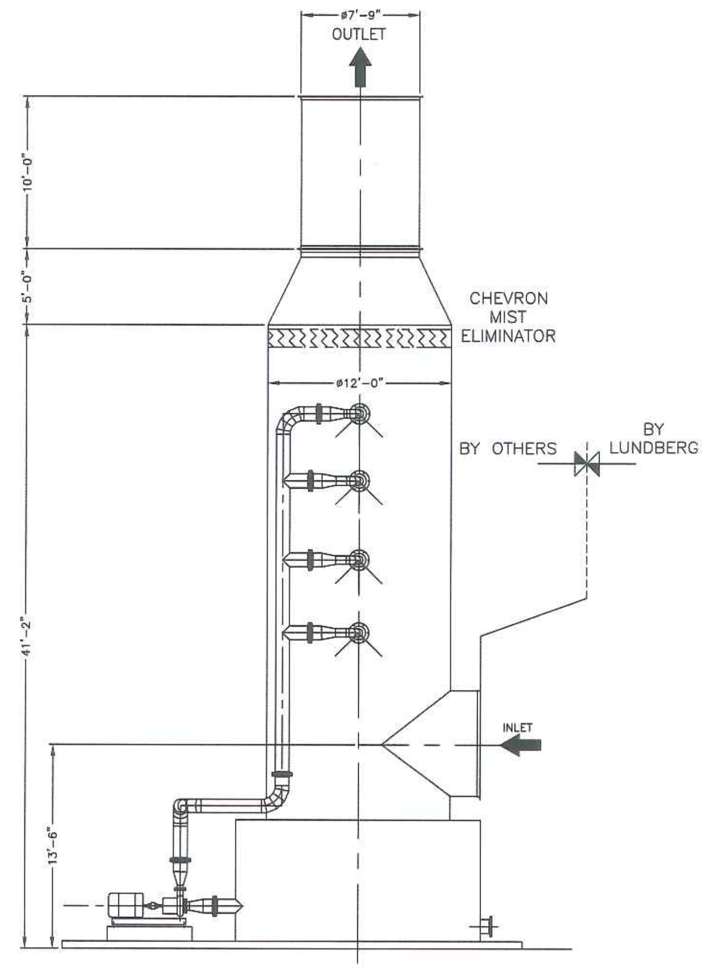
MODEL 1200 SPRAY TOWER SCRUBBER
PROCESS FLOW DIAGRAM

SCALE:	DRAWING NO.	SHT.	REV.
1/4"=1'-0"	AL-125387-P01	1/1	01

DWG. NO. AL-125387-P01 SHT. 1/1



MODEL 1200 SPRAY TOWER SCRUBBER
PLAN VIEW
BOILER # 2 EMISSIONS



MODEL 1200 SPRAY TOWER SCRUBBER
ELEVATION VIEW
BOILER # 2 EMISSIONS

LUNDBERG

DWN. BY AJS	DOMTAR ASHDOWN, ARKANSAS BOILER #2 EMISSIONS
DATE: 06/27/12	
CHK. BY	
DATE:	MODEL 1200 SPRAY TOWER SCRUBBER GENERAL ARRANGEMENT
APP. BY	
DATE:	SCALE: 1/4"=1'-0" · DRAWING NO. AL-125387-P03 · SHT. 1/1 · REV. 01

REV.	DESCRIPTION	BY	DATE	CHK	DATE	REV.	DESCRIPTION	BY	DATE	CHK	DATE

REVISIONS REVISIONS

DESCRIPTION	DRAWING NO.

REFERENCE

DWG. NO. AL-125387-P03 SHT. 1/1

because it has not been fully demonstrated for this source type and incorporates FGR, which is technically infeasible for use at the boiler. The installation and operation of SNCR is projected to result in some visibility improvement at the Class I areas. As discussed in more detail above, we concur with Domtar's position that 20% removal efficiency is the most reasonable estimate of the level of NO_X control SNCR can achieve at Power Boiler No. 1. When operated at 20% removal efficiency, SNCR is projected to result in visibility improvement of up to 0.061 dv at any single Class I area and is estimated to cost $12,700/ton of NO_X removed. We do not believe this high cost justifies the modest visibility improvement projected from the installation and operation of SNCR at 20% removal efficiency. Although there is uncertainty as to whether SNCR can achieve a long term removal efficiency of 45% or even 32.5% at Power Boiler No. 1, we believe that the associated costs are also too high and not justified by the projected visibility benefits. Installation and operation of SNCR at a 45% removal efficiency is projected to result in a visibility improvement of up to 0.136 dv at any single Class I area and is estimated to cost $7,640/ton of NO_X removed. The operation of SNCR at a 32.5% removal efficiency is projected to result in visibility improvement of up to 0.098 dv at any single Class I area and is estimated to cost $7,996/ton of NO_X removed. Therefore, we are proposing to determine that NO_X BART for Power Boiler No. 1 is no additional control and are proposing that an emission limit of 207.4 lb/hr on a 30 boiler-operating-day rolling average satisfies NO_X BART. In this particular case, we are defining boiler-operating-day as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the Power Boiler. Power Boiler No. 1 is not currently equipped with a CEMS. To demonstrate compliance with this NO_X BART emission limit we are proposing to require annual stack testing. We are inviting public comment on the appropriateness of this method for demonstrating compliance with the NO_X BART emission limit for Power Boiler No. 1. Since this proposed BART determination does not require the installation of control equipment, we are proposing that this NO_X emission limit be complied with by the effective date of the final action.

d. SO_2 BART Evaluation for Power Boiler No. 2

Step 1- Identify All Available Retrofit Control Technologies

Power Boiler No. 2 is currently equipped with two venturi wet scrubbers in parallel for removal of particulates and SO_2. Domtar's 2014 BART analysis evaluated upgrades to the existing venturi wet scrubbers and new add-on scrubbers for Power Boiler No. 2.[96] Domtar contracted with a vendor to evaluate upgrades to the existing venturi scrubbers and to provide a quote for a new add-on spray scrubber system that would be installed downstream of the existing

[96] See "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis is found in the docket for our proposed rulemaking.

venturi scrubbers.[97] Domtar's analysis states that the existing venturi scrubbers achieve an SO_2 control efficiency of approximately 90% and notes that this is within the normal range for the highest efficiency achieved by SO_2 control technologies. Domtar's analysis also indicates that the upgrades considered for the existing venturi scrubbers include (1) the elimination of bypass reheat, (2) the installation of liquid distribution rings, (3) the installation of perforated trays, (4) improvements to the auxiliary system requirement, and (5) a redesign of spray header and nozzle configuration.

Another option not evaluated in Domtar's 2014 BART analysis is the operation of the existing venturi scrubbers to achieve a higher SO_2 control efficiency than what is currently being achieved through the use of additional scrubbing reagent. Following discussions between us and Domtar, the facility provided additional information regarding the existing venturi scrubbers, including a description of the internal structure of the scrubbers, whether any scrubber upgrades have taken place, the type of reagent used, how the facility determines how much reagent to use, and the SO_2 control efficiency.[98] Domtar confirmed that no upgrades to the scrubbers have ever been performed and stated that 100% of the flue gas is treated by the scrubber systems. The scrubbing solution used in the venturi scrubbers is made up of three components: 15% caustic solution (*i.e.*, NaOH), bleach plant EO filtrate (typical pH above 9.0), and demineralizer anion rinse water (approximately 2.5% NaOH). The bleach plant EO filtrate and demineralizer anion rinse water are both waste byproducts from the processes at the plant. The 15% caustic solution is added to adjust the pH of the scrubbing solution and maintain it within the required range to ensure that sufficient SO_2 is removed from the flue gas in the scrubber to meet the permitted SO_2 emission limit of 1.20 lb/MMBtu on a three hour average. Each venturi scrubber has a recirculation tank that is equipped with level control systems to ensure that an adequate supply of the scrubbing solution is maintained. There are pH controllers in place that provide signals for the 15% caustic flow controllers to adjust the flow of the caustic solution to bring the pH into the desired set point range. The pH controllers are overridden in the event that SO_2 levels measured at the stack by the CEMS are above the operator set point of 0.86 lb/MMBtu on a two hour average (the SO_2 permit limit is 1.20 lb/MMBtu on a three hour average). This allows additional caustic feed to the scrubber solution to increase the pH and reduce the SO_2 measured at the stack. According to Domtar, the scrubber systems operate in this manner to maintain continuous compliance with permitted emission limits.

Domtar provided monthly average data for 2011, 2012, and 2013 on monitored SO_2 emissions from Power Boiler No. 2, mass of the fuel burned for each fuel type, and the percent

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[97] The information provided by the vendor to Domtar is found in Appendix D to the analysis titled "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC.

[98] See the following: Letters dated July 9, 2014; July 21, 2014; August 15, 2014; August 29, 2014; and September 12, 2014, from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. Copies of these letters and all attachments are found in the docket for our proposed rulemaking.

sulfur content of each fuel type burned.[99] According to the data provided by Domtar, the monthly average SO_2 control efficiency of the existing scrubbers for the 2011-2013 period ranged from 57% to 90%. The data indicate that the monthly average control efficiency of the scrubbers is usually below 90%. The information provided also indicates that the facility could add more scrubbing solution to achieve greater SO_2 removal than what is necessary to meet permit limits.

Based on our discussions with Domtar and the additional information provided to us, we believe it is technically feasible to increase the current SO_2 control efficiency of the existing scrubbers from current levels to 90% on a monthly average basis through the use of additional scrubbing reagent.

Step 2- Eliminate Technically Infeasible Options

Domtar's analysis discusses that the vendor determined that any upgrades to the existing venturi scrubbers for purposes of achieving additional SO_2 control would involve efforts to increase pressure drop. Additionally, it determined that any additional control that could potentially be achieved from implementation of such upgrades would be marginal, but Domtar was unable to quantify the potential additional control. Therefore, Domtar determined that the installation of new add-on scrubbers to operate downstream of the existing scrubbers was more feasible than any upgrade option. The remainder of Domtar's analysis focused on the add-on scrubber option only.

Additionally, as discussed above, based on our discussions with Domtar and the additional information Domtar provided to us, we determined it would be technically feasible to increase the current control efficiency of the existing scrubbers through the use of additional scrubbing reagent. We evaluate this control option in this TSD.

Step 3- Evaluate Control Effectiveness of Remaining Control Technologies:

Based on the information provided to Domtar by the vendor, new add-on spray scrubbers were estimated to achieve 90% control efficiency on top of the SO_2 removal currently achieved by the existing venturi scrubbers. In Domtar's analysis, it was estimated that a controlled SO_2 emission rate of 78.8 lb/hr would be achieved by the operation of add-on spray scrubbers installed downstream of the existing venturi scrubbers.

To estimate the current control efficiency of the existing venturi scrubbers, we asked Domtar to provide monthly average data for 2011, 2012, and 2013 on monitored SO_2 emissions from Power Boiler No. 2, mass of the fuel burned for each fuel type, and the percent sulfur

[99] August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. A copy of this letter and an Excel file attachment titled "Domtar 2PB Monthly SO2 Data," are found in the docket for our proposed rulemaking.

content of each fuel type burned.[100] Based on the information provided by Domtar, the monthly average SO_2 control efficiency of the existing scrubbers for the 2011-2013 period ranged from 57% to 90%. The data indicate that the monthly average control efficiency of the scrubbers is usually below 90%. Based on the monthly average SO_2 control efficiency data for the 2011-2013 period, we estimated the annual average SO_2 control efficiency for the three-year period to be approximately 69%.[101]

To determine the controlled emission rate that corresponds to the operation of the existing venturi scrubbers at a 90% removal efficiency, we first determined the SO_2 emission rate that corresponds to the operation of the scrubbers at the current control efficiency of 69%. Based on emissions data we obtained from Domtar, we determined that the No. 2 Power Boiler's annual average SO_2 emission rate for the years 2009-2011 was 280.9 lb/hr.[102] This annual average SO_2 emission rate corresponds to the operation of the scrubbers at a 69% removal efficiency. We also estimated that 100% uncontrolled emissions would correspond to an emission rate of approximately 915 lb/hr. Application of 90% control efficiency to this results in a controlled emission rate of 91.5 lb/hr, or 0.11 lb/MMBtu based on the boiler's maximum heat input of 820 MMBtu.[103]

Step 4- Evaluate Impacts and Document the Results

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

Domtar's estimates of the capital and operating and maintenance costs of add-on spray scrubbers for Power Boiler No. 2 were based on the equipment vendor's budget proposal and on calculation methods from our Control Cost Manual. Domtar annualized the capital cost of the add-on spray scrubbers over a 30-year amortization period and then added these to the annual

[100] August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. A copy of this letter and an Excel file attachment titled "Domtar 2PB Monthly SO2 Data," are found in the docket for our proposed rulemaking.

[101] See the spreadsheet titled "Domtar 2PB Monthly SO2 Data." This spreadsheet was included as an attachment to the August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "Domtar PB No2- Cost Effectiveness calculations." Copies of these documents can be found in the docket for this proposed rulemaking.

[102] See the spreadsheet titled "Domtar 2PB Monthly SO2 Data." This spreadsheet was included as an attachment to the August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "No2 Boiler_Monthly Avg SO2 emission rate and calculations." Copies of these documents can be found in the docket for this proposed rulemaking.

[103] See the spreadsheet titled "No2 Boiler_Monthly Avg SO2 emission rate and calculations." A copy of this spreadsheet can be found in the docket for this proposed rulemaking.

operating costs to obtain the total annualized cost.[104] The average cost-effectiveness in dollars per ton removed was calculated by dividing the total annualized cost by the annual SO_2 emissions reductions. The average cost-effectiveness of the add-on spray scrubbers for Power Boiler No. 2 was estimated to be $5,258/ton of SO_2 removed (see table below). Domtar's analysis notes that because of constricted space, there is no existing property or adequate structure to support the add-on spray scrubber equipment. In our discussions with Domtar, the facility indicated that the installation of add-on spray scrubbers would require construction at the facility to accommodate the equipment, but an estimate of these costs was not available and therefore not factored into the cost estimates presented in Domtar's analysis.

Table 69. Summary of Costs for Add-On Spray Scrubber for Power Boiler No. 2

Control Technology	Baseline Emission Rate (SO_2 tpy)	Controlled Emission Level (lb/hr)	Controlled Emission Rate (tpy)	Annual Emissions Reductions (SO_2 tpy)	Capital Cost* ($)	Annual Direct O&M Cost ($/yr)	Annual Indirect O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost Effectiveness ($/ton)
Add-on Spray Scrubber	2,078	78.8	208	1,870	7,175,000	8,833,382	421,789	9,833,378	5,258

* Capital cost does not include new construction to accommodate equipment.

Based on the cost information provided by the facility, increasing the monthly average SO_2 control efficiency of the existing venturi scrubbers from current levels to 90% control efficiency would require replacing two scrubber pumps, which involves capital costs of $200,000.[105] It would also require additional scrubbing reagent, treatment of additional wastewater, treatment of additional raw water, and additional energy usage, which involves annual operation and maintenance costs of approximately $1.96 million. We annualized the capital cost of the two scrubber pumps over a 30-year amortization period, assuming a 7% interest rate. We calculated the annualized capital cost to be $16,120, and added this to the annual operating costs to obtain a total annual costs of $1,976,554.[106]

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[104] See Appendices B and D to the "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC.

[105] September 30, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "Domtar PB No2- Cost of Using Additional Scrubbing Reagent. Copies of these documents can be found in the docket for this proposed rulemaking.

[106] See the Excel spreadsheet titled "Domtar PB No2- Cost of Using Additional Scrubbing Reagent" for line items of the capital and operation and maintenance costs associated with the use additional scrubbing reagent, and for calculation of the total annual cost. This spreadsheet can be found in the docket for this proposed rulemaking.

We calculated the average cost-effectiveness in dollars per ton removed by dividing the total annual cost by the estimated annual SO_2 emissions reductions. To estimate the SO_2 annual emissions reductions expected from increasing the control efficiency of the scrubbers through the use of additional scrubbing solution, we calculated the annual average SO_2 control efficiency of the existing scrubbers. As discussed above, based on data provided by Domtar for the 2011-2013 period, we estimated the annual average SO_2 control efficiency for the three-year period to be approximately 69%.[107] Considering the baseline annual emissions for Power Boiler No. 2 are 2,078 SO_2 tpy, and assuming that the scrubbers currently operate at an annual average control efficiency of 69%, we have estimated that the uncontrolled annual emissions would be 6,769 SO_2 tpy and that operating the scrubbers at 90% control efficiency would result in controlled annual emissions of 677 SO_2 tpy.[108] By subtracting the controlled annual emission rate of 677 SO_2 tpy from the baseline annual emission rate of 2,078 SO_2 tpy, we estimate that increasing the control efficiency of the existing venturi scrubbers from the current level of 69% to 90% control efficiency would result in annual emissions reductions of 1,401 SO_2 tpy.[109] We estimate the average cost-effectiveness of using additional scrubbing reagent to increase the SO_2 control efficiency of the existing venturi scrubbers from the current control efficiency (estimated to be 69%) to 90% is $1,411/ton of SO_2 removed. The cost information is presented in the table below.

Table 70. Summary of Cost of Using Additional Scrubbing Reagent to Increase Control Efficiency of Existing Venturi Scrubbers at Domtar Ashdown Mill Power Boiler No. 2

Control Option	Baseline Emission Rate (SO_2 tpy)	Controlled Emission Rate (tpy)	Annual Emissions Reductions (SO_2 tpy)	Capital Costs[110] ($)	Annual Operation & Maintenance Cost[111] ($/yr)	Total Annual Cost ($/yr)	Average Cost Effectiveness ($/ton)
Use of Additional Scrubbing Reagent	2,078	677	1,401	200,000	1,960,434	1,976,554	1,411

[107] See the spreadsheet titled "Domtar 2PB Monthly SO2 Data." This spreadsheet was included as an attachment to the August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "Domtar PB No2- Cost Effectiveness calculations." Copies of these documents can be found in the docket for this proposed rulemaking.

[108] See the spreadsheet titled "Domtar PB No2- Cost Effectiveness calculations." A copy of this spreadsheet can be found in the docket for this proposed rulemaking.

[109] *Id.*

[110] The capital costs consist of two new pumps for the existing scrubber system.

[111] The operation and maintenance costs consist of the following costs: additional scrubbing reagent, treatment of additional wastewater, treatment of additional raw water, and additional energy usage.

Domtar's 2014 BART analysis did not identify any energy or non-air quality environmental impacts associated with the use of add-on spray scrubbers. We are not aware of any unusual circumstances at the facility that create energy or non-air quality environmental impacts associated with the use of add-on spray scrubbers greater than experienced elsewhere that may therefore provide a basis for the elimination of this control option as BART (40 CFR Part 51, Appendix Y, section IV.D.4.i.2.). We are also not aware of any unusual circumstances at the facility that create energy or non-air quality environmental impacts associated with the use of additional scrubbing reagent to increase the control efficiency of the existing venturi scrubbers greater than experienced elsewhere that may therefore provide a basis for the elimination of this control option as BART. Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with these control options at Power Boiler No. 2 that would affect our proposed BART determination.

Consideration of the presence of existing pollution control technology at the source is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. Power Boiler No. 2 is equipped with multiclones for particulate removal and two venturi scrubbers in parallel for control of SO_2 emissions. It is also equipped with a combustion air system including overfire air to optimize boiler combustion efficiency, which also helps control emissions. The baseline emission rate used in the cost calculations and visibility modeling reflects the use of these existing controls. As discussed above, Domtar's analysis also evaluated upgrades to the existing venturi scrubbers to potentially achieve greater SO_2 control efficiency. Another option we have identified and are evaluating in this TSD is to use additional scrubbing reagent to achieve greater SO_2 control efficiency of the existing venturi scrubbers,

We are not aware of any enforceable shutdown date for the Domtar Ashdown Mill Power Boiler No. 2, nor did Domtar's 2014 BART analysis indicate any enforceable future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of the add-on spray scrubbers. Therefore, a 30-year amortization period was assumed in the evaluation of the add-on spray scrubbers as the remaining useful life of the boiler. A 30-year amortization period was also assumed for the scrubber pump replacements required for using additional scrubbing reagent.

Step 5- Evaluate Visibility Impacts

In the 2014 BART analysis, Domtar assessed the visibility improvement associated with the add-on spray scrubbers by modeling the controlled SO_2 emission rate using CALPUFF, and then comparing the visibility impairment associated with the controlled emission rate to that of the baseline emission rate as measured by the 98th percentile modeled visibility impact. The tables below show the emission rates modeled and a comparison of the baseline (*i.e.*, existing) visibility impacts and the visibility impacts associated with the add-on spray scrubbers. The

installation and operation of add-on spray scrubbers is projected to result in visibility improvement of 0.146 dv at Caney Creek. The visibility improvement is projected to range from 0.026 to 0.053 dv at each of the other Class I areas.

Table 71. Summary of Emission Rates Modeled for SO_2 Controls for Domtar Power Boiler No.2

Scenario	NO_X Emissions (lb/hr)	SO_2 Emissions (lb/hr)	PM_{10}/PMF Emissions (lb/hr)
Baseline	526.8	788.2	81.6
Add-on Spray Scrubber	526.8	78.8	81.6

Table 72. Domtar Ashdown Mill Power Boiler No. 2: Summary of the 98th Percentile Visibility Impacts and Improvement due to Add-on Spray Scrubbers

Class I area	Baseline Visibility Impact[112] (dv)	Add-on Spray Scrubbers	
		Visibility Impact (Δdv)	Visibility Improvement from Baseline (Δdv)
Caney Creek	0.844	0.698	0.146
Upper Buffalo	0.146	0.093	0.053
Hercules-Glades	0.105	0.054	0.051
Mingo	0.065	0.039	0.026
Cumulative Visibility Improvement (Δdv)	--	--	0.276

Using the visibility modeling analysis of the baseline visibility impacts from Power Boiler No. 2 and the visibility improvement projected from the installation and operation of new add-on spray scrubbers, we have extrapolated the visibility improvement projected as a result of using additional scrubbing reagent to increase the SO_2 control efficiency of the existing venturi

[112] The baseline visibility impacts reflect the operation of the existing venturi scrubbers.

scrubbers from the current control efficiency (estimated to be 69%) to 90%, or an outlet emission rate of 0.11 lb/MMBtu. We have assumed that the maximum 24-hour baseline emission rate used in the visibility modeling represents the operation of the existing venturi scrubbers at a 69% control efficiency. We estimate that the visibility improvement of using additional scrubbing reagent to increase the SO_2 control efficiency of the existing venturi scrubbers to 90% control efficiency is 0.139 dv at Caney Creek and 0.05 dv or less at each of the other Class I areas (see table below).

Table 73. Domtar Ashdown Mill Power Boiler No. 2: Summary of the 98th Percentile Visibility Impacts and Improvement from Use of Additional Scrubbing Reagent

Class I area	Baseline Visibility Impact (dv)	Add-on Spray Scrubber Impacts (dv)		Estimated Impacts from Use of Additional Reagent (dv)	
		Visibility Impact (dv)	Visibility Improvement from Baseline (dv)	Visibility Impact (dv)	Visibility Improvement from Baseline (dv)
Caney Creek	0.844	0.698	0.146	0.705	0.139
Upper Buffalo	0.146	0.093	0.053	0.096	0.05
Hercules-Glades	0.105	0.054	0.051	0.057	0.048
Mingo	0.065	0.039	0.026	0.04	0.025
Cumulative Visibility Improvement (dv)	--	--	0.276	--	0.262

Our Proposed SO_2 BART determination Power Boiler No. 2:

Taking into consideration the five factors, we propose to determine that SO_2 BART for Power Boiler No. 2 is an emission limit of 0.11 lb/MMBtu on a 30 boiler-operating-day rolling average, which we estimate is representative of operating the existing scrubbers at 90% control efficiency. In this particular case, we define boiler-operating-day as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the Power Boiler. We are inviting public comment specifically on the appropriateness of this proposed SO_2 emission limit. We believe that this emission limit can be achieved by using additional scrubbing reagent in the operation of the existing venturi scrubbers. We estimate that operating the existing scrubbers to achieve this level of control would result in visibility improvement of 0.139 dv at Caney Creek and 0.05 dv or lower at each of the other Class I areas.

We estimate the cumulative visibility improvement at the four Class I areas to be 0.262 dv. Based on the cost information provided by the facility, we have estimated that the use of additional scrubbing reagent to increase the control efficiency of the existing venturi scrubbers is estimated to cost $1,411/ton of SO_2 removed. Based on Domtar's BART analysis, new add-on spray scrubbers that would be operated downstream of the existing venturi scrubbers are projected to result in visibility improvement of 0.146 dv at Caney Creek and 0.053 dv or lower at each of the other Class I areas. The cumulative visibility improvement at the four Class I areas is projected to be 0.276 dv. The cost of add-on spray scrubbers is estimated to be $5,258/ton of SO_2 removed, not including additional construction costs that would likely be incurred to make space to house the new scrubbers. We do not believe that the amount of visibility improvement that is projected from the installation and operation of new add-on spray scrubbers would justify their high average cost-effectiveness. The incremental visibility improvement of new add-on spray scrubbers compared to using additional scrubbing reagent to increase the control efficiency of the existing venturi scrubbers ranges from 0.001 to 0.007 dv at each Class I area, yet the incremental cost-effectiveness is estimated to be $16,752. We do not believe the incremental visibility benefit warrants the higher cost associated with new add-on spray scrubbers. Therefore, we are proposing to determine that SO_2 BART for Power Boiler No. 2 is an emission limit of 0.11 lb/MMBtu on a 30 boiler-operating-day rolling averaging basis, and are inviting comment on the appropriateness of this emission limit. We propose to require the facility to demonstrate compliance with this emission limit using the existing CEMS. Since the SO_2 emission limit we are proposing can be achieved with the use of the existing venturi scrubbers but will require scrubber pump upgrades and the use of additional scrubbing reagent, we propose to require compliance with this BART emission limit no later than 3 years from the effective date of the final action, but are inviting public comment on the appropriateness of a compliance date anywhere from 1 – 5 years.

NO_X BART Evaluation for Power Boiler No. 2

Step 1- Identify All Available Retrofit Control Technologies

For NO_X BART, Domtar's 2014 BART analysis evaluated LNB, SNCR, and Methane de-NO_X (MdN). In the 2006/2007 Domtar BART analysis, which was submitted in the 2008 Arkansas RH SIP, other NO_X controls were also evaluated but found by the State to be either already in use or not technically feasible for use at Power Boiler No. 2. Fuel blending, boiler operational modifications, and boiler tuning/optimization are already in use at the source, while FGR, OFA, and SCR were found to be technically infeasible for use at Power Boiler No. 2. Domtar did not further evaluate these NO_X controls, and instead focused on LNB, SNCR, and MdN in its 2014 BART analysis for Power Boiler No. 2.

APPENDIX B: 1PP SIP PACKAGE INFORMATION RELATED TO NO. 2 POWER BOILER NO_X EMISSIONS REDUCTION OPTIONS

The problems with typical SNCR systems (e.g., ammonia slippage and heat transfer surface fouling with byproduct formation) also exist with the NO_XOUT process.

4.4.1.8 SELECTIVE CATALYTIC REDUCTION

SCR is a post-combustion gas treatment process in which NH_3 is injected into the exhaust gas in the presence of a catalyst bed usually located between the boiler and air preheater. The catalyst lowers the activation energy required for NO_X decomposition.[47] On the catalyst surface, NH_3 and nitric oxide (NO) react to form diatomic nitrogen and water. The overall chemical reaction can be expressed as:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

When operated within the optimum temperature range of approximately 575 to 750 °F, the reaction can result in removal efficiencies between 70 and 90 percent. For coal-fired industrial boilers, SCR can achieve approximately 80 percent NO_X control.[48] The specific temperature ranges are 600 to 750 °F for conventional (vanadium or titanium) catalysts, 470 to 510 °F for platinum catalysts, and 600 to 1000 °F for high-temperature zeolite catalysts.[49] SCR units have the ability to function effectively under fluctuating temperature conditions (usually ± 50 °F), although fluctuation in exhaust gas temperature reduces removal efficiency by disturbing the chemical kinetics (speed) of the NO_X-removal reaction.

According to the U.S. EPA, the performance of an SCR system is affected by six factors.

> *These are a) NO_X level at SCR inlet, b) flue gas temperature, c) NH_3-to-NO_x ratio, d) fuel sulfur content, e) gas flow rate, and f) catalyst condition. For SCR, when inlet NO_X concentrations fall below 150 ppm, the reduction efficiencies decrease with decreasing NO_X concentrations. Each type of catalyst has an optimum operating temperature range. Temperatures below this range result in ammonia emissions (slip), and temperatures above the desired range result in NH_3 being oxidized to NO_X. For up to about 80 percent NO_X reduction efficiencies, a 1:1 NH_3:NO_X ratio is sufficient. For higher efficiencies, higher reagent to NO_X ratios are required which may result in higher NH_3 slip. In the case of high sulfur fuels, excess NH_3 can react with sulfur trioxide to form ammonium sulfate salt compounds that deposit and foul downstream equipment. SCR application experience in the case of*

[47] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.
[48] MRPO, *Interim White Paper – Midwest RPO Candidate Control Measures*, March 29, 2005.
[49] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

medium-to-high sulfur fuels is limited. For a given flue gas flow rate, the catalyst structural design should be chosen so that the residence time needed for the reduction reactions to take place on the catalyst surface is achievable.[50]

4.4.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Per the BART Guidelines, documentation of infeasibility should "explain, based on physical, chemical, or engineering principles, why technical difficulties would preclude the successful use of the control option under review." The BART Guidelines use the two key concepts of "availability" and "applicability" to determine if a control option is technically feasible. These concepts are defined in Section IV.D.2:

> *…a technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration.*
>
> *The typical stages for bringing a control technology concept to reality as a commercial product are:*
>
> - *concept stage;*
> - *research and patenting;*
> - *bench scale or laboratory testing;*
> - *pilot scale testing;*
> - *licensing and commercial demonstration; and*
> - *commercial sales.*
>
> *A control technique is considered available, within the context presented above, if it has reached the stage of licensing and commercial availability. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as "available" for purposes of BART review.*
>
> *In general, a commercially available control option will be presumed applicable if it has been used on the same or a similar source type. Absent a showing of this type, you evaluate technical feasibility by examining the physical and chemical characteristics of the pollutant-bearing gas stream, and comparing them to the gas stream characteristics of the source types to which the technology had been applied previously.*

COMBUSTION MODIFICATIONS

[50] U.S. EPA, *New source performance standards, subpart Db – technical support for proposed revisions to NO_X*, EPA-453-/R-95-012 (republished in NCASI's Special Report 03-04).

4.4.2.1 Flue Gas Recirculation

FGR is used to reduce thermal NO_X formation. Emissions due to fuel-bound NO_X, which are significant for coal-fired boilers, are not meaningfully affected by FGR. Therefore, FGR is not technically feasible to control NO_X emissions from coal-fired boilers.[51] Similarly, FGR would not be effective in wood combustion since most of the NO_X generated during wood combustion is also from the fuel NO_X pathway.[52] Recent refusals by vendors (e.g., Entropy Technology & Environmental Consultants LP[53]) to provide budgetary estimates for installing FGR are further evidence that FGR is not applicable for the Ashdown Mill's No. 1 and No. 2 Power Boilers.

4.4.2.2 Reburning / Methane de-NO_X

Generally, Domtar considers MdN not feasible because (1) it is not fully demonstrated and (2) it incorporates FGR, which is clearly technically infeasible (see Section 4.4.2.1). However, Domtar was able to obtain equipment cost estimates from vendors of MdN. Therefore, MdN is considered further in this analysis.

Post-Combustion Modifications

NCASI points out the following issues of concern for post-combustion NO_X controls (i.e., SNCR and SCR) for pulp and paper mill power boilers:[54]

> **Load Swings** - Pulp mill combination and power boilers frequently exhibit wide and rapid load swings that are not consistent with the steady conditions required for effective use of either SNCR or SCR NO_X control technologies. The load swings produce variable temperature conditions in the boiler, causing the temperature zone for NO_X reduction to fluctuate, making it more difficult to know where to inject the reactants.
>
> **Temperature Incompatibility** - Combination and power boilers are affected by temperature profile incompatibility. To obtain the required temperature window, the only location to install this technology is upstream of the particulate matter control device, yet this is where flue gases are dirty and can foul the catalyst rapidly.

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[51] U.S. EPA. *Alternative Control Technologies Document: NO_X Emissions from Utility Boilers.* (EPA-453/R-94-023).

[52] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[53] Steve Wood (ETEC), e-mail to Joel Martin (Domtar), September 20, 2006: "Based on the design and operational data provided regarding #2 Coal Boiler, ETEC would decline to bid the application Induced Flue Gas Recirculation for Boiler #2 NO_X control. Flue gas recirculation technology is very effective in reducing natural gas and light oil fuel NO_X emissions, but is not for No.6 fuel oil, coal, bark and other solid fuels. To the best of our knowledge, flue gas recirculation for NO_X control has never been installed on a coal fired boiler."

[54] Ibid.

Downstream of the PM control device, the temperature is too low for the catalyst to be effective.

Unproven – SCR or SNCR controls, technologies which, for the most part, are untested and infeasible for pulp and paper mill boilers. These technologies must be operated on a continuous basis within a specified temperature range in order to be effective. The type of fuel burned influences the design of the technology, and FPI facilities' frequent fuel changes and co-firing of multiple fuels would result in design and operational problems.

Lack of Guarantee for FPI Boilers – Boiler owners are finding that vendors of SCR and SNCR technologies are unwilling to provide performance guarantees that the controls will meet the level of reduction called for in [NSPS Subpart Db (promulgated on September 16, 1998)].

4.4.2.3 SELECTIVE NON-CATALYTIC REDUCTION

Most boilers in the pulp and paper industry operate in the swing load mode, a consequence of supplying steam as required to the various components of the process. The problem with control of the required flue gas temperature window is an inherent difficulty with use of SNCR for load-following boilers, whether wood or fossil fuel.[55]

Controlling flue gas temperatures over the entire range of operating loads that the boiler is expected to experience will be very difficult to achieve. Boilers in the pulp and paper industry rarely operate under base loaded conditions. Consequently, the location of the desired temperature window is expected to change constantly. Accurate, instantaneous temperature measurement, as well as the ability to accurately adjust the location of the injection nozzle, would be necessary. Ammonia slip would be a recurring problem associated with the application of the SNCR process to industrial boilers with fluctuating loads.[56]

Inadequate reagent dispersion in the region of reagent injection in wood-fired boilers is also a factor mitigating against the use of SNCR technology.[57] Good dispersion of the reagent in the flue gas is needed to get good utilization of the reagent and to avoid excessive ammonia slip from the process. The need for a

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[55] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, Corporate Correspondence Memo 06-014.
[56] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.
[57] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, Corporate Correspondence Memo 06-014.

sufficient volume in the boiler at the right temperature window precludes the application of SNCR in all types of industrial boilers.[58]

Additional issues with SNCR include the potential for formation of ammonium sulfate salts (if sulfur oxides are present in the gas stream where they can react with excess ammonia from the SNCR process to form ammonium salts), which cause plugging problems. Ammonia also poses potential water quality issues - ammonia slip released to the atmosphere could contaminate surface waters by deposition.

SNCR has been applied to a few base-loaded wood and combination wood-fired boilers, mainly in the electric generating industry. However, its efficacy on wood-fired boilers with changing loads has not been demonstrated, except when used as a polishing step. Early use of ammonia injection in the case of one pulp mill wood-fired boiler met with significant problems and had to be abandoned (significant ammonia slip, caused by inefficient dispersion of the reagent within the boiler, was to blame). The boiler was unable to meet the manufacturer guarantee unless operated at less than half load. Even then, reducing NO_X to near permitted limits consumed considerably more ammonia than anticipated, leading to the formation of a visible ammonium chloride plume. A similar problem was encountered at a second FPI mill where nearly half the urea (on a molar basis) injected was being emitted as ammonia.[59]

The use of SNCR on stoker type wood-fired boilers that have significant load swings has not been demonstrated. Excessive ammonia slip is a primary concern when adequate dispersion of the SNCR chemical is not achieved in the boiler ductwork within the range of residence times available and temperatures needed for the NO_X reduction reactions to go to completion. Additional concerns include the impact of interference from higher CO levels present in many wood-fired boilers, the possibility of appreciable SNCR chemical being absorbed onto the ash matrix in a wood-fired boiler, and the extent and fate of ammonia in scrubber purge streams.[60]

The MRPO concludes, "if combustion zone temperatures within the boiler do not fall into [the ideal temperature range], then SNCR would be infeasible."[61]

4.4.2.4 SELECTIVE CATALYTIC REDUCTION

The use of SCR on boilers operating in the FPI has also never been successfully demonstrated for wood boilers, and would face the same inherent problem of requiring it to be post PM-control to protect the catalyst, and

[58] NESCAUM and MANE-VU, *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plant and Paper and Pulp Facilities*, March 2005.
[59] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.
[60] Ibid.
[61] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

achieving and maintaining the required temperature window for effective NO_X control.[62] There are numerous other issues with using SCR including catalyst plugging and soluble alkali poisoning as well as increased energy consumption.[63]

The use of SCR technology would be considered technically infeasible based upon the fact that post-particulate removal flue gas temperatures are typically significantly lower than those desired for this application. Many boilers are equipped with wet scrubbers for particulate emission (PM) control. Reheating the scrubbed flue gases from these boilers to bring them within the desired temperature window would involve a significant energy penalty. For pre-particulate removal flue gas application, catalyst deactivation from high particulate loading would be a serious concern, in addition to the impact of fluctuating loads on flue gas temperatures. Deactivation and/or poisoning could result from the size and density of fly ash particulate, and from their unique chemical and physical nature. Water-soluble alkali (such as Mg or Na) in particulate-laden gas streams has been known to poison SCR catalysts. Space considerations for installing a catalyst section in an existing boiler's ductwork are also important. Also note the use of solid fuels can result in catalyst contamination even with efficient PM control system and high moisture levels in exhaust air would result in inefficient SCR operation.[64]

Most boilers feature a flue gas temperature at the economizer exit that is below the ammonium sulfate/bisulfate dew point. Air heater surfaces must withstand corrosion from ammonium sulfates and bisulfates, be easily cleaned with conventional soot blowing, and survive corrosion-inducing water washing. SO_3 produced by the catalyst may condense on cooler surfaces, depending on the temperature, during both steady-state and non-steady-state operation. Higher levels of SO_2 to SO_3 conversion could cause accelerated corrosion or higher SO_3-induced plume opacity. Minimizing ammonia levels in the stack (typically <2 to 3 ppm) is required to avoid problems with disposal of scrubber byproduct contaminated by ammonia. The use of a particular catalyst puts restrictions on the fuel flexibility for a boiler. For example, purchasing coal with fly ash containing calcium oxide and arsenic outside the defined range absolves the catalyst supplier from responsibility for arsenic poisoning.[65]

The only "wood-fired" boiler SCR application in service in the U.S. was located at a woodworking facility in Ohio. This SCR was located downstream of a mechanical collector and electrostatic precipitator, operating in flue gas temperatures ranging from 550 to 650 °F. The only problem reported at this

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[62] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, Corporate Correspondence Memo 06-014.

[63] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[64] Ibid.

[65] Ibid.

installation was minor catalyst blinding due to the deposition of fine particulate that escaped the PM collection devices. It was learned the operating temperature for this SCR system allowed the use of conventional catalysts designed to accommodate high dust applications. For these catalysts, the catalyst openings through which the flue gas flows are sized to provide proper surface area contact and sufficient flue gas velocity to minimize fouling. Low temperature catalyst designs are considerably different and would not be recommended for use on any high dust application. Based on this description of the air pollution control system configuration and the operating conditions for this particular wood-fired boiler, it is important to identify several specific differences between this installation and those that operate in the FPI. First, due to the requirement to provide hot air to burn all but the driest of wood fuels, wood-fired boilers are usually equipped with air preheaters. Thus, even when dry particulate control devices like an ESP are utilized, the installation of an SCR catalyst section after a PM control device is not amenable for adaptation to such boilers without, of course, incurring a severe energy penalty. Second, a significant portion of the FPI's wood-fired boilers is controlled for PM emissions by multiclones and wet scrubbers. Therefore the PM emissions from these would be higher than the example situation. Third, it is unclear how the Ohio facility's SCR system would have worked under the fluctuating boiler load characteristics common to many FPI boilers. Finally, sawdust, which was the fuel fired in the Ohio facility's boiler, is a low moisture fuel and the particulate matter present in the flue gases from its combustion is likely to be of different composition than when bark or hog fuel (typically much higher moisture) is burned.[66]

Hence the use of SCR technology has clearly not been demonstrated for industrial wood, biomass or combination fuel-fired boilers in the FPI.[67]

4.4.3 STEP 3 – EVALUATE CONTROL EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

Table 4-2 presents a ranking of the technically feasible control strategies in order of their effectiveness (i.e., potential control efficiency). For controls with a range of performance levels, the BART Guidelines note:

> *It is not [the U.S. EPA's] intent to require analysis of each possible level of efficiency for a control technique as such an analysis would result in a large number of options. It is important, however, that in analyzing the technology you take into account the most stringent emission control level that the technology is capable of achieving.*

[66] Ibid.
[67] Ibid.

Step 2- Eliminate Technically Infeasible Options

MdN utilizes the injection of natural gas together with recirculated flue gases to create an oxygen-rich zone above the combustion grate. Air is then injected at a higher furnace elevation to burn the combustibles. In response to comments provided by us regarding Domtar's 2014 BART analysis, Domtar stated that discussions regarding the technical infeasibility of MdN in the 2006/2007 Domtar BART analysis, submitted as part of the 2008 Arkansas RH SIP, remain correct.[113] The 2006/2007 Domtar BART analysis submitted in the 2008 Arkansas RH SIP discussed that MdN has not been fully demonstrated for this type of boiler and incorporates FGR, which is considered technically infeasible for use at Power Boiler No. 2. Domtar also stated it recently completed additional research and found that since the 2006/2007 Domtar BART analysis, MdN has not been placed into operation in power boilers at paper mills or any comparable source types. We are also not aware of any power boilers at paper mills that operate MdN for NO_X control, and agree that this control can be considered technically infeasible for use at Power Boiler No. 2 and do not further consider it in this evaluation. Domtar also questioned the technical feasibility of SNCR for boilers with high load swing such as Power Boiler No. 2, but in response to comments from us, SNCR was evaluated in Domtar's 2014 BART analysis.

Step 3- Evaluate Control Effectiveness of Remaining Control Technologies:

Based on vendor estimates, the 2006/2007 Domtar BART analysis estimated the potential control efficiency of LNB to be 30%. In Domtar's 2014 BART analysis, SNCR was evaluated at a control efficiency of 27.5% and 35% for Power Boiler No. 2. These values were based on SNCR control efficiency estimates that came from the equipment vendor's proposal,[114] which according to the facility, is not an appropriations request level quote and therefore requires further refinement.[115] For example, Domtar's 2014 BART analysis discusses that for a base loaded coal boiler with steady flue gas flow patterns and temperature distribution across the flue gas pathway, SNCR is typically capable of achieving 50% NO_X reduction. However, Power Boiler No. 2 is not a base loaded boiler and does not have steady flue gas flow patterns or steady temperature distribution across the flue gas pathway.

To demonstrate the wide range in temperature at Power Boiler No. 2 and its relationship to steam demand, Domtar obtained an analysis of furnace exit gas temperatures for Power Boiler

[113] See the document titled "Domtar Responses to ADEQ Regarding Region 6 Comments on Domtar BART Analysis," p. 10. A copy of this document can be found in the docket for our proposed rulemaking.

[114] Fuel Tech Proposal titled "Domtar Paper Ashdown, Arkansas- NO_X Control Options, Power Boilers 1 and 2," dated June 29, 2012. A copy of the vendor proposal is included under Appendix D to the "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis and its appendices is found in the docket for our proposed rulemaking.

[115] See the document titled "Domtar Responses to ADEQ Regarding Region 6 Comments on Domtar BART Analysis," p. 9. A copy of this document can be found in the docket for our proposed rulemaking.

No. 2 from an engineering consultant.[116] The furnace exit gas temperatures were analyzed for a 12-day period that according to Domtar is representative of typical boiler operations. The consultant's report indicated that furnace exit gas temperatures are representative of temperatures in the upper portion of the furnace, which is the optimal location for installation of the SNCR injection nozzles. The consultant estimated that 1700 – 1800°F represents the temperature range at which SNCR can be expected to reach 40% control efficiency at the current boiler operating conditions. It was found that there is wide variability in the furnace exit gas temperatures for Power Boiler No. 2, with temperatures ranging from 1000 – 2000°F. The data also indicate that there is a direct positive relationship between boiler steam demand and furnace exit gas temperatures. It was also found that Power Boiler No. 2 operated in the optimal temperature zone at which SNCR can be expected to reach 40% control efficiency for only a total of 20 hours over the 12-day period analyzed (288 continuous hours), which is approximately 7% of the time.

According to Domtar, the significant temperature swings, which are due to load following and steam demand variability, create a scenario where urea injection will either be too high or too low. When not enough urea is injected, NO_X removal will be less than projected and when too much urea is injected, excess ammonia slip will occur. Domtar stated that the observed significant temperature swings demonstrate that it will be difficult to maintain stable, optimal furnace temperatures at which urea can be injected to effectively reduce NO_X with minimal ammonia slip. We agree that because of the wide variability in steam demand and wide range in furnace temperature observed at Power Boiler No. 2, the NO_X control efficiency of SNCR at the boiler would not reach optimal control levels on a long-term basis. We also believe there is uncertainty as to the level of control efficiency that SNCR would be able to achieve on a long-term basis for Power Boiler No. 2. However, we further consider SNCR in the remainder of the analysis.

Step 4- Evaluate Impacts and Document the Results

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

In the 2006/2007 Domtar BART analysis, the capital cost, operating cost, and cost-effectiveness of LNB were estimated based on vendor estimates.[117] The analysis was based on a 10-year amortization period, based on the equipment's life expectancy. However, since we believe a 30-year equipment life is a more appropriate estimate for LNB, we have we have

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[116] September 12, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. A copy of this letter and its attachments are found in the docket for our proposed rulemaking

[117] See "Best Available Retrofit Technology Determination Domtar Industries Inc., Ashdown Mill (AFIN 41-00002)," originally dated October 31, 2006 and revised on March 26, 2007, prepared by Trinity Consultants Inc. This BART analysis is part of the 2008 Arkansas RH SIP, upon which EPA took final action on March 12, 2012 (77 FR 14604). A copy of this BART analysis is found in the docket for this proposed rulemaking.

adjusted Domtar's cost estimate for LNB.[118] The annual emissions reductions used in the cost-effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. We have also adjusted the average cost-effectiveness calculations presented in the 2006/2007 Domtar BART analysis for LNB by using the boiler's actual annual uncontrolled NO_X emissions rather than the maximum 24-hour emission rate as the baseline annual emissions. The table below summarizes the estimated cost of LNB for Power Boiler No. 2, based on our adjustments to the cost estimates in the 2006/2007 Domtar BART analysis as discussed above.

In Domtar's 2014 BART analysis, the capital costs, operating costs, and cost-effectiveness of SNCR were calculated based on methods and assumptions found in our Control Cost Manual, and supplemented with mill-specific cost information for water, fuels, and ash disposal and urea solution usage estimates from the equipment vendor.[119] The two SNCR control scenarios evaluated were 27.5% and 35% control efficiencies. Domtar annualized the capital cost over a 30-year period and then added to the annual operating cost to obtain the total annualized costs. The annual emissions reductions associated with each NO_X control option were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emissions used in the calculations are the uncontrolled actual emissions from the 2001-2003 baseline period. The average cost-effectiveness was calculated by dividing the total annual cost by the estimated annual NO_X emissions reductions. The table below summarizes Domtar's estimate of the cost of SNCR for Power Boiler No. 2.

Table 74. Summary of Cost of NO_X Controls for Power Boiler No. 2

NO_X Control Scenario	Baseline Emission Rate (NO_X tpy)	NO_X Removal Efficiency of Controls (%)	Annual Emissions Reduction (NO_X tpy)	Capital Cost ($)	Total Annual Cost ($/yr)	Average Cost Effectiveness ($/ton)	Incremental Cost-Effectiveness ($/ton)
SNCR- 27.5%	1,536	27.5%	422	2,681,678	843,575	1,998	-
LNB	1,536	30%	461	6,131,745	899,605	1,951	1,437
SNCR- 35%	1,536	35%	537	2,877,523	1,026,214	1,909	1,666

[118] See the spreadsheet titled "Domtar PB No2 LNB_cost revisions." A copy of this spreadsheet is found in the docket for this proposed rulemaking.

[119] See "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis is found in the docket for our proposed rulemaking.

APPENDIX H-4

Domtar Ashdown Mill Revised Calculations

(see spreadsheet of the same name)

Division of Environmental Quality

Office of Air Quality

APPENDIX H-5

Follow-up Consultation: Domtar Ashdown Mill Revised Cost and Cost- Effectiveness

Division of Environmental Quality

Office of Air Quality

Treece, Tricia

From: Crouch, Kelley <KELLEY.CROUCH@domtar.com>
Sent: Friday, July 24, 2020 3:06 PM
To: Treece, Tricia
Cc: JJewell@trinityconsultants.com; Montgomery, William; Clark, David
Subject: RE: Domtar Regional Haze Evaluation Follow-Up

Tricia,

Thank you for the opportunity to review ADEQ's calculations. As a result of our review the following information is provided for your consideration.

1. As you point out in your 7/21 e-mail, all costs should be escalated to $2019 now that the 2019 CEPCI has been finalized at 607.5 (the values used in the original ICR response report include 603.1 for 2018, 584.6 for 2012, 576.1 for 2014, and 394.3 for 2001).

2. We believe it is inappropriate to use the bank prime rate for our capital recovery calculations. The cost analyses in our ICR response report follow Office of Management and Budget (OMB) guidance by using an interest rate of 7 % for evaluating the cost of capital recovery, as discussed below.

   The EPA Control Cost Manual (CCM or Manual) states that "when performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate, which is the rate firms actually face."[1] For our analyses, which evaluate equipment costs that may take place several years into the future, it is important to ensure that the selected interest rate represents a longer-term view of corporate borrowing rates. The CCM cites the bank prime rate as one indicator of the cost of borrowing as an option for use when the specific nominal interest rate is not available. Over the past 20 years, the annual average prime rate has varied from 3.25 % to 9.23 %, with an overall average of 4.86 % over the 20-year period.[2] But CCM also adds the caution that the "base rates used by banks do not reflect entity and project specific characteristics and risks including the length of the project, and credit risks of the borrowers."[3] For this reason, the prime rate should be considered the low end of the range for estimating capital cost recovery.

   Actual borrowing costs are typically much higher than prime rates. For economic evaluations of the impact of federal regulations, the OMB uses an interest rate of 7 %. "As a default position, OMB Circular A-94 states that a real discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or alter the use of capital in the private sector."[4]

[1] Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," *EPA Air Pollution Control Cost Manual*, Section 1, Chapter 2, p. 15. U.S. EPA Air Economics Group, November 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

[2] Board of Governors of the Federal Reserve System Data Download Program, "H.15 Selected Interest Rates," accessed April 16, 2020. https://www.federalreserve.gov/datadownload/Download.aspx?rel=H15&series=8193c94824192497563a23e3787878ec&filetype=spreadsheetml&label=include&layout=seriescolumn&from=01/01/2000&to=12/31/2020

[3] Sorrels, J. and Walton, T. "Cost Estimation: Concepts and Methodology," *EPA Air Pollution Control Cost Manual*, Section 1, Chapter 2, p. 16. U.S. EPA Air Economics Group, November 2017. https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf
[4] OMB Circular A-4, https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf - "

Additionally, based on experience, the Ashdown Mill's cost of capital is actually much higher than even 7 %. Domtar's capital projects group uses 10.5 % as the weighted average cost of capital.

3. We understand the SNCR "case 2", represented by 1.0 SNCR capacity factors, for each of the boilers was created as sensitivity analyses in order to demonstrate that even with such an extreme assumption the cost of control is infeasible. However, we are still concerned about ADEQ presenting this information since it is so unrealistic. We presented empirical evidence that SNCR would be effective only 7 % of boiler operating time based on temperature fluctuations for the load-following boilers. The 1.0 SNCR capacity factor scenario ignores this evidence. It also fails to properly account for the 93 % of time, approximately 8,000 hours per year, when the SNCR would not be effective, potentially resulting in stack emissions of more than 1,700 tons per year of urea.

4. Due to time constraints we have not completed a thorough review of the ADEQ's cost estimates for SNCR. The resulting cost effectiveness values appear to be infeasible. If the ADEQ agrees with this conclusion then we request the ADEQ move forward with its values. If the ADEQ disagrees, i.e., if the ADEQ decides that SNCR should be installed on either boiler, then we request at least two weeks to complete our review of the calculations and potentially longer (up to three months) to complete an engineering cost study.

5. Per your phone conversation on 7/21 with Jeremy, the SO2 emissions reduction value for the *increased scrubbing reagent use* option for #2 Power Boiler is mistaken in both our ICR response report and the ADEQ's calculations because the fact that current actual emissions already represent 69% (more precisely: 69.3%) control has not been appropriately considered. The emission reduction should be calculated using the following logic:

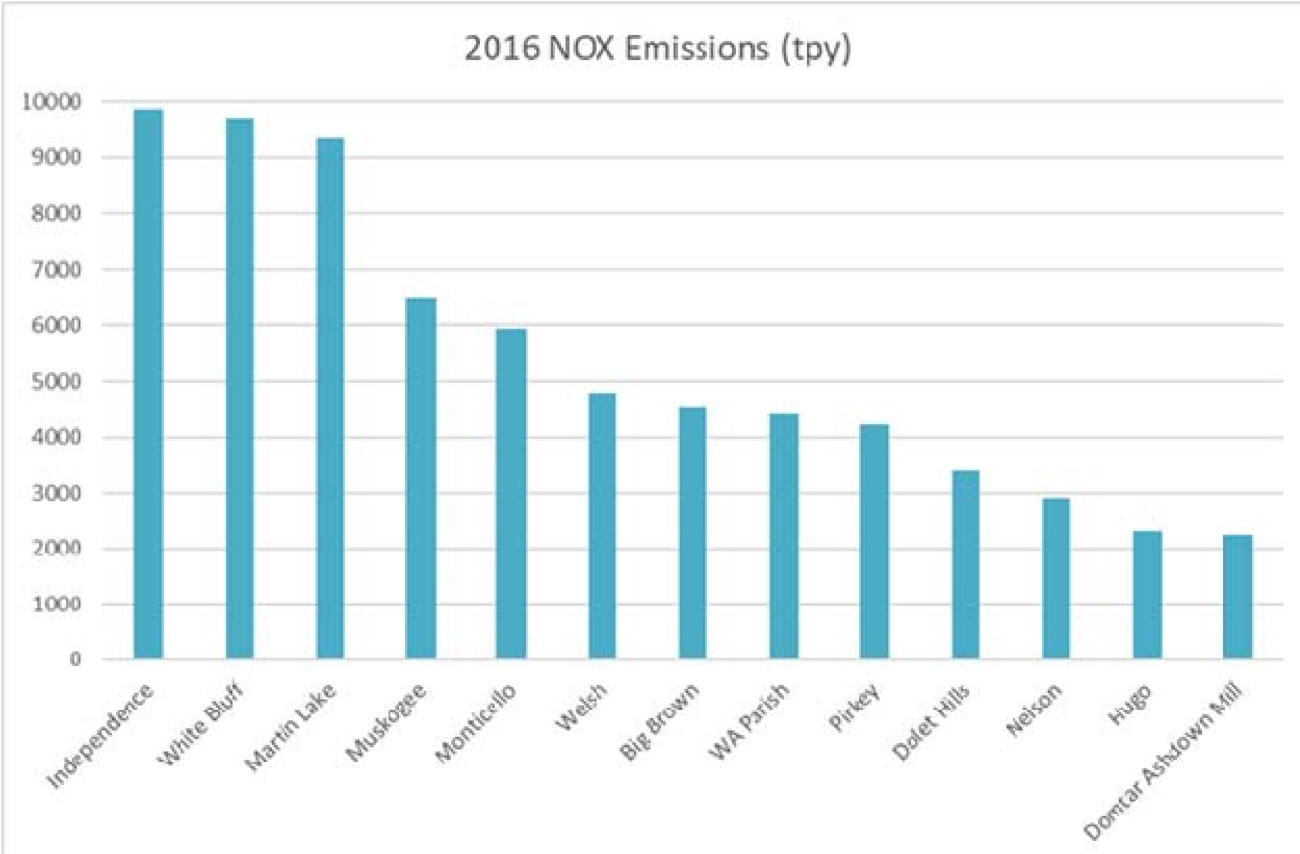
    - 858.9 tpy of actual emissions as documented in the ICR response report as the average of annual totals from 2017-2019 based on CEMS
    - The scrubber is already getting 69.3 % control as documented in the BART FIP TSD
    - 858.9 tpy / (1-0.693) = 2,797.8 tpy of "loading" to the scrubber
    - 2,797.8 tpy * (1-0.90) = 279.8 tpy of emissions after implementation of the *increased scrubbing reagent use* option
    - 858.9 tpy (emissions at 69.3 % control) – 279.8 tpy (emissions at 90 % control) = 579.1 tpy of extra emissions reductions from implementation of the *increased scrubbing reagent use* option

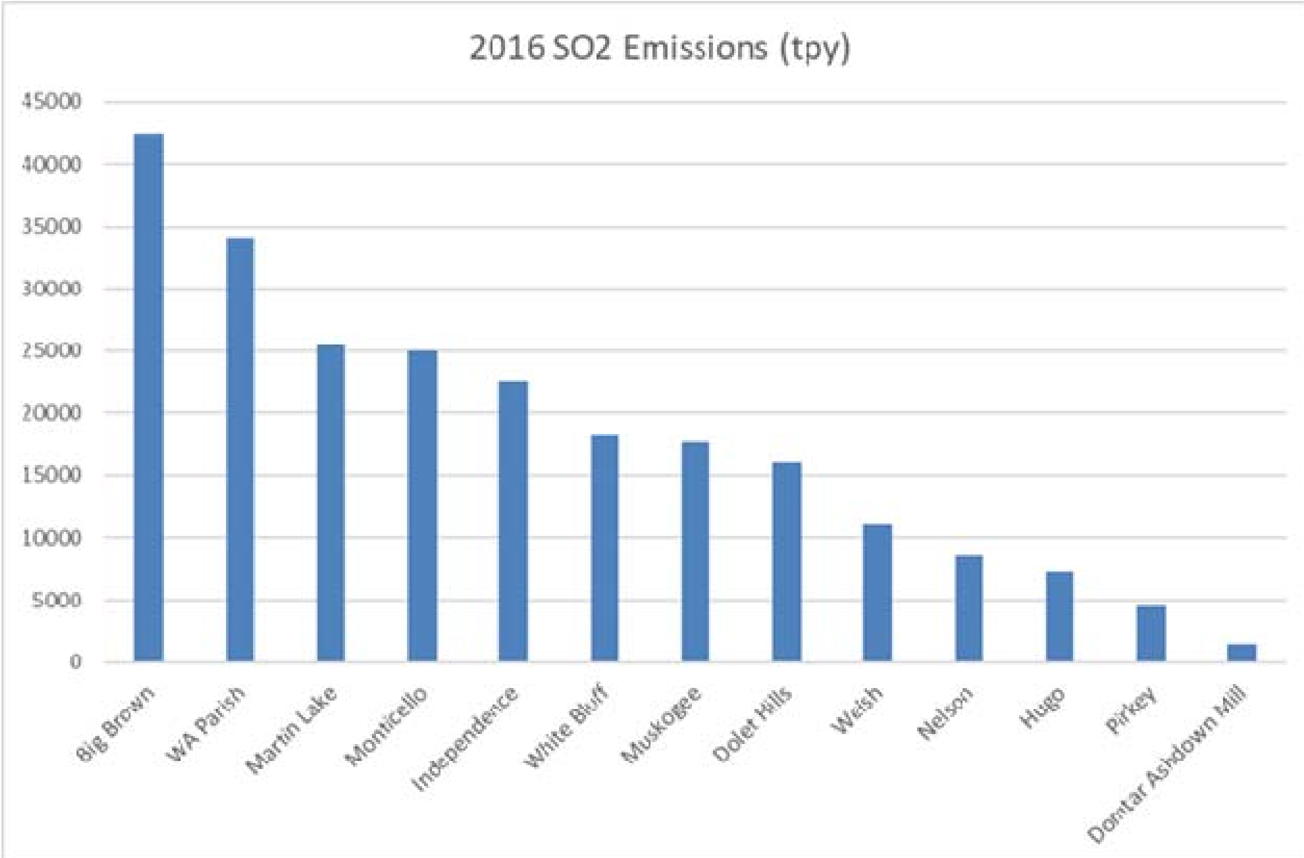
    At 579.1 tpy of emissions reduction, the cost effectiveness becomes $3,562/ton with no other adjustments. Moving to a 2019 dollar basis increases it to $3,588/ton.

6. Lastly, we implore the ADEQ to consider more than just the cost effectiveness value for the *increased scrubbing reagent use* option for #2 Power Boiler. Considering the current, depressed status of the markets in which the Ashdown Mill operates – due largely to the current economic recession created by the Covid-19 pandemic – a required expenditure of $2MM per year with no financial return on investment and especially in light of questionable sustainability of the emissions reductions, would place the Ashdown Mill in an even greater unfavorable position, both economically and competitively against mills that can operate with better margins. Such an outcome cannot be viewed as "reasonable" – the goal of the regional haze second planning period is to make "reasonable" progress – in light of several facts:

    - The Class I areas alleged affected by the Ashdown Mill (Caney Creek and Wichita Mountains) are both well ahead of schedule with respect to progress towards natural visibility conditions based on both monitoring data trends and EPA's own predictive modeling analysis.

- The Ashdown Mill is the smallest, in terms of both SO2 and NOX emissions (for 2016), of the 13 sources that were “screened in” by the ADEQ for alleged impacts to Caney Creek. The Ashdown Mill accounts for approximately 3 % of the NOX total and less than 1 % of the SO2 total.





- The Ashdown Mill is the only non-EGU source in the list. Thus, it is the only source in the list for which recovery of expenditures on air pollution control devices is not possible.

- The Ashdown Mill's emissions have decreased in recent months to levels much lower than the 2016 emissions and even lower than the 2017-2019 emissions rate that was presented in the ICR response report. Based on the first six months of 2020, the SO2 emission rate for #2 Power Boiler is 568.4 tpy, which is approximately one-third of the 1,549 tpy value from 2016 and approximately two-thirds of the 858.9 tpy value from 2017-2019.

Month in 2020	Monthly Total SO2 Emission Rate (ton/month)
Jan	63.08
Feb	71.77
Mar	52.50
Apr	16.58

May	36.16
Jun	44.10

- If 568.4 tpy were used as the baseline for the four-factor analysis, then the emission reduction value for the *increased scrubbing reagent use* option for #2 Power Boiler would be 383 tpy and the cost effectiveness value (after corrections described in items 1 and 5, above) becomes $5,386/ton.

We appreciate the ADEQ's consideration of this information, and we look forward to working with the ADEQ in its development of the SIP.

For convenience, we plan to submit by 8/14 a revised ICR response report that incorporates the factual changes described in items 1, 5, and 6.

Thanks,
Kelley

Kelley Crouch
Engineering Services Manager
Environmental, Quality & Engineering
T 870-898-2711 ext 26168

Domtar

Domtar
285 Highway 71 S
Ashdown, AR 71822

From: Treece, Tricia [mailto:treecep@adeq.state.ar.us]
Sent: Monday, July 20, 2020 4:18 PM
To: Crouch, Kelley
Cc: JJewell@trinityconsultants.com; Montgomery, William; Clark, David
Subject: Domtar Regional Haze Evaluation Follow-Up

Kelley,
We have now completed a thorough review of the cost information provided in the "Response to January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request." Based on our review, each of the cost analyses require revision to ensure consistency with EPA guidance.

DEQ has calculated, based on the information provided and EPA guidance, revised cost and cost-effectiveness values. See attached spreadsheet for an explanation of changes and DEQ's calculations. We are providing you the opportunity to review these calculation revisions and provide us additional information if site-specific considerations warrant changes to the control-cost methodology assumptions.

Please provide any feedback you may have on the revised control strategy cost calculations by COB 7/24/20.

Tricia Treece | SIP/Planning Supervisor
Division of Environmental Quality | **Office of Air Quality**
Policy and Planning Branch
5301 Northshore Drive | North Little Rock, AR 72118
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ARKANSAS ENERGY & ENVIRONMENT

APPENDIX H-6

Domtar Ashdown Mill ICR Response, Revised (2)

Division of Environmental Quality

Office of Air Quality

Domtar A.W. LLC > Ashdown Mill
AFIN 41-00002

Domtar

Response to January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request

Prepared By:

Jeremy Jewell – Principal Consultant

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April 6, 2020
Revised May 7, 2020 and August 14, 2020

Project 203702.0003

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1. Introduction

This report was prepared on behalf of Domtar A.W. LCC (Domtar) in response to the January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request ("the ICR") from the Arkansas Department of Energy and Environment, Division of Environmental Quality, Office of Air Quality ("the DEQ").

Per the ICR, this report provides information related to sulfur dioxide (SO_2) and/or nitrogen oxides (NO_X) emissions reduction options for the following sources/source numbers (SNs):

- No. 2 Power Boiler (SN-05)
- No. 3 Power Boiler (SN-01)
- No. 2 Recovery Boiler (SN-06)
- No. 3 Recovery Boiler (SN-14)

Each section of this report is related to a single source-pollutant combination, e.g., No. 2 Power Boiler – SO_2, and No. 3 Recovery Boiler – NO_X, resulting in eight (8) total sections. The following specific technical and economic information, where applicable, is provided in each section for each emissions reduction option considered, in accordance with instructions in the ICR:

- Technical feasibility
- Control effectiveness
- Emissions reductions
- Time necessary for implementation
- Remaining useful life
- Energy and non-air quality environmental impacts
- Costs

To the extent possible, information in this report is based on information prepared for the relevant Best Available Retrofit Technology (BART) assessment completed for the regional haze rule (RHR) first planning period (1PP) state implementation plan (SIP). The most recent 1PP SIP package was submitted to the U.S. Environmental Protection Agency (EPA) on August 13, 2019; it contains 594 pages. References in this report to the 1PP SIP package are to the version available on the DEQ's website as of April 6, 2020.[1]

[1] http://www.adeq.state.ar.us/air/planning/sip/pdfs/regional-haze/final-phase-III-sip-combined-files.pdf (accessed on April 6, 2020).

The ICR specifically listed the following three SO_2 emissions reduction options for consideration, and no other options have been identified:

- New scrubber downstream of existing scrubbers
- Increased reagent usage at existing scrubbers
- Upgrades to existing scrubbers

2.1. Technical Feasibility

Information about all three SO_2 emission reduction options listed above is presented in the 1PP SIP package. The relevant information (at 328-339 and 500-509) is included in Appendix A of this report for convenience. All three options were determined to be technically feasible.

2.2. Control Effectiveness

The appended (1PP SIP package pages 328-339) A.H. Lundberg Associates, Inc. (Lundberg) evaluation of the new scrubber option presented a 90 % control efficiency. Lundberg also evaluated possible upgrades to the existing scrubbers, including the elimination of bypass reheat, the installation of liquid distribution rings, the installation of perforated trays, improvements to the auxiliary system requirement, and a redesign of the spray header and nozzle configuration, and it was concluded that any control efficiency improvement to that already being achieved was unquantifiable (at 501).

Based on calculations presented in its February 2015 Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan (2015 FIP TSD), as presented in the 1PP SIP package (at 500-503), the EPA concluded that increased reagent usage at the existing scrubbers would achieve 90 % control efficiency and a controlled emission rate of 91.5 pounds per hour (lb/hr). This calculation was based on a 2009-2011 annual-average emission rate of approximately 280.9 lb/hr and a back-calculated control efficiency for the existing scrubbers of 69.3 %, i.e., $280.9 \text{ lb/hr} \div (1-0.693) \times (1-0.90) = 91.5 \text{ lb/hr}$

Domtar asserted then, and maintains now, that the control efficiency and emission rate applied by the EPA to the increased reagent usage option has not been verified as sustainable over a long-term period in practice. A one-year or at least 30-day engineering study needs to be completed to confirm the EPA's assumptions. If the DEQ decides that increased reagent usage at the No. 2 Power Power Boiler is a reasonable part of its long-term strategy for the RHR, then Domtar requests time to conduct such a study and update the information provided in this report once that study is complete.

Additionally, Domtar has already commissioned an engineering firm to study the feasibility of operating No. 2 Power Boiler without coal as a fuel. If Domtar decides to remove coal as a fuel option, then the No. 2 Power Boiler emissions profile will likely change, and all assumptions in this report about control device efficiencies and costs will be subject to significant updates.

Table 2-1 summarizes and ranks (in descending order) the control effectiveness of the technically feasible SO_2 reduction options based on current assumptions and operation of the No. 2 Power Boiler.

Table 2-1. Control Effectiveness of SO_2 Emissions Reduction Options for No. 2 Power Boiler

SO_2 Reduction Option	Control Efficiency
New scrubber downstream of existing scrubbers	90 % overall [A]
Increased reagent usage at existing scrubbers	90 % overall [A]
Upgrades to existing scrubbers	0

[A] Current/baseline emissions represent 69.3 % control; therefore, the 90 % overall control represents 20.7 % more control than is currently being achieved.

2.3. Emissions Reductions

Table 2-2 presents SO_2 emission rates from 2017 to 2019 for the No. 2 Power Boiler based on continuous emissions monitoring system (CEMS) records. Per the ICR, the baseline actual SO_2 emission rate is to be the maximum monthly value from 2017-2019, which is 103.8 tons/month, which is equivalent to 1,246.1 tons per year (tpy). Because it serves as a more appropriate basis for annual control cost calculations, the average of the three (2017, 2018, and 2019) annual total emission rates is calculated as 858.9 tpy. The average annual emission rate is used for the emissions reductions estimates and control cost calculations presented in the remainder of this section.

Table 2-2. 2017-2019 Monthly SO_2 Emissions for No. 2 Power Boiler

Month / Year	Monthly Total SO_2 Emission Rate (ton/month)	Annual Total SO_2 Emission Rate (tpy)
1/2017	93.27	928.32
2/2017	75.28	
3/2017	50.00	
4/2017	70.29	
5/2017	76.32	
6/2017	74.02	
7/2017	76.45	
8/2017	79.20	
9/2017	50.92	
10/2017	88.35	
11/2017	92.44	
12/2017	101.77	
1/2018	93.18	777.85
2/2018	77.71	
3/2018	78.81	
4/2018	71.60	
5/2018	63.65	
6/2018	39.37	
7/2018	52.47	
8/2018	45.98	
9/2018	33.14	
10/2018	61.82	
11/2018	80.72	
12/2018	79.39	

Month / Year	Monthly Total SO_2 Emission Rate (ton/month)	Annual Total SO_2 Emission Rate (tpy)
1/2019	103.84	870.52
2/2019	91.05	
3/2019	60.94	
4/2019	62.40	
5/2019	73.02	
6/2019	79.57	
7/2019	74.31	
8/2019	68.13	
9/2019	77.25	
10/2019	69.71	
11/2019	47.23	
12/2019	63.05	

Additionally, monthly emission rates for 2020 (January through June) are provided in Table 2-3, and Figure 2-1 shows a plot of the 2017-2020 monthly data. This information is provided to illustrate the downward trend in emissions/production that the Ashdown Mill is experiencing. Trendlines are shown for both the entire dataset (dotted line) and for the last 18 months (dashed line).

Table 2-3. 2020 (January-June) Monthly SO_2 Emissions for No. 2 Power Boiler

Month / Year	Monthly Total SO_2 Emission Rate (ton/month)	Annualized Monthly-Average SO_2 Emission Rate (tpy)
1/2020	63.08	568.4
2/2020	71.77	
3/2020	52.5	
4/2020	16.58	
5/2020	36.16	
6/2020	44.1	

Figure 2-1. 2017-2020 Monthly SO_2 Emissions for No. 2 Power Boiler

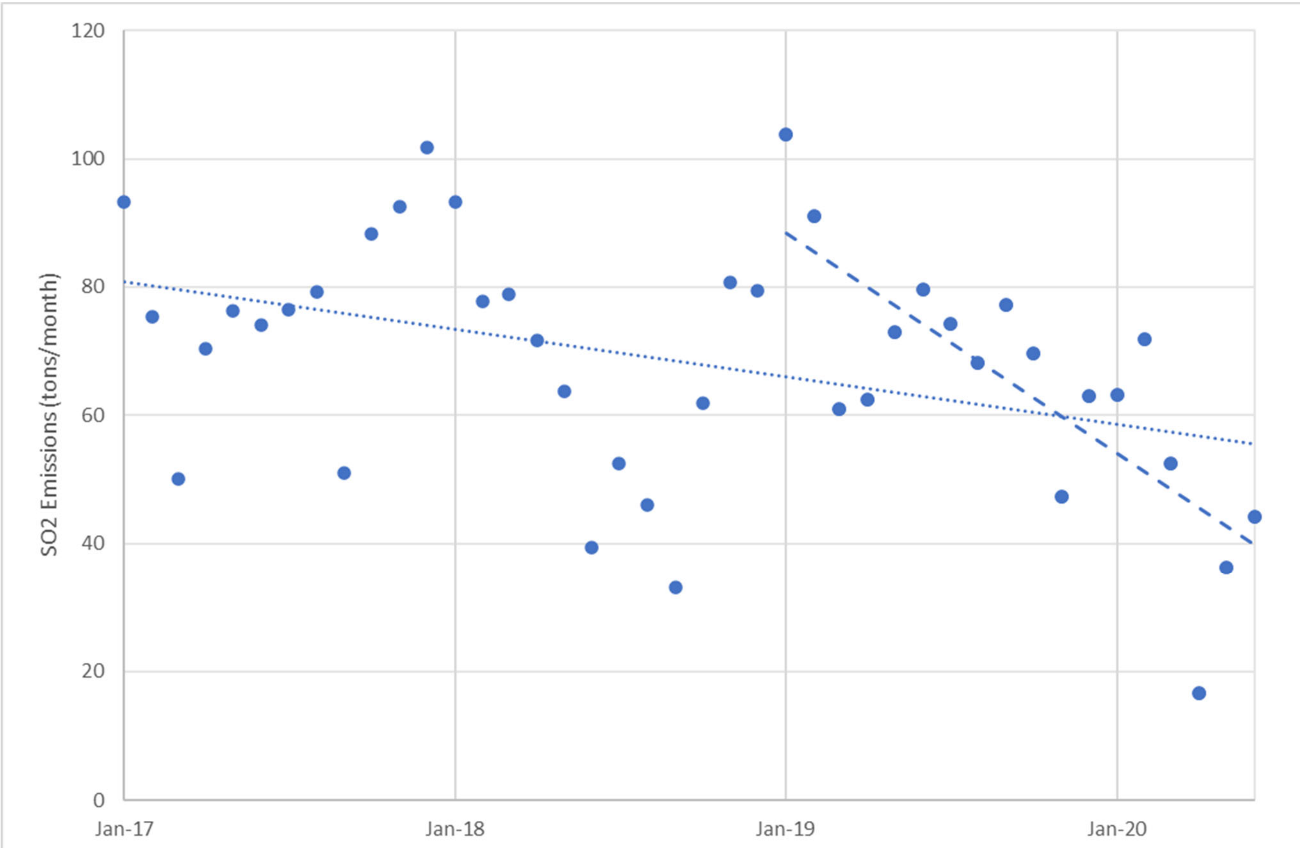

Table 2-4 summarizes the controlled emission rates and emission reduction potentials based on the control efficiencies from Table 2-1 and baseline emissions from Table 2-2 (for 2017-2019) for the technically feasible SO_2 reduction options for the No. 2 Power Boiler. The controlled emission rate calculation for the two 90 % control options is the same as described above (and used by EPA in the 2015 FIP TSD): 858.9 tpy ÷ (1-0.693) × (1-0.90) = 279.8 tpy. Then the emissions reduction is calculated as 858.9 tpy – 279.8 tpy = 579.1 tpy.

The upgrades to existing scrubbers option is not carried forward in this report because it does not provide for any quantifiable decrease in SO_2 emissions (i.e., any cost of control greater than zero would result in an undefined or infinite cost effectiveness value).

Table 2-4. Emissions of SO_2 Emissions Reduction Options for No. 2 Power Boiler

SO_2 Reduction Option	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
New scrubber downstream of existing scrubbers	279.8	579.1
Increased reagent usage at existing scrubbers	279.8	579.1
Upgrades to existing scrubbers	858.9	0

Additionally, it is noted that if 2020 data are used to establish the emission rates, then the controlled emissions rate for the 90 % control options is 185.1 tpy and the emissions reduction is 383.2 tpy.

2.4. Time Necessary for Implementation

Implementing the new scrubber option would take at least three (3) years. Domtar's capital projects approval process can take from six (6) to 18 months, and this would not begin until an enforceable requirement is effective. Depending on the timing of the effectiveness date and the project approval, it could be another 18 months before a window was available to complete construction on the No. 2 Power Boiler. According to the previously referenced Lundberg proposal, 34 weeks (8.5 months) is needed for shipment and construction of a new scrubber downstream of the existing scrubbers. This process can take place within the potential 18-month outage frequency. Domtar proposes three (3) years as an adequate time necessary to implement a new scrubber system on the No. 2 Power Boiler.

Increased reagent usage at the existing scrubbers can be implemented within approximately two (2) years of an enforcement requirement's effective date. The time is needed to procure and install two new pumps in conjunction with Domtar's outages schedule.

2.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 2 Power Boiler; it is needed in order to meet the steam demands of the Ashdown Mill processes. The useful life values found in EPA's Air Pollution Control Cost Manual (CCM)[2] are assumed to be applicable.

2.6. Energy and Non-air Quality Environmental Impacts

A new scrubber operating downstream of the existing scrubbers would incur an energy impact for the Ashdown Mill. This energy impact has been monetized. A new scrubber would also increase water usage and waste water generation. However, the increase would be small when compared to the existing quantities used and generated by the Ashdown Mill, and no further consideration is made for non-air quality environmental impacts of a new scrubber.

Energy impacts due to increased reagent usage are expected to be minimal. Non-air quality environmental impacts are also expected to be small when compared to existing storage and usage of caustic solutions at the Ashdown Mill.

2.7. Costs

The total capital cost of the new scrubber option was estimated in the 1PP SIP package (at 504) to be $7,175,000, which was annualized to $578,207 per year based on 7 % interest[3] and 30 years of operation.

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[2] EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, available at https://www3.epa.gov/ttncatc1/dir1/c_allchs.pdf (accessed on January 31, 2020)

[3] Note that the 7 % interest rate was used by the ADEQ and EPA for all first planning period determinations. Moreover, the EPA Control Cost Manual (CCM) states that "when performing cost analysis, it is important to ensure that the correct interest rate is being used. Because this Manual is concerned with estimating private costs, the correct interest rate to use is the nominal interest rate, which is the rate firms actually face." The CCM goes on to cite the bank prime rate as one indicator of the cost of borrowing as an option for use when the specific nominal interest rate is not available, but it also

Further, the estimated total annual direct and indirect costs[4] (not including annualized capital) was $9,255,171 per year (at 504). Therefore, the total annual cost of the new scrubber option was estimated to $9,833,378 per year. These values are representative of 2014 and can be escalated to 2019 (the latest final information available as of July 25, 2020) using the Chemical Engineering Plant Cost Index (CEPCI) values (576.1 for 2014 and 607.5 for 2019). The result is a total annual cost estimate of $10,369,341 per year. Based on the SO_2 emission reduction of 579.1 tpy, the cost effectiveness of the new scrubber option is $17,905/ton. It is important to note that the cost values presented above are unrealistically small as they do not adequately account for the retrofit issues that would occur if a new scrubber were to be installed. Per the 1PP SIP package (at 504), "There is no existing property or adequate structure to support the add-on spray scrubber equipment…the installation of add-on spray scrubbers would require construction at the facility to accommodate the equipment, but an estimate of these costs was not available and therefore not factored into the cost estimates…"

The cost of increased reagent usage option was estimated in the 1PP SIP package (at 504) to be $200,000 in capital, annualized to $16,117 per year, and approximately $1,960,000 per year in direct annual operations and maintenance costs (i.e., additional reagent usage, waste water treatment, raw water treatment, and energy usage) for a total annual cost estimate of $1,976,117 per year. When escalated to 2019, this becomes $2,083,824 per year. Based on the SO_2 emission reduction of 579.1 tpy, the cost effectiveness of the increased reagent usage option is $3,598/ton. Table 2-5 summarizes the estimated costs, including the cost effectiveness estimates based on the emission reduction values from Table 2-4, for the technically feasible SO_2 reduction options for the No. 2 Power Boiler.

Table 2-5. Estimated Costs (2019 Basis) of SO_2 Emissions Reduction Options for No. 2 Power Boiler

SO_2 Reduction Option	Capital Costs ($)	Annualized Capital Costs ($/year)	Annual Direct and Indirect / Operations and Maintenance Costs ($/year)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
New scrubber downstream of existing scrubbers	7,566,069	609,722	9,759,619	10,369,341	17,905
Increased reagent usage at existing scrubbers	210,901	16,996	2,066,829	2,083,824	3,598

As mentioned above, Domtar has little confidence in the control efficiency assigned to the increased reagent option, therefore, it also has little confidence in the cost effectiveness value. If the DEQ decides that increased reagent usage at the No. 2 Power Power Boiler is a reasonable part of its long-term strategy for the RHR, then

adds the caution that the "base rates used by banks do not reflect entity and project specific characteristics and risks including the length of the project, and credit risks of the borrowers." Actual borrowing costs are typically much higher than prime rates. For economic evaluations of the impact of federal regulations, the Office of Management and Budget (OMB) uses an interest rate of 7 %. (OMB Circular A-94). Additionally, based on experience, the Ashdown Mill's cost of capital is actually much higher than even 7 %. Domtar's capital projects group uses 10.5 % as the weighted average cost of capital.

[4] Annual direct costs include operations and maintenance labor, maintenance materials, and utilities. Annual indirect costs include property tax, insurance, and overhead/administration.

Domtar requests time to conduct such a study and update the information provided in this report once that study is complete.

Additionally, it is noted that if current operations (from 2020) data are used as the baseline, resulting in an emissions reduction value of 383.2 tpy, the cost effectiveness for the increased reagent usage option is $5,438/ton, which is clearly infeasible.

The ICR specifically listed for consideration the following three NO_X emissions reduction options, all of which involve the reaction of ammonia (NH_3) with NO_X, and no other options have been identified:

- Selective Catalytic Reduction (SCR)
- Regenerative Selective Catalytic Reduction (RSCR)
- Selective Non-Catalytic Reduction (SNCR)

3.1. Technical Feasibility

Two (SCR and SNCR) of the three NO_X emission reduction options listed above were examined in the BART assessment completed for the 1PP SIP. The relevant 1PP SIP packge information (at 127-133 and 510-512) is included in Appendix A of this report for convenience

For the 1PP, SCR was determined by Domtar, the DEQ, and the EPA to be technically infeasible for several reasons, all of which apply now as they did then.

RSCR, also known as tail-end SCR because it is placed downstream of the particulate matter (PM) control device, incorporates a regenerator, which pre-heats the cool gas stream from PM control device outlet before it enters the RSCR using the RSCR outlet gas that has been heated to within the optimal SCR temperature range. RSCR comes with many of the same technical challenges as traditional SCR. For example, space constraints often make retrofitting an SCR or RSCR impossible. This is true of the No. 2 Power Boiler, which is completely surrounded by existing equipment as shown in Figure 3-1 and Figure 3-2.

Additionally, the temperature of the No. 2 Power Boiler exhaust at the outlet of the scrubbers is too cold for SCR. Per the EPA's CCM, the desired minimum temperature for SCR application to achieve 70 % control efficiency is 575 degrees Fahrenheit (°F).[5] The No. 2 Power Boiler exhaust is, on average, approximately 125 °F. In an RSCR system, the regenerative heating reduces the required heat input; however, this reheating of the flue gas still represents a significant amount of auxiliary fuel that would be necessary for successful operation. Moreover, it is not considered available as RSCR has not been previously demonstrated on load-following industrial boilers. Such boilers, because of unstable and large exhaust temperature swings, make it particularly difficult to control reagent injection rates needed to ensure appropriate NO_X reductions while avoiding excessive ammonia slip.

The EPA's *Guidelines for BART Determinations Under the Regional Haze Rule* state that "[t]echnologies which have not yet been applied to (or permitted for) full scale operations need not be considered as available; we [EPA] do not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice."[6] While these "Guidelines" do not directly applicable to a four factor analysis, it is assumed that the EPA's view of availability with respect to control technologies/options is consistent within the broad regional haze rule. As such, because RSCR has not been successfully implemented on an emission unit comparable to the No. 2 Power Boiler, it is considered to be technically infeasible.

---

[5] EPA Air Pollution Control Cost Manual, Section 4.2, Chapter 2, Figure 2.2.

[6] 40 CFR part 51, Appendix Y.

Figure 3-1. Plot Plan Showing No. 2 Power Boiler and Surrounding Equipment

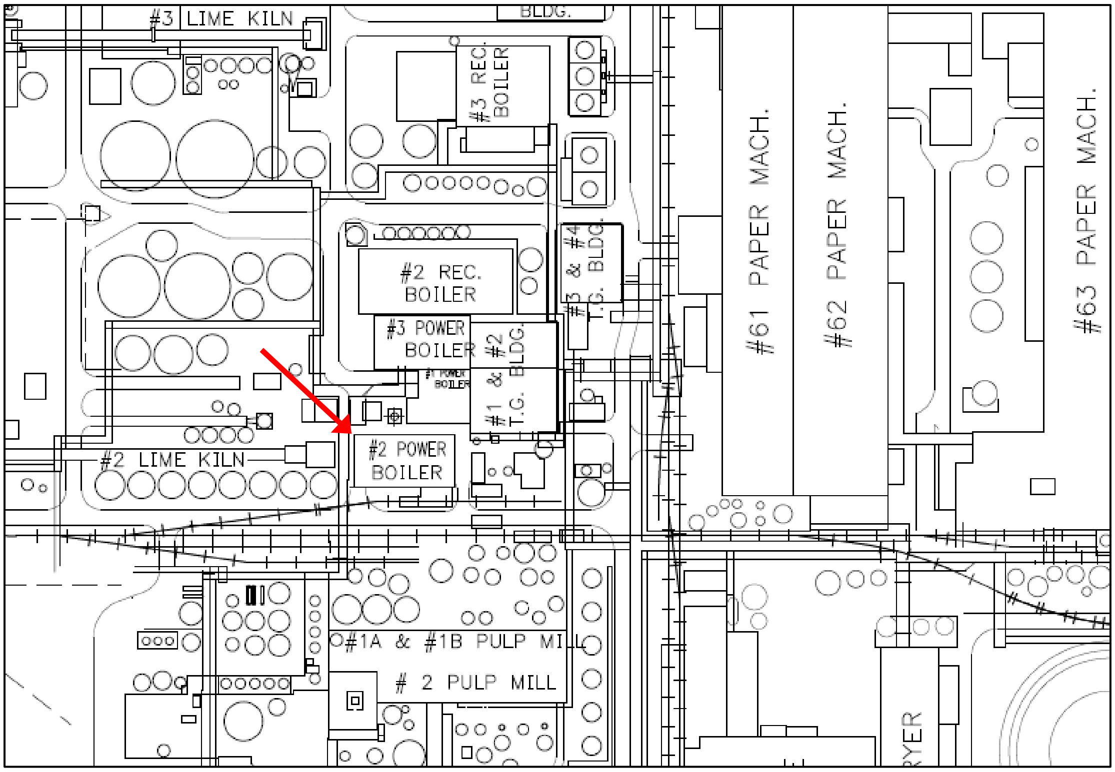

Figure 3-2. Aerial Showing No. 2 Power Boiler and Surrounding Equipment

SNCR was determined in the 1PP to be technically feasible although the effectiveness of SNCR on a boiler such as the No. 2 Power Boiler (multi-fuel, swing-load) is questionable. This issue is discussed in Section 3.2.

3.2. Control Effectiveness

As presented in the 1PP SIP package (at 511), EPA stated in its 2015 FIP TSD: "We [EPA] agree that because of the wide variability in steam demand and wide range in furnace temperature observed at Power Boiler No. 2, the NO_X control efficiency of SNCR at the boiler would not reach optimal control levels on a long-term basis. We also believe there is uncertainty as to the level of control efficiency that SNCR would be able to achieve on a longterm (sic) basis for Power Boiler No. 2." Additionally (at 510-511):

> *To demonstrate the wide range in temperature at Power Boiler No. 2 and its relationship to steam demand, Domtar obtained an analysis of furnace exit gas temperatures for Power Boiler No. 2 from an engineering consultant [International Applied Engineering, Inc. (IAE)]. The furnace exit gas temperatures were analyzed for a 12-day period that according to Domtar is representative of typical boiler operations. The consultant's report indicated that furnace exit gas temperatures are representative of temperatures in the upper portion of the furnace, which is the optimal location for installation of the SNCR injection nozzles. The consultant estimated that 1700 – 1800°F represents the temperature range at which SNCR can be expected to reach 40% control efficiency at the current boiler operating conditions. It was found that there is wide variability in the furnace exit gas temperatures for Power Boiler No. 2, with temperatures ranging from 1000 – 2000°F. The data also indicate that there is a direct positive relationship between boiler steam demand and furnace exit gas temperatures. It was also found that Power Boiler No. 2 operated in the optimal temperature zone at which SNCR can be expected to reach 40% control efficiency for only a total of 20 hours over the 12-day period analyzed (288 continuous hours), which is approximately 7% of the time.*

Based on the information published by the EPA in the 1PP, it is expected that for the No. 2 Power Boiler SNCR could achieve an overall control efficiency of approximately three (3) % based on operation at 40 % efficiency for seven (7) % of total boiler operating time.

Table 3-1 summarizes and ranks (in descending order) the control effectiveness of the technically feasible NO_X reduction options for the No. 2 Power Boiler.

Table 3-1. Control Effectiveness of NO_X Emissions Reduction Options for No. 2 Power Boiler

NO_X Reduction Option	Control Efficiency
SNCR	3 %

3.3. Emissions Reductions

Table 3-2 presents NO_X emission rates from 2017 to 2019 for the No. 2 Power Boiler based on CEMS records. Per the ICR, the baseline actual SO_2 emission rate is to be the maximum monthly value from 2017-2019, which is 65.8 tons/month, which is equivalent to 789.1 tons per year (tpy). Because it serves as a more appropriate basis for annual control cost calculations, the average of the three (2017, 2018, and 2019) annual total emission rates is calculated as 559.9 tpy. The average annual emission rate is used for the emissions reductions estimates and control cost calculations presented in the remainder of this section.

Table 3-2. 2017-2019 Monthly NO_X Emissions for No. 2 Power Boiler

Month / Year	Monthly Total NO_X Emission Rate (ton/month)	Annual Total NO_X Emission Rate (tpy)
1/2017	52.31	542.74
2/2017	46.28	
3/2017	53.55	
4/2017	41.72	
5/2017	40.74	
6/2017	41.43	
7/2017	44.43	
8/2017	44.30	
9/2017	25.21	
10/2017	44.62	
11/2017	49.42	
12/2017	58.73	
1/2018	65.76	548.33
2/2018	39.18	
3/2018	49.83	
4/2018	44.98	
5/2018	48.49	
6/2018	43.67	
7/2018	44.96	
8/2018	36.41	
9/2018	40.53	
10/2018	39.17	
11/2018	47.27	
12/2018	48.08	
1/2019	62.99	588.68
2/2019	51.19	
3/2019	32.58	
4/2019	35.76	
5/2019	37.78	
6/2019	46.00	
7/2019	48.09	
8/2019	55.15	
9/2019	53.19	
10/2019	54.19	
11/2019	54.04	
12/2019	57.72	

Table 3-3 summarizes the controlled emission rates and emission reduction potentials based on the control efficiencies from Table 3-1 for the technically feasible NO_X reduction options for the No. 2 Power Boiler.

Table 3-3. Emissions of NO_X Emissions Reduction Options for No. 2 Power Boiler

NO_X Reduction Option	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
SNCR	543.1	16.8

3.4. Time Necessary for Implementation

EPA has allowed for five (5) years for the implementation of add-on NO_X controls such as SNCR in at least two FIPs (e.g., for Utah and North Dakota). Domtar would request the same timeline if SNCR were required for either of its power boilers.

3.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 2 Power Boiler; it is needed in order to meet the steam demands of the Ashdown Mill processes. The useful life values found in EPA's CCM are assumed to be applicable.

3.6. Energy and Non-air Quality Environmental Impacts

The energy impacts (which are monetized) and non-air quality environmental impacts for SNCR, principally related to the storage and handling of ammonia/urea, are well known. They are expected to be no greater at the Ashdown Mill than any other industrial facility and are therefore not considered as a reason for rendering the control options infeasible in this context.

3.7. Costs

In the 1PP SIP package (at 512), the total capital cost of SNCR – for a 27.5 % control efficiency scenario, which, based on the above discussion, is unrealistic but is taken to be representative for the purposes of this ICR response – was estimated to be $2,681,678, which is annualized to $216,107 per year based on 7 % interest[7] and 30 years of operation. Further, the estimated total annual direct costs[8] (not including annualized capital) was $627,469 per year. Therefore, the total annual cost of SNCR was estimated to $843,576 per year. These values are representative of 2012 and can be escalated to 2019 (the latest final information available as of July 25, 2020) using the CEPCI values (584.6 for 2012 and 607.5 for 2019). The result is a total annual cost estimate of $876,620 per year. Based on the NO_X emission reduction of 16.8 tpy, the cost effectiveness of SNCR is $52,187/ton.

Table 3-4 summarizes the estimated costs, including the cost effectiveness estimates based on the emission reduction values from Table 3-3, for the technically feasible NO_X reduction options for the No. 2 Power Boiler.

[7] *See* footnote 3.

[8] Annual direct costs include operations and maintenance labor, maintenance materials, reagent, and utilities.

Table 3-4. Estimated Costs (2019 Basis) of NO_X Emissions Reduction Options for No. 2 Power Boiler

NO_X Reduction Option	Capital Costs ($)	Annualized Capital Costs ($/year)	Annual Direct and Indirect / Operations and Maintenance Costs ($/year)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
SNCR	2,786,725	224,572	652,048	876,620	52,187

The ICR specifically listed the following three SO_2 emissions reduction options for consideration:

- Wet gas scrubber (WGS)
- Spray dry absorber (SDA)

The above options are collectively referred to as flue gas desulfurization (FGD) technologies.

One other SO_2 emissions reduction options is discussed in this report:

- Inherent scrubbing by the ash created from combusting bark in the boiler ("ashes resulting from wood residue combustion typically contain significant fractions of oxides and carbonates of alkali metals such as calcium, potassium, and magnesium…wood residue ash can capture some of the sulfur dioxide released with the co-firing of sulfur-containing fossil fuels…"[9])

4.1. Technical Feasibility

All three SO_2 emission reduction options listed above are technically feasible for the No. 3 Power Boiler.

4.2. Control Effectiveness

Domtar has not commissioned site-specific studies of the FGD technologies, primarily because they are clearly economically infeasible considering the small emissions reduction potential available (i.e., small baseline emission rate). It is assumed for the purposes of this report that the FGD options can achieve 90 % control efficiency per EPA's Air Pollution Control Technology Fact Sheet.[10]

Inherent scrubbing is taken to be the base case. The baseline actual SO_2 emission rate presented below considers the inherent scrubbing that occurs in the No. 3 Power Boiler.

Table 4-1 summarizes and ranks (in descending order) the control effectiveness of the technically feasible SO_2 reduction options for the No. 3 Power Boiler.

Table 4-1. Control Effectiveness of SO_2 Emissions Reduction Options for No. 3 Power Boiler

SO_2 Reduction Option	Control Efficiency
WGS / Wet FGD	90 %
SDA / Dry FGD	90 %
Inherent Scrubbing	Base case

[9] Someshwar, Arun V. and Jain, Ashok K. (NCASI), "Sulfur capture in combination bark boilers", Tappi Journal Vol. 76, No. 7, July 1993.

[10] https://www3.epa.gov/ttn/catc/dir1/ffdg.pdf (accessed on January 30, 2020)

4.3. Emissions Reductions

Table 4-2 presents SO_2 emission rates from 2017 to 2019 for the No. 3 Power Boiler based on records of the emissions calculations required by Specific Condition 6a of Air Operating Permit No. 287-AOP-R22.[11] Per the ICR, the baseline actual SO_2 emission rate to be used for this report is the maximum monthly value from 2017-2019, which is 12.1 ton/month, which is equivalent to 144.8 tpy. Because it serves as a more appropriate basis for annual control cost calculations, the average of the three (2017, 2018, and 2019) annual total emission rates is calculated as 46.9 tpy. The average annual emission rate is used for the emissions reductions estimates and control cost calculations presented in the remainder of this section.

Table 4-2. 2017-2019 Monthly SO_2 Emissions for No. 3 Power Boiler

Month / Year	Monthly Total SO_2 Emission Rate (ton/month)	Annual Total SO_2 Emission Rate (tpy)
1/2017	4.10	40.70
2/2017	4.59	
3/2017	2.50	
4/2017	3.15	
5/2017	8.87	
6/2017	4.76	
7/2017	4.94	
8/2017	0.00	
9/2017	0.00	
10/2017	0.11	
11/2017	3.78	
12/2017	3.90	
1/2018	0.46	50.20
2/2018	7.94	
3/2018	5.09	
4/2018	6.86	
5/2018	2.39	
6/2018	12.07	
7/2018	7.40	
8/2018	4.41	
9/2018	2.64	
10/2018	0.94	
11/2018	0.00	
12/2018	0.00	
1/2019	0.00	49.84
2/2019	5.26	
3/2019	7.87	
4/2019	4.54	
5/2019	0.26	
6/2019	1.27	

[11] The issuance of the next version of the Air Operating Permit, No. 287-AOP-R23, is pending. Specific Condition 6a is not changed in draft version of this permit.

Month / Year	Monthly Total SO_2 Emission Rate (ton/month)	Annual Total SO_2 Emission Rate (tpy)
7/2019	5.09	
8/2019	0.03	
9/2019	4.28	
10/2019	4.06	
11/2019	6.11	
12/2019	11.06	

Table 4-3 summarizes the controlled emission rates and emission reduction potentials based on the control efficiencies from Table 4-1 for the technically feasible SO_2 reduction options for the No. 3 Power Boiler.

Table 4-3. Emissions of SO_2 Emissions Reduction Options for No. 3 Power Boiler

	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
WGS / Wet FGD	4.7	42.2
SDA / Dry FGD	4.7	42.2
Inherent Scrubbing	46.9	0

4.4. Time Necessary for Implementation

Domtar proposes five years as an appropriate timeline for implementing FGD systems based on numerous determinations for utilities in the 1PP.

No time is needed to implement the inherent scrubbing option; it is already in place.

4.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 3 Power Boiler; it is needed in order to meet the steam demands of the Ashdown Mill processes. The useful life values found in EPA's CCM are assumed to be applicable.

4.6. Energy and Non-air Quality Environmental Impacts

An FGD system would incur an energy impact, which can be monetized, and it would increase water usage and waste water generation. However, the increase would be small when compared to the existing quantities used and generated by the Ashdown Mill, and no further consideration is made for non-air quality environmental impacts of an FGD system.

The inherent scrubbing option represents no new energy or non-air quality environmental impacts.

4.7. Costs

There is no new cost associated with the inherent scrubbing option as it is already in place.

For wet and dry FGD, EPA's Air Pollution Control Technology Fact Sheet provides ranges for capital and O&M costs, relative to heat input capacity, representative of 2001 (the CEPCI for 2001 is 394.3). The No. 3 Power

Boiler heat input capacity is 790 MMBtu/hr. Table 4-4 summarizes the EPA Fact Sheet based cost ranges, including the cost effectiveness estimates based on the emission reduction values from Table 4-3, for the FGD options for the No. 3 Power Boiler.

Table 4-4. Estimated Costs (2019 Basis) of SO_2 Emissions Reduction Options for No. 3 Power Boiler

SO_2 Reduction Option	Capital Costs ($)	Annualized Capital Costs [12] ($/year)	Annual Operations and Maintenance Costs ($/year)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
WGS / Wet FGD (low)	30,428,925	2,452,158	973,726	3,425,883	81,143
WGS / Wet FGD (high)	182,573,548	14,712,946	2,190,883	16,903,828	400,370
SDA / Dry FGD (low)	36,514,710	2,942,589	1,217,157	4,159,746	98,524
SDA / Dry FGD (high)	182,573,548	14,712,946	36,514,710	51,227,655	1,213,336

[12] *See* footnote 3 regarding the interest rate used for capital recovery.

The ICR specifically listed for consideration the following three NO_X emissions reduction options, all of which involve the reaction of NH_3 with NO_X, and no other options have been identified:

- SCR
- RSCR
- SNCR

5.1. Technical Feasibility

The same problems with SCR and RSCR described above for No. 2 Power Boiler – principally space constraints, operation (load-swings), and cool exhaust – also apply to No. 3 Power Boiler, and these control options are deemed infeasible.

Because SNCR was determined in the 1PP to be technically feasible for the No. 2 Power Boiler it is also considered technically feasible for the purposes of this report for the No. 3 Power Boiler.

5.2. Control Effectiveness

The operation of the No. 3 Power Boiler is effectively identical to the No. 2 Power Boiler – both are swing-load boilers that operate as needed to meet demand. Therefore, a similar wide variability in exit gas temperature is expected. For the purposes of this report, the same SNCR control efficiency applied for No. 2 Power Boiler is also applied for No. 3 Power Boiler.

Table 5-1 summarizes and ranks (in descending order) the control effectiveness of the technically feasible NO_X reduction options for the No. 3 Power Boiler.

Table 5-1. Control Effectiveness of NO_X Emissions Reduction Options for No. 3 Power Boiler

NO_X Reduction Option	Control Efficiency
SNCR	3 %

5.3. Emissions Reductions

Table 5-2 presents NO_X emission rates from 2017 to 2019 for the No. 3 Power Boiler based on CEMS records. Per the ICR, the baseline actual NO_X emission rate is to be used for this report is the maximum monthly value from 2017-2019, which is is 49.7 tons/month, which is equivalent to 596.7 tpy. Because it serves as a more appropriate basis for annual control cost calculations, the average of the three (2017, 2018, and 2019) annual total emission rates is calculated as 290.1 tpy. The average annual emission rate is used for the emissions reductions estimates and control cost calculations presented in the remainder of this section.

Table 5-2. 2017-2019 Monthly NO_X Emissions for No. 3 Power Boiler

Month / Year	Monthly Total NO_X Emission Rate (ton/month)	Annual Total NO_X Emission Rate (tpy)
1/2017	10.85	256.96
2/2017	17.77	
3/2017	19.57	
4/2017	22.48	
5/2017	23.16	
6/2017	12.58	
7/2017	15.19	
8/2017	35.15	
9/2017	22.52	
10/2017	27.03	
11/2017	30.61	
12/2017	20.04	
1/2018	36.46	329.39
2/2018	25.51	
3/2018	36.02	
4/2018	25.56	
5/2018	31.60	
6/2018	20.48	
7/2018	24.75	
8/2018	26.42	
9/2018	15.54	
10/2018	17.76	
11/2018	42.35	
12/2018	26.93	
1/2019	49.73	284.07
2/2019	26.37	
3/2019	32.84	
4/2019	19.18	
5/2019	20.53	
6/2019	14.51	
7/2019	18.62	
8/2019	14.29	
9/2019	11.47	
10/2019	17.18	
11/2019	31.32	
12/2019	28.03	

Table 5-3 summarizes the controlled emission rates and emission reduction potentials based on the control efficiencies from Table 5-1 for the technically feasible NO_X reduction options for the No. 3 Power Boiler.

Table 5-3. Emissions of NO_X Emissions Reduction Options for No. 3 Power Boiler

NO_X Reduction Option	Controlled Emission Rate (tpy)	Emissions Reduction (tpy)
SNCR	281.4	8.70

5.4. Time Necessary for Implementation

EPA has allowed for five (5) years for the implementation of add-on NO_X controls such as SNCR in at least two FIPs (e.g., for Utah and North Dakota). Domtar would request the same timeline if SNCR were required for either of its power boilers.

5.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 3 Power Boiler; it is needed in order to meet the steam demands of the Ashdown Mill processes. The useful life values found in EPA's CCM are assumed to be applicable.

5.6. Energy and Non-air Quality Environmental Impacts

The energy impacts (which are monetized) and non-air quality environmental impacts for SNCR, principally related to the storage and handling of ammonia/urea, are well known. They are expected to be no greater at the Ashdown Mill than any other industrial facility and are therefore not considered as a reason for rendering the control options infeasible in this context.

5.7. Costs

The cost estimates used in the 1PP for the No. 2 Power Boiler (for the 27.5 % control efficiency scenario) are taken to be representative for the purposes of this ICR response. Table 5-4 summarizes these estimated costs, including the cost effectiveness estimates based on the emission reduction values from Table 5-3, for SNCR for the No. 3 Power Boiler.

Table 5-4. Estimated Costs (2019 Basis) of NO_X Emissions Reduction Options for No. 3 Power Boiler

NO_X Reduction Option	Capital Costs ($)	Annualized Capital Costs [13] ($/year)	Annual Direct and Indirect / Operations and Maintenance Costs ($/year)	Total Annual Costs ($/year)	Cost Effectiveness ($/ton)
SNCR	2,786,725	224,572	652,048	876,620	100,712

[13] *See* footnote 3 regarding the interest rate used for capital recovery.

The ICR did not list any specific SO_2 emissions reduction options for consideration for the recovery boilers. Trinity queried the Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) and reviewed information from the National Council for Air and Stream Improvement (NCASI) and its own library of air pollution control assessments (e.g., from previous BACT determinations) to determine what SO_2 emissions reduction options may be feasible for recovery boilers. Two potential strategies emerge from this research:

- Good operating practices, i.e., optimizing liquor properties and combustion air firing patterns
- Flue gas desulfurization (FGD)

6.1. Technical Feasibility

NCASI states in its 2013 Handbook:

> *The combustion of black liquor in a kraft recovery furnace results in SO_2 emissions that are extremely variable. These emissions depend on a variety of factors, which include a) liquor properties such as sulfidity (or sulfur-to-sodium ratio), heat value, and solids content; b) combustion air and liquor firing patterns; c) furnace design; and d) other furnace operational parameters (NCASI 1991). Liquor sulfidity in most kraft mills today is low enough that it is no more considered a determining factor for SO_2 emissions (NCASI 1991). Optimizing liquor properties (such as solids content, Btu value) and combustion air firing patterns so as to yield maximum and uniform temperatures in the lower furnace are currently considered the best strategies for minimizing kraft recovery furnace SO_2 emissions. Flue gas desulfurization is capital- and energy-intensive and its efficacy is unproven, considering the generally low but rapidly fluctuating levels of SO_2 in kraft recovery furnace flue gases.*[14]

An RBLC query[15] confirms NCASI's statements about FGD being unproven on recovery boilers as no determinations for this technology on recovery boilers were found. Because FGD has not been applied to recovery boilers, it is considered unavailable and therefore infeasible for the No. 2 Recovery Boiler.

Domtar employs good operating practices, including those listed by NCASI, for the No. 2 Recovery Boiler.

6.2. Control Effectiveness

Good operating practices is taken to be the base case. The baseline actual SO_2 emission rate presented below considers the good operating practices in place for the No. 2 Recovery Boiler.

---

[14] NCASI Handbook of Environmental Regulations and Control, Volume 1: Pulp and Paper Manufacturing, April 2013, Section 6.8.3.3. (Copies of NCASI materials must be requested from NCASI directly).

[15] RBLC searches were completed on February 3, 2020 for Process Types 30.211, 30.219, 30.290, 11.190, 11.290, and 11.900 and for Process Names that contain the word "Recovery".

6.3. Emissions Reductions

Per the ICR, the baseline actual SO_2 emission rate is to be the maximum monthly value from 2017 to 2019, which, based on CEMS records, is 3.1 tons/month, which equivalent to 36.8 tpy. Because it serves as a more appropriate basis for annual control cost calculations, the average of the three (2017, 2018, and 2019) annual total emission rates, 2.6 tpy, is also noted.

The continued employment of good operating practices will result in zero (0) emissions reduction.

6.4. Time necessary for Implementation

No time is needed to implement good operating practices.

6.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 2 Recovery Boiler; it is needed in order to meet the chemical recovery and steam demands of the Ashdown Mill processes.

6.6. Energy and Non-air Quality Environmental Impacts

Good operating practices result in no new energy or non-air quality environmental impacts.

6.7. Costs

There is no new cost associated with good operating practices already being used.

The ICR did not list any specific NO_X emissions reduction options for consideration for the recovery boilers. Trinity queried the RBLC and reviewed information from NCASI and its own library of air pollution control assessments (e.g., from previous BACT determinations) to determine what NO_X emissions reduction options may be feasible for recovery boilers. Three strategies emerge from this research:

- Good combustion practices, i.e., staged air combustion
- SNCR
- SCR

7.1. Technical Feasibility

NCASI states in its 2013 Handbook:

> *… NO_X emissions from black liquor combustion in kraft recovery furnaces are expected to result mainly from the "fuel NO_X" mechanism pathway. The highest temperatures measured in the recovery furnace, usually in the lower furnace region, range from about 1800°F to 2400°F. These are much lower than would be essential for appreciable NO_X formation by the thermal NO_X pathway (>2,800°F). Hence, factors that would aid in reducing peak gas temperatures in the lower furnace, such as the firing of lower solids content liquors, reducing combustion air temperature and pressure, changes in burner design and position, and reduced liquor feed temperature perhaps have only a limited role in controlling NO_X formation.*
>
> *A detailed investigation into the origins of kraft recovery furnace NO_X emissions and related parameters by NCASI concluded that black liquor N content was perhaps the most important factor affecting NO_X emissions from kraft recovery furnaces (NCASI 1992). Excess oxygen in the zone where the bulk of liquor combustion takes place was considered the second most important factor for NO_X formation. While very little can be done to affect the liquor nitrogen content, staged air combustion, which is already integral to the operation of most recovery furnaces, is perhaps the best strategy for minimizing NO_X formation. The precise distribution of combustion air between primary, secondary and, if relevant, tertiary or quaternary air levels is most likely quite furnace-specific…*
>
> *The above mentioned NCASI report on recovery furnace NO_X emissions (NCASI 1992) contained longterm continuous emissions monitoring data for NO_X emissions from several kraft recovery furnaces. These data showed the NO_X emissions fell within a fairly narrow range for each furnace, in spite of apparent, significant day-to-day changes in furnace operating behavior as suggested by the corresponding, widely fluctuating data for SO_2 and CO emissions. This lack of significant variability in a given recovery furnace's NO_X emissions would suggest most furnaces already utilize the concepts of staged combustion optimally, and the differences observed between one mill's furnace NO_X emissions and another's are mainly a result of the differences between their black liquor N contents…*
>
> *Relative to flue gas treatment as an (sic) NO_X control option, selective non-catalytic reduction (SNCR) is not considered technologically feasible for kraft recovery furnaces (Kravett and Hanson 1994). This conclusion was based on the fact that a recovery furnace is a complex chemical reaction system and any disruption of the delicate reaction chemistry could potentially damage the*

furnace, impact the quality of the product, or otherwise unacceptably affect the system. Also, like industrial boilers, kraft recovery furnaces operate at varying loads which makes it difficult to inject the SNCR reagent within the desired temperature window. Several technological limitations also come to bear when one considers the installation of a selected catalytic reduction (SCR) system on a recovery furnace: a) potential for plugging and fouling of the SCR catalyst, b) potential for fouling of the ESP, c) ammonia handling and ammonia slip emissions issues, d) potential for increased particulate emissions, e) creation of a new hazardous waste (spent catalyst), and f) potential significant energy penalty (Kravett and Hansen 1994).[16]

An RBLC query[17] confirms NCASI's statements about SCR and SNCR being infeasible on recovery boilers as no determinations for these technologies on recovery boilers were found.[18] For the technical reasons described above, and because SCR and SNCR have not been applied to recovery furnaces, these control options are infeasible for the No. 2 Recovery Boiler.

7.2. Control Effectiveness

Good combustion practices is taken to be the base case. The baseline actual NO_X emission rate presented below considers the good combustion practices in place for the No. 2 Recovery Boiler.

7.3. Emissions Reductions

Per the ICR, the baseline actual NO_X emission rate is to be the maximum monthly value from 2017 to 2019, which, based on CEMS records, is 46.1 tons/month, which equivalent to 553.7 tpy. Because it serves as a more appropriate basis for annual control cost calculations, the average of the three (2017, 2018, and 2019) annual total emission rates, 491.1 tpy, is also noted.

The continued employment of good combustion practices will result in zero (0) emissions reduction.

7.4. Time necessary for Implementation

No time is needed to implement good combustion practices.

7.5. Remaining Useful Life

Domtar has no plans to cease operation of the No. 2 Recovery Boiler; it is needed in order to meet the chemical recovery and steam demands of the Ashdown Mill processes.

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[16] NCASI Handbook of Environmental Regulations and Control, Volume 1: Pulp and Paper Manufacturing, April 2013, Section 6.8.3.4

[17] RBLC searches were completed on February 3, 2020 for Process Types 30.211, 30.219, 30.290, 11.190, 11.290, and 11.900 and for Process Names that contain the word "Recovery"

[18] There is one RBLC entry for SNCR on Recovery Boilers – for Apple Grove Pulp and Paper Company (RBLC ID WV-0016) – but according the RBLC's "Other Permitting Information" note for this entry, this facility was never built.

7.6. Energy and Non-air Quality Environmental Impacts

Good combustion practices result in no new energy or non-air quality environmental impacts.

7.7. Costs

There is no new cost associated with good combustion practices already being used.

8. No. 3 Recovery Boiler – SO_2

See Section 6. All statements that apply to the No. 2 Recovery Boiler also apply to the No. 3 Recovery Boiler except for the baseline actual emission rate, which is recorded below for the sake of completeness.

Per the ICR, the baseline actual SO_2 emission rate is to be the maximum monthly value from 2017 to 2019, which, based on CEMS records, is 1.0 tons/month, which equivalent to 12.0 tpy. Because it serves as a more appropriate basis for annual control cost calculations, the average of the three (2017, 2018, and 2019) annual total emission rates, 3.2 tpy, is also noted.

9. No. 3 Recovery Boiler - NO_X

See Section 7. All statements that apply to the No. 2 Recovery Boiler also apply to the No. 3 Recovery Boiler except for the baseline actual emission rate, which is recorded below for the sake of completeness.

Per the ICR, the baseline actual NO_X emission rate is to be the maximum monthly value from 2017 to 2019, which, based on CEMS records, is 64.1 tons/month, which equivalent to 769.5 tpy. Because it serves as a more appropriate basis for annual control cost calculations, the average of the three (2017, 2018, and 2019) annual total emission rates, 623.7 tpy, is also noted.

APPENDIX A: 1PP SIP PACKAGE INFORMATION RELATED TO NO. 2 POWER BOILER SO_2 EMISSIONS REDUCTION OPTIONS

LUNDBERG

13201 Bel-Red Road
Bellevue, Washington 98005
tel: 425.283.5070
fax: 425.283.5081

April 17, 2014

Reference: P-125387, Rev.01

Attention: Ms. Kelley Crouch

Subject: SO_2 Scrubber for Power Boiler No. 2

Domtar Industries, Inc.
285 Highway 71 S
Ashdown, AR 71822-8356

Dear Ms. Crouch:

In response to your recent request, Lundberg is pleased to submit the following revised budget proposal for the supply of an SO_2 scrubbing system No. 2 power boiler at the Ashdown Mill. As you know, the original June, 2012 proposal included an SO_2 scrubbing system and a wet ESP for particulate control. In this revision the wet ESP has been eliminated.

As before, the proposal is to supply add-on spray scrubbers downstream of the existing venturi scrubbers. The spray scrubbers will utilize sodium hydroxide to absorb SO_2. The design efficiency for the scrubbers will continue to be 90% and all other process considerations addressed in the first proposal will remain the same.

The only significant change in the scrubber design is that we have changed to an upflow configuration. Without a downstream wet ESP operation in the upflow mode will save some cost because the gas can discharge directly out the top of the scrubber.

If you have any questions about the proposal, please feel free to me a call at 425/283-5070.

Thank you for the opportunity to present this proposal. We look forward to working with you on this project.

Sincerely,

Steven A. Jaasund, P.E.

Manager—Geoenergy Products
Lundberg

enc: Proposal

cc: Mr. Eric Gardner, Lundberg/ Monroe, LA
Mr. Rudi Miksa, Lundberg/Monroe, LA

P-125387, Rev.01

April 17, 2014

LUNDBERG

BUDGET PROPOSAL

SPRAY SCRUBBER

DOMTAR INDUSTRIES

ASHDOWN AR

Our representative in your area:

Mr. Eric Gardner
210 Pinehurst Drive
Monroe, LA 71201
Phone: 318/366-5909

Mr. Rudi Miksa
P.O. Box 7266
Monroe, LA 71211
Phone: 318/361-0165

PRESENTED BY: Steven A. Jaasund, P.E.

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INTRODUCTION

Lundberg proposes to supply an add-on spray scrubber for the control of SO_2 emissions from the No. 2 power boiler at the Domtar Industries Pulp Mill in Ashdown, Arkansas.

The proposal includes two identical gas cleaning trains each including a spray scrubber.

PROCESS DESCRIPTION

The spray scrubber/wet ESP trains will be installed downstream of the existing venturi scrubbers and will utilize the main boiler fan on a forced draft basis. We anticipate a maximum of 3 inches w.c. will be necessary to overcome the added resistance of the add-on equipment. If this additional pressure is not available from the existing fan, the capacity can be gained by reducing the pressure drop through your existing scrubber an appropriate amount. This pressure drop reduction will not have a significant effect on the size requirements of the new wet ESP.

The spray scrubbers will be an upflow design utilizing downward facing spray headers to maximize liquid to gas contact. The unit will operate at a liquid to gas ratio of 20 gal/1000 acf and will utilize a pH adjusted scrubbing solution to affect a minimum of 90% SO_2 absorption. Sodium hydroxide will be used to maintain pH at the required level.

After exiting the spray scrubbers, the gas streams will exit directly out of the top through a stub stack.

A process flow diagram and a general arrangement drawing for the system proposed are included in the appendix of this proposal.

Design Base

The following process information will be used for the design of the spray scrubber/wet ESP system.

NO. 2 POWER BOILER DESIGN CONDITIONS	
Fuel	Coal, bark, natural gas, TDF, (planning on fuel oil in future)
Boiler Type	Stoker
Volumetric Gas Flow (scfm dry)	142,737
Scrubber Exit Gas Temp. (°F)	136
Exit Moisture (% wt)	12.3
PM Loading (lb/hr)	44.6
SO2 Concentration (ppmv)	235.9

The spray scrubber/wet ESP equipment offered will be designed to reduce the SO_2 concentration by 90%.

Energy Requirements

The following table shows the expected energy demands of the wet ESP system described in this proposal.

SPRAY SCRUBBER ENERGY REQUIREMENTS	
Scrubber pumps (kW)	108
Flange to flange pressure drop (in. w.c.)	3

PROPOSED SUPPLY

The following list summarizes the major components of the systems offered to treat the emissions from the power boiler.

ITEM	QUANTITY	DESCRIPTION
1	One (1) lot	System Engineering, including process flow diagrams, process and instrument diagrams, general arrangement drawings, functional narrative of the logic, assembly drawings, instrument specifications, pump specifications, and operation and maintenance manual complete with spare parts lists
2	Two (2) only	Spray scrubbers; T-316L SS, upflow design with recycle pump, tank and piping
3	Two (2) only	Discharge stacks; T-316L SS
4	Two (2) lots	Support and access steel
5	Two (2) lots	Field instrumentation
6	One (1) lot	Commissioning, start-up and training
7	One (1) lot	Local wiring of all electrical elements
8	One (1) lot	Complete mechanical installation

COMMERCIAL TERMS AND CONDITIONS

CLARIFICATIONS AND WORK BY OTHERS

1. Ducting from the existing scrubber to the inlet flange of the spray scrubbers is not included
2. The cost of a crane to lift the equipment offered to the top of the No. 2 boiler building is not included
3. Structural steel to the bottom of the spray scrubbers is not included. Structural and access steel above this level is included.
4. Civil work or improvements to existing structures is not included. Lundberg will provide foundation-loading information.
5. Performance testing is not included
6. Lundberg will require access to mill drawings and records required to design the proposed system.
7. The client is responsible for obtaining all necessary building/environmental permits, taxes and professional engineering fees.
8. The client is to provide a lay down area close to the work site, as well as field fabrication area for piping, etc.
9. The client is to supply steam and process water as required by the erection crew free of charge. Also parking area, trailer space(s), and access to phone lines. Phone line hookup will be by Lundberg. Lundberg is to supply electrical power for construction.
10. Construction crews may be union or non-union.
11. The client is responsible for the removal, handling, disposal, or replacement of all asbestos materials, lead paint, or contaminated soils that may be encountered.
12. The client is to provide an on-site location for construction debris.
13. Any required demolition work is not included in our bid.

PRICE

The budget price for the spray scrubber system, Items 1-7, is:

Two million fifty thousand dollars

$2,050,000.00

These prices are FOB mill site. Prices do not include applicable taxes. All prices are in U.S. dollars.

The purchaser assumes liability for payment to the state of any Sales or Use tax if he uses or consumes the property herein purchased in such a way as to render the sale subject to tax.

TERMS OF PAYMENT

The terms of payment shall be:

5%	with purchase order.
10%	with submittal of approval drawings (process flow sheets, equipment drawings and general arrangements.
25%	with order placed for major equipment (WESP) .
10%	on delivery of 10" diameter collection electrodes to the shop.
5%	on construction mobilization.
15%	on delivery of WESP to the mill; partial shipment allowed.
25%	on monthly percent completion of construction.
5%	on satisfaction of performance warranty on each unit, not to exceed six (6) months from shipment. This may be secured by a letter of credit at Lundberg's option, and due at shipment.

Payment will be due thirty (30) days after date of invoice.

ERECTION ADVISOR

If the Buyer elects to be responsible for the installation of the equipment the services of a qualified erection advisor can be made available at a rate of $1350.00 per man day (man day being ten (10) hours) plus expenses. Charges after ten (10) hours will be $170.00 per hour. Expenses are to include first class food and lodging, economy travel to and from plant site to lodging, and travel to and from project from the normal domicile of the engineer.

TRAINING SERVICES

Training is included as a part of the equipment package. The additional services of a trainer can be made available at a rate of $1,500.00 per man day (man day being eight (8) hours) plus expenses. Charges after eight (8) hours will be $210.00 per hour. Expenses are to include first class food and lodging, economy travel to and from plant site to lodging, and travel to and from project from the normal domicile of the engineer.

START-UP SERVICES

Start-up services are included as a part of the equipment package. The additional services of an engineer can be made available at a rate of $1350.00 per man day (man day being ten (10) hours), plus expenses. Charges after ten (10) hours will be $170.00 per hour. Expenses are to include first class food and lodging, economy travel to and from plant site to lodging, and travel to and from project from the normal domicile of the engineer.

SHIPMENT

Shipment will be made twenty-six (26) weeks after receipt of order. Shipment schedule requires that approval drawings, when submitted, will be returned within two (2) weeks. The time to complete erection is very dependent on site conditions. Normally equipment of this size can be installed in less than 8 weeks.

Cancellation

Should Purchaser place an order for the equipment proposed and later find it necessary to cancel, Purchaser shall pay the full amount for any equipment, portions thereof, or orders for which Vendor is liable, plus charges for engineering work completed at that time, plus fifteen (15) percent of the total costs incurred.

Performance Warranty

Lundberg will provide the equipment and process engineering as specified in this proposal for a complete and operable system and guarantee that the inlet SO_2 concentration will be reduced by 90% but no lower than 20 ppmv.

This guarantee is in effect when the system is operated in and supplied with the service conditions in general accordance with the Design Base of this proposal.

US EPA Method 1, 2, 3, 4, and 6 shall be used to quantify the SO_2 concentration at the outlet of the equipment.

Acceptance tests must be performed within three (3) months after initial start-up of the equipment, not to exceed six (6) months after final shipment. The testing shall be performed by an independent third party that is acceptable to both Buyer and Seller.

The warranty shall be fully satisfied and Lundberg discharged there from upon the earlier of: (a) obtaining guaranteed performance by the testing described above, (b) the expiration of three (3) months from initial start-up with no testing being made, (c) the expiration of six (6) months from final shipment without a test being made.

If the guaranteed performance is not obtained, then Lundberg shall have the right, and if required by the Owners, the obligation, to visit the installation to determine the cause of such failure. It is a condition of this guarantee that the Owner will cooperate with Lundberg in the making of further tests and make available necessary personnel, feed and operating conditions to enable Lundberg to conduct such tests. The tests will be paid for by the purchaser.

If failure to obtain guaranteed performance on the above is due to defect in Lundberg-supplied equipment, design, or engineering, then Lundberg will, at its expense, supply the equipment or process engineering it deems necessary until such performance is met, up to a limit of the contract price. Any remedy includes an equivalent scope of installation as outlined elsewhere in this proposal.

If failure to obtain guaranteed performance is due to the Purchaser's fault in operation, or in not providing proper feed or other specified operating conditions, the Owner shall pay the living and traveling expenses of Lundberg personnel visiting the installation. In addition, the Owner shall pay the sum of $1,300.00 per man-day or fraction thereof for such personnel. Nevertheless, such personnel will, on request, work with the Owner at the Owner's expense in making necessary corrections to accommodate the changed conditions.

MATERIAL AND WORKMANSHIP

We guarantee every part of the apparatus delivered in accordance with this proposal will be of proper material and workmanship, and agree to repair any part or parts which may prove defective in material or workmanship within twelve months from startup of equipment but not to exceed eighteen months from date of shipment on each unit, it being agreed that such replacement is the full extent of our liability in this connection. Scope of supply of such replacement shall be identical to the scope of supply of the original project. Corrosion or wear from abrasion shall not be considered as defective materials. The best engineering practice will always be followed and materials used will be clearly specified. We shall not be held liable or responsible for work done or expense incurred in connection with repairs, replacements, alterations, or additions made, except on our written authority.

VENDOR'S RESPONSIBILITY

In the course of design of processes and/or equipment where the Vendor provides process flow diagrams, layouts, and installation diagrams, it is anticipated that Vendor furnished design will be followed. Changes in design without written approval of the Vendor will relieve the Vendor of responsibility for performance of the supplied equipment.

DRAWINGS LIMITATION

All Vendor drawings supplied to the customer or his engineer under an order resulting from this proposal will remain the property of the Vendor and are conditionally loaned with the understanding that they will not be copied or used except as authorized by us. Reuse of the designs as shown on the drawings for another project is specifically prohibited.

CONFIDENTIALITY OF PROPOSAL INFORMATION

This proposal contains confidential information and remains the property of Lundberg and is conditionally loaned. The information contained herein is not to be shared with any party except those within the Buyer's company who are involved in its evaluation or outside consultants who are assisting the Buyer with this specific project. Specifically prohibited is the distribution of such information to any individual or business deemed to be a competitor by Lundberg.

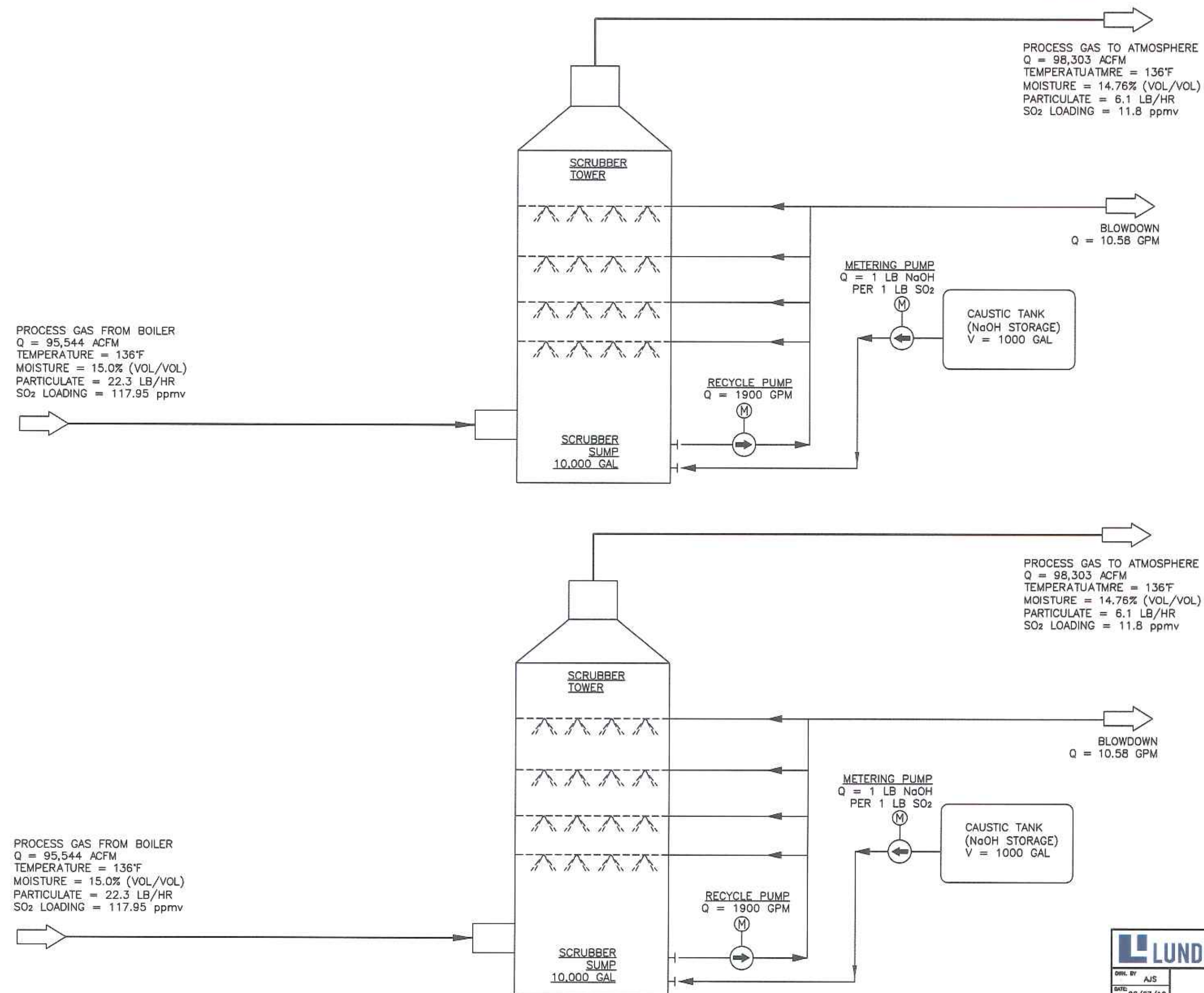
SECURITY INTEREST

Lundberg reserves the right to request a security interest in the materials provided as a part of this proposal, and Buyer agrees to provide information needed to assist Lundberg in obtaining a security interest and to execute such documents Lundberg reasonably requests to create a security interest. Security interest language is available on request.

ENCLOSURES

General Arrangement Drawing

Process Flow Diagram



LUNDBERG

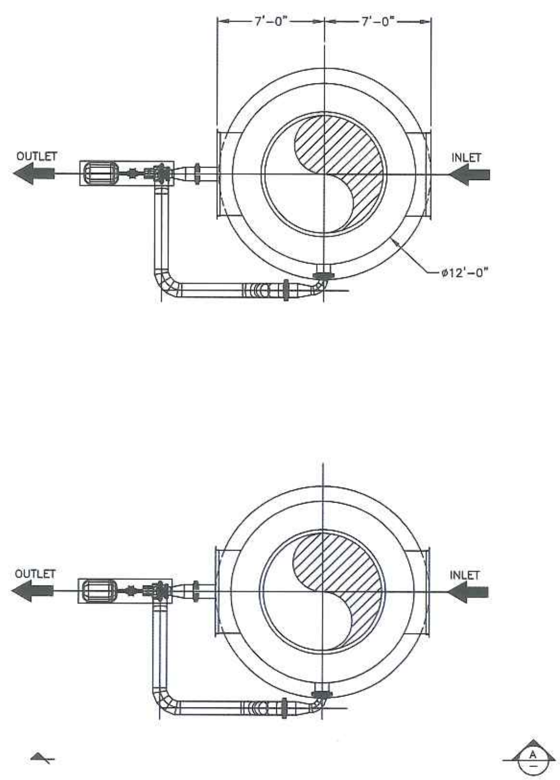
DRN. BY AJS
DATE: 08/27/12

DOMTAR
ASHDOWN, ARKANSAS
BOILER #2 EMISSIONS

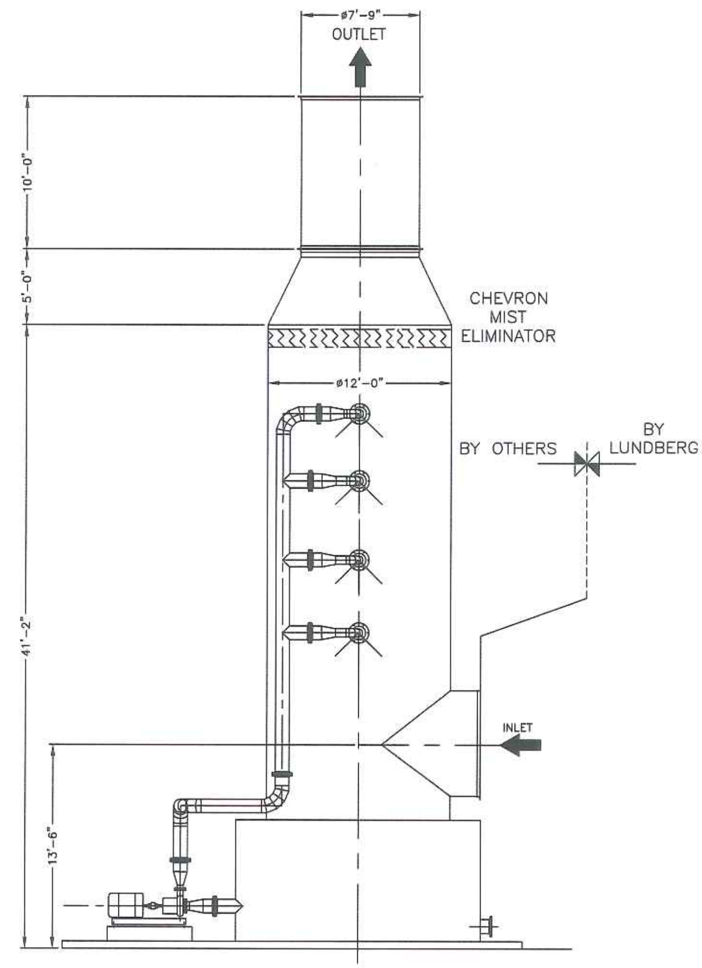
MODEL 1200 SPRAY TOWER SCRUBBER
PROCESS FLOW DIAGRAM

SCALE: 1/4"=1'-0" DRAWING NO. AL-125387-P01 SHT. 1/1 REV. 01

DWG. NO. AL-125387-P01 SHT. 1/1



MODEL 1200 SPRAY TOWER SCRUBBER
PLAN VIEW
BOILER # 2 EMISSIONS



MODEL 1200 SPRAY TOWER SCRUBBER
ELEVATION VIEW
BOILER # 2 EMISSIONS

DESCRIPTION	DRAWING NO.
REFERENCE	

REV.	DESCRIPTION	BY	DATE	CHK	DATE	REV.	DESCRIPTION	BY	DATE	CHK	DATE
	REVISIONS						REVISIONS				

LUNDBERG

DWN. BY AJS
DATE: 06/27/12
CHK. BY
DATE:
APP. BY
DATE:

DOMTAR
ASHDOWN, ARKANSAS
BOILER #2 EMISSIONS

MODEL 1200 SPRAY TOWER SCRUBBER
GENERAL ARRANGEMENT

SCALE:	DRAWING NO.	SHT.	REV.
1/4"=1'-0"	AL-125387-P03	1/1	01

DWG. NO. AL-125387-P03 SHT. 1/1

because it has not been fully demonstrated for this source type and incorporates FGR, which is technically infeasible for use at the boiler. The installation and operation of SNCR is projected to result in some visibility improvement at the Class I areas. As discussed in more detail above, we concur with Domtar's position that 20% removal efficiency is the most reasonable estimate of the level of NO_X control SNCR can achieve at Power Boiler No. 1. When operated at 20% removal efficiency, SNCR is projected to result in visibility improvement of up to 0.061 dv at any single Class I area and is estimated to cost $12,700/ton of NO_X removed. We do not believe this high cost justifies the modest visibility improvement projected from the installation and operation of SNCR at 20% removal efficiency. Although there is uncertainty as to whether SNCR can achieve a long term removal efficiency of 45% or even 32.5% at Power Boiler No. 1, we believe that the associated costs are also too high and not justified by the projected visibility benefits. Installation and operation of SNCR at a 45% removal efficiency is projected to result in a visibility improvement of up to 0.136 dv at any single Class I area and is estimated to cost $7,640/ton of NO_X removed. The operation of SNCR at a 32.5% removal efficiency is projected to result in visibility improvement of up to 0.098 dv at any single Class I area and is estimated to cost $7,996/ton of NO_X removed. Therefore, we are proposing to determine that NO_X BART for Power Boiler No. 1 is no additional control and are proposing that an emission limit of 207.4 lb/hr on a 30 boiler-operating-day rolling average satisfies NO_X BART. In this particular case, we are defining boiler-operating-day as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the Power Boiler. Power Boiler No. 1 is not currently equipped with a CEMS. To demonstrate compliance with this NO_X BART emission limit we are proposing to require annual stack testing. We are inviting public comment on the appropriateness of this method for demonstrating compliance with the NO_X BART emission limit for Power Boiler No. 1. Since this proposed BART determination does not require the installation of control equipment, we are proposing that this NO_X emission limit be complied with by the effective date of the final action.

d. SO_2 BART Evaluation for Power Boiler No. 2

Step 1- Identify All Available Retrofit Control Technologies

Power Boiler No. 2 is currently equipped with two venturi wet scrubbers in parallel for removal of particulates and SO_2. Domtar's 2014 BART analysis evaluated upgrades to the existing venturi wet scrubbers and new add-on scrubbers for Power Boiler No. 2.[96] Domtar contracted with a vendor to evaluate upgrades to the existing venturi scrubbers and to provide a quote for a new add-on spray scrubber system that would be installed downstream of the existing

[96] See "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis is found in the docket for our proposed rulemaking.

venturi scrubbers.[97] Domtar's analysis states that the existing venturi scrubbers achieve an SO_2 control efficiency of approximately 90% and notes that this is within the normal range for the highest efficiency achieved by SO_2 control technologies. Domtar's analysis also indicates that the upgrades considered for the existing venturi scrubbers include (1) the elimination of bypass reheat, (2) the installation of liquid distribution rings, (3) the installation of perforated trays, (4) improvements to the auxiliary system requirement, and (5) a redesign of spray header and nozzle configuration.

Another option not evaluated in Domtar's 2014 BART analysis is the operation of the existing venturi scrubbers to achieve a higher SO_2 control efficiency than what is currently being achieved through the use of additional scrubbing reagent. Following discussions between us and Domtar, the facility provided additional information regarding the existing venturi scrubbers, including a description of the internal structure of the scrubbers, whether any scrubber upgrades have taken place, the type of reagent used, how the facility determines how much reagent to use, and the SO_2 control efficiency.[98] Domtar confirmed that no upgrades to the scrubbers have ever been performed and stated that 100% of the flue gas is treated by the scrubber systems. The scrubbing solution used in the venturi scrubbers is made up of three components: 15% caustic solution (*i.e.*, NaOH), bleach plant EO filtrate (typical pH above 9.0), and demineralizer anion rinse water (approximately 2.5% NaOH). The bleach plant EO filtrate and demineralizer anion rinse water are both waste byproducts from the processes at the plant. The 15% caustic solution is added to adjust the pH of the scrubbing solution and maintain it within the required range to ensure that sufficient SO_2 is removed from the flue gas in the scrubber to meet the permitted SO_2 emission limit of 1.20 lb/MMBtu on a three hour average. Each venturi scrubber has a recirculation tank that is equipped with level control systems to ensure that an adequate supply of the scrubbing solution is maintained. There are pH controllers in place that provide signals for the 15% caustic flow controllers to adjust the flow of the caustic solution to bring the pH into the desired set point range. The pH controllers are overridden in the event that SO_2 levels measured at the stack by the CEMS are above the operator set point of 0.86 lb/MMBtu on a two hour average (the SO_2 permit limit is 1.20 lb/MMBtu on a three hour average). This allows additional caustic feed to the scrubber solution to increase the pH and reduce the SO_2 measured at the stack. According to Domtar, the scrubber systems operate in this manner to maintain continuous compliance with permitted emission limits.

Domtar provided monthly average data for 2011, 2012, and 2013 on monitored SO_2 emissions from Power Boiler No. 2, mass of the fuel burned for each fuel type, and the percent

[97] The information provided by the vendor to Domtar is found in Appendix D to the analysis titled "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC.

[98] See the following: Letters dated July 9, 2014; July 21, 2014; August 15, 2014; August 29, 2014; and September 12, 2014, from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. Copies of these letters and all attachments are found in the docket for our proposed rulemaking.

sulfur content of each fuel type burned.[99] According to the data provided by Domtar, the monthly average SO_2 control efficiency of the existing scrubbers for the 2011-2013 period ranged from 57% to 90%. The data indicate that the monthly average control efficiency of the scrubbers is usually below 90%. The information provided also indicates that the facility could add more scrubbing solution to achieve greater SO_2 removal than what is necessary to meet permit limits.

Based on our discussions with Domtar and the additional information provided to us, we believe it is technically feasible to increase the current SO_2 control efficiency of the existing scrubbers from current levels to 90% on a monthly average basis through the use of additional scrubbing reagent.

Step 2- Eliminate Technically Infeasible Options

Domtar's analysis discusses that the vendor determined that any upgrades to the existing venturi scrubbers for purposes of achieving additional SO_2 control would involve efforts to increase pressure drop. Additionally, it determined that any additional control that could potentially be achieved from implementation of such upgrades would be marginal, but Domtar was unable to quantify the potential additional control. Therefore, Domtar determined that the installation of new add-on scrubbers to operate downstream of the existing scrubbers was more feasible than any upgrade option. The remainder of Domtar's analysis focused on the add-on scrubber option only.

Additionally, as discussed above, based on our discussions with Domtar and the additional information Domtar provided to us, we determined it would be technically feasible to increase the current control efficiency of the existing scrubbers through the use of additional scrubbing reagent. We evaluate this control option in this TSD.

Step 3- Evaluate Control Effectiveness of Remaining Control Technologies:

Based on the information provided to Domtar by the vendor, new add-on spray scrubbers were estimated to achieve 90% control efficiency on top of the SO_2 removal currently achieved by the existing venturi scrubbers. In Domtar's analysis, it was estimated that a controlled SO_2 emission rate of 78.8 lb/hr would be achieved by the operation of add-on spray scrubbers installed downstream of the existing venturi scrubbers.

To estimate the current control efficiency of the existing venturi scrubbers, we asked Domtar to provide monthly average data for 2011, 2012, and 2013 on monitored SO_2 emissions from Power Boiler No. 2, mass of the fuel burned for each fuel type, and the percent sulfur

[99] August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. A copy of this letter and an Excel file attachment titled "Domtar 2PB Monthly SO2 Data," are found in the docket for our proposed rulemaking.

content of each fuel type burned.[100] Based on the information provided by Domtar, the monthly average SO_2 control efficiency of the existing scrubbers for the 2011-2013 period ranged from 57% to 90%. The data indicate that the monthly average control efficiency of the scrubbers is usually below 90%. Based on the monthly average SO_2 control efficiency data for the 2011-2013 period, we estimated the annual average SO_2 control efficiency for the three-year period to be approximately 69%.[101]

To determine the controlled emission rate that corresponds to the operation of the existing venturi scrubbers at a 90% removal efficiency, we first determined the SO_2 emission rate that corresponds to the operation of the scrubbers at the current control efficiency of 69%. Based on emissions data we obtained from Domtar, we determined that the No. 2 Power Boiler's annual average SO_2 emission rate for the years 2009-2011 was 280.9 lb/hr.[102] This annual average SO_2 emission rate corresponds to the operation of the scrubbers at a 69% removal efficiency. We also estimated that 100% uncontrolled emissions would correspond to an emission rate of approximately 915 lb/hr. Application of 90% control efficiency to this results in a controlled emission rate of 91.5 lb/hr, or 0.11 lb/MMBtu based on the boiler's maximum heat input of 820 MMBtu.[103]

Step 4- Evaluate Impacts and Document the Results

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

Domtar's estimates of the capital and operating and maintenance costs of add-on spray scrubbers for Power Boiler No. 2 were based on the equipment vendor's budget proposal and on calculation methods from our Control Cost Manual. Domtar annualized the capital cost of the add-on spray scrubbers over a 30-year amortization period and then added these to the annual

[100] August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. A copy of this letter and an Excel file attachment titled "Domtar 2PB Monthly SO2 Data," are found in the docket for our proposed rulemaking.

[101] See the spreadsheet titled "Domtar 2PB Monthly SO2 Data." This spreadsheet was included as an attachment to the August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "Domtar PB No2- Cost Effectiveness calculations." Copies of these documents can be found in the docket for this proposed rulemaking.

[102] See the spreadsheet titled "Domtar 2PB Monthly SO2 Data." This spreadsheet was included as an attachment to the August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "No2 Boiler_Monthly Avg SO2 emission rate and calculations." Copies of these documents can be found in the docket for this proposed rulemaking.

[103] See the spreadsheet titled "No2 Boiler_Monthly Avg SO2 emission rate and calculations." A copy of this spreadsheet can be found in the docket for this proposed rulemaking.

operating costs to obtain the total annualized cost.[104] The average cost-effectiveness in dollars per ton removed was calculated by dividing the total annualized cost by the annual SO_2 emissions reductions. The average cost-effectiveness of the add-on spray scrubbers for Power Boiler No. 2 was estimated to be $5,258/ton of SO_2 removed (see table below). Domtar's analysis notes that because of constricted space, there is no existing property or adequate structure to support the add-on spray scrubber equipment. In our discussions with Domtar, the facility indicated that the installation of add-on spray scrubbers would require construction at the facility to accommodate the equipment, but an estimate of these costs was not available and therefore not factored into the cost estimates presented in Domtar's analysis.

Table 69. Summary of Costs for Add-On Spray Scrubber for Power Boiler No. 2

Control Technology	Baseline Emission Rate (SO_2 tpy)	Controlled Emission Level (lb/hr)	Controlled Emission Rate (tpy)	Annual Emissions Reductions (SO_2 tpy)	Capital Cost* ($)	Annual Direct O&M Cost ($/yr)	Annual Indirect O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost Effectiveness ($/ton)
Add-on Spray Scrubber	2,078	78.8	208	1,870	7,175,000	8,833,382	421,789	9,833,378	5,258

* Capital cost does not include new construction to accommodate equipment.

Based on the cost information provided by the facility, increasing the monthly average SO_2 control efficiency of the existing venturi scrubbers from current levels to 90% control efficiency would require replacing two scrubber pumps, which involves capital costs of $200,000.[105] It would also require additional scrubbing reagent, treatment of additional wastewater, treatment of additional raw water, and additional energy usage, which involves annual operation and maintenance costs of approximately $1.96 million. We annualized the capital cost of the two scrubber pumps over a 30-year amortization period, assuming a 7% interest rate. We calculated the annualized capital cost to be $16,120, and added this to the annual operating costs to obtain a total annual costs of $1,976,554.[106]

[104] See Appendices B and D to the "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC.

[105] September 30, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "Domtar PB No2- Cost of Using Additional Scrubbing Reagent. Copies of these documents can be found in the docket for this proposed rulemaking.

[106] See the Excel spreadsheet titled "Domtar PB No2- Cost of Using Additional Scrubbing Reagent" for line items of the capital and operation and maintenance costs associated with the use additional scrubbing reagent, and for calculation of the total annual cost. This spreadsheet can be found in the docket for this proposed rulemaking.

We calculated the average cost-effectiveness in dollars per ton removed by dividing the total annual cost by the estimated annual SO_2 emissions reductions. To estimate the SO_2 annual emissions reductions expected from increasing the control efficiency of the scrubbers through the use of additional scrubbing solution, we calculated the annual average SO_2 control efficiency of the existing scrubbers. As discussed above, based on data provided by Domtar for the 2011-2013 period, we estimated the annual average SO_2 control efficiency for the three-year period to be approximately 69%.[107] Considering the baseline annual emissions for Power Boiler No. 2 are 2,078 SO_2 tpy, and assuming that the scrubbers currently operate at an annual average control efficiency of 69%, we have estimated that the uncontrolled annual emissions would be 6,769 SO_2 tpy and that operating the scrubbers at 90% control efficiency would result in controlled annual emissions of 677 SO_2 tpy.[108] By subtracting the controlled annual emission rate of 677 SO_2 tpy from the baseline annual emission rate of 2,078 SO_2 tpy, we estimate that increasing the control efficiency of the existing venturi scrubbers from the current level of 69% to 90% control efficiency would result in annual emissions reductions of 1,401 SO_2 tpy.[109] We estimate the average cost-effectiveness of using additional scrubbing reagent to increase the SO_2 control efficiency of the existing venturi scrubbers from the current control efficiency (estimated to be 69%) to 90% is $1,411/ton of SO_2 removed. The cost information is presented in the table below.

Table 70. Summary of Cost of Using Additional Scrubbing Reagent to Increase Control Efficiency of Existing Venturi Scrubbers at Domtar Ashdown Mill Power Boiler No. 2

Control Option	Baseline Emission Rate (SO_2 tpy)	Controlled Emission Rate (tpy)	Annual Emissions Reductions (SO_2 tpy)	Capital Costs[110] ($)	Annual Operation & Maintenance Cost[111] ($/yr)	Total Annual Cost ($/yr)	Average Cost Effectiveness ($/ton)
Use of Additional Scrubbing Reagent	2,078	677	1,401	200,000	1,960,434	1,976,554	1,411

107 See the spreadsheet titled "Domtar 2PB Monthly SO2 Data." This spreadsheet was included as an attachment to the August 29, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. See also the spreadsheet titled "Domtar PB No2- Cost Effectiveness calculations." Copies of these documents can be found in the docket for this proposed rulemaking.

108 See the spreadsheet titled "Domtar PB No2- Cost Effectiveness calculations." A copy of this spreadsheet can be found in the docket for this proposed rulemaking.

109 *Id.*

110 The capital costs consist of two new pumps for the existing scrubber system.

111 The operation and maintenance costs consist of the following costs: additional scrubbing reagent, treatment of additional wastewater, treatment of additional raw water, and additional energy usage.

Domtar's 2014 BART analysis did not identify any energy or non-air quality environmental impacts associated with the use of add-on spray scrubbers. We are not aware of any unusual circumstances at the facility that create energy or non-air quality environmental impacts associated with the use of add-on spray scrubbers greater than experienced elsewhere that may therefore provide a basis for the elimination of this control option as BART (40 CFR Part 51, Appendix Y, section IV.D.4.i.2.). We are also not aware of any unusual circumstances at the facility that create energy or non-air quality environmental impacts associated with the use of additional scrubbing reagent to increase the control efficiency of the existing venturi scrubbers greater than experienced elsewhere that may therefore provide a basis for the elimination of this control option as BART. Therefore, we do not believe there are any energy or non-air quality environmental impacts associated with these control options at Power Boiler No. 2 that would affect our proposed BART determination.

Consideration of the presence of existing pollution control technology at the source is reflected in the BART analysis in two ways: first, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. Power Boiler No. 2 is equipped with multiclones for particulate removal and two venturi scrubbers in parallel for control of SO_2 emissions. It is also equipped with a combustion air system including overfire air to optimize boiler combustion efficiency, which also helps control emissions. The baseline emission rate used in the cost calculations and visibility modeling reflects the use of these existing controls. As discussed above, Domtar's analysis also evaluated upgrades to the existing venturi scrubbers to potentially achieve greater SO_2 control efficiency. Another option we have identified and are evaluating in this TSD is to use additional scrubbing reagent to achieve greater SO_2 control efficiency of the existing venturi scrubbers,

We are not aware of any enforceable shutdown date for the Domtar Ashdown Mill Power Boiler No. 2, nor did Domtar's 2014 BART analysis indicate any enforceable future planned shutdown. This means that the anticipated useful life of the boiler is expected to be at least as long as the capital cost recovery period of the add-on spray scrubbers. Therefore, a 30-year amortization period was assumed in the evaluation of the add-on spray scrubbers as the remaining useful life of the boiler. A 30-year amortization period was also assumed for the scrubber pump replacements required for using additional scrubbing reagent.

Step 5- Evaluate Visibility Impacts

In the 2014 BART analysis, Domtar assessed the visibility improvement associated with the add-on spray scrubbers by modeling the controlled SO_2 emission rate using CALPUFF, and then comparing the visibility impairment associated with the controlled emission rate to that of the baseline emission rate as measured by the 98th percentile modeled visibility impact. The tables below show the emission rates modeled and a comparison of the baseline (*i.e.*, existing) visibility impacts and the visibility impacts associated with the add-on spray scrubbers. The

installation and operation of add-on spray scrubbers is projected to result in visibility improvement of 0.146 dv at Caney Creek. The visibility improvement is projected to range from 0.026 to 0.053 dv at each of the other Class I areas.

Table 71. Summary of Emission Rates Modeled for SO_2 Controls for Domtar Power Boiler No.2

Scenario	NO_X Emissions (lb/hr)	SO_2 Emissions (lb/hr)	PM_{10}/PMF Emissions (lb/hr)
Baseline	526.8	788.2	81.6
Add-on Spray Scrubber	526.8	78.8	81.6

Table 72. Domtar Ashdown Mill Power Boiler No. 2: Summary of the 98th Percentile Visibility Impacts and Improvement due to Add-on Spray Scrubbers

Class I area	Baseline Visibility Impact[112] (dv)	Add-on Spray Scrubbers	
		Visibility Impact (Δdv)	Visibility Improvement from Baseline (Δdv)
Caney Creek	0.844	0.698	0.146
Upper Buffalo	0.146	0.093	0.053
Hercules-Glades	0.105	0.054	0.051
Mingo	0.065	0.039	0.026
Cumulative Visibility Improvement (Δdv)	--	--	0.276

Using the visibility modeling analysis of the baseline visibility impacts from Power Boiler No. 2 and the visibility improvement projected from the installation and operation of new add-on spray scrubbers, we have extrapolated the visibility improvement projected as a result of using additional scrubbing reagent to increase the SO_2 control efficiency of the existing venturi

[112] The baseline visibility impacts reflect the operation of the existing venturi scrubbers.

scrubbers from the current control efficiency (estimated to be 69%) to 90%, or an outlet emission rate of 0.11 lb/MMBtu. We have assumed that the maximum 24-hour baseline emission rate used in the visibility modeling represents the operation of the existing venturi scrubbers at a 69% control efficiency. We estimate that the visibility improvement of using additional scrubbing reagent to increase the SO_2 control efficiency of the existing venturi scrubbers to 90% control efficiency is 0.139 dv at Caney Creek and 0.05 dv or less at each of the other Class I areas (see table below).

Table 73. Domtar Ashdown Mill Power Boiler No. 2: Summary of the 98th Percentile Visibility Impacts and Improvement from Use of Additional Scrubbing Reagent

Class I area	Baseline Visibility Impact (dv)	Add-on Spray Scrubber Impacts (dv)		Estimated Impacts from Use of Additional Reagent (dv)	
		Visibility Impact (dv)	Visibility Improvement from Baseline (dv)	Visibility Impact (dv)	Visibility Improvement from Baseline (dv)
Caney Creek	0.844	0.698	0.146	0.705	0.139
Upper Buffalo	0.146	0.093	0.053	0.096	0.05
Hercules-Glades	0.105	0.054	0.051	0.057	0.048
Mingo	0.065	0.039	0.026	0.04	0.025
Cumulative Visibility Improvement (dv)	--	--	0.276	--	0.262

Our Proposed SO_2 BART determination Power Boiler No. 2:

Taking into consideration the five factors, we propose to determine that SO_2 BART for Power Boiler No. 2 is an emission limit of 0.11 lb/MMBtu on a 30 boiler-operating-day rolling average, which we estimate is representative of operating the existing scrubbers at 90% control efficiency. In this particular case, we define boiler-operating-day as a 24-hour period between 12 midnight and the following midnight during which any fuel is fed into and/or combusted at any time in the Power Boiler. We are inviting public comment specifically on the appropriateness of this proposed SO_2 emission limit. We believe that this emission limit can be achieved by using additional scrubbing reagent in the operation of the existing venturi scrubbers. We estimate that operating the existing scrubbers to achieve this level of control would result in visibility improvement of 0.139 dv at Caney Creek and 0.05 dv or lower at each of the other Class I areas.

We estimate the cumulative visibility improvement at the four Class I areas to be 0.262 dv. Based on the cost information provided by the facility, we have estimated that the use of additional scrubbing reagent to increase the control efficiency of the existing venturi scrubbers is estimated to cost $1,411/ton of SO_2 removed. Based on Domtar's BART analysis, new add-on spray scrubbers that would be operated downstream of the existing venturi scrubbers are projected to result in visibility improvement of 0.146 dv at Caney Creek and 0.053 dv or lower at each of the other Class I areas. The cumulative visibility improvement at the four Class I areas is projected to be 0.276 dv. The cost of add-on spray scrubbers is estimated to be $5,258/ton of SO_2 removed, not including additional construction costs that would likely be incurred to make space to house the new scrubbers. We do not believe that the amount of visibility improvement that is projected from the installation and operation of new add-on spray scrubbers would justify their high average cost-effectiveness. The incremental visibility improvement of new add-on spray scrubbers compared to using additional scrubbing reagent to increase the control efficiency of the existing venturi scrubbers ranges from 0.001 to 0.007 dv at each Class I area, yet the incremental cost-effectiveness is estimated to be $16,752. We do not believe the incremental visibility benefit warrants the higher cost associated with new add-on spray scrubbers. Therefore, we are proposing to determine that SO_2 BART for Power Boiler No. 2 is an emission limit of 0.11 lb/MMBtu on a 30 boiler-operating-day rolling averaging basis, and are inviting comment on the appropriateness of this emission limit. We propose to require the facility to demonstrate compliance with this emission limit using the existing CEMS. Since the SO_2 emission limit we are proposing can be achieved with the use of the existing venturi scrubbers but will require scrubber pump upgrades and the use of additional scrubbing reagent, we propose to require compliance with this BART emission limit no later than 3 years from the effective date of the final action, but are inviting public comment on the appropriateness of a compliance date anywhere from 1 – 5 years.

NO_X BART Evaluation for Power Boiler No. 2

Step 1- Identify All Available Retrofit Control Technologies

For NO_X BART, Domtar's 2014 BART analysis evaluated LNB, SNCR, and Methane de-NO_X (MdN). In the 2006/2007 Domtar BART analysis, which was submitted in the 2008 Arkansas RH SIP, other NO_X controls were also evaluated but found by the State to be either already in use or not technically feasible for use at Power Boiler No. 2. Fuel blending, boiler operational modifications, and boiler tuning/optimization are already in use at the source, while FGR, OFA, and SCR were found to be technically infeasible for use at Power Boiler No. 2. Domtar did not further evaluate these NO_X controls, and instead focused on LNB, SNCR, and MdN in its 2014 BART analysis for Power Boiler No. 2.

APPENDIX B: 1PP SIP PACKAGE INFORMATION RELATED TO NO. 2 POWER BOILER NO_X EMISSIONS REDUCTION OPTIONS

The problems with typical SNCR systems (e.g., ammonia slippage and heat transfer surface fouling with byproduct formation) also exist with the NO_XOUT process.

4.4.1.8 SELECTIVE CATALYTIC REDUCTION

SCR is a post-combustion gas treatment process in which NH_3 is injected into the exhaust gas in the presence of a catalyst bed usually located between the boiler and air preheater. The catalyst lowers the activation energy required for NO_X decomposition.[47] On the catalyst surface, NH_3 and nitric oxide (NO) react to form diatomic nitrogen and water. The overall chemical reaction can be expressed as:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

When operated within the optimum temperature range of approximately 575 to 750 °F, the reaction can result in removal efficiencies between 70 and 90 percent. For coal-fired industrial boilers, SCR can achieve approximately 80 percent NO_X control.[48] The specific temperature ranges are 600 to 750 °F for conventional (vanadium or titanium) catalysts, 470 to 510 °F for platinum catalysts, and 600 to 1000 °F for high-temperature zeolite catalysts.[49] SCR units have the ability to function effectively under fluctuating temperature conditions (usually ± 50 °F), although fluctuation in exhaust gas temperature reduces removal efficiency by disturbing the chemical kinetics (speed) of the NO_X-removal reaction.

According to the U.S. EPA, the performance of an SCR system is affected by six factors.

> *These are a) NO_X level at SCR inlet, b) flue gas temperature, c) NH_3-to-NO_x ratio, d) fuel sulfur content, e) gas flow rate, and f) catalyst condition. For SCR, when inlet NO_X concentrations fall below 150 ppm, the reduction efficiencies decrease with decreasing NO_X concentrations. Each type of catalyst has an optimum operating temperature range. Temperatures below this range result in ammonia emissions (slip), and temperatures above the desired range result in NH_3 being oxidized to NO_X. For up to about 80 percent NO_X reduction efficiencies, a 1:1 NH_3:NO_X ratio is sufficient. For higher efficiencies, higher reagent to NO_X ratios are required which may result in higher NH_3 slip. In the case of high sulfur fuels, excess NH_3 can react with sulfur trioxide to form ammonium sulfate salt compounds that deposit and foul downstream equipment. SCR application experience in the case of*

[47] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.
[48] MRPO, *Interim White Paper – Midwest RPO Candidate Control Measures*, March 29, 2005.
[49] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

medium-to-high sulfur fuels is limited. For a given flue gas flow rate, the catalyst structural design should be chosen so that the residence time needed for the reduction reactions to take place on the catalyst surface is achievable.[50]

4.4.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Per the BART Guidelines, documentation of infeasibility should "explain, based on physical, chemical, or engineering principles, why technical difficulties would preclude the successful use of the control option under review." The BART Guidelines use the two key concepts of "availability" and "applicability" to determine if a control option is technically feasible. These concepts are defined in Section IV.D.2:

> *…a technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration.*
>
> *The typical stages for bringing a control technology concept to reality as a commercial product are:*
> - *concept stage;*
> - *research and patenting;*
> - *bench scale or laboratory testing;*
> - *pilot scale testing;*
> - *licensing and commercial demonstration; and*
> - *commercial sales.*
>
> *A control technique is considered available, within the context presented above, if it has reached the stage of licensing and commercial availability. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as "available" for purposes of BART review.*
>
> *In general, a commercially available control option will be presumed applicable if it has been used on the same or a similar source type. Absent a showing of this type, you evaluate technical feasibility by examining the physical and chemical characteristics of the pollutant-bearing gas stream, and comparing them to the gas stream characteristics of the source types to which the technology had been applied previously.*

COMBUSTION MODIFICATIONS

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[50] U.S. EPA, *New source performance standards, subpart Db – technical support for proposed revisions to NO_X*, EPA-453-/R-95-012 (republished in NCASI's Special Report 03-04).

4.4.2.1 FLUE GAS RECIRCULATION

FGR is used to reduce thermal NO_X formation. Emissions due to fuel-bound NO_X, which are significant for coal-fired boilers, are not meaningfully affected by FGR. Therefore, FGR is not technically feasible to control NO_X emissions from coal-fired boilers.[51] Similarly, FGR would not be effective in wood combustion since most of the NO_X generated during wood combustion is also from the fuel NO_X pathway.[52] Recent refusals by vendors (e.g., Entropy Technology & Environmental Consultants LP[53]) to provide budgetary estimates for installing FGR are further evidence that FGR is not applicable for the Ashdown Mill's No. 1 and No. 2 Power Boilers.

4.4.2.2 REBURNING / METHANE DE-NO_X

Generally, Domtar considers MdN not feasible because (1) it is not fully demonstrated and (2) it incorporates FGR, which is clearly technically infeasible (see Section 4.4.2.1). However, Domtar was able to obtain equipment cost estimates from vendors of MdN. Therefore, MdN is considered further in this analysis.

POST-COMBUSTION MODIFICATIONS

NCASI points out the following issues of concern for post-combustion NO_X controls (i.e., SNCR and SCR) for pulp and paper mill power boilers:[54]

> **Load Swings** - Pulp mill combination and power boilers frequently exhibit wide and rapid load swings that are not consistent with the steady conditions required for effective use of either SNCR or SCR NO_X control technologies. The load swings produce variable temperature conditions in the boiler, causing the temperature zone for NO_X reduction to fluctuate, making it more difficult to know where to inject the reactants.
>
> **Temperature Incompatibility** - Combination and power boilers are affected by temperature profile incompatibility. To obtain the required temperature window, the only location to install this technology is upstream of the particulate matter control device, yet this is where flue gases are dirty and can foul the catalyst rapidly.

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[51] U.S. EPA. *Alternative Control Technologies Document: NO_X Emissions from Utility Boilers.* (EPA-453/R-94-023).

[52] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[53] Steve Wood (ETEC), e-mail to Joel Martin (Domtar), September 20, 2006: "Based on the design and operational data provided regarding #2 Coal Boiler, ETEC would decline to bid the application Induced Flue Gas Recirculation for Boiler #2 NO_X control. Flue gas recirculation technology is very effective in reducing natural gas and light oil fuel NO_X emissions, but is not for No.6 fuel oil, coal, bark and other solid fuels. To the best of our knowledge, flue gas recirculation for NO_X control has never been installed on a coal fired boiler."

[54] Ibid.

Downstream of the PM control device, the temperature is too low for the catalyst to be effective.

Unproven – SCR or SNCR controls, technologies which, for the most part, are untested and infeasible for pulp and paper mill boilers. These technologies must be operated on a continuous basis within a specified temperature range in order to be effective. The type of fuel burned influences the design of the technology, and FPI facilities' frequent fuel changes and co-firing of multiple fuels would result in design and operational problems.

Lack of Guarantee for FPI Boilers – Boiler owners are finding that vendors of SCR and SNCR technologies are unwilling to provide performance guarantees that the controls will meet the level of reduction called for in [NSPS Subpart Db (promulgated on September 16, 1998)].

4.4.2.3 SELECTIVE NON-CATALYTIC REDUCTION

Most boilers in the pulp and paper industry operate in the swing load mode, a consequence of supplying steam as required to the various components of the process. The problem with control of the required flue gas temperature window is an inherent difficulty with use of SNCR for load-following boilers, whether wood or fossil fuel.[55]

Controlling flue gas temperatures over the entire range of operating loads that the boiler is expected to experience will be very difficult to achieve. Boilers in the pulp and paper industry rarely operate under base loaded conditions. Consequently, the location of the desired temperature window is expected to change constantly. Accurate, instantaneous temperature measurement, as well as the ability to accurately adjust the location of the injection nozzle, would be necessary. Ammonia slip would be a recurring problem associated with the application of the SNCR process to industrial boilers with fluctuating loads.[56]

Inadequate reagent dispersion in the region of reagent injection in wood-fired boilers is also a factor mitigating against the use of SNCR technology.[57] Good dispersion of the reagent in the flue gas is needed to get good utilization of the reagent and to avoid excessive ammonia slip from the process. The need for a

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[55] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, Corporate Correspondence Memo 06-014.
[56] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.
[57] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, Corporate Correspondence Memo 06-014.

sufficient volume in the boiler at the right temperature window precludes the application of SNCR in all types of industrial boilers.[58]

Additional issues with SNCR include the potential for formation of ammonium sulfate salts (if sulfur oxides are present in the gas stream where they can react with excess ammonia from the SNCR process to form ammonium salts), which cause plugging problems. Ammonia also poses potential water quality issues - ammonia slip released to the atmosphere could contaminate surface waters by deposition.

SNCR has been applied to a few base-loaded wood and combination wood-fired boilers, mainly in the electric generating industry. However, its efficacy on wood-fired boilers with changing loads has not been demonstrated, except when used as a polishing step. Early use of ammonia injection in the case of one pulp mill wood-fired boiler met with significant problems and had to be abandoned (significant ammonia slip, caused by inefficient dispersion of the reagent within the boiler, was to blame). The boiler was unable to meet the manufacturer guarantee unless operated at less than half load. Even then, reducing NO_X to near permitted limits consumed considerably more ammonia than anticipated, leading to the formation of a visible ammonium chloride plume. A similar problem was encountered at a second FPI mill where nearly half the urea (on a molar basis) injected was being emitted as ammonia.[59]

The use of SNCR on stoker type wood-fired boilers that have significant load swings has not been demonstrated. Excessive ammonia slip is a primary concern when adequate dispersion of the SNCR chemical is not achieved in the boiler ductwork within the range of residence times available and temperatures needed for the NO_X reduction reactions to go to completion. Additional concerns include the impact of interference from higher CO levels present in many wood-fired boilers, the possibility of appreciable SNCR chemical being absorbed onto the ash matrix in a wood-fired boiler, and the extent and fate of ammonia in scrubber purge streams.[60]

The MRPO concludes, "if combustion zone temperatures within the boiler do not fall into [the ideal temperature range], then SNCR would be infeasible."[61]

4.4.2.4 SELECTIVE CATALYTIC REDUCTION

The use of SCR on boilers operating in the FPI has also never been successfully demonstrated for wood boilers, and would face the same inherent problem of requiring it to be post PM-control to protect the catalyst, and

[58] NESCAUM and MANE-VU, *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plant and Paper and Pulp Facilities*, March 2005.

[59] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[60] Ibid.

[61] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

achieving and maintaining the required temperature window for effective NO_X control.[62] There are numerous other issues with using SCR including catalyst plugging and soluble alkali poisoning as well as increased energy consumption.[63]

The use of SCR technology would be considered technically infeasible based upon the fact that post-particulate removal flue gas temperatures are typically significantly lower than those desired for this application. Many boilers are equipped with wet scrubbers for particulate emission (PM) control. Reheating the scrubbed flue gases from these boilers to bring them within the desired temperature window would involve a significant energy penalty. For pre-particulate removal flue gas application, catalyst deactivation from high particulate loading would be a serious concern, in addition to the impact of fluctuating loads on flue gas temperatures. Deactivation and/or poisoning could result from the size and density of fly ash particulate, and from their unique chemical and physical nature. Water-soluble alkali (such as Mg or Na) in particulate-laden gas streams has been known to poison SCR catalysts. Space considerations for installing a catalyst section in an existing boiler's ductwork are also important. Also note the use of solid fuels can result in catalyst contamination even with efficient PM control system and high moisture levels in exhaust air would result in inefficient SCR operation.[64]

Most boilers feature a flue gas temperature at the economizer exit that is below the ammonium sulfate/bisulfate dew point. Air heater surfaces must withstand corrosion from ammonium sulfates and bisulfates, be easily cleaned with conventional soot blowing, and survive corrosion-inducing water washing. SO_3 produced by the catalyst may condense on cooler surfaces, depending on the temperature, during both steady-state and non-steady-state operation. Higher levels of SO_2 to SO_3 conversion could cause accelerated corrosion or higher SO_3-induced plume opacity. Minimizing ammonia levels in the stack (typically <2 to 3 ppm) is required to avoid problems with disposal of scrubber byproduct contaminated by ammonia. The use of a particular catalyst puts restrictions on the fuel flexibility for a boiler. For example, purchasing coal with fly ash containing calcium oxide and arsenic outside the defined range absolves the catalyst supplier from responsibility for arsenic poisoning.[65]

The only "wood-fired" boiler SCR application in service in the U.S. was located at a woodworking facility in Ohio. This SCR was located downstream of a mechanical collector and electrostatic precipitator, operating in flue gas temperatures ranging from 550 to 650 °F. The only problem reported at this

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[62] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, Corporate Correspondence Memo 06-014.

[63] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[64] Ibid.

[65] Ibid.

installation was minor catalyst blinding due to the deposition of fine particulate that escaped the PM collection devices. It was learned the operating temperature for this SCR system allowed the use of conventional catalysts designed to accommodate high dust applications. For these catalysts, the catalyst openings through which the flue gas flows are sized to provide proper surface area contact and sufficient flue gas velocity to minimize fouling. Low temperature catalyst designs are considerably different and would not be recommended for use on any high dust application. Based on this description of the air pollution control system configuration and the operating conditions for this particular wood-fired boiler, it is important to identify several specific differences between this installation and those that operate in the FPI. First, due to the requirement to provide hot air to burn all but the driest of wood fuels, wood-fired boilers are usually equipped with air preheaters. Thus, even when dry particulate control devices like an ESP are utilized, the installation of an SCR catalyst section after a PM control device is not amenable for adaptation to such boilers without, of course, incurring a severe energy penalty. Second, a significant portion of the FPI's wood-fired boilers is controlled for PM emissions by multiclones and wet scrubbers. Therefore the PM emissions from these would be higher than the example situation. Third, it is unclear how the Ohio facility's SCR system would have worked under the fluctuating boiler load characteristics common to many FPI boilers. Finally, sawdust, which was the fuel fired in the Ohio facility's boiler, is a low moisture fuel and the particulate matter present in the flue gases from its combustion is likely to be of different composition than when bark or hog fuel (typically much higher moisture) is burned.[66]

Hence the use of SCR technology has clearly not been demonstrated for industrial wood, biomass or combination fuel-fired boilers in the FPI.[67]

4.4.3 STEP 3 – EVALUATE CONTROL EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

Table 4-2 presents a ranking of the technically feasible control strategies in order of their effectiveness (i.e., potential control efficiency). For controls with a range of performance levels, the BART Guidelines note:

> *It is not [the U.S. EPA's] intent to require analysis of each possible level of efficiency for a control technique as such an analysis would result in a large number of options. It is important, however, that in analyzing the technology you take into account the most stringent emission control level that the technology is capable of achieving.*

[66] Ibid.
[67] Ibid.

Step 2- Eliminate Technically Infeasible Options

MdN utilizes the injection of natural gas together with recirculated flue gases to create an oxygen-rich zone above the combustion grate. Air is then injected at a higher furnace elevation to burn the combustibles. In response to comments provided by us regarding Domtar's 2014 BART analysis, Domtar stated that discussions regarding the technical infeasibility of MdN in the 2006/2007 Domtar BART analysis, submitted as part of the 2008 Arkansas RH SIP, remain correct.[113] The 2006/2007 Domtar BART analysis submitted in the 2008 Arkansas RH SIP discussed that MdN has not been fully demonstrated for this type of boiler and incorporates FGR, which is considered technically infeasible for use at Power Boiler No. 2. Domtar also stated it recently completed additional research and found that since the 2006/2007 Domtar BART analysis, MdN has not been placed into operation in power boilers at paper mills or any comparable source types. We are also not aware of any power boilers at paper mills that operate MdN for NO_X control, and agree that this control can be considered technically infeasible for use at Power Boiler No. 2 and do not further consider it in this evaluation. Domtar also questioned the technical feasibility of SNCR for boilers with high load swing such as Power Boiler No. 2, but in response to comments from us, SNCR was evaluated in Domtar's 2014 BART analysis.

Step 3- Evaluate Control Effectiveness of Remaining Control Technologies:

Based on vendor estimates, the 2006/2007 Domtar BART analysis estimated the potential control efficiency of LNB to be 30%. In Domtar's 2014 BART analysis, SNCR was evaluated at a control efficiency of 27.5% and 35% for Power Boiler No. 2. These values were based on SNCR control efficiency estimates that came from the equipment vendor's proposal,[114] which according to the facility, is not an appropriations request level quote and therefore requires further refinement.[115] For example, Domtar's 2014 BART analysis discusses that for a base loaded coal boiler with steady flue gas flow patterns and temperature distribution across the flue gas pathway, SNCR is typically capable of achieving 50% NO_X reduction. However, Power Boiler No. 2 is not a base loaded boiler and does not have steady flue gas flow patterns or steady temperature distribution across the flue gas pathway.

To demonstrate the wide range in temperature at Power Boiler No. 2 and its relationship to steam demand, Domtar obtained an analysis of furnace exit gas temperatures for Power Boiler

[113] See the document titled "Domtar Responses to ADEQ Regarding Region 6 Comments on Domtar BART Analysis," p. 10. A copy of this document can be found in the docket for our proposed rulemaking.

[114] Fuel Tech Proposal titled "Domtar Paper Ashdown, Arkansas- NO_X Control Options, Power Boilers 1 and 2," dated June 29, 2012. A copy of the vendor proposal is included under Appendix D to the "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis and its appendices is found in the docket for our proposed rulemaking.

[115] See the document titled "Domtar Responses to ADEQ Regarding Region 6 Comments on Domtar BART Analysis," p. 9. A copy of this document can be found in the docket for our proposed rulemaking.

No. 2 from an engineering consultant.[116] The furnace exit gas temperatures were analyzed for a 12-day period that according to Domtar is representative of typical boiler operations. The consultant's report indicated that furnace exit gas temperatures are representative of temperatures in the upper portion of the furnace, which is the optimal location for installation of the SNCR injection nozzles. The consultant estimated that 1700 – 1800°F represents the temperature range at which SNCR can be expected to reach 40% control efficiency at the current boiler operating conditions. It was found that there is wide variability in the furnace exit gas temperatures for Power Boiler No. 2, with temperatures ranging from 1000 – 2000°F. The data also indicate that there is a direct positive relationship between boiler steam demand and furnace exit gas temperatures. It was also found that Power Boiler No. 2 operated in the optimal temperature zone at which SNCR can be expected to reach 40% control efficiency for only a total of 20 hours over the 12-day period analyzed (288 continuous hours), which is approximately 7% of the time.

According to Domtar, the significant temperature swings, which are due to load following and steam demand variability, create a scenario where urea injection will either be too high or too low. When not enough urea is injected, NO_X removal will be less than projected and when too much urea is injected, excess ammonia slip will occur. Domtar stated that the observed significant temperature swings demonstrate that it will be difficult to maintain stable, optimal furnace temperatures at which urea can be injected to effectively reduce NO_X with minimal ammonia slip. We agree that because of the wide variability in steam demand and wide range in furnace temperature observed at Power Boiler No. 2, the NO_X control efficiency of SNCR at the boiler would not reach optimal control levels on a long-term basis. We also believe there is uncertainty as to the level of control efficiency that SNCR would be able to achieve on a long-term basis for Power Boiler No. 2. However, we further consider SNCR in the remainder of the analysis.

Step 4- Evaluate Impacts and Document the Results

The four factors considered in this step are the costs of compliance, energy and non-air quality environmental impacts of compliance, existing pollution control technology in use at the source, and the remaining useful life of the source.

In the 2006/2007 Domtar BART analysis, the capital cost, operating cost, and cost-effectiveness of LNB were estimated based on vendor estimates.[117] The analysis was based on a 10-year amortization period, based on the equipment's life expectancy. However, since we believe a 30-year equipment life is a more appropriate estimate for LNB, we have we have

[116] September 12, 2014 letter from Annabeth Reitter, Corporate Manager of Environmental Regulation, Domtar, to Dayana Medina, U.S. EPA Region 6. A copy of this letter and its attachments are found in the docket for our proposed rulemaking

[117] See "Best Available Retrofit Technology Determination Domtar Industries Inc., Ashdown Mill (AFIN 41-00002)," originally dated October 31, 2006 and revised on March 26, 2007, prepared by Trinity Consultants Inc. This BART analysis is part of the 2008 Arkansas RH SIP, upon which EPA took final action on March 12, 2012 (77 FR 14604). A copy of this BART analysis is found in the docket for this proposed rulemaking.

adjusted Domtar's cost estimate for LNB.[118] The annual emissions reductions used in the cost-effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. We have also adjusted the average cost-effectiveness calculations presented in the 2006/2007 Domtar BART analysis for LNB by using the boiler's actual annual uncontrolled NO_X emissions rather than the maximum 24-hour emission rate as the baseline annual emissions. The table below summarizes the estimated cost of LNB for Power Boiler No. 2, based on our adjustments to the cost estimates in the 2006/2007 Domtar BART analysis as discussed above.

In Domtar's 2014 BART analysis, the capital costs, operating costs, and cost-effectiveness of SNCR were calculated based on methods and assumptions found in our Control Cost Manual, and supplemented with mill-specific cost information for water, fuels, and ash disposal and urea solution usage estimates from the equipment vendor.[119] The two SNCR control scenarios evaluated were 27.5% and 35% control efficiencies. Domtar annualized the capital cost over a 30-year period and then added to the annual operating cost to obtain the total annualized costs. The annual emissions reductions associated with each NO_X control option were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emissions used in the calculations are the uncontrolled actual emissions from the 2001-2003 baseline period. The average cost-effectiveness was calculated by dividing the total annual cost by the estimated annual NO_X emissions reductions. The table below summarizes Domtar's estimate of the cost of SNCR for Power Boiler No. 2.

Table 74. Summary of Cost of NO_X Controls for Power Boiler No. 2

NO_X Control Scenario	Baseline Emission Rate (NO_X tpy)	NO_X Removal Efficiency of Controls (%)	Annual Emissions Reduction (NO_X tpy)	Capital Cost ($)	Total Annual Cost ($/yr)	Average Cost Effectiveness ($/ton)	Incremental Cost-Effectiveness ($/ton)
SNCR- 27.5%	1,536	27.5%	422	2,681,678	843,575	1,998	-
LNB	1,536	30%	461	6,131,745	899,605	1,951	1,437
SNCR- 35%	1,536	35%	537	2,877,523	1,026,214	1,909	1,666

[118] See the spreadsheet titled "Domtar PB No2 LNB_cost revisions." A copy of this spreadsheet is found in the docket for this proposed rulemaking.

[119] See "Supplemental BART Determination Information Domtar A.W. LLC, Ashdown Mill (AFIN 41-00002)," originally dated June 28, 2013 and revised on May 16, 2014, prepared by Trinity Consultants Inc. in conjunction with Domtar A.W. LLC. A copy of this BART analysis is found in the docket for our proposed rulemaking.